NIGERIAN ELECTRICITY REGULATORY COMMISSION

MULTI-YEAR TARIFF ORDER (MYTO)

FOR THE DETERMINATION OF CHARGES

AND

TARIFFS FOR ELECTRICITY GENERATION, TRANSMISSION AND RETAIL TARIFFS

FOR THE PERIOD 1 JULY 2008 TO 30 JUNE 2013

ORDER NO: NERC/GL059

ORDER on the establishment of a MULTI-YEAR TARIFF

PREAMBLE:

One of the primary functions of NERC as contained in Section 32 (d) of the Electric Power Sector Reform (EPSR) Act, 2005 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 EPSR Act further empowers the Commission to establish one or more tariff methodologies for regulating electricity prices.

In consultation with industry stakeholders and consumers, NERC adopted a holistic and scientific approach to correct pricing of electricity to ensure a fair and cost-reflective tariff regime which will sustain the present operators while at the same time attract investment into the sector. The key principles of cost reflectivity and affordability were taken into consideration in evolving the new tariff regime.

This forms the basis of the Multi-Year Tariff Order (MYTO) methodology. The MYTO further provides for continuous reduction in transmission and distribution/retail loses. Revenue earned by operators is made dependent on achieving these performance improvements.

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

The Order is divided into six parts; Introduction, Legal and Regulatory Framework, Pricing Methodology, Tariff Rates, Procedures for Annual Review, and Tariff Schedules.

By virtue of the powers conferred by S. 76 of the Electric Power Sector Reform Act, NERC hereby, makes the following **ORDER**:

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Glossary of Terms

ARR	Annual Revenue Requirement
BPE	Bureau of Public Enterprises
CAPM	Capital Asset Pricing Model
CCGT	Combined Cycle Gas Turbine
CPI	Consumer Price Index
DISCO	Distribution and marketing company
DUOS	Distribution Use of Service
EPSR	Electric Power Sector Reform
FGN	Federal Government of Nigeria
GENCO	Generator Company
HQ	Head Quarters
IFC	International Finance Corporation
IMF	International Monetary Fund
IPP	Independent Power Producer
KWh	1000 watt hours of electrical energy
LRMC	Long Run Marginal Cost
MAR	Maximum Allowable Revenue
MLF	Marginal Loss Factor
MO	Market Operator
MWh	1 million watt hours of electrical energy
MYTO	Multi Year Tariff Order
N/KWh	Naira per Kilo Watts Hour
NEPA	National Electric Power Authority
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
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
TSO	Transmission System Operation
TCN	Transmission Company Of Nigeria
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital

1 Introduction

By these presents the Nigerian Electricity Regulatory Commission (NERC) establishes the schedule of tariffs to be paid each year for the following Nigerian Electricity Supply Industry (NESI) charges over the period 1 July 2008 to 30 June 2013:

- The Wholesale price of generated electricity sold to national grid ;
- Transmission charges;
- Retail tariff schedules;
- The Transmission System Operator (SO and MO) charge;
- The PHCN Headquarters charge;
- The regulatory charge; and
- The payment and level of tariff equalisation payments between distributors in order to continue to maintain a national uniform tariff.

The tariff path set for the next 5 years is derived from a regulatory model of the NESI which has been developed from historical industry data and forecasts provided by Power Holding Company of Nigeria (PHCN) and its predecessor and adopted by NERC. This approach forms the basis for a Multi Year Tariff Order (MYTO) based on an industry wide determination of current and future costs.

These regulated charges are established for the period 1 July 2008 to 30 June 2013 pursuant to the authority given under Section 76 of the Electric Power Sector Reform Act (2005).

Retail tariff schedules will be reviewed each year and changes made to the regulated charges if there are material variations greater than plus or minus 5% (in magnitude) in the rate of inflation, exchange rate and cost of gas.

A major review of all inputs to the tariff calculation will be undertaken in 2012 as the basis for a new Multi Year Tariff Order (MYTO) to commence for 5 years from 1 July 2013.

1.1 Background

NERC's commitment and mission is to ensure that electricity is adequate, safe, reliable and affordable.

In January 2006, PHCN requested an average increase in its tariff by 60% from the tariff that had been operative since 2002. The Commission considered this along with the industry's performance over recent years.

The Commission found it necessary to adopt a holistic and scientific approach to correct pricing of electricity over time to ensure gradual sector development through the instrument of a cost reflective and fair tariff regime. The process took into consideration the interest of consumers and investors simultaneously in addressing the problem of electricity supply and proper pricing of power in Nigeria.

Central to the resolution of the problems of the power sector in Nigeria is the issue of commercial viability of the industry. The industry is barely able to generate enough revenue to cover its operating costs let alone meet its considerable capital expenditure needs. Therefore, the industry is not in a position to attract private sector investment, which is much needed if the twin problems of inadequate and unreliable electricity services are to be tackled.

To this end, the Commission developed a new tariff order for the industry predicated on revenue requirement and sustainability of the incumbent operators and new entrants. While cost-reflectivity is a key consideration in the new tariff order, the Commission is mindful of the impact of any tariff review on consumers.

At the centre of the new tariff order is a multi-year tariff model, which calculates electricity prices based on revenue requirements of the whole industry. This approach is aimed at ensuring the necessary support for operating and capital expenditures of the various sub-sectors i.e. generation, transmission and distribution.

The Commission is introducing a tariff methodology that will aid pricing of electricity in the most reasonable and equitable manner. MYTO will set electricity tariffs for consumers over the 15-year path (1 July 2008 to 30 June 2023). The tariffs are set at levels that support the viability and growth of the Nigerian Electricity Supply Industry (NESI).

To avoid rate shock, the tariffs paid by consumers will be less than cost reflective values over the first three years of the introduction of MYTO. However, Federal Government support will be provided in the form of subsidy to make up the shortfall caused by the difference between actual and cost reflective tariffs over this period, while the tariff moves gradually towards viable levels.

The subsidy is also intended to ensure that the shortfall that arises as a consequence of tariffs being below costs is provided for. Allowing the tariff to reach viable levels over a period of time is expected to lessen the burden on consumers while allowing them to adjust to the new price level overtime. Power availability is also expected to increase during this time. The subsidy is intended to sunset when price reaches the cost reflective level (i.e. in the 4th year).

1.2 Electricity Pricing in Nigeria

In Nigeria, electricity prices are generally lower than the production cost. The tariff was last reviewed in February 2002 (from an average of N4.50/kWh to about N6/kWh) where it has remained to date. In the intervening years inflation in labour and fuel costs and increases in the cost of capital equipment have increased the unit cost of electricity production significantly.

The new tariff order is intended to provide financial incentives for increased investments in the industry and for improvements in plant availability, enhanced metering, billing, and collection performance.

The Commission has over the last one year carried wide consultation with the industry operators, labour unions, consumer advocacy groups, the legislature and relevant Government departments on both the MYTO methodology and tariff. (See Appendix 1 for the list of stakeholders consulted)

1.3 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. gas), and capital items, such as turbines, switchyards and transformers; and the transmission and distribution networks. The industry is capital intensive and the plant has a long technical and economic life. It differs from other products in that it cannot be stored. 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. 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 tariff level in the industry can barely fund routine activities and certainly cannot provide for investment in new generation, transmission and distribution infrastructure.

The pricing regime developed by NERC and embodied in the MYTO approach is intended to facilitate the industry's successful passage through a period of significant performance improvement and growth. The order developed by NERC 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 and non-technical losses, lowering forced outages and levels of unsaved energy;
- 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 in time, 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 wires activities, will remain regulated.

2 Legal and Regulatory Framework

The Electric Power Sector Reform (EPSR) Act of 2005 provides the legal and regulatory framework for the electricity supply industry in Nigeria. The Act empowers the Nigerian Electricity Regulatory Commission (NERC) to regulate the electricity sector in the country, including Generation, Transmission, System Operations and Distribution.

The establishment of the Nigerian Electricity Regulatory Commission (NERC) was the direct result of a genuine desire to transform the electricity supply industry in the country into a market-based industry in line with the government's reform agenda for the country's economic, industrial and social development. Thus, the Nigerian Electricity Regulatory Commission (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 the Commission 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.

According to Section 76(1) of the Act, the following activities are subject to tariff regulation:

(a) Generation and trading, in respect of which licences are required pursuant to this Act, and where the Commission 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 the Commission 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

Section 76(7) of the Act provides that in preparing a tariff methodology, the Commission shall:

a) Consider any representations made by license applicants, other licensees, consumers, eligible customers, consumer associations, associations of eligible customers and such other persons as it considers necessary or desirable;

b) Obtain evidence, information or advice from any person who, in the Commission's opinion, possesses expert knowledge which is relevant in the preparation of the methodology.

