CONSULTATION PAPER FOR THE 2011 MAJOR REVIEW OF THE MULTI YEAR TARIFF ORDER (MYTO)

Nigerian Electricity Regulatory Commission

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Part 1: ***Background***

1.1 Introduction

1.1.1 The Nigerian Electricity Regulatory Commission (NERC) is an independent regulatory agency established by the Electric Power Sector Reform Act (EPSR), 2005. NERC was officially inaugurated on 31st October 2005.

1.1.2 The Act provides the legal and regulatory framework for the electricity supply industry in Nigeria. It empowers the Commission to regulate the electricity sector in the country, including Generation, Transmission, System Operations and Distribution and Trading.

1.1.3 The problems among others in this Industry can be summarized as follows:

- Shortage of generation capacity to meet demand exacerbated by the unusable generation capacity due to lack of maintenance and re-investment;
- Gas (pricing and supply);
- Lack of private sector participation due to inadequate incentives, guarantees etc;
- Lack of functioning institutional players in the sector e.g. Bulk Trader, NELMCO, etc;
- Inadequate generation mix e.g. solar, wind, coal, etc.

1.1.4 The establishment of the 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, the Commission was established to facilitate the introduction and management of competitive, safe, reliable and fairly-priced electricity in the country.

1.1.5 Pursuant to the above, the objectives of the Commission include:

- to create, promote, and preserve efficient industry and market structures, and to ensure the optimal utilization 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.

1.1.6 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.*

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

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

1.1.8 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.*

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

1.2 *The 2008 Multi Year Tariff Order*

1.2.1 In describing its methodology the Commission noted that it had adopted three basic principles in the determination of an appropriate pricing 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 devoid of excessive regulatory costs.

1.2.2 The MYTO was then decided to be based on the new entrant cost profile for generators 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 was (and still is) to provide the industry with a stable and cost reflective pricing structure that provides a modest return on investment to efficient industry players. At the same time the tariff would protect consumers against excessive pricing, since the price is set at the entry level price of the most efficient generator.

1.3 The Regulatory Foundations of the MYTO Tariff Regime

1.3.1 The three standard building blocks used in the MYTO framework are:

a. The allowed return on capital (to achieve a fair rate of return on the necessary assets invested in the business)
b. The allowed return of capital (to allow for depreciation of capital assets over a specific period of time)
c. Efficient operating costs and overheads

1.3.2 The building blocks method is used to derive the revenue requirement for transmission and distribution/retailing and is used as a 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 MYTO provides a fifteen (15) year tariff path and allows for annual minor reviews and 5 yearly major reviews so as to keep the tariffs more in line with current realities. A major review involves a complete overhaul of all the assumptions in the MYTO model.

1.3.3 The minor reviews only take into consideration three variables, namely:

a. Rate of inflation,
b. gas prices, and
c. foreign exchange rates

1.3.4 There are a number of principles or objectives that guide the pricing of electricity in Nigeria and these are namely:

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 efficiency in the extent 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 removal of subsidies at the earliest opportunity.

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 most efficient 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 ideally be non-discriminatory and transparent. Non-discriminatory access to monopoly networks (currently in transmission and distribution) 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 that affect the market.

Social and political objectives: the pricing framework needs to provide for the achievement of social policy goals such as user affordability, universal (especially rural) access, lifeline tariff and consumer assistance, etc.

1.3.5 With such a wide and sometimes opposite range of objectives and principles, it is inevitable that there will be some trade-offs on which judgments will have to be made. The exact mechanisms for putting these principles into practice are also likely to vary according to particular circumstances. Coming to such judgments correctly requires consideration of the particular circumstances currently applying to the Nigerian Electricity Supply Industry (NESI) and the Federal Government's overall reform strategy for introducing competition and private sector participation. NERC's commitment and mission is to ensure that electricity is adequate, safe, reliable and affordable.

1.4 *Basis for the 2010 – 2011 MYTO Review*

1.4.1 During the minor review of MYTO in May 2009, the Distribution Companies requested that the major review of MYTO scheduled for 2013 be brought forward in order to take care of increasing cost of power, rising cost of operations and maintenance expenses and also declining volume and revenue due to lack of generation capacity which was not envisaged in the 2008 Tariff Order.

1.4.2 The main reasons can be thus summarised as follows:

- There were serious concerns particularly from the Industry on the adequacy of some of its inputs and;
- Due to pressure from potential investors wishing to enter the market using other sources of fuel for generating electricity such as coal, wind, solar, etc.

1.4.3 The Commission considered this request and resolved to carry out the major review of the Tariff Order effective January 2012. Since then, the sector reform and privatization has been thoroughly rejuvenated, with the advent of substantial private sector investment being yet another driver of a major review.

1.4.4 This consultation paper aims at reviewing the 2008 Tariff Order to determine its symmetry with the objectives to which it was issued, review its assumptions and present assumptions for a 2011 Tariff Order that are robust and accurate enough to keep with the current situation in an increasingly very dynamic Nigerian electricity market. The paper is divided into five parts: The background to this work is Part 1, Part 2 will provide a critical review of the 2008 Tariff Order and pricing methodology for the Generation, Transmission and Distribution/Retailing sectors, Part 3 will highlight the proposed technical and cost assumptions which the Commission intends to consider in the forthcoming 2011 Tariff Order. Part 4 will discuss the financial assumptions proposed in determining the 2011 Multi Year Tariff Order (MYTO). Finally, Part 5 will state issues/questions requiring consideration and representations from stakeholders and the public alike to the issues stated herein.

1.4.5 The Commission will adopt a holistic and scientific approach to review current pricing of electricity to ensure gradual sector development through the instrument of a cost reflective and fair tariff regime. The process will take into consideration the interest of consumers and investors simultaneously in addressing the problem.

1.4.6 The attention of the general public are hereby drawn to Parts 3,4 and 5 of the paper and are kindly requested to comment on the assumptions stated therein. The suggestions, if any should propose either a modification or an alternative of the proposed assumptions for the consideration of the Commission. For further enquiries, please contact:

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Part 2: *The Review of the 2008 Tariff Order*

2.1 Introduction

2.1.1 The following sections of the Nigerian Electricity Regulatory Commission's – Notice of Proposed Establishment of a Methodology for a Multi-Year Tariff Order, Gazette conferred to the Commission the powers to set tariffs for the NESI. Paragraphs 2.1.6 & 2.1.7 states:

> *"At the commencement of the MYTO all prices will be regulated but this will be reduced over time as competition increases in the market and electricity supply is sufficient to meet requirements. The major parts of the electricity industry are generation, transmission and distribution and retailing. These parts will be regulated as follows: Generation will be subject to vesting contracts which will set prices to be received by all generators who do not currently hold Power Purchase Agreements. Eventually, when the industry matures, generation prices will not be regulated". Paragraph 2.1.11 then states that "In the transition and medium term market phases, therefore, the MYTO derives a tariff for transmission and distribution/marketing using a building blocks approach as well as prices for generation under vesting contracts. Brought together, these three components combine to produce an end-user tariff".*

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

2.1.3 Some of the assumptions to be reviewed include:

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

2.2 Generation tariff

2.2.1 The MYTO Methodology in Paragraphs 3.5 & 3.6 states that, *"The main objective in setting bulk electricity prices in vesting contracts (wholesale contact price) are to cover the costs of existing plant and allow for their efficient maintenance and on-going investment programs while ensuring that an appropriate price for bulk electricity supplied by generators under vesting contracts is the unit price an efficient new plant would require in the Nigerian electricity supply industry.*

The method to be used in determining the unit price of an efficient plant is the Long Run Marginal Cost (LRMC) Method.

2.2.2 *Long Run Marginal Cost (LRMC) Method:* involves calculating the full life cycle cost of the most efficient (cost) new entrant generator taking into account current costs of plant and equipment, return on capital, operation and maintenance, fuel costs, etc. There are two approaches under this method:

- Single cost as the benchmark: is to create a proxy for the market price below which an efficient generator is expected to operate.
- Individual long run marginal cost for each generator: this sets prices for each generator according to their cost. It is therefore plant and site specific.

2.2.3 The advantage of the LRMC method is that its basis is in economic theory and it encourages new investment in capacity in the lowest cost of generation. The first approach can also be calculated and applied to all generation and does not involve the Commission calculating a different price for each generator. It aims at providing a reasonably efficient price as it is set at the lowest cost form of new entrant and should help to keep costs and tariffs at their minimum. However, its disadvantages include that it does not take into account the different conditions that new or existing generators face unlike the second approach. The first approach generation price may be too low for new and local forms of generation (e.g. solar, wind) which might provide a reliable local source of electricity. If wrong or lower cost assumptions are used in the model, then new investment in capacity will be discouraged.

2.2.4 The advantage for the second approach is that it allows the Commission to price new entry and existing generation at a price that is set according to the specific costs of the type of generation technology being used. This will encourage efficient new investment in a broader range of generation technologies. However, the main disadvantage is that it will probably lead to an increase in the price of generation which will flow through the electricity tariffs, as it is not set at the lowest and most efficient generation price. That is, it allows higher generation prices than those of the lowest cost new entrant. Another disadvantage is that it would encourage lobbying and undue influence as investors are likely to try and persuade the Commission directly or through political connection, to give them the highest generation prices than those of the lowest cost new entrant. A further disadvantage is in determining the cost of existing generation, due to poor cost data or even lack of such data, the practice is to use replacement cost method which uses the cost of new equipment.

