NIGERIAN POWER SECTOR REPORT
IS THERE LIGHT AT THE END OF THE TUNNEL?

February 2017
Executive Summary

In this report, we initiate a coverage of the Nigerian power sector with reviews and insights into developments in the post-privatization era. In 2013, Nigeria commenced a comprehensive reform of the sector, in a privatization move that was proclaimed to be one of the boldest power reform initiatives globally, with proceeds from divested assets estimated at c.US$3bn. The overarching objectives of the reform were two-fold: to address chronic efficiency gaps in the old public utilities, and attract private capital needed to propel the sector to meet Nigeria’s fast growing electricity demand. The question we attempt to answer in this publication is why the sector has seen little progress on these two fronts. Further, we provide our outlook for the industry and the factors we consider as imperative to the success of Nigeria’s power sector reforms given the experiences of similar countries. We conclude that bold decisions will need to be made to kick-start a new era in electricity delivery in Nigeria.

The trouble with Nigeria’s power sector

The power sector reform in Nigeria has come with both pains and gains, with the former taking the shine off the noble intents of the privatization exercise. Broadly, the challenge with effective and efficient electricity supply in the post-privatized electricity market in Nigeria can be summarised in one word: “shortage”. From feedstock availability to electricity units delivered to the end-user, there are severe strains that not only threaten the financial viability of the sector, but also practically repel fresh funding and investment across the value chain. Whilst the persistence of these challenges in a privatised framework does not call into question the validity of the reforms, it points to the need for Nigeria to do more in addressing lingering bottlenecks such as:

- the sub-optimal utilization of generating capacity;
- inadequate transmission infrastructure and high distribution losses; and
- low rates of collection.

For example, over 3,000MW of generating capacity is stranded due to gas constraints. Transmission capacity can only wheel 50-60% of installed capacity, while collection losses range between 40-60% at the distribution company (Disco) level.
Route to Bankability: Like Telecoms, like Power?

At the onset of the power sector reforms, local expectations were high as the privatization of the National Electric Power Authority (NEPA)/Power Holding Company of Nigeria (PHCN) was often compared, albeit wrongly, to the revolution engendered by the earlier liberalization of the telecommunications sector. However, events post-privatization have proven disappointing as the sector continues to grapple with systemic challenges, with negligible improvement in supply relative to the pre-reform era. It would appear that stakeholders took too long to come to terms with the dissimilarities between the two sectors. With regard to the telecommunications sector, save for early teething problems, bankability was established very quickly as lenders dimensioned the risk-reward potential of the sector in a clear and consistent manner. This was aided by the fact that the telecommunication companies (telcos) had more control over the “universes” they created and didn’t have as many inter-dependencies as the electricity generation companies (GENCOs) and distribution companies (Discos) have. As a result, the telcos were considered to be more “bankable”.

Getting the economics right: The tariff puzzle

The biggest hurdle against the commercial viability of the Nigerian electricity value chain is insufficient cash flows. This has significantly impaired the ability of the Gencos and Discos to recover all costs and generate appropriate returns on investment. It has been a rather daunting task aligning the charges for electricity consumption with the cost of electricity generation, transmission and distribution. In this regard, to set the tone for our proposition for the Nigeria Electricity Supply Industry (NESI), it would be useful to work with two central principles in mind: 1) The cost of not having electricity is much greater than the cost of putting the right machinery in place given that self-generation costs 62-94kWh, two times grid-based power in Nigeria; 2) An efficient supply system where losses are at the barest minimum, and an inefficient system with significant losses (typical of the Nigerian case) will both bear the same cost in delivering electricity to the end user. With these principles in mind, and as we show later in this report, tariffs should be significantly higher than they are now. Further, gas prices need to be completely liberalised to ensure producers become largely indifferent between export potential and local sale to Gencos.
Seeking quick and optimal generation: Expanding the grid or looking beyond it?

We argue for a decentralized power generation model in Nigeria as current challenges are insurmountable within the existing framework. Currently, the national grid supplies more than 90.0% of Nigeria’s power output. Efforts seem to be focused on ramping up investment in the grid, but we believe a less centralised structure, where off-grid solutions are prioritised and supply close to 50.0% of power output, would ensure improved efficiency and a more competitive electricity market (similar to what obtains in other jurisdictions). In this regard, independent system operators and mini-grids must be explored to achieve quick wins in electricity supply. It is clear that the failure to achieve optimal gas utilization is telling on power output, a trend that effectively begs 2 questions: 1) Should Nigeria continue to pipe gas to where generating plants are sited?, or; 2) Should it generate power where the gas is and transmit the power to where it is needed? Either way, the oil companies still require significantly higher incentive in the form of large increases in regulated gas prices to build gas infrastructure sufficient to achieve a quantum leap in Nigeria’s power supply.

For the Nigerian transmission sub-sector, achieving the significant amount of non-government funding, as spelt out in the Transmission Company of Nigeria (TCN’s) most recent 5-year outlay will be a key challenge going forward. The recent change in management of the TCN means that the company is now completely owned and operated by the federal government. In effect, the government will be shouldering the credit risk of the TCN for the foreseeable future. Given that investors would likely be more disposed to taking sovereign risk directly (preferably via treasury or bond instruments), relative to an indirect exposure via the TCN, a continued government control of transmission will cap capital inflows into the sector. Therefore, it is important that the government hands-off the transmission sector via a complete privatization or concessioning, if it is to attract the much needed private capital in that space. There needs to be a bold departure from seeing the transmission grid as a national asset that needs to be centrally managed.
The Disco Challenge: Liquidity crisis compounds capital shortfall

In our view, the delay in the implementation of the Transitional Electricity Market (TEM) was the first set-back in the way of capital inflows into power sector post-privatization. Whilst the Interim Rules Period lingered, creating what was effectively a string of non-enforceable contracts, a liquidity over-hang was built up. The role of government in the settlement and payments system extended far longer than it should, with debilitating impact on investor confidence and the operational efficiency of the market. Further down the value chain, lax regulation and enforcement of sanctions at the Discos level with respect to collection efficiency created cash flow shortages which continue to impede the overall efficiency of the sector.

With regard to capital investment, the Discos are currently overleveraged, hence equity injection is the most efficient way to plug capital shortfalls in the sub-sector. The domestic financial system is overexposed to the sector and lacks the capacity and depth to provide further funding support, especially debt capital. A good proportion of future Capital Expenditure funding, by necessity, needs to be forex-based which, as of late, has become an issue given the currency volatility and acute shortage of forex being experienced in Nigeria. Additionally, the existing CBN intervention fund, ranking superior to other debts in the books of the Discos make them highly unattractive for more debt funding especially from domestic sources. Therefore, we recommend off-balance sheet financing as a viable option for getting round current capex challenges.

Investment Outlook: Long term value, short term pain

In spite of the numerous headwinds confronting the Nigerian power sector today, the electricity market remains an attractive long term investment opportunity. In the medium term, we expect the biggest investment inflows to come into the generation segment which offers the highest risk-adjusted returns at the moment, as the overall systemic risk appears to be skewed in favour of the Gencos largely due to sovereign guarantees backing contracts in that segment. However, because independent power plants have in-built transmission capabilities (hence not dependent on the grid) they are likely to continue to attract a larger share of investment as the power sector evolves. In this regard, the National Independent Power Plants (NIPPs) will be integral to achieving a major boost in electricity supply over the medium term.
Nigerian Power Sector …Is there light at the end of the tunnel?

Analyst
Kayode Tinuoye
Kayode.tinuoye@unitedcapitalplcgroup.com
+234-706-881-6408

Team
research@unitedcapitalplcgroup.com
+234-1-280-7334

Disclaimer
This publication was prepared by United Capital Research ("UCR"). UCR notes are prepared with due care and diligence based on publicly available information as well as analysts’ knowledge and opinion on the markets and companies covered; albeit UCR neither guarantees its accuracy nor completeness as the sole investment guidance for the readership. Therefore, neither United Capital (UCAP) nor any of its associates or subsidiary companies and employees thereof can be held responsible for any loss suffered from the reliance on this report as it is not an offer to buy or sell securities herein discussed. Please note this report is a proprietary work of UCR and should not be reproduced (in any form) without the prior written consent of Management. UCAP is registered with the Securities and Exchange Commission and its subsidiary, UBA Securities Limited is a dealing member of the Nigerian Stock Exchange. For enquiries, contact United Capital Plc, 12th Floor, UBA House, 57 Marina, Lagos. ©United Capital Plc 2016.*
## Contents

### The Evolution and State of Nigerian Power Sector
- The History of the Nigerian Power Sector 9
- The Nigerian Power Sector Today: A bird’s eye view 11

### Post-Privatisation Challenges
- Will the power deficit ever shrink? 17
- Whither the Transitional Electricity Market? 18
- Evolving a sustainable trading arrangement: The Role of NBET 20

### Gas-to-Power: The Heart of the Value Chain
- Closing the gas-to-power gap 22
- Gas Flaring: seeking a sustainable solution 23
- Gas Pricing and the Nigeria Gas Master Plan 25
- The DSO: How far and how well? 26
- Beyond gas pricing: looking down the value chain 27

### Electricity Pricing Model: Where should tariffs be?
- The MYTO Methodology 30
- The elusive cost-reflective tariff 37
- The danger of tariff regulation 39

### Electricity Transmission: The Weakest link?
- Striving to close a massive funding gap 41
- Funding TCN: Expanding the range of options 43
- Beyond the grid: Pros and cons of embedded generation 45

### Electricity Distribution: The burden of the Last mile
- Post-Privatization state of Discos 50
- Way forward for Discos 53
- Closing Efficiency gaps 55

### Concluding Remarks
- The imperatives of successful power sector reforms 57
- Investment Outlook: Long term gain short term pain 59
- Road to Bankability: Past, present and future 60

Appendix 1: Company profiles: Generating companies 64
Appendix 2: Company Profiles—Distribution companies 73
Appendix 3: Roles of Key Institutions 79
Appendix 4: MYTO Building Blocks 83
The Evolution and State of the Nigerian Power Sector
History of the Nigerian Power Sector

The Pre-Reform Era

The history of Nigeria’s electricity supply industry (NESI) dates back to the end of the 19th century, when the first generating power plant was installed in Marina, Lagos with an installed capacity of 20MW. Nigeria’s first utility company, the Nigerian Electricity Supply Company, was established in 1929. Further developments included the establishment of the Electricity Corporation of Nigeria (ECN) in 1950 to co-ordinate the distribution of electricity. The post-independence era saw the establishment of the Nigerian Dams Authority (NDA) in 1962 to oversee the construction and management of hydropower stations. The NDA was principally a power generating entity whilst the ECN was mainly responsible for distribution and sales. However, in 1973, the ECN and the NDA were merged to form the now defunct National Electric Power Authority (NEPA). The two entities were merged at the time as a result of the need to vest the production and distribution of electric power supply throughout the country in one entity, which could assume responsibility for its financial obligations1.

The Necessity of Reforms

The state-owned utility, NEPA operated as a monopoly and consistently failed to meet the country’s power needs. It was evident that the vertically integrated structure of the institution was not working and there were no reasonable grounds to expect it to be revived, even if more money was invested in it. In a bid to address the ensuing chronic power shortage and improve efficiency, the National Electric Power Policy (NEPP) of 2001 was formulated, heralding power sector reform in Nigeria. Subsequently, the reform drive for the sector encompassed a number of models but a common theme was the involvement of the private sector as the quantum of investment needed to improve capacity and efficiency was clearly beyond the scope of government financing. The NEPP, which was later enacted as the Electric Power Sector Reform Act (EPSRA) 2005 spelt out the overarching objective of reforms in the sector as follows: “...establishing a long term electricity market structure in Nigeria in which multiple operators provide services on a competitive basis to the broadest range of customers. Under such a regime, competitive market forces would be the best determinant of the appropriate and sustainable levels of prices charged by various carriers for their services”.

In 2005, NEPA, later renamed the Power Holding Company of Nigeria (PHCN), was unbundled into 18 companies – 11 Discos, 6 Gencos, and the TCN, with the intention of onward sales to private sector operators. An independent regulator, the Nigeria Electricity Regulatory Commission (NERC) was established that same year and the Roadmap for Power Sector Reform was drawn up in 2010, and subsequently revised in 2013. The Roadmap culminated in the privatisation of the successor distribution and generation companies in 2013 with the privatised assets handed over to new owners in November that year. Although there were plans to revise the Road Map, that was never officially done.

Structurally, the Nigerian power sector has seen significant transformations due to these reforms. The market has evolved from a fully state-owned and technically regulated market with non-existent wholesale structure to an unbundled system now governed by “arms length” regulation.

Although the privatization of the power sector has often been described as a “forced” sale, credit must be given to past governments for beginning the reform journey. That having been said, it is important to note that similar to the old (pre-reform) structure, it is still a small market in terms of installed capacity and units sold. This is however expected to change over time with new investments.
Nigeria Power Ecosystem: A bird’s eye view

Generation

There are 23 generating plants connected to the national grid with a total installed capacity of 10,396 Megawatts (MW) and available capacity of 6,056MW as at June 2016. Generation is mostly thermal based (c.81% of installed capacity). Gas-powered plants have a cumulative installed capacity of 8,457.6MW with an available capacity of 4,996MW. Hydropower from three major plants account for 1,938MW of total installed capacity from an available capacity of 1,060MW. The plants run by generation companies include those formerly under PHCN, NIPPs, and the Independent Power Producers.
Transmission

The transmission of generated electricity is undertaken by the Transmission Company of Nigeria (TCN) which emerged from the unbundled PHCN following the conclusion of the privatization exercise in 2013. The FGN opted to outsource management of TCN to private sector operators, Manitoba Hydro International (MHI), a wholly owned subsidiary of Manitoba Hydro in Canada, involved in electricity generation and distribution.

Although controversial at the time (with respect to the Board composition of the TCN), the move was a deliberate effort to ensure a more efficient management of the grid/transmission infrastructure. Having won the contract to manage and operate TCN in 2012, MHI did not commence operations until March 2013 due to bureaucratic delays.