Section 76(6) of the Electric Power Sector Reform Act also provides that the Commission, prior to approving a tariff methodology, shall give notice in the Official Gazette, and in one or more newspapers with wide circulation, of the proposed establishment of a tariff methodology, indicating the period within which objections or representations in connection with the same may be made to the Commission.

In addition, Section 76(8) of the Act provides that the Commission shall fix the date on which the tariff methodology shall come into operation and it shall cause notice to be given in the official gazette of that date.

The Commission issued the final methodology, in the form of a decision which was published and gazetted.

By virtue of Section 76 (11) of the EPSR Act 2005, Licensees are required to comply with the provisions of the methodology, under the conditions of their licences.

2.1 The Methodology and Guiding Principles

In describing its methodology, the Commission had adopted three basic principles in the determination of an appropriate methodology. 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 to Nigeria and encourages investment in electricity generation; and
- Is simple, transparent and avoids excessive regulatory costs.

The MYTO model was based on a set of pricing principles and cost assumptions and designed to provide tariffs for each of the generation, transmission, distribution (including retail) sectors.

The underlying pricing principles that guided the development of the MYTO model were:

- **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 user affordability, universal access and specific policies such as the National Uniform Tariff, etc.

In accordance with Section 76(6) of the EPSR Act, NERC published the Notice of Proposed Methodology upon which the MYTO was to be based in both Nigerian national Newspapers on the 14th May 2007 as well as the Federal Government Official Gazette No 18 of 2007. Comments were invited from Industry participants and other interested parties. The deadline for the receipt of comments was the 14th of June 2007 which deadline was further extended for another 14 days. (See attached copy of MYTO Methodology, which is also available online.)

The review of the comments and observations received (see Appendix 2) indicated no objection to the MYTO methodology. Therefore, it was adopted as the path to correct pricing of electricity.

2.2 Tariff Formulation and Development

The MYTO lays out the due process to be followed in meeting the statutory requirement. It provides a 15-year tariff path for the electricity industry with potential minor adjustments every year and major reviews every five years. The methodology used by the Commission to determine the MYTO tariff path is the building blocks approach. Building blocks approach is used extensively in regulated industries. It is simply a way of bringing together all of the industry's costs in a consistent accounting framework.

There are three standard building blocks used in this approach:

- Efficient operating costs and overheads
- The allowed return on capital (to achieve a fair rate of return on the necessary assets invested in the business)
- The allowed return of capital (depreciation)

The building blocks approach to electricity pricing is 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 investments to efficient industry players. At the same time the tariff order will protect consumers against excessive pricing, since the price is set at the entry level price of the most efficient generator.

The tariff approach provides regulated prices for each sector and as the industry develops and becomes more competitive, the scope of tariff regulation will reduce.

The NESI consists of four parts in the electricity supply chain:

- Generation
- Transmission
- Distribution
- Retail

Distribution and retail are often treated together and will be taken as one in the remainder of this Tariff Order. In the future, when the industry is further opened up to competition, distribution and retail will be separated with distribution continuing to be a regulated activity while retail becomes competitive.

Determination of generation pricing is based on a slightly different approach compared to transmission and distribution. Given that it is the sector that lends itself readily to competition, its pricing is based on an efficient new entrant model, of an open-cycle gas turbine given the fact that they offer the lowest cost form of generation, given current conditions and gas prices in the NESI. At this transition stage of the industry, generation output pricing will be determined by the Commission to ensure that only prudently incurred costs are recoverable and to protect consumers.

2.3 Inputs and Outputs of the Electricity Pricing Model

2.3.1 Inputs

The key assumptions that go into the model are predominantly macroeconomic (inflation, interest rates, exchange rates) and sector specific (load factor, losses, fuel prices, depreciation, etc). Other key inputs include projections of generation capacity capital expenditure, operating expenditure, etc.

2.3.2 Outputs

The key outputs from the model are the revenue requirements and tariff Summary for the first five (5) years of the Tariff Order (July 2008 – to June 2013), which capture the following information:

- Revenue requirement for generation, transmission, distribution and retailing with all the cost components, including capital expenditure, fuel costs, labour input, administration, sales and metering.
- Estimates of the industry's growth over the coming 5 years, taking into account the targets for installed capacity, generation output and sales.
- Separation of this average revenue requirement into a tariff schedule for 5 years for each consumer group taking into account some of the specific costs and characteristics of supplying these different groups.
- Industry's billing and collection rates, including a rate of improvement for these over time. If distributor/retailers can do better than these rates they will collect and retain more revenue.

2.4 Application of Tariff Order

The tariffs derived from the electricity tariff model applies to all regulated industry participants. The retail tariff is a composite of generation, transmission, distribution prices, ancillary and regulatory charges, and charges to the market operator and PHCN Headquarters (HQ). NERC will enforce the tariff order carrying out annual and five- year reviews and recalibrate the model.

2.5 Appropriate Pricing and Rate Design

Electricity tariff is the key to cost recovery and underpins the long-term viability of the industry. Currently, prices charged do not reflect the true cost of providing electricity services. To achieve an economically efficient allocation of resources in a market economy, producers and consumers should be paid and pay, respectively, for the full costs associated with their activities.

The tariff order, while focusing on cost-reflectivity, gradually rebalances tariffs between customer classes to reflect the true cost of supply, reduces cross-subsidies and sends the right price signals to consumers as an incentive to rationalize their consumption.

With respect to rate design, the Commission has produced a tariff schedule for the different categories of customers so that they are charged based on the average cost, with the exception of lifeline tariff consumers as a safety net provision.

2.6 Tariff Options and Appropriate Path

The Commission considered a number of options for tariff paths for consumers and approved the option with government subsidy to reach the viable tariff by 2010. The subsidy make up the difference between the average retail tariff paid and the viable costs as determined by NERC.

3 Pricing Methodology

The price referred to in this section concerns regulated prices by the Commission. Different approaches are used for generation and transmission, distribution and retailing. The end state plan for reform of the industry involves the generation sector becoming unregulated with negotiated generation bilateral contracts.

The regulated wholesale price determined in this Tariff Order for generation is in place of a spot market price. The Commission considers it important to regulate both wholesale and retail rates, because the market is not currently competitive with little supply for free trading of power in open market.

The price determination for transmission and distribution is subject to price regulation based on a building blocks approach. This approach, explained in more detail below, provides an accounting framework in which the NESI's costs can be brought together in a consistent way to produce a tariff path.

3.1 Pricing of Generation

NERC has determined that the price of electricity to be paid generators will be at the level required by an efficient new entrant to cover its life cycle costs (including their short run fuel and operating costs and their long run return on capital invested). Since demand is in excess of supply the price of electricity should be at the price required to attract new entrant investors into the market. This price will be paid to all generators who sell to national grid except those who hold PPAs.

Given current forms of new generation technology and the price of gas in Nigeria, NERC has determined that the lowest cost new entrant generator is an open cycle gas turbine (OCGT) using natural gas. OCGT was selected because it was considered as one of the most efficient power plant, in addition to availability of natural gas in Nigeria. Therefore, all new entrants are expected to use efficient technology benchmark for project evaluation and analysis.

3.1.1 Generation Plant Characteristics

The Commission has gathered inputs from a number of industry sources in order to bring together estimates of plants costs and technical characteristics. The table 1 below shows the assumptions made about the technical characteristics of the power station. Auxiliary requirements cover the electricity used inside the generation plant itself which is generated but not available for sale. In the case of OCGTs, this is typically quite small and has been set here at a maximum of 1%.

Table 1: Technical characteristics of the OCGT new entrant plant

Assumption	Units	Value	Comments
Capacity	MW	**250**	Gross capacity of the plant
Life of plant	years	**20**	The life over which costs are recovered
Auxiliary requirements	%	**1**	Internal energy use, difference between gross and sent out capacity
Capacity factor	%	**70**	Average output divided by sent out capacity
Availability	%	**95**	% of time when available to generate
Station Marginal Loss Factor(MFL)		**0.92**	Reflects network losses incurred at the point of injection to transmission, average 8%
Construction period	years	**2**	Completed and commissioned in 24 months
Sent out efficiency	%	**34**	The conversion efficiency of gas into electricity including internal energy use
Average sent out heat rate	MJ/MWh	**10,588**	The MJ of gas required to produce a MWh of electricity after internal use

The capacity factor has been set at 70%. New plant will have a high level of availability and should be running at maximum output for a high proportion of the time in order to meet demand. The difference between availability and capacity factor occurs because the network is likely to have more downtime than the plant and it is likely to be called upon to generate for less time than it is available. This assumes that the plant has a reliable gas supply.