2.2.5 *Issues and recommendations:*

- *Type of technology benchmark*: Though the MYTO Methodology does not categorically state that the pricing for generation should be based on the cost of an open cycle gas turbine (OCGT), paragraph 3.5 of the methodology states that *the appropriate price for bulk electricity supplied by generators under wholesale contracts is the unit price an efficient new plant would require in the Nigerian electricity supply industry*. Based on this, the Commission decided to adopt the OCGT plant as its benchmark in calculating generating prices. However, some investors have queried the use of the OCGT rather than a Combined Cycle Gas Turbine (CCGT) which we all know to be more efficient. Though it is a more efficient type of plant it would most probably mean lower tariffs for potential generators. The Commission has conducted a simulation and discovered that until gas prices get to about $3/mmbtu (currently $1.30/mmbtu), the OGCT plant is more efficient and gives a lower tariff. Nevertheless, some investors have requested for Commission's justification for the continued use of OCGT as its benchmark.
- *Wholesale tariff (Price Caps)*: There have been complaints that the wholesale price is not attractive enough to bring in the much desired investment considering the risk in the country. The Commission is addressing this issue and coming up with more acceptable assumptions for determining or fixing the price cap in order to achieve its objectives of being fair and cost reflective.
- *Methodology*: Paragraph 3.5 of the MYTO Methodology further implies that tariffs for the generators are to be at the LRM cost of production in the country as it states that "*vesting contract price is the unit price"* all generators are expected to take. Some stakeholders have expressed that this price should not be general but be site and plant specific as stated in the second approach under the LRMC method. The Commission is willing to reconsider any one of the approaches to setting the wholesale contract price under the LRMC method as they both have their advantages and disadvantages. It should however be noted that going for the second approach would result in changing the methodology and this will involve resources, time and creating regulatory uncertainty. At this stage of the market, it is important to assure investors of regulatory stability and maintain the current position in line with the Methodology.

2.3 *Transmission tariff*

2.3.1 The transmission price as specified in the Paragraph 4.1 of the MYTO Methodology was based on the building blocks and the charge will have the following components:

- *A connection charge for new generators that covers their costs in connecting to the high voltage network.*
- *The covering of transmission losses at different connection points on the network by generators injecting enough power to cover their contracted amounts plus the associated transmission losses.*
- *A charge on distributors per unit of energy taken from the high voltage system at the bulk supply points.*

2.3.2 MYTO applied the building blocks methodology in determining the revenue requirement for transmission. The objectives of the methodology are:

- Ensuring that new loads and generators locate in the most beneficial place by providing mechanisms to ensure that additional costs of transmission arising from their connection are paid by them (generators), and
- Supporting the development of transmission augmentations that may be necessary to maintain the performance of the existing system or to meet the needs of new connected parties.
- The level of prices relates directly to the need for cost recovery, and
- The pricing structure impacts on the achievement of the other objectives by providing signals for efficient system operation and for investment decisions.

2.3.3 The overall level of prices should enable the transmission company to recover its costs, but not exploit its monopoly power while providing incentives for improving performance. The building blocks methodology is usually applied to capital valuation and future levels of capital expenditure, operating costs and sales volumes to derive a future average regulated tariff for each year of the MYTO. Here, the Commission uses an incentive approach, the revenue requirement on which prices are set incorporates assumptions about energy savings that should be achieved in practice if these targets are met (but any efficiencies in excess of the target are able to be retained, at least for a period).

2.3.4 Structure of transmission tariff

2.3.5 Below are the more detailed explanation of the costs associated with the transmission network:

i. The cost of connecting generators and load customers to the network: there are two approaches to connection charges: shallow and deep charges:
   - Shallow connection cost is the cost of construction, operation and maintenance of the network facilities that are strictly needed to connect a network user to the main grid. The connection fee here will cover the cost of the meter and the cost of the line between the customer and the existing network.
   - Deep connection charge provide locational signals for new users as it is more expensive to connect in an area where reinforcements are necessary due for

example to non-existent or saturated/congested network. This charge may be considered in areas to which the existing network does not extend.

Costs of connecting new customers (generators) to the transmission network and maintaining existing connections are typically recovered through connection charges levied on individual customers (generator). The cost of grid reinforcement will therefore have to be recovered through Transmission Use of Service (TUOS) charges that are part of the fixed costs of building and maintaining the grid.

ii. The fixed costs of building and maintaining the network, including a return on capital employed: Transmission prices should be sufficient to cover the fixed costs of the network, which include depreciation, maintenance and a return on capital. The level of the costs to be recovered will depend heavily on the regulatory asset base value as at end 2010 that is ascribed to the transmission network.

iii. The cost of operating and maintenance of the network.

2.3.6 Issues and recommendations

- *Cost recovery*: a persistent issue here is that the IPPs are proposing to invest in the provision of transmission infrastructure to connect to the grid where they are located at long distances (i.e. above 1km from switch yard to TCN main line) due to any constraints on the part of TCN. The Commission is however deliberating on various ways in which to handle this issue with the consent of the various parties. One option being proposed is for the IPPs to build the necessary T-line or spur line and then recover their investment from TCN for such construction from the Market Operator (MO) separate from but alongside their generation tariff. Meanwhile ownership of the infrastructure remains with TCN.
- The Commission recommends retaining the building blocks to develop the revenue requirement for transmission and the current five yearly reviews should be retained. This approach should also be used for the distribution sector. The structure of transmission tariffs should then be designed to yield this revenue while providing as far as possible appropriate signals to users of the costs they impose on the system network.

2.4 Distribution and retail tariff

2.4.1 Background

Paragraph 5.1&5.2 of the MYTO Methodology states that:

> *"Distribution tariffs are similar in a number of respects to transmission tariffs. 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 would 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****".*

2.4.2 A major change in the 2011 MYTO model is the recognition that separate revenue requirements will need to be established for each Disco and so 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. The approach to regulation should contain incentives for reducing these losses. Progress toward reductions should be checked during each of the major reviews. The challenge, especially in the light of the impending privatization will be setting the rate at which to assume that technical losses will reduce. Setting the technical losses to reduce too rapidly might have the Discos under-collecting the revenue assumed for them and become bad regulatory risks, however setting them too slow might see them collecting more money than they need to cover their costs.

2.4.3 *Issues and recommendations*

- *Losses*: The targets set for the reduction of non-technical and technical losses should be carefully reviewed and reduction targets be developed for the next five years. If the Discos are to continue to improve their performance in reducing both technical and non-technical losses they will need to make investment in both capital equipment the training and change Management. The current allowances in the MYTO for these activities was based on the administration, operation and maintenance costs of the Discos collected some years ago. These costs were escalated over time but were derived from poor data and now need to be revised. The MYTO will allow for both the expenditure incurred on these programs and the improvements in performance they should produce. The Commission has requested for data from the 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*: The MYTO should include customer service standards as part of performance indicators. Appropriate indicators have been developed in discussion with the Discos and as set out in the Commission's KPI and customer

service standards Regulation. The Commission has developed guidelines on service level agreement and need to be enforced to further punish recalcitrant Discos.

- *Realistic benchmarks for non-technical losses*: NERC recommends that the building blocks continue to be used in establishing the initial revenue requirements for distribution which will be applied in the form of an annual distribution charge with regulatory reviews every five years. Benchmarks on reducing non-technical losses should also be recognized in the revenue requirement as a way for NERC to encourage reduction of these losses.
- *End-user tariffs (retail tariffs):* End-user tariffs need to reflect the costs associated with all the components of the Industry. Until customer choice is introduced the end-user tariffs will be regulated to protect the interests of the consumers being supplied by a monopoly. Our approach is to ensure that prices are cost-reflective and the rate of non-technical losses is reduced. MYTO should continue to provide for the gradual unwinding of cross-subsidies, which have been embodied in the tariffs. The end-user tariff is expected to cover cost of power (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.
- Also to be included is a requirement for working capital to cover the period when the Discos are required to pay monthly for their electricity supplied and when they collect revenue from their customers. Working capital should be determined as follows:
  - Operating costs: operations and maintenance expenses for two months;
  - Cost of energy: receivables equivalent to three (3) months capacity charge for purchase of electricity, to be calculated based on power allocation factor.

  The working capital shall be included in the rate base for the purpose of giving appropriate return on investment at the approved weighted average cost of capital (WACC).

- *Uniform Tariff/tariff equalisation*: Realistically, no two Discos have the same costs, thus making the case for a policy/practice of National Uniform Tariffs. 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. Going forward, the Commission will have to revisit this issue and decide if this policy is necessary in keeping with its objectives and whether it is beneficial to the market.
- *Rate consolidation*: The current tariff schedule being utilized by the Industry has nineteen (19) rate classes. It was inherited from PHCN in 2007 and there might be

need to review these classes with a view to merging some of them and having fewer tariff classifications of customers.

Table 2.1: Analysis of the 2010 Tariff Schedule

	Tariff classification	**No. of rate elements Under classification**	**Remark**
R	Residential	5	R4 & R5 have the same energy charge
C	Commercial	4	C2, C3 & C4 have the same energy charges
D	Industrial	5	D2, D3, D4 & D5 have the same energy charges
A	Special	4	All the elements have the same energy charges here
S	Street lighting	1	

N.B. - The analysis above shows that most of the rate elements have the same charges.