One of the major areas of focus of MHI was to reorganise TCN and ensure that the Market Operator (MO) and the System Operator (SO), the two integral parts of the transmission sub-sector become autonomous. MHI recently handed over the management of the TCN to the FGN.
Independent Power Plants (IPPs)

IPPs are power plants owned and managed by the private sector. Although there were Independent Power Producers existing prior to the privatisation exercise, a slew of IPPs has come on stream in the last 4 years. Post-privatization, the Nigerian Electricity Regulatory Commission (NERC) has issued over 70 licenses for IPPs. There are currently three (3) private IPPs supplying power to the national grid. They consist of those owned by Shell (Afam VI, 642MW), Agip, (Okpai, 480MW), and one run by AES Corporation (270MW). The Shell and Okpai power plants were amongst the five power plants originally conceived to be constructed by the joint venture between the IOCs and NNPC. The other three, Chevron’s Agura Power Plant, ExxonMobil’s Qua Iboe Power Plant* and Total’s Obite Power are yet to be concluded due to the non-availability of upstream projects to supply gas feedstocks to the power plants.

The IPPs were conceived as a veritable means to monetize Nigeria’s gas assets, and stop gas flaring by the IOCs, thereby boosting electricity supply. However, the lack of economic viability tied to gas production remains an impediment. Besides the gas constraints, the weak contribution from the IPPs is also attributable to uncertainties regarding payments from the bulk trader, NBET for electricity sold to the national grid.

The National Integrated Power Project (NIPP)

The NIPP initiative was birthed in 2004 as a fast-track public sector funded project designed to add new power generation capacity to existing electricity supply. A special purpose vehicle, the Niger Delta Power Holding Company Limited (NDPHC) was set up with ownership by the three tiers of government to facilitate the implementation of the project. The NIPPs came alongside transmission, distribution and natural gas supply infrastructure required to deliver power throughout the country.

The privatisation of the NIPP plants commenced in November 2013. The plants were sold with contracted power purchase and gas supply arrangements. The winning bidders for the 10 plants emerged in March 2014 and the plants were sold for a cumulative value of c.US$5.7bn. Post-privatization, NDPHC is to retain a 20% holding. Under the sale agreement, the plants were to be handed over to the successful bidders by June 2014.

*undergoing divestment as at the time of writing report
The NIPP plants are yet to be fully completed and handed over to their new owners due to recurring issues of community restiveness, security threats in the Niger Delta with attendant impact on gas supply given that 7 of the 10 plants are situated in the restive region. Furthermore, disruptions arising from probes by the National Assembly continues to stall the complete delivery of the project.

### Table 1: NIPP projects in Nigeria

<table>
<thead>
<tr>
<th>s/n</th>
<th>Name</th>
<th>Location</th>
<th>Installed Capacity</th>
<th>Preferred Bidder</th>
<th>Acquisition Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Alaoji</td>
<td>Abia State</td>
<td>1074 MW</td>
<td>AITEO Consortium</td>
<td>US$902.0m</td>
</tr>
<tr>
<td>2</td>
<td>Calabar</td>
<td>Calabar, Cross Rivers</td>
<td>634.5 MW</td>
<td>EMA Consortium</td>
<td>US$625.0m</td>
</tr>
<tr>
<td>3</td>
<td>Egberama</td>
<td>Near Owerri, Imo State</td>
<td>380.7 MW</td>
<td>Dozy Integrated Power Limited</td>
<td>US$415.1m</td>
</tr>
<tr>
<td>4</td>
<td>Gbarain</td>
<td>Near Yenagoe, Bayelsa State</td>
<td>253.8 MW</td>
<td>KDI Energy Resources</td>
<td>US$340.0m</td>
</tr>
<tr>
<td>5</td>
<td>Geregu II</td>
<td>Ayakoru, Kogi State</td>
<td>506.1 MW</td>
<td>Yellowstone Electrical Power</td>
<td>US$613.1m</td>
</tr>
<tr>
<td>6</td>
<td>Ihovbor</td>
<td>Benin City, Edo State</td>
<td>507.6 MW</td>
<td>EMA Consortium</td>
<td>US$580.0m</td>
</tr>
<tr>
<td>7</td>
<td>Olorunsogo</td>
<td>Olorunsogo, Ogun State</td>
<td>754 MW</td>
<td>EBNL Consortium Limited</td>
<td>US$751.2m</td>
</tr>
<tr>
<td>8</td>
<td>Omoku II</td>
<td>Near Port Harcourt Rivers State</td>
<td>264.7 MW</td>
<td>Shayobe International Limited Consortium</td>
<td>US$318.7m</td>
</tr>
<tr>
<td>9</td>
<td>Omotosho</td>
<td>Okitipupa, Ondo State</td>
<td>512.8 MW</td>
<td>Omotosho Electric Power Limited</td>
<td>US$660.0m</td>
</tr>
<tr>
<td>10</td>
<td>Sapele II</td>
<td>Sapele, Delta State</td>
<td>507.6 MW</td>
<td>Daniel Power</td>
<td>US$531.8m</td>
</tr>
</tbody>
</table>

Source: www.nipptransactions.com, United Capital

### Distribution

Power distribution in Nigeria is managed by 11 Discos. Geographically, each distribution company covers 3 to 5 states, excluding Ikeja and Eko Distribution Companies, both of which serve Lagos State. The Discos construct, operate and maintain distribution systems and facilities, including, but not limited to the connection of customers for the purpose of receiving supply of electricity; the installation, maintenance and reading of meters, billing, collection and other distribution services. A distribution licensee may also have the obligation to provide electricity to its distribution customers, if consistent with the terms of a trading licence issued by the regulatory Commission.
Nigerian Power Sector ... is there light at the end of the tunnel?

Post Privatization Challenges
Post-Privatization Power Sector

Will the power deficit ever shrink?

In spite of years of structural reforms, the power sector has continued to operate at a sub-optimal level due to a series of challenges. Whilst the persistence of these challenges in a privatised framework does not call into question the validity of the reforms, they point to the need for Nigeria to do more in addressing the sub-optimal utilization of generating capacity, inadequate transmission infrastructure as well as high distribution losses.

Today, approximately 95 million Nigerians (c. 55% of the population) have no access to electricity from the grid and those who are connected to the grid face extensive power interruptions. Systemic issues which affect all phases of the power value chain (gas supply, generation, transmission and distribution), forcing Nigerians to rely on expensive self-generation.

According to the World Bank, an estimated 41% of Nigerian businesses generate their own power supply to augment the national grid supply. At 126kWh per capita, Nigeria lags significantly behind other developing nations in terms of electricity consumption. Based on the country’s current demographics and global trends, electricity consumption should be four to five times higher than it is today. For instance, the global minimum average electricity consumption per capita for developing economies is 500kWh, 4 times Nigeria’s. Ghana’s per capita consumption stands at 361kWh, 2.9 times Nigeria, while South Africa with 3,926kWh consumes over 30 times Nigeria’s power. The rule of thumb is that an industrial nation requires 1,000 MW per million inhabitants. This would imply that Nigeria requires 180,000 MW for full power, which is a massive distance away from the new government’s target of 10,000MW by 2020.
The trouble with the power sector in Nigeria can be summarised in one word: “shortage”. From feedstock availability to electricity units delivered to the end-user, there are severe cash flow strains that not only threaten the financial viability of the sector, but also practically repel fresh funding and investment across the value chain. Therefore, the biggest challenge that needs to be overcome is repositioning the sector to attract more funding from local and international sources.
Whither the Transitional Electricity Market?

Based on the Road Map for the Power sector reform as launched in 2010, the Nigeria Electricity Supply Industry was envisaged to evolve over 5 stages of development: Pre-TEM Stage, Interim Rules Period, Transitional Electricity Market (TEM), Medium Term Market, and the Long Term Market, with a set of governance mechanisms for each stage (see figure 6 below). The Market has passed the first two stages which were governed by “interim” and non-enforceable transaction rules. The third stage, the TEM, originally scheduled to commence in 2014 was declared in February 2015; hence by virtue of the announcement, the market can be said to be in the transitional stage, at least on paper. However, given ongoing structural challenges affecting the implementation of TEM, it could be argued that the market is still somewhere in-between the pre-transition (interim rules) market and TEM. Technically, TEM is meant to create a legally binding backdrop for the enforcement of all contracts initiated during the Rules period effectively kick-starting the institutionalisation of all structures that define a competitive electricity market. We highlight that the initial delay in the declaration of the TEM not only stalled investment but also threw up legacy cash flow strains reminiscent of the chronic payment problems that characterised the pre-TEM era.

Fig. 6: Expected Life Cycle of Nigeria Electricity Supply Industry

Declared in Feb 2015

- Physical Unbundling of PHCN.
- Privatisation of PHCN.
- Establishment of performance incentives for generation and distribution activities.
- Test Run of the Grid Code.
- Continuation of pre-TEM trading arrangements.
- Power generation output not covered by the PPAs put in place for the successor company privatisations, and Discos continued to be billed by the Market Operator (MO) for electricity from these sources.
- Electricity trading arrangements consummated through contracts.
- No centrally administered balancing mechanism for the Market.
- Development of a Market Procedure for the management of inadequate supply and shortage conditions.
- Balancing Market will be a spot market (daily trading at prevailing market price).
- Distributor may enter into bilateral contracts for purchase and or sale of energy.
- Open entry to the market.
- Retail competition - all consumers choose their suppliers.
- Clear differentiation between distribution (delivery) and retail activities.
- Open access to transmission and distribution networks.
Knotty systemic challenges still casting shadows on TEM

As stated earlier, the commencement of the TEM was meant to herald the beginning of a legally backed “power market” in Nigeria, and arguably the first in Africa. TEM was designed to pave the way for the introduction of a competitive electricity market, speed up the enforcement of supply contracts and attract the much needed investments into the sector.

Though fraught with implementation challenges, the declaration of TEM remains laudable, as it theoretically makes the privatization of the power sector almost irreversible. We also note that the declaration of TEM in a politically charged atmosphere just weeks before the 2015 elections, signaled the regulator’s commitment to the reform process, a development that has been well received by prospective investors. That being said, the first 18 months of TEM has seen little or no progress, on account of a myriad of factors.

The constraints to the full operationalization of TEM are both structural and exogenous. The strain on the government’s fiscal balance sheet due to macroeconomic challenges continues to create spill-over effects on the fulfilment of NBET’s obligations. Moreover, the delay in policy pronouncements post the 2015 election, as well as eventual sweeping changes in the managerial structure of relevant government parastatals have constituted a clog in the functioning of the new system. These, in addition to stretched lending portfolios of banks to the power sector, have led to a persistent build-up of unmet obligations. For instance, the declining trend of payment of verified invoices from NBET to Gencos has created a stock of outstanding receivables of c.N140.0bn (average payment made between January and June 2016 stood at 38.2% for thermal Gencos and 20.8% for Hydro Gencos). Furthermore, the slow recovery of Aggregate Technical, Commercial and Collection (ATC &C) Losses, which remain critical to the liquidity of Discos and Gencos continues to plague the system.

In summary, despite providing the clear legal backdrop to enforce contracts, TEM is still far from achieving its strategic objectives due to system-wide challenges such as bottlenecks around full cost recovery for Discos, gas supply challenges and generally low sector-wide capacity. These issues are extensively discussed in subsequent sections of this report.
Evolving a Sustainable Trading Arrangement: The role of NBET

Before the advent of recent regulations which allow eligible buyers to procure directly from Gencos and IPPs, the post-privatised Nigerian electricity market operated under a single buyer model for too long, with NBET at the centre of procurement. In essence, over time, the liquidity of the Bulk Trader has become too critical to the cash management of the electricity value chain. Currently, there is no clear timeline for winding down the operations of NBET as originally envisaged in the Power Road Map. Beside stifling the competitiveness of the industry, the lack of credible alternatives in power procurement is akin to a monopoly structure with all its attendant deficiencies. In fact some of these weaknesses are already manifesting in susceptibility to government interference, lack of payment discipline and most importantly, the ever increasing contingent liabilities on the government.

In our opinion, the role of NBET looks likely to be extended beyond its original intent and what is economically justified. If the utility companies had been allowed to operate as commercial entities before privatization, the current level of tariff uncertainty would have been much lower as losses would have been better verified through a more comprehensive due diligence process prior to take-over. In essence, the omission of this critical leg of the reform process due to political and/or commercial necessity is now likely to prolong the life-span of NBET as a buffer for system-wide commercial and credit risk.

Source: NBET, United Capital

Fig. 7: Transitional Market Trading Arrangement
Nigerian Power Sector ...Is there light at the end of the tunnel?

Gas-to-Power: The Heart of the Value Chain
The Gas Challenge

Closing the gas-to-power gap

Globally, Nigeria ranks as the 8th largest country in terms of gas reserves and the 13th largest gas producer, accounting for c.20% of Africa’s gas production. Expectedly, gas remains the most prominent source of electricity generation in Nigeria. By our estimates, thermal plants account for 69% and 81% of Nigeria’s available and installed generating capacities as at June 2016.

In spite of the abundance of gas resources, insufficient gas production and a poor distribution network have constituted long-standing bottlenecks to steady power supply in Nigeria. According to the TCN, average daily power generated in August 2016 stood at 3,354MW, of which reported gas constraint to generation averaged 3,420MW. In effect, if constraints to optimal gas supply are removed, Nigeria could easily double its current power generation given that available capacity still stands at 6,056MW. This would undoubtedly have a noticeable impact on the end user and the sector as a whole.

The abundance of gas reserves is a low-hanging fruit for Nigeria. Whilst upstream gas availability has never been an issue, the major constraint arises from years of significant underinvestment in pipeline transportation to deliver gas to where it is needed in order to keep pace with power generation.

Nigeria has the 8th largest gas reserves in the world and the largest in Africa.

Nigeria could double its current power generation if gas supply constraints are removed.