The Marginal Loss Factor (MLF) applied is 0.92. Under the Tariff Order covering transmission pricing, generators are required to inject enough electricity to cover their contract plus transmission losses. Electricity delivered by a generation company to a distributor/retailer is calculated by multiplying the output injected at a particular point in the network by the MLF at that point. Overall transmission losses on the Nigerian network are currently about 8%.

The “Sent out efficiency” and “Heat rate” reflect the same parameter, which is the efficiency of converting the thermal energy of the gas into electrical energy after the internal use of energy (1%) in the power station.

The estimation of the generation costs of an open cycle gas turbine power station in Nigeria is based on the estimation of the price required over the life of such a generation project to pay all of its component costs, including fuel, operation and maintenance, tax and a return on capital. These costs are brought together in a financial model to determine the average price per unit of output that needs to be achieved in order for all of the component costs to be met over the project's life.

The component costs are:

- Fuel
- Capital
- Fixed and variable operation and maintenance
- Company tax
- Transmission costs

Other factors that must be determined in calculating generation cost in this way include conversion efficiency (heat rate) and internal energy use. The capacity factor assumed is an important factor as it determines the output over which fixed costs such as capital can be spread.

Having determined the values to be assigned to these inputs, they are brought together in a financial model that determines the life cycle price by calculating a price that makes the net present value of the power station equal to zero.

The financial model used to estimate life cycle cost attempts to broadly simulate the financial approach taken by a new entrant when making their investment decision. It includes tax payments, a weighted average cost of capital that reflects generator risks and the effects of other costs, such as an allowance for transmission losses.

3.1.2 Wholesale Price

The price of electricity provided by generators to distribution and retail companies will be regulated by NERC. Contracts will be granted to generators and will cover all of the generators' output sold to retailer/distributors other than electricity currently provided under Power Purchase Agreements (PPAs) and for export. Generators include PHCN and successor PHCN generation assets as well as new Independent Power Producers (IPPs) who begin generating after 1 July 2008.

Given the NESI's need for reliable electricity generation NERC would not limit the level of wholesale contracts that will be available for generation in any year during this 5 year tariff period (1 July 2008 to 30 June 2013).

3.1.3 Existing Power Purchase Agreements

Existing PPAs with existing Independent Power Producers (IPPs) will be managed by the Transmission System Operator (TSO) and allocated among distribution companies. The TSO will assign these contracts among the discos in proportion to their share of the total Nigerian (system) load.

3.2 Pricing of Transmission and Distribution

The building blocks approach was used as a regulatory method to set tariffs and charges for transmission, distribution and retail activities in the MYTO. 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 (necessary) assets invested in the business;
- **The allowed return of capital** – associated with recouping the capital over the useful lives of the assets (depreciation); and
- **Efficient operating costs** and overheads.

In the MYTO the demand on the NESI as a whole was projected over the next 15 years. The costs incurred in meeting this forecast load were brought together in a financial model using the building blocks framework to produce a 15-year tariff path for the generation, transmission, distribution and sale of electricity. Load forecasts, new capital expenditure, improvements in industry performance with respect to losses and billing and revenue collection and the required return on capital and depreciation were projected for the 15 year period for this Tariff Order

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

- The initial value of transmission and distribution capital assets;
- A particular weighted average cost of capital (WACC) to be achieved each year;
- A capital expenditure program for transmission and distribution/retail as a whole 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 covering transmission, distribution, billing and revenue collection.

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 electricity delivered to distribution from transmission and per unit of final sales.

The annual revenue requirements for transmission were divided by the annual energy delivered to distribution in order to derive a transmission charge per unit. Annual revenue requirements for distribution/retail were divided by the forecast level of energy sold (and paid for) to arrive at an average tariff in Naira per kWh. This average tariff was then converted into the industry's standard tariff schedules for different customer rate classes as well as the steps within each tariff class.

3.2.1 Transmission Prices

Transmission network users will be subject to three forms of payment for transmission services:

- A connection charge- for new generators,
- A transmission use of system charge (TUOS) paid by distributor/retailers, and
- A loss factor applied to generation so that generators provide for transmission losses.

This pricing structure is intended to assign charges for system use to the user or group of users who are incurring those costs. Generators are exposed to connection charges they may wish to choose a location that minimises these charges. Similarly, if they are exposed to the costs associated with the losses incurred in transmitting their generation they will have an appropriate incentive to locate so as to minimise transmission losses. These mechanisms will begin to work more effectively when Marginal Loss Factors (MLFs) are set for various injection points on the network.

The distributor/retailers will be effectively paying for the fixed costs of the transmission network, analogous to paying for the power delivery system to be available to them.

3.2.2 The Connection Charge

This is a one-off charge levied when new power stations are connecting to the existing transmission network. It is intended to cover the costs associated with the generator's connection to the nearest node on the system. This might include transmission lines and towers, a switch yard and transformer if necessary and any additional power conditioning equipment required for safe and reliable injection of power to the network. The connection charge covers only costs incurred between the generator's site and the nearest node where it is connecting to the network; costs incurred elsewhere on the system as a result of the generator's connection are not included.

The one-off connection charge will vary according to where generators locate their new plant with respect to the existing network. The charge for generators will be calculated by TCN and approved by NERC. TCN can then proceed to build the connection using the funds from the connection charge but if generators can get their connection for a lower cost, or in a shorter time, by having it built by an alternative provider to a standard acceptable to TCN then they may do so. Such a connection shall be built to the standard required to maintain the integrity of the network at the lowest cost.

3.2.3 Transmission Use of System (TUOS) Charge

The TUOS charge is to be levied on distributor/retailers and charged per unit of energy metered to them at the bulk supply points. The TUOS charge is constructed using a building blocks methodology, described above, bringing together existing and forecast capital costs, an allowance for a return on capital and depreciation and efficient operating costs

The TUOS charge is comprised of the system's fixed charges, such as the return on capital, depreciation and fixed operation and maintenance. The charge will be uniform throughout Nigeria (sometimes referred to as a postage stamp tariff) and billed monthly to distributor/retailers.

3.2.4 Transmission Line Losses

Transmission line losses vary with the position of generation with respect to load centres. They also vary from year to year according to changes that take place during the year in load growth and the location of new generation.

Each node on the system at which generators connect will have a loss factor associated with it. The loss factor reflects the average losses incurred each year by generators connecting at that point. The loss factor is called a Marginal Loss Factor (MLF) as it is calculated by estimating the losses associated with injecting an additional, or marginal, unit of electrical energy at that point.

In fulfilling their contracts, generators are required to make an allowance for the rate of loss at their connection point. For example, if the loss factor at a bulk supply point is 8% and a generator has contracts over an hour requiring 100 units then the generator must supply 108.7 units in that hour to meet their contracts and the losses associated with them.

3.3 Distribution/Retail Prices

Retail tariff reflects the costs of the whole supply chain for the NESI, beginning with generation and transmission, distribution metering and billing to the final consumer. The components of cost taken into account in constructing the retail tariff are as follows:

- Payment for electricity supplied into the transmission network.
- Payment of a Transmission Use of System (TUOS) charge to TCN for each MWh delivered to the distributor/retailer's bulk supply point(s).
- The cost of electricity distribution through the local distribution network owned and operated by the distributor/retailer.
- The cost of marketing, metering, billing and revenue collection (retailing).
- Administration, market operation and regulatory charges collected by the MO.

- Payments or distributions, administered through the MO to provide for a national uniform tariff.
- In the years 2008, 2009 and 2010, payments from the FGN fund for tariff support allowing for the gradual introduction of viable tariffs over 3 years.

Payments to generators are set out in NERC's Tariff Order on Wholesale Prices. TUOS charges are also set by NERC in the Tariff Order on Transmission Pricing.

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, losses across the distribution networks and metering costs.

Retailing costs are brought into the building blocks framework as on-going operation and administration 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, revenue collection and human capacity building. As a consequence, the tariff calculation also includes rates of losses that reduce each year of the Tariff Order. The three important causes of loss for the distributor/retailers are; non-technical losses, non-collection of amount billed and distribution technical losses. Distribution technical losses result from line losses across the distribution network and although they can be minimised through good management and design, they are a feature of all distribution networks.