The Commission recommends that in keeping with our rate making objective which is to have simplified rates that are easy to administer and understand, it might be beneficial to consolidate some of the tariff classes.

Further to this, a report by Tractebel Engineering on the "National Load Demand Study" had recommendations on the need to collapse the nineteen classes into a more realistic group structure of tariff classes. The report specifically observed that:

- the R3, R4 and R5 classes were very similar and also
- the C3, C4 and C5 tariff classes

The 2011 Tariff Order will propose a new tariff structure for the Industry as follow:

Table 2.2: Proposed Tariff Schedule for new Tariff Order

Description	Tariff Codes	Customer Demand Level
Residential	R1	< 5KVA
	R2	>5KVA - 45KVA
	R3	Above 45 KVA
Commercial	C1	5KVA - 15KVA
	C2	15KVA - 50KVA
	C3	Above 50KVA
Industrial	D1	5KVA - 15KVA
	D2	15KVA - 50KVA
	D3	Above 50 KVA
Special	A1	15KVA - 45KVA
	A2	Above 45KVA
Street Light	S1	1-Ph, 3-Ph

- *Subsidy*: The FGN MYTO subsidy first introduced with 2008 Tariff Order, was conceived for two reasons. First, to cushion the effect of sudden price increases as caused the Industry move towards a cost reflective tariff. Secondly is to align the increase with anticipated increase in power supply. The recipients of the subsidy were to be the distribution companies and it was to be disbursed over a three (3) year period. The initial budgeted amount for the subsidy was N177.95Bn, though this has been revised over the period due to the minor review of the MYTO. The purpose of the subsidy was to cover the difference between the retail tariff and what the customers were actually billed.

  The Federal Ministry of Power in March, 2009 introduced a guideline for the subsidy disbursement which was approved by the President, as follows:

  i. The first step in accessing the funds was that the Market Operator (MO) calculates the subsidy requirement of the Discos and forwards this on a monthly basis to the Ministry for approval to disburse.
  ii. The Ministry would then request that the Commission verifies MO's submission, authenticates and sends it back to the Ministry for approval.
  iii. The Ministry then sends approval to CBN to release subsidy into the market settlement account operated by the MO, who then instructs payment in line with applicable settlement rules.

  The problems however with the subsidy were the untimely release and for some months, non-release of the monies. During the thirty six (36) months of its operation, the subsidy has been released only four times (the last two in December 2010 and

January 2011) and the sum of about N105Bn is still outstanding. Since the subsidy constitutes a share of the total revenue requirement of the three years of its application, this led to the unattainment of the efficiency targets in the market. Two options were suggested for future disbursement of the subsidy:

i. *OPTION 1*: The MO should write directly to the Federal Ministry of Finance every month requesting for the release of the subsidy for the previous month based on invoices submitted by Discos and verified in collaboration with the SO;

ii. *OPTION 2*: The MO's letter of request goes through the Ministry of Power provided that the Ministry processes and forwards the request for payment within three (3) days to the CBN to release funds to the Market Settlement Account, without need for recourse to NERC (which still retains its independent power of audit).

The Commission is firmly of the view that the conditions for the withdrawal of the subsidy have not been attained. We are also in no doubt that if the subsidy were to be retained, its payment mechanism would have to be fundamentally upgraded to accord with the settlement calendar; particularly because private sector participation, the deliquent payment of such a huge component of the tariff would guarantee market failure and constitute an acceptable risk. Part 5 of this paper further discusses the issue of subsidies and the recommendations of the Commission.

- *Rate elements*: The methodology states that the capacity charges of the generators have to be recouped. The distribution companies, in order to meet with this target were allowed fixed and minimum charges for all classes of customers. This has placed a huge burden on consumers who have to pay for these fixed charges regardless of whether they have enjoyed supply for a particular month or not.

  The most controversial rate element is the Meter Maintenance Charge, as it is so referred to in the tariff design for the NESI and it is the intention of the Commission to reach a final decision as to veracity of this charge and its uses. In one instance, the Commission recommended that though the meter maintenance charge is a valid charge in the tariff design as it forms a part of the revenue requirement it cannot be matched to any service rendered to the customer since meters are neither maintained, repaired nor replaced free of cost to the customer. Secondly, the Meter maintenance charges are levied on all including unmetered customers who receive monthly estimated bill. The question then arises as to what meters are the utilities maintaining for the customers when meters have not been installed?

  The Commission is further aware that monies collected for this charge are remitted to the Headquarters and never made available for the Discos to use for the purpose for which it was created. The Commission based on its review recommends that the meter maintenance fee name be rephrased so that it could reflect its real and proper use. The other suggestion is that it could be included as part of the fixed charges if it is considered essential in the tariff.

- *Customer numbers*: In 2007, an actual figure of 4.7million customers was used to derive the tariff schedules. Customers within each customer class are assumed to increase over time. The Commission is in the process of updating the figures for customer population in the model and is currently collating the figures.

Based on the 2007 figures, MYTO projected the customer numbers as follows:

Table 2.3: Customer number projections from the MYTO Model

Customer class	2008	2009	2010	2011
Residential	3, 980, 035	5, 248, 854	11, 025, 141	19, 513, 272
Commercial	843, 697	880, 737	919, 404	959, 768
Industrial	27, 040	27, 859	28, 703	29, 571
Special	12, 376	23, 748	26, 506	28, 829
Street Lighting	1, 101	1, 101	1, 101	1, 101
Total	**4, 864, 250**	**6, 182, 300**	**12, 000, 856**	**20, 532, 542**

The basis for the 2010 and 2011 figures was due to the MYTO's targets for load growth during those years. For instance the load capacity target for 2011 was 16, 000MW so with this, over twenty million customers were expected to have connected to the Discos.

Part 3 *Assumptions for 2011 Tariff Order*

3.1 The *new entrant model*

3.1.1 The 2008 Tariff Order determined that the generation price is to be based on the level required by an efficient new entrant to cover its life cycle costs and this price is to be paid to all generators who sell to the grid. Further to this, it was determined that this new entrant will be an Open Cycle Gas Turbine Plant (OCGT).

3.1.2 The OCGT plant was chosen due to the abundance of gas in Nigeria and new, efficient forms of generation technology. It is therefore regarded as one of the most efficient plants and all new entrants are to use this efficient technology benchmark for project evaluation and analysis.

3.1.3 *Technical characteristics of the new entrant model*

3.1.4 The price of electricity to be paid to generators is at the level required by an efficient new entrant to cover its life cycle costs which includes their short run fuel and operating costs and their long run return on capital invested.

3.1.5 The assumptions to calculate the long run marginal costs (LRMC) for wholesale contract prices using or benchmarked with OCGT plant are as follows:

- *Capacity factor:* 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 2008 Tariff Order set this factor at 70% as being the available capacity for a new plant the general opinion is that it should go up to 80%. However, considering normal plant capacity and heat rate degradation of about 2% each over the lifecycle of 20yrs for OCGT, the Commission recommends a factor of 76%.
- *Sent out efficiency/heat rate:* refers to the efficiency in converting the thermal energy of the gas into electrical energy after the internal use of station. The figure from the 2008 Tariff Order of 34% has been reviewed down to 32% as some stakeholders have indicated that this is a more realistic figure.
- *Auxiliary requirement:* This is the internal energy use in the power station and it has been reviewed upwards to 2% for the OCGT Generators.
- *Construction period:* The time it takes to complete and commission the plant and this been reviewed to 3yrs from the initial 2yrs that was in the 2008 Tariff Order, as follows because of the peculiarities of Nigerian in terms of bottlenecks associated with the design, procurement and installation (community related issues, etc):

Table 3.1: Breakdown of assumption for construction period for OCGT plant

Year	Proportion (%)
Year 1	20%
Year 2	40%
Year 3	40%

- *Plant life:* This is the life over which costs are recovered and for the purpose of calculating the long run marginal cost of a new plant the project life of twenty years is proposed.
- *Plant availability:* The percentage (%) of time in a year that the plant is available to generate taking into consideration maintenance and forced outages.
- *Capital cost:* The capital cost covers the cost of engineering, land acquisition, Engineering, procurement and construction (EPC), Planning and approval, professional services, Land acquisition, Infrastructure costs (including water), Spares and workshop, Connection to the electricity transmission network and Fuel connection, handling and storage.
- *Fuel:* is what drives the turbines to produce energy which is converted to electrical energy. The new entrant model is benchmarked against OCGT plant using natural gas, the price of which is set by NNPC and is a pass through cost.
- *Fixed and variable operation and maintenance:* These are the expenses that the utility incurs in providing service to its customers. They include the cost of labour, materials, rent, etc. Fixed costs are not a function of energy produced.