![Graph showing gas-to-power declining month-on-month](image)

Source: NNPC, United Capital

*Fig. 7*
Fig. 8: Main Gas Infrastructure in Nigeria

Source: Oando, United Capital

Fig. 9: Nigeria Gas Production and Utilization as at June 2016

Source: NNPC, United Capital
Gas Flaring: seeking a sustainable solution

One of the major reasons why effective gas-to-power has proven difficult to achieve is the knotty issue of gas flaring (i.e., the burning of natural gas associated with crude oil when it is pumped from the ground). We note that there seems to be conflicting reports about the state of gas flaring in Nigeria. An EIA report (2016) ranked Nigeria 5th amongst countries in the world to have flared the highest volume of gas per day with the cost of the country’s associated gas production flared in 2015 estimated at 379 billion cubic feet (BCF) representing about 12% of gross production. This suggests that the relative position of Nigeria in the global gas flaring league has seen little change in the last 5 years (in 2011, Nigerian ranked 2nd to Russia, having flared 620 billion cubic feet of natural gas). However, the NLNG maintains that the country has made significant progress in reducing gas flaring, currently estimated at less than 10% according the latest NNPC report.

Despite these conflicting reports, what is clear is that the incentive system for monetizing natural gas is currently below the threshold that could discourage gas flaring given that gas production is not core business of oil companies, especially the IOCs. Like all rational economic decisions, gas flaring thrives because the next best alternative costs more. In 2015, only 7% of total daily gas production was supplied to power firms while c.8% was flared in the first half of 2016. Furthermore, enforcement of penalties for gas flaring has been abysmally weak.

Fig. 10

8% of Nigeria’s natural gas production flared between Jan-June 2016

Source: NNPC, United Capital
Gas Pricing and the Nigeria Gas Master Plan

The need to strike a balance

The Nigerian Gas Master Plan (GMP) was launched in February 2008 with the overarching objective of optimizing the country’s abundant gas resources and minimizing gas flaring. Central to the theme of the GMP is the need to ensure that sufficient gas is made available for certain sectors that were deemed “strategic” to the economy, including the power sector. At the design stage, whilst the GMP emphasized an export oriented gas sector, it also envisaged the attainment of full commerciality in the domestic gas market, a task that has however proven to be less than straightforward.

The critical question remains- why has the GMP not successfully explored the diversity of the Nigerian downstream gas portfolio? The biggest challenge, in our view, is the varying capacities of the targeted sectors to pay for gas. In fact, the power sector, the largest industrial user, appears to have the least capacity to pay. Furthermore, for a long time post the launch of the GMP, a significant portion of the supplied domestic gas was not backed by standard and bankable Gas Supply and Purchase Agreements (GSA), partly due to the slow take-off of the Transition Electricity Market (TEM). To add, the history of non-payment for gas especially from government parastatals, has created a disincentive towards IOC’s investment in gas supply. The implication of these challenges has been a slow build-up of gas infrastructure needed to propel the Nigerian power sector.

The GMP focuses on optimal utilization of gas resources

Downstream gas investment opportunities remain vastly unexplored

Fig.11: Nigeria Gas Master Plan Proposed Implementation Stages

Source: NNPC, United Capital

1. Increasingly unstable position
   - Introduction of domestic obligation rule
   - Transitional Pricing Framework
   - Commercial Structures – GSPAs and Securitization
   - Infrastructure Blue Print Development

2. Thriving Export
   - Full Commerciality in domestic gas
   - Increased Infrastructure Investment
   - Legislation Process progressing

3. Starved Domestic Market
   - Introduction of domestic obligation rule
   - Transitional Pricing Framework
   - Commercial Structures – GSPAs and Securitization
   - Infrastructure Blue Print Development

4. Sub-commercial domestic market
   - Full market status
   - End of intervention steps and transitional arrangements
   - Commercial Structures – GSPAs and Securitization
   - Infrastructure Blue Print Development

5. Market led investments
The Domestic Supply Obligation (DSO): How far and how well?

An aspect of the GMP that seeks to facilitate the supply of gas to the thermal plants is the DSO. Other aspects include the Gas Pricing Policy and the Gas Infrastructure Blueprint.

The DSO, which became operational in 2010, is a framework within the GMP that stipulates that every gas producer must allocate a certain proportion of its output to the domestic market before export. In other words, the critical sectors have the right of first refusal to gas supply. Before the DSO became effective, virtually all gas produced was either exported or flared mainly because the major off taker, the PHCN Gencos could not pay a commercial rate for gas supply to the power plants.

The fundamental drawback of the DSO is that it is predicated on a regime that was both price and volume regulated, implying excessive government influence in the market. The amount that each gas supplier must allocate is not fixed but determined each year depending on the number of suppliers as well as the volume of supply and demand in the market. Also, the regulated price for the DSO (predominantly allocated to the power sector) was hinged at a 15% margin for gas supplied at the lowest possible cost. This lack of certainty in base-price determination creates additional disincentive for gas producers. In fact, the minister of petroleum determined that the cost-reflective baseline was US$1.0 per MCF in 2012 before later reviewing the price to US$2.0 per MCF in 2013. The price was further reviewed to US$2.5 per MCF in 2015.

The DSO stipulates that gas producers must allocate a certain proportion of output to the strategic local industries.

DSO operates under a heavily regulated regime.

![Figure 13](image-url)
Fixing the Challenges in the gas industry: A Holistic Approach

Beyond gas pricing: looking down the value chain

Undoubtedly, the uneconomic pricing of gas-to-power has served as a major disincentive to expansion in gas production and distribution infrastructure as IOCs find it more profitable to flare or re-inject existing gas. That being said, the cash flow problems at the gas aggregation level go all the way to the end of the value chain due to the high collection losses in the system. For example, significant distribution and collection losses at the Disco level lead disproportionate cash flow shortages at the gas-to-power segment, creating a cycle of negative cash flows. Therefore, solving the gas problem has to begin from the last mile of the value chain (i.e. the Discos).

Fig.13: Gas-to-Power Cash flows

Gas Supply disruption: Finding a lasting solution

Broadly, the sticking point with Nigeria’s gas-powered generation over time has been the initiation of power generation projects on the assumption that gas would be readily available, without considering the cost of getting the gas to generation sites, or the possibility of disruption in the course of transporting the gas.
In effect, the Nigerian power sector has always been exposed to risk of gas supply interruption ab initio. Given recent challenges with evolving a lasting political solution to pipeline vandalism, it is imperative to reconsider a different model that not only ensures that future disruption to gas supply is eliminated, but also facilitates a quick fix to power supply challenges as they relate to gas availability.

Revisiting Gas Upstream Strategy: The Non-associated Gas Solution

About half the total gas produced in Nigeria is from Associated Gas (i.e. gas produced alongside crude oil). Associated Gas (AG) is usually not intended to be produced. Therefore, it comes at a low pressure and requires compression to propel through processing, costing sometimes more than 4 times non-associated gas to transmit to the point of use.

Clearly, the failure to achieve optimal gas utilization in the power sector is telling on power output. This therefore begs two questions: 1) Should Nigeria continue to pipe gas where the power plants are sited? or; 2) Should it generate power where the gas is and transmit the power where it is needed?. If the status quo is maintained, the implicit assumption would be that a sustainable political solution is quickly found to the recurring pipeline disruption the sometimes alleged vested interests’ resistance to reforms. Even if that is achieved, the oil companies, especially IOCs, would still require significantly higher incentives in the form of large increases in regulated gas prices to build gas infrastructure sufficient to achieve a quantum leap in Nigeria’s power supply.

With that being said, there needs to be a shift in upstream gas production in a way that prioritizes non-associated gas. Historically, the siting of power plants has been driven more by political considerations than feedstock availability. This has led the power sector to rely on associated gas to serve plants located too remotely from fuel sources. If gas-to-power targets are to be achieved, we believe the many stranded fields of non-associated gas need to be brought into productive use with fiscal terms clearly defined to encourage indigenous participation. Apart from being the most effective response to our power emergency need given that it complements an embedded generation strategy, the added merit of this approach is an abrupt end to gas flaring, faster execution of power projects and a more efficient distribution of power supply across the country. It also eliminates the logistics of laying pipelines across complex terrains which leads to longer project delivery.
Electricity Pricing Model: Where should tariffs be?
Getting the Economics Right

The Tariff Conundrum

The biggest hurdle militating against the financial viability of the Nigerian electricity value chain is the insufficiency of cash flows that recover all costs and generate an appropriate return on investment.

In this section, we review Nigeria’s current electricity pricing framework: The Multi-Year-Tariff Order (MYTO) system. We examine the different changes made to the pricing model over the years, especially in the post-privatization era. The question on our mind is: what should be the ideal pricing mechanism that generates sufficient cash flows, minimises government subsidy, ensures the highest level of transparency and makes for reasonable predictability of investment returns over a long period of time?

Background to the MYTO Methodology

Balancing cost-reflectivity and affordability

One of the clear problems with NEPA/PHCN’s business model was its opaque tariff plan. In the old transfer/shadow pricing model, there appeared to be little or no correlation between the cost of producing and supplying electricity and the tariff charged to the customer. In essence, there was no transparent commercial electricity tariff framework that reflected the true cost of generating, transmitting and distributing electricity. NEPA/PHCN simply set the prices using a simplified template. Once set, the prices were presented to the president for approval.

The Multi-Year Tariff Order (MYTO) was intended to set electricity tariffs for consumers over a longer time period (15-year period beginning from 2008 to 2023). There were to be minor reviews of the pricing mechanism twice a year (announced on 1 December and 1 June) and major reviews every five years. Minor reviews can only consider four variables, namely: the rate of inflation, gas prices, foreign exchange rates and actual daily generation capacity. Major reviews are meant to re-assess the methodology and make further inputs to the existing tariff model. In order to smooth out the transition to a cost-reflective tariff plan, the federal government was required to maintain subsidies though for a limited period of time.
MYTO-1: Incentive driven but lacking in versatility

MYTO-1 was introduced in 2008. The methodology set tariffs for electricity consumers for a five-year time period, while providing a 15-year projection on the evolution of tariffs over time. Under the system, generation prices were set using what is called a new entrant cost profile while transmission and distribution prices were determined using the building block approach. For both approaches, there was an underlying set of pricing principles and cost assumptions (see appendix 4).

The aim of MYTO-1 was to provide the industry with a stable and cost-reflective pricing structure in order to ensure a decent return on investment for efficient industry operators, while protecting consumers against excessive pricing. One major advantage of MYTO-1 was that it had its basis in economic theory and was designed to encourage new investment in capacity enhancement. The tariff regime also provided incentives for reducing technical and non-technical losses, with signals for suppliers to invest more and consumers to adjust their consumption style efficiently. Tariffs for the initial five years ranged from N9 to N11.50 per Kwh, translating to approximately 67% increase in electricity tariff of N6 per Kwh in the pre-MYTO era. Owing to this marked tariff increase, the FGN designed a strategy that allowed for a gradual rise in the price over four years (2008-2011) with subsidies for low energy consumers. There was however no increase in the first year with increases then occurring in years 2, 3 and 4. Despite its economic appeal, the major challenge with MYTO-1 was its narrow approach to generation pricing which we will further elaborate on.

NERC pre-determines that the most optimal plant is one that utilizes gas

<table>
<thead>
<tr>
<th>Year</th>
<th>Subsidy</th>
<th>NERC determined Tariff</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>6.0</td>
<td>NERC determined Tariff</td>
</tr>
<tr>
<td>2009</td>
<td>3.64</td>
<td>6.2</td>
</tr>
<tr>
<td>2010</td>
<td>0.99</td>
<td>8.5</td>
</tr>
<tr>
<td>2011</td>
<td>0.0</td>
<td>10.0</td>
</tr>
<tr>
<td>2012</td>
<td>0.0</td>
<td>10.0</td>
</tr>
</tbody>
</table>

Fig. 14 Under MYTO 1, subsidy was projected to decline to zero over a 5-year period

Source: NERC, United Capital

There were two key weaknesses of the MYTO-1:

1. It failed to consider the pricing of other sources of electricity, including coal, wind, and solar
2. It also failed to consider the different conditions that new or existing generators faced.
MYTO-2: Different strokes for different folks

Given the challenges with MYTO-1, and the complaints by the distribution companies, NERC considered an earlier-than-scheduled major review of MYTO-1 in 2012. This was after the Regulator estimated that the pricing structure only covered 50% of the revenue required to make investments in the sector viable. Besides the shortcomings of MYTO-1 identified earlier, most of its projections were largely missed, with implications for end-user pricing. For example, MYTO-1 had projected that by 2011, Nigeria would be generating 16,000 MW of electricity at which the revenue requirement (cost plus return) of the value chain would be met. It also assumed that the privatization of the Discos and Gencos would have been completed by 2009.

The key changes made with MYTO-2 relative to MYTO-1 were as follows:

- The divergence in the operating conditions of the Discos was considered in determining the building block for each of them.
- More credible data (obtained in consultation with the Discos) was used in setting targets for loss reductions which are factored into the tariff computations.
- Discos were allowed to make allowance for working capital to meet maturing debts and basic operational expenses.
- Customer classes were consolidated into 14 compared to 17 classes under MYTO-1.

Fig. 15

Under MYTO-2 tariff charged varied by Discos

MYTO 2.0 Average Tariff Charges (Naira/kWh)

<table>
<thead>
<tr>
<th>City</th>
<th>Tariff</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jos</td>
<td>29.0</td>
</tr>
<tr>
<td>Kaduna</td>
<td>26.9</td>
</tr>
<tr>
<td>Abuja</td>
<td>26.0</td>
</tr>
<tr>
<td>Enugu</td>
<td>25.9</td>
</tr>
<tr>
<td>PH</td>
<td>25.4</td>
</tr>
<tr>
<td>Yola</td>
<td>24.4</td>
</tr>
<tr>
<td>Ibadan</td>
<td>23.2</td>
</tr>
<tr>
<td>Kano</td>
<td>23.1</td>
</tr>
<tr>
<td>Eko</td>
<td>22.4</td>
</tr>
<tr>
<td>Ileja</td>
<td>21.2</td>
</tr>
<tr>
<td>Average</td>
<td>24.8</td>
</tr>
</tbody>
</table>

Source: NERC, United Capital
According to NERC, the MYTO 2 system is meant to achieve the following:

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

The MYTO was designed to be an incentive based tariff system for consumers over a 15-year period (2008—2023).

The components of costs that go into the tariff computation are depicted in the figure below:

![MYTO Tariff Components Diagram]

Source: NERC, United Capital
MYTO-2.1: Still in search of fairness

After the privatization, NERC conducted a revalidation exercise to ascertain the actual ATC&C losses in the system. These losses turned out to be significantly more than the bid-based figures for most of the Discos. Following the exercise, the loss reduction targets of the Discos were adjusted appropriately. All the Discos (except Eko and Ikeja) recorded ATC&C losses greater than the uniform bid basis of 35.0% during the privatization exercise. As shown in figure 17 below, the highest verified collection losses were recorded in Kaduna (60.8%) and Enugu (59.1%).