Non-technical losses are described as electricity lost from the system which is not metered and not paid for. It is the most significant area of loss and a reduction of these losses represents the single most effective strategy for improving distributor/retailer revenues Similarly, billing losses, representing sales billed but whose revenue has not been collected, are also a significant area of loss and a reduction here will also help improve sales revenues.

3.4 The Treatment of Capital Expenditure

In the building blocks methodology, there are two building blocks base on capital expenditure. The first is a cost of capital, or rate of return, and the second is a depreciation charge, representing the decline in the value of capital stock over time. This section explains how these two building blocks are calculated in the Tariff Order.

The cost of capital, or required rate of return, is calculated slightly differently for generation compared to the other parts of the NESI. It is also observed as a consequence the rate of return for this part of the NESI should reflect the somewhat higher investment risk profile compared to the return on assets for transmission and distribution.

The cost of capital used is a blended rate, combining the average returns to both equity and debt. This blended industry return is referred to as the weighted average cost of capital (WACC). This section also sets out the depreciation rates to be applied to the regulated asset base to determine annual depreciation.

3.4.1 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 the inputs. This is the case here and most of the inputs to the WACC calculation are, necessarily, NERC 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:

$$R_e = R_f + ß_e (R_m - R_f) \qquad (1)$$

Where:

R_e = equity returns;
R_f = the risk free rate observed in the market;
$ß_e$ = correlation between the equity asset's risk and overall market risk;
R_m = the return on the market portfolio, and
$R_m - R_f$ = the market risk premium.

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

$$WACC = R_d \times D/(D+E) + R_e \times E/(D+E) \qquad (2)$$

Where:

D = total market value of debt;
E = total market value of equity;
R_d = the nominal cost of debt; and
R_e = 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:

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

Where:

T_c = the company tax rate,

V = 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:

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

Where:

w = the nominal post tax WACC, as given by equation (3), and

i = the inflation rate.

The company tax rate used is the statutory corporation rate of 32%.

3.4.2 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 14.8%

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 19.29% for generation and 16.5% for transmission and distribution 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. Thus:

$$R_d = R_f + DRP + DIC \qquad (5)$$

Where

DRP is the debt risk premium; and

DIC is the debt issuance cost

lending in Nigeria.

Betas

The Commission has selected a beta of 0.5 in the construction of a WACC. This is based on the assumption that the level of risk in the regulated NESI will have a similar relationship to market wide risk. It is understood that the electricity sector is an infant industry where statistically significant Betas would be difficult to derive.

Beta reflects the riskiness 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.

Gearing

The ratio of equity and debt is used to weight the equity and debt returns in the WACC calculation. The Commission has selected a gearing ratio of 70:30 in the development of the WACC for the NESI.

In Table 2 below the Commission's calculated WACC for transmission and distribution is shown, along with the inputs to this calculation. In Table 3 the WACC for generation is presented with slight variations in the input, and the resulting WACC, to reflect the slightly higher risk profile attached to investment in generation.

Table 2: WACC estimate for Transmission and Distribution

NERC's WACC Calculation	2008	2009	2010	2011	2012
Nominal risk free rate	14.80%	14.80%	14.80%	14.80%	13.80%
Nigeria annual inflation (long term assumption)	11.00%	11.00%	11.00%	11.00%	10.00%
Real risk free rate	3.80%	3.80%	3.80%	3.80%	3.80%
Nominal cost of debt	16.56%	16.56%	16.56%	16.56%	17.80%
Gearing (D/(D+E))	70.00%	70.00%	70.00%	70.00%	50.00%
Asset beta	50.00%	50.00%	50.00%	50.00%	50.00%
Company tax rate	32.00%	32.00%	32.00%	32.00%	32.00%
Nominal market ROR (estimated)	22.80%	22.80%	22.80%	22.80%	21.80%
Nominal post tax WACC	13.42%	13.42%	13.42%	13.42%	14.88%
Nominal pre tax WACC	19.73%	19.73%	19.73%	19.73%	21.88%
Real pre tax WACC	7.87%	7.87%	7.87%	7.87%	10.80%

Table 3: WACC estimate for Generation

NERC's WACC Calculation	%
Nominal risk free rate	14.80
Nigeria annual inflation (long term assumption)	11.00
Real risk free rate	3.80
Nominal cost of debt	19.29
Gearing (D/(D+E))	70.00
Asset beta	50.00
Company tax rate	32.00
Nominal market ROR (estimated)	27.00
Nominal post tax WACC	17.41
Real post tax WACC	5.84
Nominal pre tax WACC	25.72
Real pre tax WACC	13.26

3.5 The Rate of Depreciation

The optimised depreciated replacement cost (ODRC) is used to calculate the value of TCN's and each distributor/retailer's capital stock and it is this value which is then depreciated each year to calculate the value of depreciation in the annual revenue requirement. The ODRC methodology involves:

- Escalating the cost of an asset from the year of its purchase to the year of the tariff calculation at the inflation rate applying to the asset;
- Optimising its capacity (i.e., assuming it is the size that is needed for the job it is required to do now); and
- Applying depreciation over the economic life of the individual asset or groups of assets.

The depreciation schedule for regulatory purposes was 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. PHCN and TCN provided capital expenditure forecasts for distribution and transmission assets respectively and NERC adopted these forecasts as the capital expenditure required to allow the networks to do the job required of them in the future.

Within the life of the Tariff Order the Commission does not envisage that any transmission or distribution assets would be reduced in value (or “optimised”) because they are found to be in excess of what is required now to do their job. The rationale for this is that currently there is a severe deficit of reliable network infrastructure in the NESI and the transmission and distribution networks will be used to the fullest. While this is the case at present the ODRC approach can help to prevent expenditure on “gold-plating” (or over spending on) assets to find its way into the regulated annual revenue requirement and 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 in Table 4. These asset lives are used in a straight line depreciation method to provide an annual depreciation schedule for each asset until the end of its depreciable life. For example, the 30 year asset life indicates that this group of assets would be depreciated by 3.33% of the escalated replacement cost each year of its life.

Table 4: Asset lives used in depreciation and rates

Existing assets	**Economic life (Years)**	**Depreciation rate**
Plant & Machinery	20	5%
Land & Buildings	40	2.5%
Furniture & Fittings	10	10%
Motor Vehicles	5	20%
New assets		
Plant & Machinery	35	2.8%
Land & Buildings	50	2.0%
Furniture & Fittings	15	6.67%
Motor Vehicles	5	20%

4 ORDERS ON TARIFF RATES

4.1 Wholesale Generation Prices

The wholesale contract price was calculated for each year in MWh per Naira as capacity and energy charge. The capacity charge comprises of fixed operation and maintenance cost, capital cost and two-third (2/3) of tax cost. While the energy charge comprises of fuel cost, variable operation and maintenance cost, the transmission loss cost and a third (1/3) of tax cost. The capacity and energy charge will be included in the wholesale contract and are to be the basis for payments to the eligible generators.

Table 5: Wholesale Generation Prices

Year commencing 1 July	2008	2009	2010	2011	2012
Total wholesale Contract Price (N/MWh)	**3,104.1**	**3,179.1**	**3,364.6**	**3,570.7**	**3,777.4**
Capacity Charge (N'000/MW/month)	**1435.1**	**1468.2**	**1502.1**	**1536.8**	**1559.6**
Energy Charge (N/MWh)	**1156.5**	**1186.6**	**1326.1**	**1485.0**	**1660.9**

4.2 Transmission Revenue Requirement and Tariff

4.2.1 Asset Value and Capital Expenditure

TCN's initial asset valuation will largely reflect TCN's valuation of its assets on the basis of historical costs plus recent additions to its asset base. This provides an initial asset value as of 1 July 2008 of 189.4 N billion. In order to calculate the asset value in each year's tariff period, the escalated and depreciated capital asset value at the start of the preceding year is added to the investments in new assets acquired during the same year.

The allowance for capital expenditure in the calculation of the TUOS charge allows for a significant increase in capital expenditure by TCN. This is to include expenditure on the System Operator, which will become an increasingly important part of the NESI as it grows. (See table 6)

Table 6: Capital expenditure included in the TUOS calculation (nominal N billion, years commencing 1 July)

2008	2009	2010	2011	2012
156.0	182.0	142.2	232.8	90.3

4.2.2 Transmission Use Of System (TUOS) Charges

TCN will be required to pay a number of institutional charges in order to cover the cost of industry bodies. These institutional charges are as follows:

- PHCN Headquarters charge, which is intended to cover the temporary staffing and operations of PHCN during the transition period. The PHCN Headquarters charges are shown in Table 7 below. It is charged against energy leaving the transmission system and delivered to the distributor/retailers at their bulk supply points.
- The Regulatory charge, which for now covers part of the cost of NERC's operations in regulating TCN.