3.1.6 Assumption for new entrants

Table 3.2: Assumptions for the major review

S/N	Category	Old assumptions	Proposed assumptions
1	Capacity (MW)	250	250
2	Life of plant (yrs)	20	20
3	Average sent out heat rate (MJ/MWh)	10, 588	10, 588
4	Auxiliary requirement (%)	1	2
5	Capacity factor (%)	70	76
6	Station marginal loss factor (%)	8	8
7	Construction period (yrs)	2	3
8	Sent out efficiency (%)	34	32
9	Nominal risk free rate (%)	14.80	16.2
10	Exchange rate (N/US $)	149.83	1% above CBN rate
11	Nominal cost of debt (%)	19.29	25
12	Real pre tax WACC (%)	5	11
13	Fixed O&M (N/MW/Yr)	1, 947, 901	2, 400, 000
14	Variable O&M (N/MWh)	252.25	800
15	Capital cost ($/KW)	866	1, 200
16	Gas price (US$/mmbtu)	1.10	1.30

3.2 Assumptions for coal

NERC has decided to develop a methodology for deriving the Long Run Marginal Cost (LRMC) or the life cycle cost of a coal powered generating plant in Nigeria. This is aimed at taking advantage of the abundant coal resources in the country and also opening up the market to give investors in power generation more choices.

3.2.1 For a coal powered generation in Nigeria, two possible sources of coal are considered, namely; domestic and imported coal. The consideration for an imported coal source may be a short term measure pending when coal mines become operational in Nigeria.

3.2.2 The explanation of the assumptions considered in the LRMC for coal are as follows:

- *Capacity per generating unit:* The actual effective plant capacity which would be achievable in Nigeria is assumed to be 500MW. The plant in question would be a supercritical water cooled plant
- *Thermal efficiency:* The estimates of heat rate have been based on published sent out and generated output by existing black coal generators in Australia and Asia. NERC considers 42% to 43% as appropriate. This heat rate takes into account the average plant heat rate, ageing, load frequency of starts and lifetime extension.

- *Plant Availability:* Availability is the proportion of time in any operational year that a plant is available to generate. The outage times that reduces availability consists of planned outages for scheduled maintenance and forced outages when plant is forced to stop or operate at reduced output for technical reasons. Experience with new plant and technologies is that outage rates can be high and so availability for a new coal fired plant in Nigeria is estimated at 86%.

- *Construction period:* The construction period or build time assumed for Supercritical black coal technology is four (4) years in the following proportions:

Table 3.3: Breakdown of assumption for construction period for a coal fired plant

Years	**Proportion (%)**
Year 4	20
Year 3	30
Year 2	20
Year1	30

- *Fixed O&M cost:* Fixed O&M costs include maintenance, operating, and overhead costs that are not dependent on the hour-by-hour level of generation from the station but on available capacity. The estimate of fixed O&M costs is $32,000 per MW.
- *Economic lifetime of the plant:* For the purpose calculating the long run marginal cost of a new plant a project life of twenty five (25) years has been assumed.
- *The capacity factor of the plant:* NERC has continued to adopt the approach of setting the plant factor based on the actual performance of the most efficient supercritical black coal in the operations in the system. This is then projected forward for the two years of the review period and if necessary adjusted downwards to take account of any expected constraints on the operation of this capacity. 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 high proportion of the time in order to meet demand.
- *Auxiliary/Internal usage:* The supercritical black coal plant will require a water cooling system. The auxiliary is estimated at 7.5%
- *Capital Cost:* The estimate of project capital cost for a new coal fired power station includes the following components:
    - Engineering, procurement and construction (EPC)
    - Planning and approval
    - Professional services
    - Land acquisition
    - Infrastructure costs (including water)
    - Spares and workshop etc and
    - Connection to the electricity transmission network
    - Fuel connection, handling and storage

- *Capital Cost:* The capital cost estimate for a Greenfield supercritical coal is **US$1,995/kw** for 2009. This estimate of project capital cost will exclude interest during construction (IDC) and capital costs and site works for a coal mine. IDC is excluded as a return on investment is required in this model from year zero (that is, at the commencement of the project before construction has begun) and interest charges are a component of the WACC. Including another explicit IDC charge would therefore result in double counting.
- *Variable cost:* The estimates of variable O&M cost is presented as cost per MWh sent-out. This is estimated at **$0.96** MWh.

Table 3.4: Assumptions for Coal plant

S/N	Assumptions	Unit	Value
	Technology	**Supercritical**	
1	Capacity	MW	500
2	Fuel	N/GJW	519
3	Sent-out efficiency	%	42
4	Auxillary	%	7.5
5	Capital cost	N/KWh	299, 250
6	Fixed O&M	N	4, 800, 000
7	Variable O&M	N/MW	140
8	Construction period	Yrs	4
9	Life of plant	Yrs	25
10	Capacity factor	%	70
11	HHV Heat Rate	Btu/kwh	40
12	Inflation Rate	%	15
13	Equity	%	70
14	Debt	%	30
15	Corporate Tax Rate	%	32

3.2.3 *Issues and recommendations*

- *Type of Technology:* the use of the supercritical technology as a benchmark has come under a lot of scrutiny as some investors have favoured the adoption of the subcritical plant as a benchmark. However, based on best international practice the Commission proposes to retain the supercritical technology as its benchmark.

3.3 *Feed-in tariffs*

3.3.1 Background

The Commission has considered encouraging the use of different renewable energy sources in order to:

- Encourage local, embedded generation, thereby reducing load on the network and reducing distribution losses associated with the transmission network.

- Encourage uptake of and stimulating innovation in, renewable energy technology (either generally, or a specific type of technology), and

- Reduce greenhouse gas emissions by lessening reliance on fossil fuels.

3.3.2 The following assumptions are proposed for the Feed-in tariffs:

- *Installed Capacity:* this is the total available capacity of the plant and the assumption here differs for each of the technologies.
- *Capital Cost:* this refers to the one-time set cost of the plants. A common description of the scope included in all the cost estimates include the following, among others:

Table 3.5: Some of the components of the capital costs for Feed-in tariffs

WIND	SOLAR PHOTOVOLTAIC	SMALL HYDRO	BIOMASS
Turbine	PV Panels	Turbine	Electrical instrumentation and controls
Tower	Panel supports	Ground property	Civil/structural material and installation
Control systems	Foundations	Channel	Mechanical equipment supply and installation
Electrical interconnection within the farm	Electrical wiring	Machine house	Project indirect costs, fees and contingency
Foundations	DC to AC inverter	Generator	Owner's cost (excluding project financing costs)
Road and civil work	Roads within the immediate area of array	Engineering	
Turbine installations	Installations/Engineering	Dam (optional)	

- *Fixed O&M Cost:* these are the expenses that the utility incurs in operating and maintaining of their facilities. It is indicated in N/MW/Yr.
- *Variable O&M Cost:* The variable operations and maintenance costs vary with the plant capacity factor.

- *Capacity Factor:* The plant capacity factors are relatively low due to the fact that i.e. natural fuels i.e. wind, sun and water are not always optimally available.
- *Auxiliary Requirement:* This is the internal use of station and is assumed at a rate of 1% for all the plants.
- *Economic Life:* A project life of twenty (20) years is assumed for all the categories of plants and it is used to derive the period over which the costs are recovered.
- *Construction period:* This is the assumed length of time it will take to design, import and construct the plant to get it up and running assumed to be three years.

Table 3.6: Breakdown of assumption for construction period for FITs

Year	**Proportion**
Year 1	20%
Year 2	40%
Year 3	40%

Table 3.7: Assumptions for Feed-in tariffs`

S/N	**Description**	***UNITS***	**Assumptions**			
			WIND	**SOLAR**	**HYDRO**	**BIOMASS**
1	Installed capacity	*MW*	10	5	10	1
2	Capital cost	*US$/Kw*	2,525	5,545	3,020	3, 289
3	O&M Cost (Fixed)	*NGN/MW/Yr*	2,900,000	9,570,000	5,655,000	8, 370, 000
4	O&M Cost (Variable)	*NGN/MWh*	232	87	87	775
5	Capacity Factor	*%*	29	33	30	68
6	Auxiliary Requirement	*%*	1	1	1	10
7	Economic life	*Years*	20	20	20	20
8	US$/NGN exchange rate	*NGN per US$*	1% above CBN rate	1% above CBN rate	1% above CBN rate	1% above CBN rate
9	Depreciation	*%*	5	5	5	5
10	Inflation	*%*	15.0	15.0	15.0	15.0
11	Real post-tax WACC	*%*	11	11	11	11
12	Construction period	*Years*	3	3	3	3

3.4 Gas prices

3.4.1 The Ministry of Petroleum Resources and the Commission signed an MOU on transitional gas pricing for the Power Sector for the calendar years from 1st Jan, 2010 to 31st December, 2013. The objective of this agreement was to incentivize investment in gas supply and transport infrastructure for the domestic market.

3.4.2 Gas prices have been regulated since the adoption of the MYTO in 2008 and the regulated prices are as follows:

Table 3.8: Gas prices from 2008 – 2014 used in the calculation of the generation price (US$/mmbtu)

	2008	**2009**	**2010**	**2011**
Price (US $/mmbtu)	0.40	0.60	0.90	0.90

N.B -This is inclusive of gas transmission costs which are pegged at 30cents for all the years.

3.4.3 Gas prices are a pass through costs to the electricity producer so with any material change in the price, the Commission has the responsibility of immediately effecting this change in wholesale contract price.

3.5 Load projections

3.5.1 The 2008 Tariff Order load projections was based on the following:

Table 3.9: Load projection and actual from 2008 – 2011 (MW)

Year	**Load projection (MW)**	**Actual (MW)**
2008	4, 000	3, 595.9
2009	6, 000	3, 710.0
2010	10, 000	4, 333.0
2011	16, 000	3, 700

3.5.2 These projections were incorporated into the model to calculate the unit cost a kw/hr of electricity. However, none of the Ministry of Power's load projections were ever achieved causing disequilibrium in the market. Therefore, going forward in the major review careful consideration has to be given to this area so as to have more realistic targets in achieving a cost reflective tariff.