In addition, NERC carried out a minor review of MYTO-2 triggered by a more than 5.0% change in some of the four variables meant to be assessed under minor reviews i.e. rate of inflation, gas prices, actual generation capacity and exchange rate. Hence, MYTO 2.1 was issued for the period January 2015–December 31 2018. The review resulted in significant increases (up to 100.0% for some customer classes) leading to a public outcry culminating in a public hearing where NERC decided to reduce the tariff by removing the collection losses. After this reduction, the Discos again raised the concern that the tariffs were no longer cost reflective, issuing notices of force majeure. The Discos’ concern was further exacerbated by their recurring failure to meet financial obligations to the NBET and by extension other service providers upstream. Consequently, NERC considered another tariff review. After consultations with the Discos, NERC issued a set of guidelines for tariff review after which Discos were required to come up with their tariff plans on 1st July 2015. After the submission of tariff plans by the Discos, NERC issued the Amended MYTO 2015 in December 2015.
The Amended MYTO 2015: A mere change of name?

Following the submission of the tariff plans by the Discos, NERC revised MYTO2.1 and renamed it Amended MYTO 2015. Under the new framework, electricity prices increased by between 30-58% across the Discos with an average increase of 42.6%.

Other major highlights of the Amended MYTO 2015 were as follows:

- The collection loss component of the verified ATC&C losses was reinstated into the end-user tariffs.
- The 10 year tariff plan submitted by each of the Discos was adopted by NERC with the guidelines specifying that there should be under-recovery in the first few years and over-recovery in subsequent years.
- A retention of the customer classification under MYTO 2.1 with the scope for customers to migrate from one class to another depending on volume of usage. (see table 3 below).
- The fixed charge tariff component for all Discos was removed and re-balanced to energy charge, which implies that customers will only pay more for energy consumed.
- The macro economic variables underpinning the model (i.e. rate of inflation, exchange rate and gas prices were reviewed to reflect current reality while the generation capacity projections were revised (2016 - 5,465MW; 2017- 7,199MW; 2018- 8,999MW; 2019 10,473MW; 2020-11,383MW)

Table 3: Classifications under MYTO 2015

<table>
<thead>
<tr>
<th>Customer Classification</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>RESIDENTIAL</td>
<td>A consumer who uses his/her premises exclusively as a residence - a house, flat or multi-storied house.</td>
</tr>
<tr>
<td>R1, R2, R3 &amp; R4</td>
<td></td>
</tr>
<tr>
<td>COMMERCIAL</td>
<td>A consumer who uses his/her premises for any purpose other than exclusively as a residence or as a factory for manufacturing goods.</td>
</tr>
<tr>
<td>C1, C2 &amp; C3</td>
<td></td>
</tr>
<tr>
<td>INDUSTRIAL</td>
<td>A consumer who uses his/her premises for manufacturing goods including welding and ironmongery.</td>
</tr>
<tr>
<td>D1, D2 &amp; D3</td>
<td></td>
</tr>
<tr>
<td>SPECIAL</td>
<td>Customers such as agriculture and agro-allied industries, water boards, religious houses, government and teaching hospitals, government research institutes and educational establishments.</td>
</tr>
<tr>
<td>A1, A2 &amp; A3</td>
<td></td>
</tr>
<tr>
<td>STREET LIGHTING</td>
<td></td>
</tr>
<tr>
<td>S1</td>
<td></td>
</tr>
</tbody>
</table>

Source: NERC, United Capital
What is wrong with the MYTO methodology?

Clearly, in spite of the series of amendments, cash flows from MYTO have proven insufficient to service the entire value chain. The biggest shortfall has historically occurred at the distribution level which we highlighted earlier as the most critical segment from the perspective of sufficiency in cash flows.

In our review of the evolution of the MYTO model, a number of things have become clear:

1. The current MYTO tariff is being set from a low base. The tariffs were originally set too low. In effect, they have not mirrored completely, the changes in associated variables since 2008. The movement in exchange rate variable is the most dramatic, especially given the huge reliance of players on importation for critical power equipment.

2. The government has persistently been weary of the “rate shock” that otherwise economically justified increases in tariffs would have on the end-user. This has prevented the enforcement of the necessary adjustments in line with economic realities. This is an ideology that has to change, otherwise investors will continue to perceive the market as still subject to government interference.

3. The cost-reflectivity of the current tariff is currently being impeded by the netting-off of MDA debts from the collection loss estimates contained in MYTO 2015 as amended. These receivables have proven difficult to collect in light of current fiscal challenges in the public sector. This, in our view, calls for some upfront cash availability to the Discos either by way of outright settlement or securitization of these receivables.

4. Overtime, the MYTO has focused too narrowly on one source of generation (i.e. gas) with very little wiggle room for incorporating other sources of power generation such as coal, solar, hydro etc. In fact, the slow take-off of embedded power generation, especially for plants fuelled by other sources outside gas, is linked to a lack of a clearly defined regulatory framework. Over time, this has constituted a limiting factor to the capacity expansion of Discos who could have entered into long term partnerships with embedded generators to increase power delivery.
The elusive cost-reflective tariff
Where should electricity prices be?

A cost-reflective tariff is one which reflects the true cost of supplying electricity and removes the reliance on government subsidies to cover the variance between the ruling tariff and the true cost of supply. This broad definition presupposes that for tariff to be truly cost-reflective, the subsidy element must be completely absent, creating a perfect market for electricity where demand and supply interact to set the price. This is not the case for Nigeria as each variant of the MYTO has retained a subsidy component. The unavoidable reality is that in a bid to ensure the financial viability of the electricity value chain, operators must align charges for electricity consumption with the cost of electricity consumption.

To set the tone for our proposition for the NESI, it would be useful to work with two central principles in mind (1) the cost of not having electricity is much greater than the cost of putting the right machinery in place given that the self-generation costs 112-158kWh considering recent fuel price increase), two times grid-based power; (2) An efficient supply system where losses are at the barest minimum and an inefficient system with significant losses (typical of the Nigerian case) will both bear the same cost in delivering electricity to the end user.

With the above in mind, we opine that first off, the current tariff needs to be benchmarked against the revenue needed in an ideal or much more efficient system. We note however, that the highest level of efficiency can only occur when power systems are coagulated in one place. Since this ideal system is unpopular given our extensive reviews of reformed electricity markets across the globe, we compare the Nigerian case with a less-than-perfect but efficiently run scenario.

To illustrate, let us compare two power systems: one that functions optimally, with generating plants running at 90.0% capacity, transmission losses at 5.0%, distribution losses at 10.0%, and collection rate at 99.0%. The second system has characteristics similar to the Nigerian case where generating plants are running at a capacity of 60.0%; transmission losses are 20.0%, distribution losses, 25.0% and collection rate is 70.0%. Both of the systems described above would bear the same cost. The table below shows the relative revenue that would accrue to both systems given, say, 5,000MW of available capacity.

Regardless of the relative level of efficiencies, the cost to generate electricity is the same under all scenarios.
The table shows that system A’s revenue will be 87.0% higher than B holding cost constant given our earlier assumption of uniform cost to run the two systems. Therefore, tariffs should be set at least 87.0% higher in B relative to current levels. Put differently, for tariffs to be cost-reflective in B, it needs to be 87.0% higher than the well functioning system. If we compare this needed rate of increase with the recent 42.0% average increase in electricity tariff in the amended MYTO 2015, we can appreciate the extent to which electricity prices still need to adjust to make them more cost reflective.

Non-cost-reflective tariffs are a major disincentive to private-sector investment in the power sector. As we will elaborate later, the TCN and Discos require significant equity capital injection which may be muted until the economics of the value chain is more appropriate.

The flip side of non-cost reflective tariffs is their impact on the national budget. If the consumer tariff does not reflect the full cost of electricity generation and delivery, the government must pay for the shortfall. This extra financial commitment can constitute a significant burden to fiscal authorities because as the power sector grows and more electricity is generated and delivered, the burden on the government increases. Furthermore, it creates a downward spiral when the added electricity increases economic growth, leading to even higher electricity consumption and subsidy requirements.

Electricity tariffs need to adjust upward to cover the inefficiencies in the system.

Besides being a disincentive to investment, non-cost reflective tariff will constitute progressively higher fiscal burden to the government as the power sector grows.
Sounding the alarm bell: The danger of tariff regulation

The California Electricity Crisis

As stated earlier, the subject of non cost-reflective tariff lies at the heart of the dearth of sufficient cash flows and low profitability across the electricity sector value chain in Nigeria. Tariff increases, especially the end-user tariff have been treated with political sentiment, to the detriment of viability of the entire value chain.

Evidence from other jurisdictions suggest that if tariff does not rise enough to cover costs and ensure reasonable profitability to investors, the electricity sector will not offer long term investment opportunity. It is against this backdrop that the recent reversal of the increase in electricity as a result of revision to MYTO II in February 2016 becomes largely inimical to the growth of the industry.

A case in point is the US state of California electricity crisis of 2000 and 2001. After a partial deregulation of the power sector, the government of California put a cap on retail prices. In 2000, wholesale prices were deregulated, but retail prices remained regulated. As electricity supply gap widened, and end-user tariffs remained capped, wholesale electricity prices eventually exceeded retail prices.

By keeping the retail price of electricity supply low, the government discouraged citizens from practising electricity conservation. In addition, when electricity demand rose, Gencos and Discos had no incentives to expand production. Instead, utilities like Enron manipulated the market. For instance, in a practice widely known as megawatts laundering, utilities bought electricity in California at low price to sell out-of-state, creating a shortage.

Eventually the state’s largest electricity producers filed for bankruptcy and many others entered a near bankruptcy state. This led to more and more blackout which negatively impacted the political standing of the state governor, leading to his eventual recall.

We can avoid a repeat of this in Nigeria if necessary steps are taken.
Electricity Transmission: The Weakest link?
Electricity Transmission
Striving to close a massive funding gap

The Transmission Company of Nigeria (TCN) and the Nigeria Bulk Electricity Trading Company (NBET) emerged from the 18 successor companies after the old PHCN was unbundled; the others being the 6 Gencos and 11 Discos. These two (TCN and NBET) are the only entities in the electricity value chain that remain entirely managed and operated by the government. NBET is jointly owned by the Bureau for Public Enterprises (BPE) with 80% stake whilst the Federal Ministry of Finance Incorporated, holds 20%. The TCN is thus wholly-owned by the FGN. The TCN is made up of two entities, the System Operator (SO) responsible for the co-ordination of the flow of electricity within the system, and the Market Operator, which carries out administrative functions.

During the privatization exercise, the FGN opted to outsource the running of TCN to private sector managers. This move was informed by the need to address the inefficiencies that characterised the management of the grid in the pre-privatization era. In April 2012 Manitoba Hydro International (MHI), subsidiary of Canada’s leading energy utility companies, Manitoba Hydro, won the contract to manage and operate TCN. After some bureaucratic delay, MHI finally began operations in 2013. The first contract with MHI expired in 2015 but was renewed by the government till July 2016. After the expiration of the contract in July 2016, the management of TCN reverted to government hands.

The MHI exit: What next for power transmission?

It is worthwhile to note that the strategic intent for the outsourcing of the management of TCN was to position the company as a private-sector managed entity, a profile that could facilitate access to the significant private capital needed to address its huge infrastructure and capacity needs. Besides the funding requirement, investment in the transmission infrastructure usually has a long pay-back period, the risk of which can easily be borne by the government until some decent improvement is seen in power transmission. The baseline expectation was for TCN to have the capacity to evacuate all the power transmitted at the time. Furthermore, the long-standing issue of right of way for transmission infrastructure was thought to be much easier for the government to navigate relative to the private sector.

The TCN and NBET are the only entities remaining in government hands post privatization

The management of TCN is back in government hands

As things stand, the TCN remains a monopoly in the electricity value chain
Following the recent change in management of the TCN, it is pertinent to ask whether the original intent of the outsourcing has been achieved. With little or no publicly disseminated details on relevant KPIs and milestones before and during the term of the contract, such clarifications would be difficult to make. What is even more critical is the outlook for Nigeria’s power transmission in the post-MHI era.

With regard to the change in management of TCN, our key concerns are summarised below:

- By regaining control of TCN, and with NBET in government hands, the FGN remains the critical link at the heart of the Nigeria electricity supply industry. In effect, the government is still responsible for the network build-out and the stability of power infrastructure even in a “privatised” framework. The risk of a re-surfacing of the old order of inefficiency in resource allocation in a public sector led system is therefore staring us in the face again.

- Given this recent change in management of TCN, the lack of private sector involvement in key decision making going forward means that the FGN will now be responsible for taking on the credit risk of TCN for the foreseeable future. Ironically, investors, would prefer to take on sovereign risk directly rather than taking on TCN risk due to the uncertainty in its return outlook. In essence, the FGN would need to either concession TCN or establish a commercial investment vehicle to fund the entity.
Funding the TCN: Expanding the range of options

Decades of poor funding of the Nigeria’s electricity transmission infrastructure currently manifests in hugely suboptimal grid capacity. Less than 40.0% of the country is connected to the National Grid while between 15-20.0% of generated electricity is lost due to the poor transmission network alone. The share non-storable nature of electricity makes adequate evacuation capacity for generated power extremely important to the minimization of stranded capacity. An intensive funding programme for the TCN is therefore needed to expand its wheeling capacity beyond the current c.5,500MW in view of the pipelines of generation projects in place today.

Over the years, the FGN has funded TCN via annual budgetary allocations which have been paltry at best (see above chart). From over 40.0% in 2014, the FGN allocated just 4.2% of the total budgetary outlay to the power sector to the TCN in 2015. The 2016 budget has however seen a significant increase in the level of allocation to TCN (c.50% of total allocation to the power sector).