Table 7 below shows the annual costs that have been allowed by NERC for each year of the TUOS calculation, including the institutional charges set out above. The table shows the revenue requirement from the 3 building blocks (operation and maintenance, return on capital and depreciation) plus the costs associated with institutional charges.

These costs are brought together and aggregated to a total annual revenue requirement each year. This annual revenue requirement is then divided by the forecast energy transmitted through the transmission network and delivered to distributor/retailers each year to produce the estimated costs per unit of transmission.

At the transmission stage an additional levy of 1% is collected for payment to the MO to contract for ancillary services. This will be paid through the TUOS charge and collected by the MO for use in purchasing these services only. If this fund proves too much the MO will allow the fund to accumulate over time and the rate of payment can be adjusted at the next major review in 2012.

This cost is high in the first 2 years of the tariff order and then declines to 2011 and increases again in 2012. These variations in the estimated cost per unit over time reflect the different capital expenditures and the growth in energy transmitted each year. NERC has determined that this charge will be averaged across the 5 year period and set at a constant level each year of 1,200 N/MWh, which is NERC's determined TUOS charge for the period 1 July 2008 to 30 June 2013, including an allowance for regulatory and HQ charges.

Table 7: Transmission Revenue Requirement (N 000) and TUOS charges per MWh

	2008	2009	2010	2011	2012
Total Operation & Maintenance Costs	7,205,828	10,551,980	16,403,993	25,435,536	29,498,607
Return on Capital	4,203,778	17,827,760	33,842,697	46,280,420	91,352,273
Return of Capital (depreciation)	6,329,823	9,794,178	11,535,707	17,640,530	24,203,450
Annual Corporate HQ Admin charge	3,037,482	2,429,985	1,943,988	1,555,191	1,555,191
Regulatory Charge	311,654	609,059	637,264	909,117	1,466,095
Ancillary Service Charge (1%)	177,394	381,739	617,824	893,565	1,450,543
Total	**21,265,957**	**41,594,701**	**64,981,473**	**92,714,359**	**149,526,160**
Electricity Delivered to Distribution (GWh)	20,733	33,492	55,820	89,312	100,476
Calculated charge N/MWh	1,026	1,242	1,164	1,038	1,488
Regulated TUOS charge N/MWh (including charges)	**1,200**	**1,200**	**1,200**	**1,200**	**1,200**

4.3 Electricity Distribution and Retail Tariff

4.3.1 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 adopted initial asset valuation be based on an historical cost calculation plus recent additions to their asset base suitably depreciated. The projections of capital expenditure for the next five years are based on existing and projected demand and the need to build up the distribution area and improve coverage and quality of supply.

This provides an initial asset value at the beginning of 2008 year. Each year of the calculation the forecast capital expenditures are added to the asset base and depreciation is deducted. The replacement costs of assets are escalated to current values and any reduction in asset value through optimisation is deducted. NERC has not included any reductions in valuation through optimisation of assets in this Tariff Order.

Table 8: below shows the asset value determined by NERC for the start of the period (beginning of 2008) for each of the distributor/retailers and the annual capital expenditure that NERC has allocated to each in setting the tariff for the period 1 July 2008 to 30 June 2013. 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 8: Regulated asset value and forecast capital expenditures (nominal N billion)

	Asset Value	Capital expenditure				
Year starting 1 July	**2008**	**2008**	**2009**	**2010**	**2011**	**2012**
Abuja	9.89	6.94	6.94	6.94	15.95	6.19
Benin	17.11	9.08	9.08	9.08	20.88	8.11
Enugu	19.72	9.47	9.47	9.47	21.76	8.45
Ibadan	27.91	11.55	11.55	11.55	26.57	10.32
Jos	8.67	7.60	7.60	7.60	17.46	6.78
Kaduna	10.28	8.86	8.86	8.86	20.38	7.91
Kano	10.05	7.90	7.90	7.90	18.16	7.05
Eko	11.95	10.22	10.22	10.22	23.49	9.12
Ikeja	21.22	15.63	15.63	15.63	35.93	13.95
Port Harcourt	7.68	7.83	7.83	7.83	18.01	6.99
Yola	7.33	6.18	6.18	6.18	14.21	5.52
TOTAL	151.83	101.25	101.25	101.25	232.80	90.40

4.3.2 Operating and Maintenance Expenditure

Table below shows the allowance made for annual operation and maintenance, administration, marketing, metering and billing for each distributor/retailer. These costs include provision for staff capacity building. These costs have been derived by NERC from historical costs provided by PHCN and adjusted in some cases.

Table 9: Annual allowance for operation, maintenance, administration, metering and billing(nominal N 000)

	2008	2009	2010	2011	2012
Abuja	971,943	1,078,857	1,197,531	1,329,260	1,462,186
Benin	1,468,749	1,630,311	1,809,645	2,008,706	2,209,577
Enugu	1,326,055	1,471,921	1,633,832	1,813,554	1,994,909
Ibadan	2,280,820	2,531,711	2,810,199	3,119,321	3,431,253
Jos	757,452	840,772	933,257	1,035,915	1,139,507
Kaduna	1,047,371	1,162,581	1,290,465	1,432,416	1,575,658
Kano	811,713	901,002	1,000,112	1,110,124	1,221,137
Eko	876,667	973,101	1,080,142	1,198,957	1,318,853
Ikeja	1,755,967	1,949,124	2,163,527	2,401,515	2,641,667
Port Harcourt	874,397	970,581	1,077,344	1,195,852	1,315,437
Yola	605,482	672,085	746,014	828,076	910,883
Capacity Building	**638,831**	**709,102**	**472,263**	**524,211**	**576,632**
Total	**13,415,448**	**14,891,147**	**16,214,332**	**17,997,908**	**19,797,699**

4.3.3 Institutional charges

Distributor/retailers will be required to pay a number of charges to help meet the costs of a number of necessary market institutions. These bodies are:

- The Transmission System Operator (TSO), which will be located within TCN but will not have access to TCN revenues. Its functions are those of a system operator (SO) and Market Operator (MO). The SO is to dispatch generation according to availability and system requirements (demand) and to allocate available electricity to distributors through their bulk supply points. The MO will also carry out settlement functions, collect payments from distributor/retailers and make payments to TCN and the generators as well as other market institutions. It will also be required to collect and make equalisation payments which will be netted out of distributor/retailer transactions with the MO. The charge for the TSO is set at 3 N/MWh, indexed to inflation of 11% per year over the next 5 years.
- PHCN Headquarters charge, which is intended to cover the temporary staffing of PHCN during the transition period. The PHCN Headquarters charge is shown in Table 10 below and is charged against energy consumed by the distributor/retailers at their bulk supply points as well as on TCN to cover energy passing through the transmission system.
- The Regulatory charge, which cover the cost of NERC's operations in regulating and licensing the TCN.

4.3.4 Aggregated Distribution Costs – The Annual Revenue Requirement

Table 10 shows the costs for all distributors and retailers brought together in a building blocks framework, summing the running costs (operation, maintenance, administration, metering, and billing) with the return on capital and the return of capital (depreciation).

Table 10: Aggregated regulated costs for distributor/retailers (N 000)

Year starting 1 July	2008	2009	2010	2011	2012
O & M, admin, metering, billing	12,776,617	14,182,045	15,742,069	17,473,697	19,221,067
Return on capital	13,594,425	35,839,767	58,296,998	80,952,244	147,968,167
Return of capital (depreciation)	3,805,815	4,945,667	6,190,990	11,696,541	16,007,458
Corporate HQ charge	4,364,007	3,491,205	2,792,964	2,234,371	1,787,497
TSO charge	76,636	137,414	254,216	451,487	558,715
Regulatory charge	528,845	889,578	1,256,242	1,699,988	2,791,793
Capacity building	**638,831**	**709,102**	**472,263**	**524,211**	**576,632**
Total	**35,785,174**	**60,194,778**	**85,005,741**	**115,032,539**	**188,911,328**

These costs increase sharply over the 5 year regulatory period reflecting the high level of investment assumed in the distribution system and in new meters and billing systems. These investments will be needed to improve the quality of service to consumers and improve billing and metering, thereby reducing the currently high level of non-technical and billing losses. The Corporate HQ, TSO and regulatory charges are discussed in 4.3.3 above. MYTO has made provision for human capacity building in the approved revenue requirement as shown above.