3.5.3 The Commissions, Research, Renewable and Development Division have made projections of the load from July 2011 to July 2020. The projection was based three Scenarios as follows:

- **Worst case scenario (WCS):** is based on the historic data captured since the inception of the Commission. The trend showed the gradual improvement in power generation arising from the rehabilitation of the existing power stations, minor additions from the IPPs, poor implementation of the federal government policies and project, etc.
- **Most-likely scenario (MLS):** this is the WCS with expected improvement in generation from the Licensed IPPs if bottlenecks in off-take and fuel supply arrangements are removed.
- **Best case scenario (BCS)**: Actualisation of generations expected from the NIPP projects.

Table 3.10: Peak Generation forecast for 2011 to 2020 (MW)

Year end	**Energy (MW)**		
	WCS	**MLS**	**BCS**
2011	3, 850	3, 952	3, 952
2012	3, 967	4, 096	5, 596
2013	4, 088	4, 546	7, 046
2014	4, 212	8, 288	11, 288
2015	4, 341	8. 660	11, 617
2016	4, 473	8, 924	12, 380
2017	4, 609	9, 196	14, 650
2018	4, 749	9, 476	14, 929
2019	4, 894	9, 765	15, 216
2020	5, 043	10, 062	15, 512

3.5.4 Further to this, based on submissions by the Commissions Research, Renewable and Development Division, Engineering, Safety & Standards Division, Management of the Nigerian Delta Power Holding Company (NDPHC) and other technical experts, a projection of generation capacity for the next 5 years was based on three scenarios as follows:

- Scenario 1 (pessimistic case): This scenario assumes that improvements in the generation capacity are solely from the successor Gencos. Projections consider realistic expectations for improvements in efficiency and the refurbishment and expansion of facilities.
- Scenario 2 (base case): This takes Scenario 1 figures and adds the projected capacities of the NIPP projects.

- Scenario 3 (optimistic case): This takes Scenario 2 figures and adds the capacities of the IPP projects that are expected to be available over the next five years. It is important to note that since IPP output is contingent on signing PPAs with the Bulk Trader, 2-3 years of construction, and evacuation to the transmission network, we do not expect to feel their impact until 2014 at the earliest.

The Commission has chosen to base the MYTO 2 model on Scenario 2 as it is the most realistic and most likely scenario out of the three.

Table 3.11: Peak Generation forecast for 2012 to 2016 (MW)

Scenario		2012	2013	2014	2015	2016
1	Capacity	4,000	4,200	4,500	5,000	5,500
2	**Capacity**	**5,750**	**7,500**	**9,061**	**10,071**	**10,571**
3	Capacity	5,750	7,500	9,061	11,571	14,761

3.6 *Load allocation*

The Commission at a meeting held in September, 2010 agreed with TCN and Discos on a load allocation for the sector based on the above load projection as follows:

Table 3.12: Proposed load allocation for the distribution companies (%)

Disco	% age of generation
Abuja	11.89
Benin	9.40
Eko	11.36
Enugu	9.44
Ibadan	13.12
Ikeja	15.34
Jos	5.09
Kaduna	8.26
Kano	5.49
Port Harcourt	5.61
Yola	5.00
Total	**100.00**

3.7 *Losses/Efficiency target*

3.7.1 Losses are a cost in the system which is borne by the final consumer so the figures in the test year have to be as close to reality as possible if not exact. Further to this, the

Commission wrote to the distribution and transmission companies to provide their level of losses as this would provide for a more robust projection.

3.7.2 The 2008 Tariff Order in paragraph 4.3.5 (table 11) shows the allowances made for losses in the MYTO at various stages for five years (2008 – 2012) as follows

Table 3.13: Projected losses for 2008 – 2012 from MYTO Model (%)

	2008	**2009**	**2010**	**2011**	**2012**
Transmission losses	8.05%	8.05%	8.05%	8.05%	8.05%
Distribution losses	11%	11%	11%	11%	11%
Non-technical losses	20%	18%	16%	14%	12%
Billing losses	16%	13%	10%	8%	6%

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3.7.3 Considering the level of investment allowed Discos over the last four (4) years, the following are the recommended minimum level of losses for the Industry.

Table 3.14: Projected losses for 2011 – 2015 (%)

	2011	**2012**	**2013**	**2014**	**2015**
Transmission losses	8.05%	8.05%	8.05%	8.05%	8.05%
Distribution losses	11%	11%	11%	11%	11%
Non-technical losses	14%	12%	10%	8%	6%
Billing losses	8%	6%	4%	2%	2%

3.8 PHCN *Corporate Headquarters*

3.8.1. The 2008 Tariff Order made provision for the funding of PHCN Corporate Headquarters. The Commission however proposes the complete removal of Headquarter charges from the revenue requirement of the Industry.

3.8.2 This is in consideration of the fact that PHCN CHQ is neither a market participant nor a licensee of the Commission. PHCN ought to have been liquidated at least four years ago. PHCN has not been shown to provide vital or essential service to the NESI to justify funding from the consumer from this market.

3.8.3 Accordingly, the Commission could not find any legal, commercial or technical justification for continuing this charge.

3.9 *Regulatory Expenses*

3.9.1 The EPSR Act (2005) provides for recovery of 1.5% of Industry revenue as regulatory charges. The Commission may however choose to recover less than 1.5% if necessary. In 2008 the amount recouped was less than 1%, most of which was not paid by the Market Operator.

3.9.2 The Commission recommends however that the charge of 1.5% is retained so that it can take care of necessary expenditure that will come with its increasing responsibilities and the HR recruitment and development obligations required to ensure NERC's mandate under the EPSRA is fully executed.

4.10 Ancillary Services cost

4.10.1 The 2008 Tariff Order provided a 1% charge on the OPEX of TCN for the purposes of payment for this service to generators. However, the exact methodology as to how these charges were to be paid to eligible generators was left unclear.

4.10.2 The 2011 Tariff Order will be based on more credible forecast as provided by the system operator. Pricing arrangements are being finalized with assistance of external consultants.

4.11 Nigerian Electricity Liability Management Company (NELMCO)

4.11.1 NELMCO was established as a special purpose vehicle by the Federal Government to assume and manage the liabilities and other obligations of PHCN. The SPV has been incorporated but however it is yet to be properly resourced and operationalised. NELMCO has requested in writing that the Commission allow it recover its operating revenue from the market.

4.11.2 However, since they are not market participants, the Commission will find it difficult to allow such request. NELMCO must be financed by grant from Government or the proceeds of liability management.

4.12 Bulk Trader

4.12.1 The EPSR Act (2005) allows for the existence of a "special purpose entity" to conduct contract management and bulk trading on behalf of the distribution companies. However, similar to the NELMCO issue above it has to be determined what rate the bulk trader will be assigned from the market as an administrative charge for the extremely important intermediary role it will play on behalf of the Discos if at all. When the rate has been determined, an allowance will made in the revenue requirement in the Industry.

4.13 Hydro-electric Power Producing Areas Development Commission (HYPADEC) Bill

The Senate has passed the above Bill with the purpose of ameliorating the plight of people living in the localities hosting dams and other energy infrastructure. The Bill has ramifications for investors in Hydro-power as it has funding implications since it proposes "that a total of 30% of the total revenue generated from the operation of any company or authority involved in hydroelectric dams in any of the member states (Kebbi, Kogi, Kwara, Niger and Plateau) shall be paid to its funds". Clearly, the Hydro power plants have to be allowed to recover these funds through their revenue requirement and thus from the market.

Part 4: *Financial and economic assumptions*

4.1 Introduction

4.1.1 The Multi Year Tariff Order (MYTO) Model is also a financial model and there are a number economic and financial assumptions that have to be considered in arriving at the tariffs.

4.2 Economic assumptions

4.2.1 Inflation

This is defined as the persistent increase in the level of consumer prices or the persistent decline in the purchasing power of money. It is measured by the consumer price index and is country specific as it depends on the economic climate in that country. Therefore, Nigeria being an importer of machines and parts for electricity production is also susceptible not only to inflation within the country but also to foreign inflation. This is why the MYTO model also benchmarks inflation rate with that in the US as well as Nigeria. The US dollar exchange rate annual adjustment factor is calculated by comparing the projected rate of inflation in Nigeria with the projected rate in the US.

Table 4.1: Nigerian Inflation rate assumptions in the model vs actual figures (%)

Year	**2008**	**2009**	**2010**	**2011**
MYTO assumption (%)	11	11	11	14.4
Actual (%)	11	14.4	11.8	TBA

N.B – These figures are from the Central Bank of Nigeria/National Bureau of statistics

4.2.2 The Monetary Policy Committee (MPC) meeting held in March, 2011 by the Central Bank of Nigeria suggested that inflation is likely to remain high. They attributed short term inflation primarily to election related spending, continued non performing loan purchased by AMCON, imported inflation and the passage of an expansionary budget for 2011.

4.2.3 Analysts believe that long term inflation rate will continue at mid-double figure rate due to rising food prices and new minimum wage. The factors attributable to imported inflation are rising cost of building materials and transportation cost and all due to recent calamities in Japan and political uprising in the Middle East.