In our view, transforming the TCN to a commercially viable entity is currently the biggest task confronting the Nigeria power sector today. Whilst we note that increased government funding signals its level of commitment to the sector, it predisposes TCN to government interferences. Ironically, making up for years of under-investment in TCN would require that the Transmission Use of Service Charge (TUOS) charged by TCN under the MYTO system is fully cost-reflective*, with a resulting tariff rate that is significantly higher than current levels. The unwillingness to increase tariffs therefore means TCN’s current cash flow stream is insufficient to attract private investors to invest in the entity.

*Inclusive of operating expenses and Capex

Fig. 18

TCN: Chequered history of budgetary allocations

Budgetary Allocations to TCN Vs. Power Sector (N'bn)

<table>
<thead>
<tr>
<th>Year</th>
<th>Power</th>
<th>TCN</th>
</tr>
</thead>
<tbody>
<tr>
<td>2014</td>
<td>62.4</td>
<td>24.9</td>
</tr>
<tr>
<td>2015</td>
<td>24</td>
<td>1</td>
</tr>
<tr>
<td>2016</td>
<td>99</td>
<td>50</td>
</tr>
</tbody>
</table>

Source: Federal Budget Office, United Capital Research

An intensive programme for funding TCN is urgently needed.

Budgetary allocations have been paltry.
In August 2016, the new management of TCN rolled out a 5-year capacity expansion plan to raise transmission capacity to 11,500MW with a total outlay of US$7.5bn by 2019 and 20,000MW by 2022. In the interim, it plans to build its transmission capacity to 8,200MW by 2018. A breakdown of the funding sources shows that budgetary allocations are projected at US$1.5bn. Other sources of funding include concessionary loans and grants, as well as other investor financing initiatives by the TCN.

The significant level of non-FGN funding sources is likely to be a key challenge for TCN going forward given its current status as a government controlled institution with a largely non-cost reflective revenue profile. If the government continues to meet funding obligations, we calculate this would require a 57.1% year-on-year increase in budgetary allocations from the 2016 base. Given that government funding only translates to 20.0% of the funding mix, there is a huge financing gap that needs to be filled by the private sector.

A range of funding sources can be considered for TCN. We propose some of them below:

- **Partial Privatization**: Akin to the privatization of the Discos where the FGN held 40%, with 60% for acquisition by the private sector, TCN’s privatization could toe a similar line. This partial privatization will see the government hand over the technical capabilities to the private sector while ensuring that it still has a say in the ultimate decision making. The key arm to be so privatized would be the System Operator.

- **Full privatization**: Similar to the Gencos’ sale, the complete ownership of the TCN could be ceded to the private sector. This would see a total handover to the private sector as has been done successfully in the telecommunications space.

Any of the aforementioned options will see the FGN earn significant income from the sale. These funds may therefore be re-invested in the sector via recapitalization of NBET, loans/bailouts/intervention funds to the sector, as well as payment of legacy debts.
Beyond the grid

The pros and cons of the embedded power solution

On-grid electricity generation has been the dominant source of power supply in Nigeria since the pre-privatization era. “On-grid” refers to a mechanism whereby power generation is wheeled through the national grid to an off-taker, which in the Nigerian case, is the Bulk Trader (NBET). This bulk trader then supplies the power to distribution companies through vesting contracts. The NBET may also supply directly to eligible customers as determined by the Minister of Power.

Transmission bottlenecks are currently driven by low on-grid capacity. The long period of time it takes to build mega transmission lines does not make for achieving quick-wins in addressing current power supply deficit in Nigeria.

More importantly, a critical demerit of the on-grid transmission model is the vulnerability of the integrated system to nationwide crisis due to centralised control. The failure of a single point system could lead to nationwide outages as recently experienced in Nigeria in the first half of 2016 where for the first time in a long while, the entire transmission grid shut down. The System Operator reported in September 2016, that the power sector witnessed a total of six system collapses within the second quarter of 2016. Besides this systemic risk, one can also argue that the on-grid system creates a poor, or sometimes virtually non-existing service relationship between power generating companies and the end-users.
Given the extent of the deficit in Nigeria’s power sector today, there is a need for an integrated approach that allows for quick fixes as well as more efficient modes of delivering power to the end-user. The embedded generation system therefore needs to complement the existing on-grid system. We argued in an earlier chapter for a shift in the gas-to-power model in a way that guarantees the availability of the feedstock. Complementary to this decentralized model is the off-grid (embedded) electricity generation system.

In simple terms, embedded power generation is where a generator is directly connected to the distribution network. It consists of smaller or modular generators that use a variety of generation technologies such as solar, wind, biomass, diesel, fuel oils, crude oil and small hydro. The distribution network for the embedded power generator is operated by a distribution licensee. In effect, it by-passes the national grid.

The off-grid system offers numerous advantages, some of which are:

- Lower capital costs, shorter construction times as well as modular architectural backdrop. The beauty of modular architecture is that one component of the system can be replaced easily without affecting the rest of the system.
- Lower transmission and network losses due to the shorter distances from generator to the load centre. It is also an effective way of dedicating power to state governments, local governments and industrial clusters, to power strategic infrastructure such as water plants, hospitals, schools, courts, offices and street lightening.
- Power is generated closer to the area of need. The smaller the focus area, the more effective the management.
- Close client relationship between the power supplier and the consumers.
- Introduction of competition as the consumers, especially industrial users are able to choose the network of their choice.
That being said, a major demerit of the embedded system is the wide differentiation in power tariffs due to differing costs of generation across the nation. Although it is likely to be more expensive for the end user, it could potentially compensate for the inefficiencies in the current on-grid system.

**Scope for off-grid generation: Dealing with regulatory bottleneck**

NERC regulates various aspects of embedded generation including distribution planning, connection requirements and commissioning procedure. The MYTO methodology is used as a benchmark in calculating tariffs for embedded operators with the final NERC-approved wholesale tariff negotiated by the generator and the distribution licensee on commercial terms. The slow take-off of the embedded generation system in Nigeria is attributable to considerable regulatory uncertainty with respect to off-grid projects, with NERC exercising significant discretion in most instances. For instance, the issue of whether an embedded generator can exist within a DISCO’s franchise; how to deal with excess power produced by either captive or off-grid generators; and the applicability of tariffs and procurement rules to off-grid generators consist a significant degree of uncertainty within this space. These issues need to be urgently resolved.

**Tab.5: NERC-Licensed Embedded Power Plants in Nigeria**

<table>
<thead>
<tr>
<th>S/N</th>
<th>Plant</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>NLNG</td>
<td>400MW</td>
</tr>
<tr>
<td>2</td>
<td>Dangote Cement (Obajana and Ibeshe)</td>
<td>258MW</td>
</tr>
<tr>
<td>3</td>
<td>Indorama Eleme Petrochemical/Indorama Fertiliser plant</td>
<td>225MW</td>
</tr>
<tr>
<td>4</td>
<td>Island Power</td>
<td>114MW</td>
</tr>
<tr>
<td>5</td>
<td>WAPCO</td>
<td>90MW</td>
</tr>
<tr>
<td>6</td>
<td>Flour Mills</td>
<td>60MW</td>
</tr>
<tr>
<td>7</td>
<td>Western Metal Product Company Limited</td>
<td>52MW</td>
</tr>
<tr>
<td>8</td>
<td>Notore Fertiliser</td>
<td>50MW</td>
</tr>
<tr>
<td>9</td>
<td>United Cement Company</td>
<td>47MW</td>
</tr>
<tr>
<td>10</td>
<td>BUA Cement</td>
<td>45MW</td>
</tr>
<tr>
<td>11</td>
<td>BUA Sugar Refinery</td>
<td>20MW</td>
</tr>
<tr>
<td>12</td>
<td>Nigerian Breweries plc</td>
<td>16.8MW</td>
</tr>
<tr>
<td>13</td>
<td>Dangote Sugar</td>
<td>15MW</td>
</tr>
<tr>
<td>14</td>
<td>IMIL</td>
<td>14MW</td>
</tr>
<tr>
<td>15</td>
<td>Oando Akute</td>
<td>12.1MW</td>
</tr>
<tr>
<td>16</td>
<td>Golden Sugar</td>
<td>12MW</td>
</tr>
<tr>
<td>17</td>
<td>Guinness Nigeria’s Ogba brewery</td>
<td>9.3MW</td>
</tr>
<tr>
<td>18</td>
<td>Cadbury</td>
<td>7.3MW</td>
</tr>
<tr>
<td>19</td>
<td>Unilever</td>
<td>6MW</td>
</tr>
<tr>
<td>20</td>
<td>Nestle Nigeria plc</td>
<td>3MW</td>
</tr>
<tr>
<td>21</td>
<td>Academy Press</td>
<td>1.2MW</td>
</tr>
</tbody>
</table>

Source: NERC

The embedded power framework introduces competition in electricity supply as industrial consumers can choose their preferred suppliers.
Electricity Distribution: The Burden of the Last Mile
Electricity Distribution

Contending with the “last-mile” Challenge

Nigeria’s eleven electricity distribution companies occupy the last node of the electricity value chain. By providing the connection between the generators of electricity and the end-users, Discos bear the burden of the quality and reliability of service delivery at the end of the supply chain. For Nigerian Discos, the last mile function involves stepping down electricity supply from a high voltage of 132kV at the transmission level to lower levels of 33kV/11kV/0.415kV at the distribution/retail level depending on the category of the customer. Most residential homes typically use electricity at 0.415kV.

The privatization of the power sector in 2013 saw the BPE, on behalf of the FGN retain 40.0% of the shares of all of the eleven Discos, while core investors own the balance of 60.0%. The exercise yielded a cumulative sum of c.US$1.5bn as sales proceeds.

Tab. 6: Discos Privatization Sales Proceeds

<table>
<thead>
<tr>
<th>Discos</th>
<th>Purchase Value</th>
<th>Distribution</th>
<th>Purchaser</th>
</tr>
</thead>
<tbody>
<tr>
<td>Abuja</td>
<td>US$144m</td>
<td>1,002GWh</td>
<td>KANN Consortium</td>
</tr>
<tr>
<td>Benin</td>
<td>US$137m</td>
<td>1,545GWh</td>
<td>Vigeo Power</td>
</tr>
<tr>
<td>Eko</td>
<td>US$128m</td>
<td>1,440GWh</td>
<td>West Power &amp; Gas</td>
</tr>
<tr>
<td>Enugu</td>
<td>US$174m</td>
<td>1,725GWh</td>
<td>Integrated Energy</td>
</tr>
<tr>
<td>Ibadan</td>
<td>US$169m</td>
<td>1,709GWh</td>
<td>NERC/NEPCO</td>
</tr>
<tr>
<td>Ikeja</td>
<td>US$131m</td>
<td>2,077GWh</td>
<td>Aera Energy Ltd</td>
</tr>
<tr>
<td>Jos</td>
<td>US$85m</td>
<td>714GWh</td>
<td>Northwest Power Ltd</td>
</tr>
<tr>
<td>Kaduna</td>
<td>US$201m</td>
<td>1,233GWh</td>
<td>Scadion Power FV</td>
</tr>
<tr>
<td>Kano</td>
<td>US$137m</td>
<td>788GWh</td>
<td>Power Consortium</td>
</tr>
<tr>
<td>Port Harcourt</td>
<td>US$142.2m</td>
<td>1,164GWh</td>
<td>Integrated Energy</td>
</tr>
<tr>
<td>Yola</td>
<td>US$23.2m</td>
<td>262GWh</td>
<td></td>
</tr>
</tbody>
</table>

Fig. 19: Discos Coverage Areas

Discos bear the burden of the last mile of the power distribution chain.

The Privatization of the Discos yielded a total of US$1.5bn.
Post-Privatization State of Discos
...A Myriad of Challenges

In fulfilling the bid evaluation criteria during the privatization exercise, the core investors for the Discos made two key commitments contained in the Performance Agreement signed by the FGN and the Discos: 1) Reduction in the Aggregate Technical, Commercial and Collection (ATC&C) losses, and 2) A 5-year investment outlay that totalled US$1.6bn for the 11 successor Dis-cos. In fact, the first commitment was the overriding criterion for evaluating most of the bids. Three years after, progress seems to have stalled as the power distributors continue to grapple with a legion of challenges that have not only limited further investments in the sector but also prevented the Discos from providing optimal distribution of power wheeled to them. Some of these challenges are highlighted below.

Veiled Lending (and borrowing?): We argue that the genesis of the challenges currently plaguing the Discos lies in the rather unfavourable terms under which the initial acquisitions were made. The dearth of information as to the real state of affairs of the Discos during the privatization exercise meant that the lenders could not accurately assess the risks of the transactions. In effect, this lack of transparency coupled with limited technical expertise of the stakeholders meant that both the lenders and the investee companies negotiated without clear visibility of the earnings/profitability profile of the Discos.

Currency Mismatch: The acquisition of the assets of the successor companies was largely aided by finance obtained from both local and foreign financial institutions with an estimated 65.0% of the financing in foreign currency. With receivables in Naira, Discos’ books are riddled with significant currency mismatch which is currently impacting their ability to re-pay existing debts. Between 2013 and 2016, the NGN/USD had depreciated by a cumulative 100.9%. This same challenge is applicable to the successor Gencos.

MDA Debt Overhang: A large proportion of Disco receivables are from government’s departments and agencies (MD&A). Recovery efforts have yielded little fruits, impacting Disco cash flows and ability to meet debt service obligations. The exclusion of the MDA debt from the MYTO 2015 computation has also been attributed to the non-cost reflective nature of the end-user tariffs.
**Capex Shortfall:** For most of the Discos, infrastructure in place are currently obsolete and requires significant investment to ramp up distribution capacity and reduce technical and commercial losses. Inadequate investment has led to recurring network infrastructure challenges such as overloaded transformers and feeders, limited network, lack of automation, among others. High cost of borrowing combined with poor credit history of Discos has constrained access to long term patient capital in the form of equity or debt needed to fund these significant capex investments. As at the time of acquisition, the 5-year loss reduction CAPEX only was estimated at N319bn.