4.3.5 Performance of Operators

MYTO has set minimum level of capital investment expected from TCN and all Distribution Companies (table 6 and table 8). Allowed revenue requirement was based on the projected level of investment. Operators are expected to comply fully with level of Capital Investment and notify the Commission accordingly. Reports on work in progress and Certificate for completion of capital projects are to be submitted to the Commission on quarterly basis. This will be one of the bases for release of Federal government subsidy and update of capital stock for future tariff review.

Table 11 shows the allowances made in the MYTO for losses at various stages in the transmission, distribution/retail of electricity. The technical losses associated with transmission and distribution networks are held constant throughout the 5 year period as these appear to be similar to losses experienced by transmission and distribution networks in other countries with comparable networks. This notwithstanding, TCN and distribution companies are expected to improvement in these losses.

MYTO has included reducing levels of billing and collection losses, reflecting an urgent need on the part of distributor/retailers to increase their tariff base by reducing non metered withdrawals from the system and improving on the rate of uncollected bills. MYTO has reduced the allowance for billing losses from 20% (average all distributor/retailers) in 2008 to 12% in 2013. The allowance for revenue collection losses is reduced from 16% in 2008 to 6% in 2013.

If distributor/retailers can improve on these levels of loss reduction then they stand to earn revenues in excess of those included in this Tariff Order. MYTO will monitor the level of performance of all operators in line with the table below.

Table 11: Technical and non-technical losses allowed for in the Tariff Order

	Units	2008	2009	2010	2011	2012
System Capacity(Gross)	MW	4,000	6,000	10,000	16,000	18,000
Sent-out from stations (SO)	GWh	22,548	36,424	60,707	97,131	109,272
Transmission losses	% of SO	8%	8%	8 %	8 %	8 %
Delivered to distribution(DD)	GWh	20,733	33,492	55,820	89,312	100,476
Distribution losses	% of DD	11.00%	11.00%	11.00%	11.00%	11.00%
Delivered to customers(DC)	GWh	18,452	29,808	49,680	79,488	89,423
Non-technical losses (non-billed energy)	% of DC	20%	18%	16%	14%	12%
Billed to customers(BC)	GWh	14,762	24,442	41,731	68,359	78,693
Revenue collection losses	% of BC	16%	13%	10%	8%	6%
Sales where revenue is collected	GWh	12,400	21,265	37,558	62,891	73,971

4.3.6 Tariff Equalisation

The final tariff to consumers is uniform across Nigeria. However, distribution and retailing costs vary considerably according to the density of customers on the network and the geography of the distribution area. In more remote areas, the costs for the distribution of electricity are considerably higher than in the more densely populated areas. The end user tariffs was determined on aggregate costs and as a consequence there will be a redistribution of revenue from lower cost to higher costs distributors to enable a national uniform tariff.

Currently the MO operates the payment system with distribution/retail companies paying the MO for energy and transmission and the MO paying the generators and TCN for these services. In managing the collection and payment of cross subsidies between high and low cost distributors, the MO will collect higher payments from those distributors with lower costs and re-distribute those funds in the form of lower payments for energy and transmission to high cost distributor/retailers.

The balancing payments set by NERC for the period of this Tariff Order are shown in Table 12. These payments made into and out of the equalisation pool are intended to balance annually and NERC will monitor the payments and the pool to see if a positive or negative balance is accumulating, in which case NERC will reset the equalisation payments during an annual review of the tariff.

Table 12: Equalisation payments to be collected and paid (N/kWh)

	2008	2009	2010	2011	2012
	Equalisation payments to be paid per kWh of sales				
Abuja	(0.03)	(0.08)	(0.09)	(0.08)	(0.17)
Ikeja	(1.01)	(1.15)	(1.40)	(1.65)	(1.72)
Eko	(1.06)	(1.29)	(1.59)	(1.89)	(2.06)
	Equalisation payments to be received per kWh of sales				
Benin	0.21	0.19	0.18	0.17	0.18
Enugu	0.57	0.63	0.76	0.89	0.92
Ibadan	0.37	0.29	0.28	0.28	0.21
Jos	0.93	1.25	1.62	1.96	2.19
Kaduna	0.37	0.50	0.66	0.81	0.88
Kano	0.74	0.97	1.24	1.50	1.67
Port Harcourt	1.09	1.46	1.89	2.32	2.55
Yola	1.00	1.42	1.73	1.94	2.49

4.3.7 FGN Subsidy

The Federal Government of Nigeria (FGN) is providing a subsidy to help introduce a viable tariff for the industry. This tariff will take the form of a per unit payment which reduces each year in order to allow the gradual introduction of a viable industry tariff of 10N/kWh by 1 July 2011.

Table 13: shows the cost of supply per unit of paid sales over the regulatory period as calculated in the MYTO regulatory model. The cost of supply in the first year of the Tariff Order (2008) is high because industry losses are still high. As losses begin to reduce the viable tariff also reduces slightly, although other underlying costs, such as the gas price and operation and maintenance, are forecast to increase by this time.

The table also shows the level of FGN subsidy to be paid per unit and the average price to consumers, including the effects of the subsidy, determined by NERC for each year of the Tariff Order.

Table 13: Average cost of supply, FGN subsidy and effective average tariff (N/kWh)

Year starting 1 July	2008	2009	2010	2011	2012
Estimated cost of supply	**11.20**	**10.64**	**9.49**	**10.00**	**10.00**
Less subsidy	5.20	3.64	0.99	0	0
NERC determined tariff	6.00	7.00	8.50	10.00	10.00

5 Procedure for Annual Review

The Commission's regulated prices for generation, transmission and final consumers are based on a set of inputs projected over the coming 5 years. Some of these inputs are at least partly outside of the control of the regulated electricity bodies and NERC has determined that if certain significant inputs change from those included in the tariff calculation then NERC will vary the regulated tariff accordingly. NERC will consider variations after the matter has been raised by interested parties and suitable evidence presented on the variation in costs.

5.1 Generation Prices

The Commission has noted that its determination of Wholesale Contract prices is based on current estimates of the cost of generating electricity with an open cycle gas turbine. The Commission also notes that the NESI is likely to change over the coming years and that the commercial conditions applying to generators may change.

The Commission is willing to review the Wholesale Contract prices each year prior to 1 July when the next year's price will begin to apply. If interested parties wish the Commission to consider variations in the Wholesale Contract price they need to make a submission to the Commission supporting their case before close of business on 31 March of that year.

The Commission will consider reviewing the wholesale contract price of generation if there is a material change in:

- the inflation rate, and therefore the inflation of input costs to generation,
- the exchange rate with the US dollar
- the delivered price of gas

The Commission considers that a material change would be plus or minus 5% in these inputs to the price. The Commission will consider the combined effects of these parameters only. Other parameters will be considered as part of the comprehensive review of the MYTO in 2012 prior to a new determination from 1 July 2013.

The inflation rate, exchange rate and the delivered price of gas used in the wholesale contract price calculation are set out in Table 14.

Table 14: Inflation rate, exchange rate and delivered gas price used in the calculation of the generation price

	2008	2009	2010	2011	2012
Inflation (% per year)	11.0	11.0	11.0	11.0	10.0
Exchange rate N/US dollar	125	125	125	125	123.7
Delivered gas price (N per GJ)	61.6	61.6	70.8	81.5	93.7

5.2 TUOS Charges

The Commission will review the TUOS charges each year prior to 1 July. If TCN or other interested parties wish the Commission to consider variations in the TUOS charge they need to make a submission to the Commission supporting their case before close of business on 31 March of that year.

The Commission will consider reviewing the TUOS charge if there is a material change in the inflation rate used in the calculation of TUOS charges. The Commission considers that a material change would be plus or minus 5% in the inflation rate and foreign exchange rate. The Commission will consider the effect of this potential change only. 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 as part of the comprehensive review of the MYTO in 2012 prior to a new determination from 1 July 2013.

5.3 Retail Tariffs

The Commission will review the retail price schedule each year prior to 1 July when the next year's price will begin to apply. If interested parties wish the Commission to consider variations in the tariff schedule they need to make a submission to the Commission supporting their case before close of business on 31 March of that year.