4.2.4 Based on the above forecast, the Commission recommends an inflation rate of 15% from 2011, with a five percent escalation over the next five (5) years as follows:

Table 4.2: Projection for inflation from 2011 – 2015 (%)

Year	2011	2012	2013	2014	2015
Projection	15	15.8	16.5	17.4	18.2

4.3 Foreign Exchange rate

4.3.1 Further to 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 an annual basis during the minor reviews.

Table 4.3: Exchange rate assumptions in the model vs actual figures (₦)

Year	**2008**	**2009**	**2010**	**2011**
MYTO assumption (₦)	125	147	147	147
Actual (₦)	125	147.16	149.83	155

N.B – These figures are from the Central Bank of Nigeria/National Bureau of statistics

4.3.2 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 only accessible to them or that they are often charged a commission. The Commission therefore recommends that in the assumption, 1% should be added over what the CBN rates are.

4.3.3 The Commission recommends an exchange rate of ₦155 to USD$1 and for the base year (2011) also assumes that the Naira will continuously inflate at the rate of 5% from 2012 onwards.

4.4 Capital and operating cost assumptions

4.4.1 Capital expenditure and operating expenditure projections

4.4.2 Transmission

4.4.3 The tables (4.4 & 4.5) below shows the level of capital expenditure and operating expenditure that was allowed in the 2008 MYTO Tariff Order for TCN:

Table 4.4: Estimate of capital expenditure (CAPEX) for the years 2008 - 2012 (N'Billions)

2008	**2009**	**2010**	**2011**	**2012**
156.0	182.0	142.2	232.2	90.3

Table 4.5: Estimate of operating expenditure (OPEX) for the years 2008 - 2012 (N'Billions)

2008	2009	2010	2011	2012
2.7	3.1	3.5	4.0	4.6

4.4.4 Based on the TCNs submission, the tables below indicate the current projections for the OPEX and CAPEX:

Table 4.6: Projection of CAPEX for TCN (N' Billion)

2011	2012	2013	2014	2015	2016
0	137	126	115	65	44

Table 4.7: Projection of OPEX for TCN (N' Billion)

2011	2012	2013	2014	2015	2016
9.03	9.40	9.72	9.93	10.04	10.15

4.4.5 Distribution

The tables below indicate the level of capital expenditure, operating expenditure that was allowed in the MYTO for the distribution companies:

Table 4.8: Estimate of capital expenditure (CAPEX) for the years 2008 - 2011 (N'Billions)

	Asset Value 2008	**2008**	**2009**	**2010**	**2011**
Abuja	9.89	6.94	6.94	6.94	15.95
Benin	17.11	9.08	9.08	9.08	20.88
Enugu	19.72	9.47	9.47	9.47	21.76
Ibadan	27.91	11.55	11.55	11.55	26.57
Jos	8.67	7.60	7.60	7.60	17.46
Kaduna	10.28	8.86	8.86	8.86	20.38
Kano	10.05	7.90	7.90	7.90	18.16
Eko	11.95	10.22	10.22	10.22	23.49
Ikeja	21.22	15.63	15.63	15.63	35.93
Port Harcourt	7.68	7.83	7.83	7.83	18.01
Yola	7.33	6.18	6.18	6.18	14.21
Total	**151.83**	**101.25**	**101.25**	**101.25**	**232.80**

Table 4.9: Estimate of operating expenditure (OPEX) for the year 2008 - 2011 (N'Billions)

	2008	**2009**	**2010**	**2011**
Abuja	0.97	1.07	1.19	1.32
Benin	1.46	1.63	1.80	2.00
Enugu	1.32	1.47	1.63	1.81
Ibadan	2.28	2.53	2.81	3.11
Jos	0.75	0.84	0.93	1.03
Kaduna	1.04	1.16	1.29	1.43
Kano	0.81	0.90	1.00	1.11
Eko	0.87	0.97	1.08	1.19
Ikeja	1.75	1.94	2.16	2.40
Port Harcourt	0.87	0.97	1.07	1.19
Yola	0.60	0.67	0.74	0.82
Capacity building	0.63	0.70	0.47	0.52
Total	**13.41**	**14.89**	**16.21**	**17.99**

4.4.6 Based on the recent valuation of assets of successor companies as at end 2010, the new opening regulatory asset base is as follows:

Table 4.10: Estimates of the regulatory assets base of the Discos as at 2010 and projections to 2015 (N' Billions)

	Opening asset	**Projections**				
Company	**Value (₦)**	**2011**	**2012**	**2013**	**2014**	**2015**
Abuja	95.02	7.12	8.75	10.89	14.04	16.48
Benin	245.23	7.12	8.75	10.89	14.04	16.48
Eko	55.74	4.26	4.23	3.54	2.96	2.80
Enugu	69.73	14.84	12.35	11.83	11.40	9.35
Ibadan	250.73	16.27	15.34	14.50	13.70	11.93
Ikeja	73.88	16.27	15.34	14.50	13.70	11.93
Jos	149.40	6.19	7.43	8.92	10.70	12.84
Kaduna	51.13	1.17	1.18	1.08	0.72	0. 57
Kano	56.31	1.06	1.11	0. 97	0. 86	0. 86
Port Harcourt	26.36	0. 60	1.18	0. 79	0.79	0. 66
Yola	31.40	0. 60	1.18	0. 79	0. 79	0. 66
Total	**1, 104.93**	**75.56**	**76.82**	**78.73**	**83.73**	**84.56**

4.4.7 The figures above represent the tentative values of the companies' assets included in the MYTO model. The values are presently being reviewed by the coordinating consultants, Messrs Parsons Brinckerhoff (PB) United Kingdom. It is very likely that the final figures to be derived after the review process might be slightly higher or lower than the figures presented above.

Table 4.11 (i): Table of projected operating expenditure for the Discos from 2011 – 2015 (N'Billions)

Annual Variable O&M Costs excluding Admin					
Company	**2011**	**2012**	**2013**	**2014**	**2015**
Abuja	1.56	1.95	2.44	3.05	3.81
Benin	2.29	2.74	3.29	3.95	4.74
Eko	1.52	1.58	1.64	1.70	1.76
Enugu	1.04	1.33	1.60	1.92	2.31
Ibadan	1.57	1.73	1.98	2.28	2.63
Ikeja	1.63	1.53	1.45	1.37	1.19
Jos	0.52	0.62	0.75	0.89	1.07
Kaduna	1.17	1.25	1.37	1.51	1.29
Kano	0.73	0.84	0.97	1.12	1.28
Port Harcourt	1.08	1.14	1.20	1.27	1.36
Yola	0.84	0.99	1.16	1.36	1.61
Total	**14.04**	**15.80**	**17.89**	**20.37**	**22.86**

Table 4.11 (ii)

Annual Fixed O&M Costs excluding Admin					
Company	**2011**	**2012**	**2013**	**2014**	**2015**
Abuja	0.52	0.65	0.81	1.02	1.27
Benin	0.76	0.91	1.10	1.32	1.58
Eko	0.51	0.53	0.55	0.57	0.59
Enugu	0.35	0.44	0.53	0.64	0.77
Ibadan	0.52	0.58	0.66	0.76	0.88
Ikeja	0.54	0.51	0.48	0.46	0.40
Jos	0.17	0.21	0.25	0.30	0.36
Kaduna	0.39	0.42	0.46	0.50	0.43
Kano	0.24	0.28	0.32	0.37	0.43
Port Harcourt	0.36	0.38	0.40	0.42	0.45
Yola	0.28	0.33	0.39	0.45	0.54
Total	**4.68**	**5.27**	**5.96**	**6.79**	**7.62**

Table 4.11 (iii)

Annual Fixed O&M Costs Admin					
Company	**2011**	**2012**	**2013**	**2014**	**2015**
Abuja	3.12	3.90	4.88	6.10	7.62
Benin	4.57	5.49	6.59	7.91	9.49
Eko	3.04	3.16	3.28	3.40	3.52
Enugu	3.33	3.66	4.03	4.43	4.88
Ibadan	3.14	3.45	3.97	4.57	5.25
Ikeja	3.25	3.07	2.90	2.74	2.39
Jos	1.04	1.24	1.49	1.79	2.15
Kaduna	2.33	2.49	2.74	3.02	2.58
Kano	1.45	1.68	1.94	2.25	2.57
Port Harcourt	2.16	2.27	2.40	2.54	2.72
Yola	1.68	1.97	2.32	2.73	3.22
Total	**26.54**	**29.55**	**33.24**	**37.64**	**41.93**

4.4.8 The tables in 4.11 (i, ii & iii) above represent 50% of the submission made by the distribution companies for the period under review. The Commission considered the original submission rather too high and decided to review them downward. The reviewed figure is even less than what NETGroup recommended as ideal based on a due diligence of NEPA carried out in November 2002 for BPE. In the report, NETGroup recommended an efficient OPEX of ***₦25.87 Billion*** for 2011. The current MYTO model projected an efficient OPEX of ***₦18 Billion*** for 2011.

Table 4.12: Actual projections of OPEX from the Discos for 2011 - 2015

2011	**2012**	**2013**	**2014**	**2015**
92.93	104.66	119.04	135.24	153.67

4.5 *Cost escalators*

4.5.1 Admin cost escalation

4.5.2 Admin escalation

4.5.3 There are two escalators for admin costs applicable to all the sectors. The first relates to the administration cost reduction, while the second administration escalator relates to increases in wages for employees.