### Table: 2014-18 Capex (USD m)

<table>
<thead>
<tr>
<th>DisCo</th>
<th>Capex (USD m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Abuja DisCo</td>
<td>180</td>
</tr>
<tr>
<td>Benin DisCo</td>
<td>119</td>
</tr>
<tr>
<td>Eko DisCo</td>
<td>134</td>
</tr>
<tr>
<td>Enugu DisCo</td>
<td>215</td>
</tr>
<tr>
<td>Ibadan DisCo</td>
<td>112</td>
</tr>
<tr>
<td>Ikeja DisCo</td>
<td>147</td>
</tr>
<tr>
<td>Jos DisCo</td>
<td>149</td>
</tr>
<tr>
<td>Kaduna DisCo</td>
<td>222</td>
</tr>
<tr>
<td>Kano DisCo</td>
<td>288</td>
</tr>
<tr>
<td>Port Harcourt</td>
<td>125</td>
</tr>
<tr>
<td>Yola DisCo</td>
<td>64</td>
</tr>
</tbody>
</table>

Source: BPE

**Losses and Revenue Challenges:** Currently, ATC&C losses in the industry average 46.0% but are as high as 59.0% in some Discos. The major issue with the ATC&C loss reduction methodology largely used for the privatization of the Discos was the absence of credible baseline loss data to ascertain the existing loss levels at the point of handover. Currently, there is still no credible baseline data establishing loss levels. Without a credible baseline information, it has proven quite difficult to measure the level of ATC&C loss reduction so far achieved by core Investors since handover in line with the Performance Agreement between the Discos and the BPE at the point of privatization.
**Government Response**

**Has the Power Intervention Fund been helpful?**

In 2014, the CBN instituted a special intervention fund tagged Nigerian Electricity Market Stabilisation Facility (NEMSF), totalling N213bn, aimed at injecting liquidity into the power sector. According to media statements credited to the CBN, total disbursement in 2015, specifically targeted at distribution and generation segments of the value chain, was estimated to have added 1,274 MW to generating capacity as well as 120km gas pipeline on the gas-to-power segment. However, there was no specific mention of how these funds improved the distribution capacity of the Discos within the period.

Similar to most government funded interventions, the implementation of the NEMSF has not come without bureaucratic bottlenecks. After an abrupt stop in 2015, the CBN re-commenced the disbursement of the fund in Q2-16, following the implementation of the new tariff, with total cumulative disbursements standing at N120.2bn, only c.57.0% of the total amount planned. Further, as at June 2016, 79.7% of disbursed funds were not cash backed.

**Fig. 20**  
_Slow disbursement of the CBN Power Intervention Funds_

<table>
<thead>
<tr>
<th></th>
<th>Disbursed</th>
<th>Planned</th>
</tr>
</thead>
<tbody>
<tr>
<td>GenCos</td>
<td>54.3</td>
<td>49.7</td>
</tr>
<tr>
<td>DisCos</td>
<td>86.9</td>
<td>54.2</td>
</tr>
<tr>
<td>Gas Companies</td>
<td>15.7</td>
<td>42.5</td>
</tr>
<tr>
<td>Other service providers</td>
<td>0.5</td>
<td>29.4</td>
</tr>
</tbody>
</table>

Source: CBN, United Capital

Although the NEMSF appears to provide liquidity for Discos, the flip side of the intervention is the interest burden the loan constitutes on the finances of the Discos. The fund, with an interest rate of 10.0% translates to a total of N124bn interest payments over the next 10 years. This does not only raise operating leverage for the Discos given already strained cash flows, the liabilities rank senior to any other form of financing. As a result, it automatically makes them unattractive for more debt capital.
Way Forward

Our views and recommendations

Whilst the challenges currently facing the Discos appear to be multi-faceted, the solutions to them are two-fold, in our view. First, stakeholders need to come to terms with the fact that minimal funds were injected into the Discos at the point of acquisition. The core investors, who are indeed separate entities from the Discos, paid the acquisition price for their 60.0% stake directly to the FGN. Hence, the capital shortfall we see today existed from day one. Second, a significant amount of the financing gap can be closed just by improving operating efficiency. In fact, a study by the African Development Bank (ADB) uncovers that out of US$23.2bn financing gap for Africa’s power sector, c.US6.0bn (20.0%) is associated with power utilities’ operating inefficiencies and the absence of cost recovery. In light of these, we categorise our recommendations for addressing the challenges facing the Discos into two: 1) Expanding the range of funding options for Discos; and 2) Possible fixes for lingering efficiency gap.

Financing Options for Discos

In dire need of “patient” capital

Our interactions with players in the power sector reveal that the Discos are actively seeking to restructure or refinance their existing loans. Whilst moratoriums, longer tenors and more favourable terms are currently being pursued, we believe it is important for core investors to put more “skin in the game” and urgently capitalise the Discos in line with their performance agreements. Furthermore, it is important to note that the probability of obtaining additional funding from Nigerian banks is quite remote at the moment given the many challenges that have plagued the banking sector in recent times. As noted earlier, a further disincentive to more debt funding is the CBN intervention facility sitting in the books of the Discos. Moreover, CBN restricts the banks from being over exposed to a sector. This seemingly overleveraged position of the Discos calls for significant equity injection, which can be invested either at the holding company level or at the Disco level. It is also worthwhile to note that fast-tracking investments into Discos may require that the anti-dilution restriction placed on core investors by the BPE be relaxed as quickly as possible.

Specifically, BPE restrains the investors from diluting their shares by more than 5.0% over the five years post privatization. To further enable quick capital injection into the Discos, the BPE’s 40.0% holdings can be diluted in a structured financing arrangement. In all, we estimate that a 30.0% dilution in the shareholding of BPE could lead to a capital injection of up to N139.0bn for the Discos.

**Fig.21: Proposed Change in Ownership Structure of Discos**

<table>
<thead>
<tr>
<th>Current Ownership Structure</th>
<th>Proposed Ownership Structure</th>
</tr>
</thead>
<tbody>
<tr>
<td>60% Government</td>
<td>40% Government</td>
</tr>
<tr>
<td>40% Private</td>
<td>60% Private</td>
</tr>
</tbody>
</table>

**Indirect and Off-Balance Sheet Financing**

Due to the urgent need for capital injection into the Discos, it would be useful to seek the most effective way to bypass BPE’s current prohibitive clause on the sale or transfer of equity holdings within the first five years of privatization. One way to achieve this is via an indirect investment at the holding company level (i.e investing in the shareholder of the purchaser). This would be particularly useful for the private equity investors who are willing to take a long-term strategic position in the sector, while benefiting from relatively attractive valuation at this early stage. However, indirect investment may need to seek regulatory approvals as well as consent from lenders.

Exploring further options with the above constraint in mind, and more importantly due to the excessive gearing position of the Discos, off-balance sheet solutions can be employed to keep the debt/equity ratio in check and stay within current debt covenants. Such off-balance sheet solutions include leasing or vendor financing for metering roll-out, adopting joint-venture model for embedded generation and the expansion in overall network infrastructure. It is important to note that the range of financing options available for Discos to address the current liquidity crisis is not exhaustive. We however caution that over-reliance on short term financing structures will continue to compound working capital challenges.

Source: BPE, United Capital

**Figure: 27**
Closing Efficiency Gaps

Reviewing energy allocation amongst Discos

In addition to our proposed review of the electricity tariff as discussed in Section 3 of this report, we believe quick wins in efficiency improvement is possible with a tweak in the energy allocation model, coupled with more effective regulatory oversight. An improvement in the energy allocation model for the Discos can be an effective way of improving efficiency in energy delivery. The current criteria for allocating energy to Discos is stated below:

<table>
<thead>
<tr>
<th>Criteria for energy allocation amongst Discos</th>
<th>% Allocation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loss Reduction</td>
<td>5%</td>
</tr>
<tr>
<td>Attainment of metering targets</td>
<td>15%</td>
</tr>
<tr>
<td>Customer Services Ratings</td>
<td>15%</td>
</tr>
<tr>
<td>Achievement of distribution network plans</td>
<td>30%</td>
</tr>
<tr>
<td>Distribution Capacity</td>
<td>35%</td>
</tr>
</tbody>
</table>

Source: NERC

While some of the criteria have more objective parameters than others, there is still a significant degree of subjectivity in the allocation criteria. This remains concerning, due to the potential for political and other vested interests to use this as an opportunity to create a bias in favour of one or the other Disco. One way to address the distribution bottlenecks and reduce collection losses is to review this criteria. Because the market is still in a transition stage, energy allocation criteria need not be based on multiple factors. A more efficient method, in our view, is to allocate energy in a manner that addresses one of the most pressing problems - collection losses and distribution capacity. In this case, metering should be the dominant yardstick for energy allocation. Once an appreciable level of metering is achieved, energy allocation can then be based on network expansion and customer service.

Source: NERC, United Capital
Concluding Remarks
The Imperatives of Successful Power Sector Reforms

Lessons from offshore

The challenges that have come alongside the privatization of Nigeria’s power sector are not without precedents in other countries that have undertaken bold reforms of their electricity markets. Argentina was one of the first countries in the world to implement a comprehensive reform of its power sector. Among developing countries, only Chile has had a comparably comprehensive and successful reform. The success stories of these two countries connotate useful lessons for a developing country like Nigeria as the learning points cut across the areas of generation, transmission, distribution/retailing, regulation and general institutional framework. These countries are particularly apt for our purpose as they possess similar demographic and socio-economic attributes as Nigeria.

In a review of the Argentina and Chile reform models, especially as they relate to power generation, the World Bank stated: “Effective competition requires that there be enough companies generating power to prevent dominance by one or a few, that capacity and energy payments at system marginal cost be available to new market entrants, that generators lack the ability to affect access to or pricing of transmission or dispatch services, and that the retail market be at least partially open (for example, for large users) …..New generators must construct any transmission facilities needed to deliver their output to the trunk system, and meet industry conventions for interconnection in accordance with a grid code”.4

Generation markets work best when characterised by a lack of integration with monopoly transmission and distribution networks, low degrees of concentration in the price setting segment of the market and when generators freely contract with customers. Whilst the Nigerian market has been able to fulfil a few of the above-mentioned criteria, it is evidently lacking in others. For example, though the supply contracts (PPAs) are typically long term in duration, averaging 20 years for successor Gencos, the utilities’ minimal input into the pricing means that the contracts were not negotiated in a manner that allowed the Gencos to factor into the long term scarcity, price of electricity.

The Argentinian and Chilean experiences provide useful learning points for Nigeria.
A pure price based bidding system could have provided less scope for government interferences and reduced the clamour for a more cost-reflectivity pricing system in the current regime. This is one reason why we believe the profitability outlook of the new IPPS and NIPPs look the most positive as the Nigerian market evolves, provided the contract terms favour a price-based bidding system.

With regard to transmission, the first attribute to note about both Argentinian and Chilean models of transmission is that both operate under a private sector driven framework. Second, in both systems, privately owned transmission companies must provide open access to all generators but are not allowed to sell energy for their own account. Third, the payments from generators to the transmission companies are structured in a manner that covers the cost that could reasonably be incurred by an efficient comparable transmission company. Fourth, independent generators can by-pass the transmission companies and sell energy to large consumers at negotiated price rather than the regulated prices it sells to distribution companies. These key attributes suggest that in addition to being private sector led, transmission systems need appropriate regulation from the incumbent to ensure both fair prices and an adequate rate of return on investment. There needs to be an appropriately regulated institution charged with proposing and overseeing system wide planning to ensure timely building of new transmission links. In light of this, we would say that the transmission system in Nigeria is yet to take-off.

Distribution companies need to be regulated to ensure that distribution charges both incentivise efficiency and are as fair as possible. Consumers should have both the opportunity and the incentive to choose among alternative suppliers when these have lower economic costs than the incumbent distribution companies. Furthermore, supply competition requires adequate separation of distribution from retailing (supply) via effective legal unbundling of the two functions.

Lastly, the general institutional environment in which the electricity sector is placed must be stable and foster long-term investment based on protection from arbitrary changes in government policy. Legislation regarding the sector especially in a privatized era should be credible and sustainable.
Investment Outlook

Long term value, short term pain

In spite of the numerous headwinds confronting the Nigerian power sector today, the electricity market remains an attractive long term investment opportunity. Though the sector exhibits all the rigidities of a typical Frontier economy, it equally boasts of all the potentials of a mass market. The key to getting the sector started on the path of sustained growth and profitability is to get the framework for pricing right, from feedstock to actual units supplied to the end-user, as it is crucial for cash flows to be sufficient to service the entire value chain. Furthermore, from a risk-reward perspective, the distribution of these cash flows across the value chain must also reflect the allocation of network risk and the relative levels of efficiency amongst players. In this regard, there is clearly a need to revisit the MYTO model.

Further, the industry needs to break the reliance on the FGN to follow through on building gas and transmission infrastructure. Relinquishing government control of the transmission system is the only way to remove the vestiges of the inefficient NEPA regime as well as undue political interference which has become the undoing of public-controlled enterprises. The national grid needs to be decentralized as a matter of urgency as a way to achieve quick fixes to capacity and efficiency issues. Additionally, the role of government in the settlement and payments system has to be gradually wound down to build investor confidence in the operational efficiency of the market. To address the overleveraged state of the Discos, there is need for equity injection as the domestic financial system is overexposed to the sector. In the interim, however, off-balance sheet financing approaches can be employed to fund key capex projects.

In the medium term, we expect the biggest investment inflows to come into the generation segment which appears to offer the highest risk adjusted returns at the moment given the sovereign risk guarantees backing contracts in that segment. However, with a growing pipeline of generation projects, transmission deficit may eventually constitute a constraint unless independent plants become more active than they are now. In this regard, NIPPs, with their built-in transmission capabilities, are of strategic importance to improved power delivery in the next couple of years.
Road to Bankability: Past, Present and Future

Lauded as one of the boldest reform initiatives globally, the privatisation of the Nigerian power sector fetched c.US$3.2bn in sales of government owned power assets. Successor Gencos were sold for a cumulative US$1.7bn, while the sale of the Discos raised US$1.5bn. The acquisition debts for these assets were almost entirely sourced from domestic banks albeit with significant foreign currency component (approximately 65.0% of total funding, based on our estimates). The proceeds were, in principle, largely expected to be channelled to the funding of NBET, which could have effectively addressed the current under-capitalization and insufficient liquidity of the Bulk Trader.