The Commission will consider reviewing the retail tariff schedule if there is a material change in the price of generation in vesting contracts, in TUOS charges and in the inflation rate and exchange rate used in the calculation of these tariffs. The Commission considers that a material change would be plus or minus 5% in these inputs to the price. The Commission will consider the effects of these parameters only. Other parameters will be considered as part of the comprehensive review of the MYTO in 2012 prior to a new determination to take effect from 1 July 2013.

The price of generation, the TUOS charge and the rate of inflation used in the calculation are set out in Table 15.

Table 15: Inputs to the retail price subject to annual review

Year commencing 1 July	2008	2009	2010	2011	2012
Inflation (% per year)	11.0	11.0	11.0	11.0	10.0
Exchange rate (N /US dollar)	125	125	125	125	123.7
TUOS charge (N/MWh)	1,200	1,200	1,200	1,200	1,200
Price of generation in wholesale Contracts *(N/MWh)	3,104	3,179	3,364	3,570	3,777

- Note , the price of generation in wholesale Contracts is set in a capacity and energy charge and the price included here is the effective total price per MWh

6 Retail Tariff Schedules

Tariff schedules are created for the years 2008 to 2013 inclusive and use the existing tariff schedule as a starting point. This schedule includes fixed charges under the titles of ‘fixed’, ‘meter’ and ‘minimum’ charges. Two variable charges in the form of a demand (per kVA) and energy (per kWh) are also included, although many customers are not subject to the demand charge.

All of the fixed costs in the schedule (metering, fixed and minimum charges) were escalated using the forecast of Nigerian inflation applied throughout the MYTO while variable charges were scaled to meet the revenue requirements over the longer term.

Crucial to these calculations are revenue and load forecasts from the other components of the MYTO. The ‘revenue’ used is the total cost of the system, comprising the aggregate of generation, transmission, distribution and retailing costs. The load forecast used is the sales upon which revenue is collected. (See table 11)

The tariff schedules now determined by NERC and based on the NERC determined average tariffs in Table 13:6 are set out below in Tables 17 - 21. The tariffs apply in the year commencing 1 July of the year shown.

Table 16: **Regulated Revenue Requirement (N’000)**

Operators	Details	2008	2009	2010	2011	2012
Total Generation	Wholesale contract costs + PPAs	81,017,719	123,304,225	204,243,476	334,996,488	395,153,914
	Annual Licence charge	810,177	1,233,042	2,042,435	3,349,965	3,951,539
	Sub Total	**81,827,896**	**124,537,267**	**206,285,911**	**338,346,452**	**399,105,453**
Transmission	Total Opex	7,205,827	10,551,980	16,403,993	25,435,536	29,498,607
	Return on Capital	4,203,778	17,827,760	33,842,697	46,280,420	91,352,273
	Return of Capital	6,329,823	9,794,178	11,535,707	17,640,530	24,203,450
	HQ Admin charge	3,037,482	2,429,985	1,943,988	1,555,191	1,555,191
	Regulatory charge	311,654	609,059	637,264	909,117	1,466,095
	Ancillary service charge 1%	177,394	381,739	617,824	893,565	1,450,543
	Sub Total	**21,265,957**	**41,594,701**	**64,981,473**	**92,714,358**	**149,526,160**
All Discos	Total Opex	13,415,448	14,891,147	16,214,332	17,997,908	19,797,699
	Return on Capital	13,594,425	35,839,767	58,296,998	80,952,244	147,968,167
	Return of Capital	3,805,815	4,945,667	6,190,990	11,696,541	16,007,458
	HQ Admin charge	4,364,007	3,491,205	2,792,964	2,234,371	1,787,497
	Market Operator charge	76,636	137,414	254,216	451,487	558,715
	Regulatory charge	528,845	889,578	1,256,242	1,699,988	2,791,793
	Sub Total	**35,785,174**	**60,194,778**	**85,005,741**	**115,032,539**	**188,911,328**
Grand Total		**138,879,027**	**226,326,747**	**356,273,126**	**546,093,349**	**737,542,942**

Average and Levelised Tariff N’KWh	**11.20**	**10.64**	**9.49**	**10.00**	**10.00**
NERC adopted Retail Tariff N”KWh	**6.00**	**7.00**	**8.50**	**10.00**	**10.00**
NERC adopted Regulated costs (nominal) (NGN '000)	**74,400,339**	**148,854,331**	**319,241,838**	**546,093,349**	**737,542,942**
Subsidy requirement (NGN'000)	**64,478,689**	**77,472,416**	**37,031,288**	**0**	**0**
Subsidy N/KWh	5.20	3.64	0.99	0	0

Table 17: Tariff schedule for the year starting 1ST July 2008

Tariff Code Details	Year starting 1 July				2008
Tariff Code	Fixed N/Month	Meter N/Month	Minimum N/Month	Demand N/KVA	Energy N/KWh
Residential					
Residential R1	24	121	24	0.00	1.2
Residential R2	36	121	36	0.00	4.0
Residential R3	145	603	145	0.00	6.0
Residential R4	145	1,930	6,031	0.00	8.5
Residential R5	0	2,654	37,695	0.00	8.5
Commercial					
Commercial C1	107	119	107	0.00	6.5
Commercial C2	142	593	142	0.00	8.5
Commercial C3	285	1,897	5,929	202.02	8.5
Commercial C4	0	2,609	37,057	21.96	8.5
Industrial					
Industrial D1	106	118	106	0.00	6.5
Industrial D2	141	588	141	0.00	8.5
Industrial D3	282	1,882	5,882	217.20	8.5
Industrial D4	0	2,588	36,761	236.09	8.5
Industrial D5	0	2,588	1,764,505	254.97	8.5
Special					
Special A1	143	597	143	0.00	5.7
Special A2	286	1,909	5,966	0.00	5.7
Special A3	0	2,625	37,288	0.00	5.7
Special A4	0	2,625	37,288	0.00	5.7
Street Lighting					
Street Lighting S1	0	551	264	0.00	6.5

Table 18: Tariff schedule for the year starting 1ST July 2009

Tariff Code Details		Year starting 1 July			2009
Tariff Code	Fixed N/Month	Meter N/Month	Minimum N/Month	Demand N/KVA	Energy N/KWh
Residential					
Residential R1	31	154	31	0.00	1.3
Residential R2	46	154	46	0.00	4.4
Residential R3	185	772	185	0.00	6.6
Residential R4	185	2,469	7,716	0.00	9.4
Residential R5	0	3,395	48,228	0.00	9.4
Commercial					
Commercial C1	138	153	138	0.00	7.4
Commercial C2	184	767	184	0.00	9.7
Commercial C3	368	2,456	7,673	262.53	9.7
Commercial C4	0	3,376	47,959	28.54	9.7
Industrial					
Industrial D1	136	151	136	0.00	7.9
Industrial D2	181	755	181	0.00	10.3
Industrial D3	362	2,416	7,550	278.88	10.3
Industrial D4	0	3,322	47,188	303.13	10.3
Industrial D5	0	3,322	2,265,011	327.38	10.3
Special					
Special A1	161	671	161	0.00	6.9
Special A2	322	2,147	6,709	0.00	6.9
Special A3	0	2,952	41,930	0.00	6.9
Special A4	0	2,952	41,930	0.00	6.9
Street Lighting					
Street Lighting S1	0	651	312	0.00	5.9

Table 19: Tariff schedule for the year starting 1ST July 2010

Tariff Code Details	Year starting 1 July				2010
Tariff Code	Fixed N/Month	Meter N/Month	Minimum N/Month	Demand N/KVA	Energy N/KWh
Residential					
Residential R1	41	204	41	0.00	1.8
Residential R2	61	204	61	0.00	5.9
Residential R3	245	1,019	245	0.00	8.9
Residential R4	245	3,260	10,188	0.00	12.5
Residential R5	0	4,483	63,676	0.00	12.5
Commercial					
Commercial C1	174	193	174	0.00	9.4
Commercial C2	232	967	232	0.00	12.3
Commercial C3	464	3,094	9,668	332.10	12.3
Commercial C4	0	4,254	60,426	36.10	12.3
Industrial					
Industrial D1	170	189	170	0.00	9.8
Industrial D2	226	943	226	0.00	12.9
Industrial D3	452	3,017	9,427	348.28	12.9
Industrial D4	0	4,148	58,917	378.56	12.9
Industrial D5	0	4,148	2,828,031	408.85	12.9
Special					
Special A1	237	986	237	0.00	8.6
Special A2	473	3,154	9,857	0.00	8.6
Special A3	0	4,337	61,606	0.00	8.6
Special A4	0	4,337	61,606	0.00	8.6
Street Lighting					
Street Lighting S1	0	751	361	0.00	6.8