Table 4.13: Projected admin cost for 2008 – 2011 from MYTO Model

	2008	**2009**	**2010**	**2011**
Admin cost reduction per annum	0%	0%	0%	0%
Labour cost escalation	11%	14%	14%	14%

4.5.4 Capacity building was initially accommodated as part of admin costs in the 2008 Tariff Order; however it has not been utilized for the purpose it was meant for so it is the recommendation of the Commission to remove this from the revenue requirement. In light of the on-going privatization exercise, the companies are expected to be more responsive to the capacity needs of their staff and would be willing to utilize their own funds for this purpose.

4.5.5 Further to this, it should also be noted that pensions and gratuity for retired staff of the successor companies will go under the purview of the Nigerian Electricity Liability Management Company (NELMCO). Therefore, only current staff pensions will be allowed into the current admin costs.

4.6 Fixed operational and maintenance cost escalation

4.6.1 Fixed O&M escalation

4.6.2 These are percentage values of the expected annual escalation in fixed operational and maintenance costs for each sector of the business.

Table 4.14: Projected fixed 0&M cost for 2008 – 2012 from MYTO Model

	2008	**2009**	**2010**	**2011**	**2012**
Generation O&M	4%	4%	4%	4%	4%
Transmission O&M	4%	4%	4%	4%	4%
Distribution O&M	4%	4%	4%	4%	4%

Variable operational and maintenance cost escalation

Variable O&M escalation

These are percentage values of the expected annual escalation in variable operational and maintenance costs for each sector of the business.

Table 4.15: Projected Variable O&M cost for 2008 – 2012 from MYTO Model

	2008	**2009**	**2010**	**2011**	**2012**
Generation O&M	12%	12%	12%	12%	12%
Transmission O&M	12%	12%	12%	12%	12%
Distribution O&M	12%	12%	12%	12%	12%

The cost escalators for 2011-2016 should be as follows:

Table 4.16: Proposed projections for the cost escalators (%)

	Costs	**2011**	**2012**	**2013**	**2014**	**2015**
	Admin costs reduction rate	10	10	10	10	10
	Labour costs	13	15	15	15	15
FIXED O&M	**Generation**	4	4	4	4	4
	Transmission	4	4	4	4	4
	Distribution	4	4	4	4	4
VARIABLE O&M	**Generation**	12	12	12	12	12
	Transmission	12	12	12	12	12
	Distribution	12	12	12	12	12

The escalators in the model have to be properly scrutinized as they have to be considered attainable and realistic targets for all of the companies.

4.7 Weighted average cost of capital

4.7.1 Financial indices are used to derive the cost of capital (weighted average cost of capital). This weighted average cost of capital becomes the return on rate base that a utility is allowed to earn. The utility's weighted average cost of capital is determined by first calculating the average cost of each of the sources of capital and then weighing each source by the percentage of the total capital from that source.

4.7.2 The Weighted Average Cost of Capital (WACC) is to be utilized to evaluate an actual investment decision for a specific project due to the fact that it is by definition genetic and designed to be suitable for a range of projects and proponents.

4.7.3 We use a calculated WACC as a conservative proxy for an investment decision hurdle rate for regulatory purposes. The regulatory asset value at the start of a given year is determined by taking the depreciated replacement cost of capital assets as the start of the immediate proceeding twelve months and adding the investments in new capital assets acquired during the same period.

4.7.4 The Nigerian Electricity Supply Industry uses the Capital Asset Pricing Model (CAPM) to estimate the WACC. The CAPM provides estimates of the appropriate return on equity are measured in relation to the risk premium on the equity market as a whole.

The basic CAPM formula is:

Re=Rf+βe (Rm-Rf)

Where: Re=equity returns

Rf=risk free rate in the market

βe=correlation between the equity assets risk and overall market risk

Rm=return on the market portfolio

Rm-Rf=market risk premium

The WACC lies between the cost of equity and the cost of debt so it is thus calculated as:

WACC=Rd*D/(D+E)+Re*E/(D+E)

Where: D=total market value of debt

E=total market value of equity

Rd=the nominal cost of debt, and

Re=the nominal cost of equity

The formulae that allows for the effects of tax is as follows:

Nominal post tax WACC=Re*E/V+Rd(1-Tc)*D/V

Where: Tc=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:

Real pre tax WACC (RW)=[(1+w/(1-Tc)) / (1+i)] – 1

Where: w=the nominal post tax WACC, and

i=the inflation rate.

Company tax rate is statutory at 30% plus 2% education tax rate thus giving 32%.

4.7.5 The components of the WACC utilized in the 2008 Tariff Order are as follows:

The risk free rate: The Commission selected a risk free rate of 14.8% and it is the yield on Government bonds.

The cost of debt: NERC adopted a nominal cost of debt of 19.29% for generation and 16.5% for transmission and distribution.

Betas: The beta measures the volatility of an individual stock market relative to the market. the Commission assumed the assumption 0.5, based on the assumption that the level of risk in the Industry will have a similar relationship to market wide risk.

Gearing: the Commission has set 70:30 as the ratio of debt to equity in the model.

4.7.6 Components of the WACC for 2011 Tariff Order are as follows:

The following are the recommended rates for 2011 – 2016

Table 4.17: WACC assumptions

Assumption	Value
Risk free rate	16.2%
Cost of debt (generation)	25%
Cost of debt (transmission and distribution)	25%
Betas	0.5
Gearing	70:30
Real pre-tax WACC	11%

4.8 *Depreciation*

4.8.1 Plant or facilities wear out or become obsolete over time. Depreciation is a term used to recognize this limited life span of plant investment and to allocate the cost of plant over its useful life. In line with Paragraph 2.2.2 of the MYTO Methodology, the Commission utilizes the optimised depreciated replacement cost method (ODRC) to calculate the value of TCN and each distributor capital stock. This value is then included in the annual revenue requirement. The single line depreciation method is used for the asset lives to provide an annual depreciation schedule for each asset until the end of its depreciable life.

The following are the rate of depreciation used for years 2008 – 2011 and shall be retained:

Table 4.18: Schedule of depreciation rates for the year 2011 – 2015

Existing assets	**Economic life (yrs)**	**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

4.9 *Valuation methods*

4.9.1 A common valuation method was adopted for the valuation of the generation and distribution assets of the successor companies known as the Gross Replacement Cost Method (GRCM). The basis for this choice is that it was not only a more robust way for valuation but the electricity services sector is illiquid in Nigeria and the current tariffs are not substantially below the actual tariffs.

4.9.2 Though the GRCM does not take normally into cognizance the existing condition of the assets, the method was improved as the age and condition of the assets were taken into consideration.

4.9.3 The methodology used covered the following items:

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

Valuation of assets: here the initial value of the assets based on the asset register owned by the business is established.

- Amalgamates the assets into type and age
- Applies linear depreciation in a formulaic approach to all assets classes based on age
- Applies a standardized approach to missing data
- Applies a standardized approach to condition assessment following site visits

Templates were created for collecting data from the successor companies. One for the generation companies and one for the distribution companies.

Asset Register Value (ARV): The successor companies' asset register is the beginning of this process. The ARV will reflect the cost incurred when the equipment was installed and this will be a real cost that has not been inflated from the date installed to the current date.

Gross Asset Replacement Cost (GAP): It was determined that the GAP will be used for the valuation of distribution assets in Nigeria. Average Unit Costs are gross unit costs and exclude any indirect costs such as property operating costs, pensions and wayleaves.

Depreciated Asset Value (DAV): This method is based on the industry weighted replacement profiles and average unit costs. The principal steps applied in determining DAV are:

- Find Gross Asset Replacement Cost (GAP)
- Make an estimate of the present age of an Asset (PAA)
- Benchmark Mean Life of an Asset (MLA)
- Calculate Depreciated Asset Value (DAV)

$$DAV = MLA - PAA$$

Condition Based Asset Valuation (CBAV): This is used to take into account conditions of the assets. Calculating the condition based depreciation enables account for the decrease in usefulness of assets caused by conditions.

Table 4.19: Table indicating category of condition of assets

Category	Maintenance Quality	Years Remaining
0.3	Excellent	15
1.3	Acceptable	10
2.3	Poor	5
3.3	Critical	2

$$RAV = GAR * (1-CBAV)$$

Final Asset Value (FAV): In calculating the FAV it has been assumed that an overall value variance of less than 5% (including any unadjusted variance arising from the asset value assessment part of the methodology) is material.

$$FAV = \frac{RAL}{PAA + RAL} * (GAR-RAV) + RAV$$

Where:

GAP – Gross Asset Replacement Cost

RAV – Residual Asset Value

PAA – Present Age

RAL – Residual Asset Life

FAV – Final Asset Value

Part 5: *Other special issues for comments by the stakeholders*

5.1 Inclusion of breakdown of the revenue requirement funds

5.1.1 The 2008 Tariff Order was not clear about the deduction of the various components in the revenue requirement for the Industry. It is therefore the intention of the Commission to correct this going forward in the major review to review these charges.

5.1.2 Therefore the new Order will be specific in determining tariffs for:

- Ancillary charges
- Capacity building
- Market Operator charge
- System Operator charge
- Regulatory charge
- Annual license charge

5.1.3 Similar, to the charges in the revenue requirement, the formulae for tariff equalization is not very clear and the Commission no longer expects tariff equalization to be feasible under Section 76 of the EPSR Act (2005).