Although, local financiers appeared to be well positioned to dimension and mitigate the credit risk of the sector at the time, it has since turned out to that the lenders were not completely aware of the intricacies around the power firms as the sector was an untested terrain for the banks. There is little surprise that international banks were not involved in financing the acquisition despite the prima facia prospects of Nigeria’s unserved power market. Notably, the new institutions (successor companies) had no track record of credit worthiness, in addition to poor history of operational viability, which further increased their risk profiles.

Domestic banks’ power portfolio: Reeling from systemic challenges

Nigerian banks’ current exposure to the power sector is at least $1.7bn based on our review of 10 banks that reported power and energy exposures as at the first half of 2016. When we compare this number to the nominal value of over US$3.2bn that was invested into the sector three years ago, it becomes clearer the extent to which Naira devaluation has impacted the loan book of the banks. Currently, on average, power exposures account for 5.6% of the banks’ loan books, with exception of Fidelity Bank and UBA, which reported 10.5% and 10.0% exposures respectively (see figures 23 and 24 below for individual banks’ exposures). Although none of the banks have yet to report any material deterioration in the quality of their power risk assets, keeping these books clean would require sustainable fixes to lingering efficiency issues in the sector.
The next phase of funding: Where, how, when?

Financing the next stage of growth in the Nigerian power sector is a critical issue in the discussion on the outlook of the sector. There are 4 major limiting factors against domestic funding of the sector at this time: 1) Current CBN restriction on domestic banks’ exposure to sectors of the economy; 2) Profitability challenges facing Nigerian banks amidst weak macroeconomic backdrop and worsening asset quality; 3) Illiquidity in the domestic FX market versus the need to fund the largely import-driven power equipment and infrastructure; 4) Stretched capacity of most local banks with respect to the headroom to accommodate the long term assets on balance sheets that are principally financed by short term liabilities.

These constraints on domestic funding would suggest a recourse to international lenders such as commercial banks, export credit agencies, frontier market funds, global emerging market funds, sovereign wealth funds, private equity funds, as well as development finance institutions for the next round of financing of the power sector.
Route to Bankability: Like telecoms like power?

At the onset of the power reforms, local expectations were high as the privatization of NEPA/PHCN was compared, albeit wrongly, to the revolution engendered by the earlier liberalization of the telecommunications sector. Events post-privatization have however proven disappointing as the sector continues to grapple with systemic challenges, with negligible improvements in supply relative to the pre-reform era. It would appear that stakeholders took too long to come to terms with the striking structural dissimilarities between the two sectors. With regard to the telecommunications sector, bankability had never been an issue as lenders could dimension the risk-reward potential of the sector in a clear and consistent manner. Hence, re-distributing key sector risks, in a manner that improves the attractiveness of telecommunication projects was never a major consideration for lending.

On the contrary, the power sector presents different dynamics. First, it is important to note that the interconnectedness of the various nodes of the power value chain (i.e generation, transmission and distribution segments) is likely to take a considerable length of time to mature, especially given the low level of efficiency that characterised the pre-reform era. Unlike the telecommunications sector, where operators could build their own universes and insulate themselves against systemic challenges, power sector players are conjoined in a way that leads to high levels of interdependencies. Therefore, cash flows are not as visible as they are in the telecommunications space, making lenders weary of financing grid-based power projects.

In light of this, getting round this systemic constraint is key to the bankability of the power sector, at least in the medium term. Interestingly, the IPPs appear to have a clear advantage here and are better positioned to attract a reasonable quantum of capital in the next phase of funding for the Nigerian power sector. This is however not without the need to address risk factors, which we expand upon below.
Striking bankable project agreements: Risk factors and mitigants

As we have alluded to severally in this report, mitigating the risks of future funding for the Nigerian power sector begins with ensuring operators’ ability to generate sufficient revenue from the sale of power to cover their costs, including debt servicing and repayment obligations.

In a bid to mitigate the risk of disruption in feedstock supply, the Gas Supply Agreements (GSA), in addition to providing sufficient pipeline capacity, must also cover arrangement for alternative feedstock supply in the case of disruption in gas supply, as well as contract protection (e.g. insurance). This further implies that the Discos need to attain commercial viability as quickly as possible so as to demonstrate their capacity to assume the role of power purchaser under long term PPAs, particularly as the transfer of NBET’s obligations results in the loss of credit enhancement provided by the Nigerian government.

As stated earlier in this report, NBET plays a critical role in the cash management cycle of the electricity supply value chain. Given that NBET is effectively a government agency with all the ramifications of efficiency bottlenecks and the need for sovereign support, investor confidence is likely to be boosted if the bulk trader’s role is gradually seen to be winding down.

Finally, foreign currency mismatch is arguably one of the biggest downside risks to power sector financing at least from a developing country’s perspective. For Nigeria, the majority of funding for power assets is denominated in foreign currency (USD), while receivables are in Naira. The reliance on foreign currency funding sources stems from the high cost and shorter tenor associated with Naira denominated facilities. Given recent experiences in the Nigerian market, exposure to capital control and devaluation risks are likely to pose challenges to future funding for the power sector. In order to mitigate these currency risks, players need to prioritise currency hedging products and/or risk insurance, and explore the utilization of offshore collection accounts or obtain guarantees from the Nigerian Government (typically through the CBN) covering possible currency-related risks.
Appendix 1: Company Profiles – Gencos
## Privatized Genco Assets

<table>
<thead>
<tr>
<th>Assets</th>
<th>Purchase Value</th>
<th>Installed Capacity</th>
<th>Purchaser</th>
<th>Acquired Stake</th>
</tr>
</thead>
<tbody>
<tr>
<td>Afam**</td>
<td>US$260.05m</td>
<td>776MW</td>
<td>Televaras *</td>
<td>60%</td>
</tr>
<tr>
<td>Egbin</td>
<td>US$407.3m</td>
<td>1,320MW</td>
<td>NEDC/KEPCO</td>
<td>70%</td>
</tr>
<tr>
<td>Geregu II</td>
<td>US$132m</td>
<td>414MW</td>
<td>Amperion Power</td>
<td>51%</td>
</tr>
<tr>
<td>Kainji &amp; Jebba</td>
<td>US$257m</td>
<td>760MW</td>
<td>Mainstream Energy</td>
<td>15-yr concession with a varied fee structure</td>
</tr>
<tr>
<td>Ughelli</td>
<td>US$300m</td>
<td>972MW</td>
<td>Transcorp Consortium</td>
<td>100%</td>
</tr>
<tr>
<td>Sapele</td>
<td>US$201m</td>
<td>1,020MW</td>
<td>CMEC/EURAFIC</td>
<td>100%</td>
</tr>
<tr>
<td>Shiroro</td>
<td>US$111.65m</td>
<td>600MW</td>
<td>North South Power</td>
<td>15-yr concession</td>
</tr>
<tr>
<td>Total</td>
<td>US$1,669.1m</td>
<td>5,862MW</td>
<td>*on the verge of pulling out the transaction as at the time of writing report</td>
<td></td>
</tr>
</tbody>
</table>

Source: BPE, United Capital
Transcorp

Transcorp Power Limited is the power subsidiary of Transnational Corporation of Nigeria Plc (Transcorp). It is the owner and operator of Ughelli Power Plant in Warri, Delta State. The company manages Transcorp Plc’s strategic interests in the Power sector.

During the privatization of Nigeria’s power assets in September 2012, Transcorp Plc won the bid for the distressed power generating company, Ughelli Power Plc – operator of Ughelli Power Plant. The company invested $300 million as part of Heirs Holdings’ commitment to USAID’s Power Africa initiative. In November 2015, Transcorp Ughelli Power Limited and Ughelli Power Plc were merged to form Transcorp Power Limited. The merger harmonized the management and operations of Transcorp’s power business for greater efficiency. When Transcorp took ownership of the 1000MW capacity plant in 2013, the company had planned to take it from generating only 160MW of power daily, to producing at its full 972MW capacity. Transcorp Power has increased its generating capacity by 525% in the last three years, and plans to grow it to over 3,000MW in the next five years.
Egbin Power

Egbin Power Plc is one of the largest power generating stations in Nigeria with an installed capacity of 1,320 MW consisting of 6 Units of 220MW each. The station is located at Ijede / Egbin, in Ijede Town, about 40 km North East of the city of Lagos. It is situated on a low land and bounded by the Lagoon. Egbin Power was acquired during the privatization exercise by a consortium formed by the partnership between New Electricity Distribution Company and the Korean Electric Power Corporation (NEDC/KEPCO).

The company plans to double its installed generating capacity to provide additional projected capacity of 1,350MW commencing by 2017. Upon completion of this project, Egbin’s capacity is projected at 2,670MW, with a target of over 10000MW in the next decade if demand permits.
Kainji/Jebba
Completed in 1969, Kainji Dam has an installed capacity of 836MW. The dam is 85.5m in height and about 8km in length. The lake is supplied with water from the upper Niger River and it flows from Futa Djarlon Island through Guinea, Mali, Sierra Leone, Senegal and Niger. The reservoir lake stretches about 136 km upstream and has a breadth of close to 110km at its widest point from Warra to Zamare. The lake has a total capacity of 15 billion cubic meters covering an area of 1,270 square kilometres.

The Kainji hydro Power Plant concession was granted to Mainstream Energy Solutions Limited, with estimated cost of $418.5 million in February 2013 for 30 years. Jebba Hydro Electric Plant is situated 99km downstream of Kainji Dam on the River Niger. The plant was commissioned on April 13th, 1985 but commenced commercial operation in 1983. It has six fixed blade propeller hydraulic turbines with a total installed capacity of 578.4 MW. Jebba Hydro Electric Plant is situated 99km downstream of Kainji Dam on the River Niger. The plant was commissioned on April 13th, 1985 but commenced commercial operation in 1983. It has six fixed blade propeller hydraulic turbines with a total installed capacity of 578.4 MW.
Shiroro

Shiroro Hydro Electric Plc owns and operates a hydro power station. The company engages in the generation of hydroelectricity. Power Plant was commissioned in 1990; it has an installed capacity of 600 MW.

At full capacity, it can generate 2,100 GWh of electricity annually. Shiroro is equipped with switchyard facilities that include a technical “step down” function to aid distribution into the national grid. The plant is situated in the Shiroro Gorge on the Kaduna River, approximately 60 km from Minna, capital of Niger State, in close proximity to Abuja, Nigeria’s Federal Capital Territory. In November 2013, Shiroro was concessioned to the North South Power Company Limited.
Sapele Power Plant is a thermal generating station located in Nigeria’s gas-rich Delta State. Sapele has an installed capacity of 1020 MW. Sapele power’s six 120 MW steam turbines generate a daily average of 86.72 MWH/H or approximately 2,500 GW/H annually. Sapele currently operates at a peak capacity of 972MW. The plant is located in the Niger Delta region, close to sources of both natural gas feedstock and a river for cooling its steam turbine generators.

Sapele Power includes an updated control room, a switchgear room, a staff training school, and medical and recreational facilities. Sapele Power began operations in 1978. The company operates Nigeria’s second largest power plant by installed capacity of 1020MW; capable of meeting the energy needs of around 750,000 homes at full capacity.
Geregu Power Plant (Geregu) is a simple cycle gas Turbine Plant of a total installed capacity of 414MW (available 246MW), comprising of SIEMENS 3 x 138MW V94.2 gas plant using natural gas supplied by the Nigerian Gas Company. The Plant was constructed by the Obasanjo administration in an effort to increase power generation which hitherto was at its lowest. The Station was constructed by SIEMENS AG OF Germany and commissioned by former President Olusegun Obasanjo on 26th February 2007. Unit GT13 came on stream in March 2007, GT 12 on 20th April 2007, and lastly GT11 on May 12 2007.
Afam Power Station has an installed capacity of 776MW. The plant was commissioned in phases. During the Initial phase, 1962-1963, gas turbine units 1-4 were commissioned. During the second phase, 1976 to 1978, gas turbine units 5 to 12 were commissioned. Gas turbine units 13 to 18 were commissioned in 1982. Two gas turbine units were added in 2001 during the final phase of the Afam Power Station extension.

The Taleveras Group emerged as the preferred bidder for the Afam Power Plant in 2013, offering a sum of $260,050,000. The Group was one of two bidders for Afam Generation PLC, the successor company that took over operation of the plant post-privatization. The rival bidder, TES Power Limited, offered a sum of $222,900,000.
Appendix 2: Company Profiles – Discos
## Privatized Disco Assets

<table>
<thead>
<tr>
<th>DisCo</th>
<th>Purchase Value</th>
<th>Distribution</th>
<th>Purchaser</th>
<th>Acquired Stake</th>
</tr>
</thead>
<tbody>
<tr>
<td>Abuja</td>
<td>US$164m</td>
<td>1,802GWh</td>
<td>KANN Consortium</td>
<td>60%</td>
</tr>
<tr>
<td>Benin</td>
<td>US$129m</td>
<td>1,855GWh</td>
<td>Vigeo Power</td>
<td>60%</td>
</tr>
<tr>
<td>Eko</td>
<td>US$135m</td>
<td>1,440GWh</td>
<td>West Power &amp; Gas</td>
<td>60%</td>
</tr>
<tr>
<td>Enugu</td>
<td>US$126m</td>
<td>1,920Wh</td>
<td>Interstate Electric</td>
<td>60%</td>
</tr>
<tr>
<td>Ibadan</td>
<td>US$169m</td>
<td>1,989GWh</td>
<td>Integrated Energy</td>
<td>60%</td>
</tr>
<tr>
<td>Ikeja</td>
<td>US$131m</td>
<td>2,077GWh</td>
<td>NEDC/KEPCO</td>
<td>60%</td>
</tr>
<tr>
<td>Jos</td>
<td>US$82m</td>
<td>714GWh</td>
<td>Aura Energy Ltd</td>
<td>60%</td>
</tr>
<tr>
<td>Kaduna</td>
<td>US$201m</td>
<td>1,233GWh</td>
<td>Northwest Power Ltd.</td>
<td>60%</td>
</tr>
<tr>
<td>Kano</td>
<td>US$137m</td>
<td>788GWh</td>
<td>Sahelian Power SPV</td>
<td>60%</td>
</tr>
<tr>
<td>Port Harcourt</td>
<td>US$124.2m</td>
<td>1,164GWh</td>
<td>4Power Consortium</td>
<td>60%</td>
</tr>
<tr>
<td>Yola</td>
<td>US$59.3m</td>
<td>265GWh</td>
<td>Integrated Energy</td>
<td>60%</td>
</tr>
</tbody>
</table>

Source: BPE, United Capital

Figure: 38
Abuja Electricity Distribution Company

Abuja Electricity Distribution Company (AEDC). AEDC is the electricity distribution network operator for the Federal Capital Territory, Niger State, Kogi State and Nassarawa State.