Table 20: Tariff schedule for the year starting 1ST July 2011

Tariff Code Details	Year starting 1 July				2011
Tariff Code	Fixed	Meter	Minimum	Demand	Energy
	N/Month	N/Month	N/Month	N/KVA	N/KWh
Residential					
Residential R1	50	250	50	0.00	2.2
Residential R2	75	250	75	0.00	7.3
Residential R3	300	1,251	300	0.00	11.0
Residential R4	300	4,003	12,509	0.00	15.6
Residential R5	0	5,504	78,178	0.00	15.6
Commercial					
Commercial C1	204	227	204	0.00	11.1
Commercial C2	272	1,134	272	0.00	14.5
Commercial C3	544	3,629	11,340	391.05	14.5
Commercial C4	0	4,990	70,874	42.51	14.5
Industrial					
Industrial D1	201	223	201	0.00	11.7
Industrial D2	268	1,116	268	0.00	15.2
Industrial D3	536	3,570	11,157	412.31	15.2
Industrial D4	0	4,909	69,733	448.16	15.2
Industrial D5	0	4,909	3,347,191	484.01	15.2
Special					
Special A1	120	500	120	0.00	11.2
Special A2	240	1,600	5,000	0.00	11.2
Special A3	0	2,200	31,250	0.00	11.2
Special A4	0	2,200	31,250	0.00	11.2
Street Lighting					
Street Lighting S1	0	940	451	0.00	8.6

Table 21: Tariff schedule for the year starting 1ST July 2012

Tariff Code Details	Year starting 1 July				2012
Tariff Code	Fixed	Meter	Minimum	Demand	Energy
	N/Month	N/Month	N/Month	N/KVA	N/KWh
Residential					
Residential R1	50	250	50	0.00	2.2
Residential R2	75	250	75	0.00	7.4
Residential R3	300	1,251	300	0.00	11.2
Residential R4	300	4,005	12,515	0.00	15.8
Residential R5	0	5,506	78,217	0.00	15.8
Commercial					
Commercial C1	208	231	208	0.00	11.3
Commercial C2	277	1,154	277	0.00	14.8
Commercial C3	554	3,692	11,536	399.32	14.8
Commercial C4	0	5,076	72,101	43.40	14.8
Industrial					
Industrial D1	208	231	208	0.00	12.1
Industrial D2	277	1,155	277	0.00	15.8
Industrial D3	554	3,696	11,549	426.89	15.8
Industrial D4	0	5,082	72,184	464.01	15.8
Industrial D5	0	5,082	3,464,822	501.13	15.8
Special					
Special A1	290	1,208	290	0.00	11.6
Special A2	580	3,864	12,077	0.00	11.6
Special A3	0	5,314	75,478	0.00	11.6
Special A4	0	5,314	75,478	0.00	11.6
Street Lighting					
Street Lighting S1	0	1,043	501	0.00	9.6

Effective Date: This **ORDER** shall take effect from 1st July 2008

BY ORDER OF THE COMMISSION

Dated 27th June, 2008

Dr. Ransome Owan

Chairman/CEO

7.0 APPENDIX 1

List of parties consulted on MYTO methodology and tariff

1. Senior Staff Association of Electricity and Allied Companies (SSAEAC)
2. National Union of Electricity Employees (NUEE)
3. Independent Power Producers (Operating & Licensed)
4. Geometric Power Ltd.
5. Ethiope Energy Ltd.
6. Supertek Nig. Ltd.
7. Westcom Technologies & Energy Services
8. Anita Energy Ltd.
9. Hudson Power Ltd.
10. Ibafo Power Station Ltd.
11. First Independent Power Co. Ltd.
12. Minaj Holdings Ltd.
13. Lucra Energy Ltd
14. Negris/Encon Ltd
15. Kainji Power Plc
16. Shiroro Hydro Power Plc
17. Sapele Power Station
18. Afam Electric Power Station
19. Egbin Power Plc
20. Jebba Power Plc
21. Ughelli Power Station
22. Kano Electricity Distribution Company
23. Kaduna Electricity Distribution Company
24. Yola Electricity Distribution Company
25. Enugu Electricity Distribution Company

26. Ibadan Electricity Distribution Company
27. Jos Electricity Distribution Company
28. Port-Harcourt Electricity Distribution Company
29. Benin Electricity Distribution Company
30. Abuja Electricity Distribution Company
31. Ikeja Electricity Distribution Company
32. Eko Electricity Distribution Company
33. Transmission Company of Nigeria
34. Market Operator
35. System Operator
36. PHCN liaison unit
37. Electricity Consumers Association of Nigeria (ECAN)
38. Licensed Electrical Contractors Association of Nigeria(LECAN)
39. Consumer Protection Council (CPC)
40. The Nigerian Association of Chamber of Commerce, Industry, Mines and Agriculture (NACCIMA)
41. Manufacturing Association of Nigeria (MAN)
42. Nigerian Association of Small and Medium Enterprises (NASME)
43. Nigeria Electricity Liability Management Company
44. Nigerian Guilds of editors
45. Nigerian Labour Congress (NLC)
46. Trade Union Congress (TUC)
47. Presidential Committee on the Accelerated Expansion of Nigeria's Electricity Infrastructure

48. Federal Ministry of Energy
49. Federal Ministry of Finance
50. Economic Management Team (EMT)
51. National Planning Commission
52. Senate Committee on Power
53. House of Representatives Committee on Power
54. The Presidency
55. Federal Executive Council
56. National Economic Council

APPENDIX 2

2.0 Comments and Observations on MYTO methodology

A total number of twenty two (22) responses were received from a broad range of stakeholders. The comments and observations received focused on support for the concept of MYTO and request for more information on definitional and operational issues. The Commission noted all the comments and responded to issues that are fundamental to the methodology; all comments are available with the Commission.

2.1 List of individuals and institutions that sent comments;

	Name:	**Date sent**
1.	PHCN Egbin Electricity Power Business Unit Premises Egbin, Ikorodu, Lagos P. O. Box 50796 Falomo, Ikoyi	17th May, 2007
2.	Electricity Distribution Company of Nigeria 9, Ahmadu Bello Way, Jos Plateau State	24th May, 2007
3	Standard Organization of Nigeria Corporate Headquarters Plot 1687, Lome Street, Wuse Zone 7, Abuja	30th May, 2007
4	Mohammed Abdullahi 667 Kofar Nassarawa Kano.	1st June 2007
5	Moscant International Business Consultant Ltd. 3A Alhaji Muritala Street, Atunrase-Estate Gbagada, Lagos Nigeria.	2nd June, 2007
6	Punaka Attorneys and Solicitors International Law Center Plot 45, Oyibo Ajarho Street, Lekki Peninsula Phase 1 Lagos State.	
7	Chevron Nigeria Limited 2 Chevron Drive, Lekki Peninsula PMB 125825 Lagos State	11th July 2007
8	Njirika Dennis	4th June, 2007
9	Power Cap Limited Suite 3 Flat 39 Eko Court, Kofo Abayomi Street Victoria Island, Lagos	7th June, 2007

10	Mobil Producing Nigeria Unlimited Mobil House, Lekki Expressway Victoria Island, PMB 12054, Lagos.	7th June, 2007
11	Transmission Company of Nigeria Corporate Headquarters, Plot 441, Zambezi Crescent, Maitama- Abuja	5th June, 2007
12	Obi Michael Lagos	7th June, 2007
13	Aldwych International	8th June, 2007
14	Supertek Nigeria Limited Power Generation Products No2. Misratah Street, Off Parakou Street. Candastral Zone A7, off Amino Kano Crescent Wuse 2 Abuja	12th June, 2007
15	Globeleq Limited	14th June 2007
16	Genevieve Mbama Access Bank Multinational Group Head Office.	14th June, 2007
17	Sunil Katial Head (Power) Nigerian Operations, Global Infrastructure Nigeria Limited	16th June 2007
18	Nigeria Electricity Supply Corporation(Nigeria) Limited P.O.Box 15 Bukuru, Plateau State	18th May, 2008
19	Larry Holloway, Kansas Corporation Commission	Date not stated.
20	Shreline Power Shoreline House 46, Industrial Avenue, Ilepuju PMB 21055, Ikeja Nigeria	14th June, 2007

21 Shell Petroleum Development Company of Nigeria Limited
Shell Industrial Area, Rumuobiakani
P O Box 263, Port Harcourt.
Rivers State — 7th June, 2007

22 AES Nigeria, Ikorodu Lagos

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