5.2 Subsidies/Inclining Block tariffs/Lifeline tariffs

5.2.1 The need for some sort of subsidy is evident given the setbacks of the previous tariff order, higher gas prices and the inclusion of renewable sources of generation and coal in the Industry. The result will be higher wholesale contract prices leading to higher end-user tariffs which may be unaffordable to some consumers. A Subsidy may be direct, in which case the poor and needy receive direct compensation which is granted either from the Government or other sources. The advantage of such subsidies is that they can be targeted more effectively than other forms of support, and adverse effects may be limited with effective design of the subsidy. The on-going FG approved subsidy is an example of a direct subsidy, but it lacked one very important factor which a direct subsidy must have to be effective, which is the speed and simplicity with which the subsidy arrives since belated compensation will lead to problems.

5.2.2 There is also indirect support which may be given with the use of an inclining block tariff or some other social tariff. Inclining block rates are prices that increase with increasing blocks of usage. A well designed inclining block tariff will reduce bills for low-use consumers; keep bills unchanged for average-use consumers and increase bills for high-use consumers. An example of this with our residential customers will be to retain the lifeline tariffs (R1) and (R2) customers as they presently are and for the R3 customers if they exceed a certain level of consumption then they will be charged as R4 customers. These may however prove ineffective in targeting vulnerable consumers as it not only the poor that consume little and it is not only the wealthy who consume a lot of energy. Though indirect tariffs may have the advantage of simplicity and low implementation cost, the cross-financing of vulnerable consumers by other consumer classes may also be less visible since all households are entitled to the discounts of the first tariff blocks. Another problem with implementing this inclining block tariff is that a condition precedent to it is the provision of adequate metering for consumers. This is however not the case as only about 40% of consumers in the country are metered. Though the use of an inclining block tariff would have been better suited as it better targets consumers who impose more cost to the system to a higher tariff, the current lack of metering will not make it an effective tool in targeting underprivileged customers. Especially in the light of the fact that those without meters in the first place are the underprivileged customers. The lifeline tariffs should also be continued and pending when there has been adequate metering in rural areas then the option of the inclining block tariff may then be revisited.

5.2.3 The social, economic and political implications of both forms of subsidy have to be weighed before seeking for a scheme that will ease the suffering of consumers who will not be able to afford the increase in tariffs. Further to this, a timeline for any subsidy decided has to be formulated because in order to be effective a subsidy must have a timeline.

5.2.4 The current tariff schedule has the (R1) tariff subclass (for loads up to 5KVA) as its lifeline tariffs. This subclass of consumers pays the least tariff and is heavily cross-subsidized by other tariff classes. It is recommended that the (R2) and (R3) subclasses are merged to form one tariff subclass that will then be regarded as lifeline tariff consumers. The loads as to which this new classification will apply should be considered as this will be a form of subsidy for underprivileged consumers. However, some challenges exist with the concept of lifeline tariffs as stated above.

5.2.5 Though provision for metering has been provided for in the capital expense (CAPEX) in the model, in order to implement inclining block tariffs and lifeline tariffs it may be necessary for the Commission to set targets for the Discos to install meters especially rural areas. Another point to consider is that lifeline block tariffs do not work with some of the existing prepayment meters, so it might be necessary to consider these costs in the Discos CAPEX. The ideal timeline for implementing appropriate metering across the consumer classes and the minimum required percentage of success is a matter of discussion.

5.2.6 Tariff cross subsidies, which are another type of indirect subsidy is a common phenomenon throughout the world as it is often embedded in tariff schedules. One group of customers will often be made to be pay lower and this money will be recouped by charging another group of consumers a higher tariff. An example will be the lifeline tariffs for poor households as industrial/commercial consumers will have to balance this by paying a higher tariff than what they would have otherwise paid. Even though the fundamental regulating principle is that tariffs shall be cost reflective, the EPSR Act (2005) also states in section 76(2) (f) *“that tariff methodologies shall phase out or* *substantially reduce cross subsidies"*. The Act then goes on further to state that the Commission will take into account any subsidy needed and then allows for the provision of a lifeline tariff for some consumers. It therefore stands to reason that the Act also recognizes and makes provision for certain classes of customers to be cross-subsidized by others.

5.2.7 Another option is the Power Consumer Assistance Fund (PCAF), as Sections 83 of the EPSR Act (2005) gives the Commission:

> *"the powers to set up and administer a Power Consumer Assistance Fund to assist underprivileged customers. It is to be funded by contributions from designated consumers, eligible customers and any subsidies received from the Federal Government of Nigeria".*

The income/revenue of the Fund is to be derived from;

a. Contributions by other customers of electric power, such as eligible customers
b. Subsidies received from the Federal Government as appropriated by the National Assembly.

5.2.8 NERC is required to take responsibility for the establishment, operative and maintenance of the Fund. The establishment of the power consumer fund can only come about with the introduction of competition and eligibility in the power sector. The Commission has prepared guidelines as to consumers who qualify be classified as eligible customers but this has yet to be announced by the Minister as required by the Act.

5.2.9 Further to this, the Commission has to prepare a framework for the PCAF and it is currently in the process of doing this. The framework has to include among others, the specification of all consumers that will fund it and how it will be administered in the market. It is the recommendation of the Commission that the direct subsidy such as FGN Subsidy discussed in Section 2.3 of the paper be prolonged with better coordination and targets (such as collection efficiency targets, etc).

5.3 Additional stipulations/additions in the new Tariff Order

5.3.1 The new Order will stipulate that the MO should not purposely fix monies for participants outside the requirements of the Market Rules. The practice of arbitrary derogation and requests for funding in a manner not contemplated by the Act, regardless of the source of such requests shall not be tolerated. Similarly, the operation of successor companies (SCs) by entities that have no place in the day to day or boardlevel policy-making of these SC's (whether public or private sector driven) all of which impose distortions and/or extra costs on the system shall also not be tolerated any longer. Henceforth, the Management of any market participant that allows its decision-making and daily operations to be influenced by entities that are not part of the formal or licensed Management structure shall along with the entity itself be directly penalized by NERC for such failure.

5.3.2 Similarly, the Commission has recently become aware that certain market participants operate as part of corporate entities that carry on other non-electricity business under the same corporate personality. This applies especially to the current IOC market participants, such as Shell and AGIP. The serious potential for the above market power (given the current and future importance of the IOCs for the supply of both natural gas and electric power to the NESI) speaks very eloquently for itself.

5.3.3 Similarly, the Commission has taken account of the on-going transition in the NESI from NASB SAS2 financial reporting standards to benchmarks set under IFRS. Accordingly, the Commission will require in the reviewed MYTO that the IOCs and any other incorporated market participants separate their staff and electricity regulated assets/liabilities and incorporate them under CAMA; and also set up systems for financial accounting to IFRS.

5.3.4 The new tariff order should include the formulas for calculating any subsidies in the market.

5.3.5 Lastly, the issue of whether private distribution companies are allowed to benefit from any subsidies should be addressed.

5.4 Commencement date for MYTO 2

5.4.1 Though the date of the review was meant to be in July, 2011 in line with the 2008 Tariff Order. Of great concern, is the fact that the time might be insufficient for the Commission to conclude on some pertinent policy/practice issues which are critical for the success of MYTO 2 which include:

a. National Uniform Tariffs
b. Subsidy payment mechanism
c. Power Consumer Assistance Fund
d. Transition steering group for preparation of the market
e. Downsizing of the successor companies by the BPE and public buy-in to be obtained
f. Metering and billing systems

5.4.2 It is with these factors in mind that the Commission is reviewing its effective date to January, 2012.

5.5 Development of a National Feed-in Tariff Fund

5.5.1 Due to the lack of creditworthiness of the distribution companies, a tariff payment mechanism for FITs should be managed nation-wide. Thus the proposal of a national feed-in tariff fund by the Commission which will serve a cost sharing mechanism.

5.5.2 Several emerging economies and developing countries have utilized such a mechanism and if transparently managed it could help reduce the risk of corruption. It could be adopted by use of a premium on the eventual retail electricity price e.g. 1%. This revenue will then go into a fund which will be established to finance the tariff payment for renewable electricity producers under the national FIT.

2010 Tariff Schedule

Tariff Code Details		Year starting 1 July			2010
Tariff Code	Fixed	Meter	Minimum	Demand	Energy
	N/Month	N/Month	N/Month	N/KVA	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	360.98	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

	Tariff Codes	Customer Demand Level
RESIDENTIAL	R1	<5KVA
	R2	>5KVA<15KVA
	R3	>15KVA<45KVA
	R4	>55KVA<500KVA
	R5	>500KVA<2MVA
	C1	>5KVA<15KVA
	C2	>15KVA<45KVA
	C3	>55KVA<500KVA
COMMERCIAL	C4	>500KVA<2MVA
	D1	>5KVA<15KVA
	D2	>15KVA<45KVA
INDUSTRIAL	D3	>55KVA<500KVA
	D4	>500KVA<2MVA
	D5	>2MVA
	A1	>15KVA<45KVA
	A2	>55KVA<500KVA
	A3	>500KVA<2MVA
	A4	>2MVA
SPECIAL TARIFF CLASS	S1	1-Ph, 3-Ph
STREET LIGHTING		