KANN Utility Limited (KANN) holds 60% equity in AEDC while the Federal Government of Nigeria holds the remaining 40%. AEDC has a franchise for the distribution and sale of electricity across an area of 133,000 km² in the Federal Capital Territory, Niger State, Kogi State and Nassarawa State.

Benin Electricity Distribution Company

Benin Electricity Distribution Company ("BEDC") is responsible for retail distribution of electricity in Delta, Edo, parts of Ekiti, and Ondo States with geographical coverage of 55,770 square kilometres. The company operates from twenty-two business districts with approximately 350 offices located across the four states with about 13 million people and about 4 million households.

BEDC is the 4th largest Disco in distribution capacity and 3rd largest in number of households among the Distribution Companies. BEDC is a joint venture between Vigeo Power Limited (Vigeo Power) and the FGN, with the majority being held by Vigeo Power as the core investor.

Eko Electricity Distribution Company

Eko Electricity Distribution Company (EKEDP) is located in Marina, Lagos. EKEDP covers the license area of southern part of Lagos state and Agbara in Ogun state. For the ease of operations and division of work, the license area of EKEDP is segmented into 3 Circles and 8 Districts, namely: West Circle: 3 Districts – Agbara, Ojo, Festac; Central Circle: 3 Districts – Ijora, Mushin (also covers Orile areas), Apapa; East Circle: 2 Districts – Lekki (also covers Ibeju areas) and Island (also covers Ajele areas).
Enugu Electricity Distribution Company

Enugu Electricity Distribution Company (EEDC) distributes and markets electricity in the five (5) South Eastern States of Nigeria, namely; Abia, Anambra, Ebonyi, Enugu and Imo State.

Ibadan Electricity Distribution Company

Ibadan Electricity Distribution Company (IBEDC) covers the largest franchise area in Nigeria, made up of Oyo, Ogun, Osun, Kwara and parts of Niger, Ekiti and Kogi states. To ensure effective and competent management of such a large network, IBEDC is organized into five regions, namely Oyo, Ibadan, Osun, Ogun & Kwara regions, the regions are made up of Business Hubs. IBEDC’s technical partner is MERALCO, the largest power distribution company in the Philippines.

Eko Electricity Distribution Company

Ikeja Electricity Distribution Company (Ikeja Electric) covers business units such as Abule Egba, Ikeja, Ikorodu, Shomolu, Akowonjo, Oshodi. Ikeja Electric has over 700,000 customers. Ikeja Electric Plc is Nigeria’s largest power distribution network. The company was acquired by a consortium that has the Korean Electric Power Corporation (KEPCO) as a technical partner. The company generates about 84,000MW in capacity.
Jos Electricity Distribution Company

Jos Electricity Distribution Company (JED Plc) carries out electricity distribution and retail sale in the regions of Plateau, Gombe, Bauchi and Benue States.

Kaduna Electricity Distribution Company

Kaduna Electricity Distribution Company (Kaduna Electric) is responsible for retail distribution and marketing of electricity in Kaduna, Kebbi, Sokoto and Zamfara States. Kaduna Electric is the 7th largest DisCo in distribution capacity and 6th largest in number of households among the 11 Distribution Companies (Discos). Kaduna Electric has a total of 113 injection substations across the 4 States. Kaduna Electric also has a total of 11,247 distribution substations across the four States. This brings a total of 11,360 substations managed by the Disco.

Kano Electricity Distribution Company

Kano Electricity Distribution Company (KEDCO) is located in the north western geopolitical zone of Nigeria. The Company generates, and distributes and market electricity in the three states of Kano, Jigawa and Katsina. Geographical coverage of the company is 67,128 Km². The company has the largest potential in terms of customer population with the combined population of the three states at 19,564,000.00 (2006 national census).

KEDCO is owned by a consortium of five companies: the Sahelian Energy and Integrated Services Ltd (SEIS); the Kayseri ve Civari Electric T.A.S (KCETAS) Turkey, and the Dantata Investment and Securities Company Ltd. Others are, INCAR Power Ltd and the Highland Electricity Ltd. Together under an SPV Sahelian Power SPV Ltd; which became the core investor in KEDCO IN 2013.
Port Harcourt Electricity Distribution Company

Port Harcourt Electricity Distribution Company (PHED) was acquired by 4Power Consortium. PHED distributes electricity in four states namely: Rivers, Cross River, Akwa-Ibom and Bayelsa. The total service area is 39,206.25 sq km. The Consortium Members of 4Power are Taleveras Group of Companies Limited; Lilleker Brothers Nigeria Limited; Skyview Power Technologies Limited; Income Electrix Limited; CESC Limited; Iredcom Limited; Akwa Ibom Investment and Industrial Promotion Council; Paradise Power Nigeria Limited; Bayelsa Electricity Company Limited

Yola Electricity Distribution Company

Yola Electricity Distribution Company (YEDC) distributes electricity to Adamawa, Taraba, Borno, and Yobe states.
Appendix 3: Roles of Key Institutions
Roles of Key Regulatory Institutions

The Federal Ministry of Power, Works and Housing
This is the government arm that focuses on policy formulation and provides general direction to other agencies operating in the sector. The function of the Ministry revolves around policy formulation. It is guided by the provisions of the National Electric Power Policy, 2001, the Electric Power Sector Reforms (EPSR) Act, 2005, the Roadmap for Power Sector Reform. It also has the mandate to monitor the planning and execution of various projects in generation, transmission, distribution and fuel-to-power that are critical to meeting the stated service delivery targets of the power sector.

Nigeria Electricity Regulatory Commission (NERC)
NERC is an independent regulatory agency mandated to regulate and monitor the Nigerian power sector. The commission establishes or approves appropriate operating codes and safety, security, reliability and quality standards. It also licenses and regulates persons/organizations engaged in the generation, transmission, system operation, distribution and trading of electricity. The NERC is led by seven commissioners representing the 6 geo-political zones in the country in addition to one commissioner designated as Chairman and Chief Executive Officer.

The Energy Commission of Nigeria (ECN)
The ECN serves as a centre for gathering and dissemination of information relating to national policy on energy. It also supervises the government on adequate funding of the energy sector including research R&D, production and distribution. ECN monitors the performance of the Energy sector in the execution of government policies on energy and serves as a centre for providing solutions to inter-related technical problems that may arise in the implementation of any policy relating to the field of energy. The ECN is headed by a Director General, who also serves as its Chief Executive.

The Energy Commission of Nigeria (ECN)
The Rural Electrification Agency (REA) is a Federal Government Parastatal under the Federal Ministry of Power. It was established by the EPSR Act with the statutory functions of promoting, supporting and providing electricity access to rural and semi-urban areas of the country. The Agency also administers the Rural Electrification Fund (REF) set up to provide rural electrification programmes through public and private sector participation in order to achieve more equitable regional access to electricity, and promote expansion of the grid and development of off-grid electrification. Eligible customers and licensees are required to contribute to the Fund at rates to be determined by the NERC.
The Niger Delta Power Holding Company Limited (NDPHC)
The NDPHC is a special purpose vehicle jointly owned by the three tiers of government (Federal, State and Local). It is charged with the responsibility for the implementation of the National Integrated Power Project (NIPP). Wholly-owned subsidiaries of NDPHC own each of the ten (10) power generation stations that have been developed under the NIPP. The Managing Director is the Chief Executive officer of the NDPHC.

The Nigerian Bulk Electricity Trading Plc (NBET)
NBET is a government-owned entity. It is fully owned by the Bureau of Public Enterprises and Ministry of Finance with shareholdings of 80% and 20%, respectively. The NBET is an electricity trading licensee that engages in the purchase of electrical power and ancillary services (from IPPs and Gencos and subsequent resale to distribution companies. It is not envisaged to be the sole authorized or designated electricity buyer, as other entities, such as distribution companies that have attained commercial viability, will also be able to procure power directly from the generation companies after the transitional stage of the Nigerian power sector reforms. It has the legal backing to drive private sector investment in generation activities by executing bankable Power Purchase Agreements (PPAs) with them. These PPAs may subsequently be novated to the distribution companies when it becomes economically viable for all parties.
The NBET is run by a Managing Director assisted by a nine-member Board of Directors.

The Energy Commission of Nigeria (ECN)
The Gas Aggregation Company Nigeria Limited (GACN) was incorporated in 2010 for the purpose of stimulating growth of natural gas utilization in the domestic market. GACN is the vehicle for the implementation of the Nigerian Gas Master Plan (NGMP) commercial framework.

The National Power Training Institute
A key objective of the Institute is to design, develop and deliver a wide variety of training courses that will enhance the skills and capacity of both technical and non-technical power utility personnel.

Nigeria Electricity Liability Management Company Limited
NELMCO was established in 2006 as a company limited by guarantee, to assume and manage the non-core assets, all liabilities and other obligations that would not be taken over by the successor companies. NELCOM manages the stranded liabilities, non-core assets, PPAs of the old PHCN.
### Structure of the Transmission Company of Nigeria (TCN)

#### System Operator
- Implements and enforces the Grid Code, and draft/implementation of operating procedures as may be required for the proper functioning of the System Operator Controlled Grid;
- Implements and supervises open access to the System Operator Controlled Grid;
- Provides demand forecasts;
- Planning operation and maintenance outages;
- Undertakes dispatch and generation scheduling;
- Schedules energy allocated to each Load Participant in the event that available Generation is not sufficient to satisfy all loads;
- Ensures Reliability and availability of Ancillary Services;
- Undertakes real time operation;
- Administers system constraints (congestion), emergencies and system partial or total recovery; and
- Coordinates regional Interconnectors.

#### Market Operator
- Implements and enforces Market Rules;
- Centralises the information required for market administration, organise and maintain the related data bases;
- Calculates and recovers Ancillary Service and Must-Run Generation costs, when necessary;
- Administers the Market settlement process and Market payment system;
- Calculates and settles payments in respect of ancillary services and other costs of operating the system and administering the Market;
- Manages Market billing including issuance of invoices, settlement and payment system in accordance to these Rules;
- Recovers the Transmission Usage Charge from the Participants and remit it to Transmission Service Provider (TSP) and other Transmitter(s), if any; and
- Supervises Participants compliance with, and enforce the Market Rules and Grid Code.

Over the term of its contract, MHI’s main aim was to re-organise TCN to ensure that TSP operates as an independent entity from the System Operator (SO) and the Market Operator (MO). In doing so TCN would have a structure more suitable for eventual privatisation, the ultimate goal of the FGN. However, FGN recently decided no to renew the contract with Manitoba. Hence, TCN was handed over to Nigerian management effective July 2016.
Over the term of its contract, MHI’s main aim was to re-organise TCN to ensure that TSP operates as an independent entity from the System Operator (SO) and the Market Operator (MO). In so doing TCN would have a structure more suitable for eventual privatisation, which is the FGN’s ultimate goal. However, FGN recently decided not to renew the contract with Manitoba. Hence, TCN was handed over to Nigerian management effective July 2016.

Appendix 4: MYTO Building Blocks

<table>
<thead>
<tr>
<th>DISCO Regulatory Asset base</th>
<th>Initial value of the asset base adjusted every year for capital additions.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost of Capital</td>
<td>Determined by using the Weighted Average Cost of Capital (WACC) methodology and covers costs of debts, equity, gearing and corporate tax</td>
</tr>
<tr>
<td>Return on Capital</td>
<td>Included to provide return on existing assets as well as incentives for future investments</td>
</tr>
<tr>
<td>Annual CAPEX</td>
<td>Expenditure on metering, network improvement, expansion and other capital cost</td>
</tr>
<tr>
<td>Return of Capital</td>
<td>Depreciation rate applied Discos’ regulatory asset base and additions</td>
</tr>
<tr>
<td>Projected Generation Capacity*</td>
<td>Projected daily generation capacity for the next 5 years</td>
</tr>
<tr>
<td>Energy Allocation to Discos</td>
<td>% of total generation capacity allocated to different Discos</td>
</tr>
<tr>
<td>Aggregate Loss Levels</td>
<td>Aggregate losses and the reduction in established baseline losses over a 5-year period based on the annual % reduction committed to by each Disco</td>
</tr>
<tr>
<td>Repayment of CBN facility and accrued interest</td>
<td>The portion of the tariff set aside for the repayment of the CBN N213bn intervention tariff</td>
</tr>
<tr>
<td>Distribution Cost</td>
<td>Operating expenses by the Discos( administration costs, maintenance, metering, billing etc)</td>
</tr>
<tr>
<td>Institutional Charges</td>
<td>Due to NERC, Market Operator, System Operator, NBET</td>
</tr>
<tr>
<td>Customer Population Growth Rate</td>
<td>Increases in respective Discos customer base</td>
</tr>
<tr>
<td>Customer Classification</td>
<td>Segmentation of customers (Commercial, Residential, Industrial and Special)</td>
</tr>
<tr>
<td>Macroeconomic Indicators</td>
<td>Inflation,( US and Nigeria), Exchange rate, Gas Prices</td>
</tr>
</tbody>
</table>
Nigerian Power Sector...Is there light at the end of the tunnel?

Investment Banking • Asset Management • Securities Trading • Trusteeship

www.unitedcapitalplcgroup.com

Head Office:
United Capital Plc,
12th Floor, UBA House, S7,
Makinde, Lagos, Nigeria.
• +234-1-280-7399,
• +234-1-280-8919.
• info@unitedcapitalplcgroup.com

Abuja Investment Centre:
United Capital Plc,
PLOT 134, Ahmadu Bello way,
Garki 2, FCMB Plaza, Nigeria.
• +234-1-6533077/41,
• info@unitedcapitalplcgroup.com

Port-Harcourt Regional Office:
United Capital Plc,
12th Floor, UBA House, 14, Askwe Road,
Port-Harcourt, Nigeria.
• +234-5-455-577, +234-5-617-5444,
• info@unitedcapitalplcgroup.com