Document of
The World Bank

Report No: 82664-NG

INTERNATIONAL BANK FOR RECONSTRUCTION AND DEVELOPMENT

PROJECT APPRAISAL DOCUMENT

ON A PROPOSED SERIES OF
PARTIAL RISK GUARANTEES

FOR THE
FEDERAL REPUBLIC OF NIGERIA

IN SUPPORT OF
INDEPENDENT POWER GENERATION PROJECTS
AND
PRIVATIZED GENERATION AND DISTRIBUTION COMPANIES
FOR THE
POWER SECTOR GUARANTEES PROJECT (PSGP)

AND
AS PART OF SUCH SERIES:
(I) THE AZURA EDO INDEPENDENT POWER PROJECT FOR AN AGGREGATE AMOUNT OF UP TO US$245 MILLION AND (II) THE QUA IBOE INDEPENDENT POWER PROJECT FOR AN AMOUNT OF UP TO US$150 MILLION

April 14, 2014

Energy Unit
Sustainable Development Department
Africa Region

CURRENCY EQUIVALENTS
(Exchange Rate Effective April 14, 2014)

Currency Unit	=	Nigeria Naira
US$1	=	Naira 164.5

FISCAL YEARS

Government	–	January 1 - December 31
Azura Edo IPP	–	January 1 - December 31
Qua Iboe IPP	–	January 1 - December 31

WEIGHTS AND MEASURES

1 meter (m)	=	3.28 feet
1 cubic meter (m^3)	=	35.31 cubic feet
1 gigawatt hour (GWh)	=	1 million kilowatt hours
1 hectare (ha)	=	10,000 m^2 or 2.471 acres
1 kilometer (km)	=	0.62 miles
1 kilowatt hour (kWh)	=	1,000 watts hour
1 megawatt (MW)	=	1,000 kilowatts

ABBREVIATIONS AND ACRONYMS

AFD	Agence Francaise de Développement
AFDB	African Development Bank
ATC&C	Aggregate Technical, Commercial, and Collection Losses
BPE	Bureau of Public Enterprises
BOOT	Build, Own, Operate, and Transfer
BPP	Bureau of Public Procurement
CAPEX	Capital Expenditures
CCGT	Combined Cycle Gas Turbine
CFADS	Cash Flow Available for Debt Service
COD	Commercial Operational Date
CPS	Country Partnership Strategy
DFI	Development Finance Institution
DFID	Department for International Development
DISCOs	Distribution Companies
DSCR	Debt Service Cover Ratio
DSO	Domestic Supply Obligation
EA	Environmental Assessment
EBP	Energy Business Plan
EIRR	Economic Internal Rate of Return
ELPS	Escravos-Lagos Pipeline System
EOI	Expression of Interest
EPC	Engineering Procurement Contract
ESMF	Environmental and Social Management Framework
EPSR	Electric Power Sector Reform
ERSU	Environmental, Resettlement and Social Unit
FGN	Federal Government of Nigeria

FIRR	Financial Internal Rate of Return
FMEnv	Federal Ministry of Environment
FM	Financial Management
FMF	Federal Ministry of Finance
FMP	Federal Ministry of Power
GACN	Gas Aggregation Company of Nigeria
GEF	Global Environment Facility
GENCOs	Generation Companies
GDP	Gross Domestic Product
GSAA	Gas Supply Aggregation Agreement
HRSG	Heat Recovery Steam Generator
HT	High Tension
HV	High Voltage
HVDS	High Voltage Distribution Systems
IBRD	International Bank for Reconstruction and Development
IDA	International Development Association
IDC	Interest during Construction
IFC	International Finance Corporation
IHC	Initial Holding Company/NEPA
IPF	Investment Project Financing
IPP	Independent Power Producers
IRR	Internal rate of Return
ISR	Implementation Status Report
JICA	Japan International Cooperation Agency
KVA	Kilo-Volt Ampere
KW	Kilo Watt
L/C	Letter of Credit
LNG	Liquefied Natural Gas
LV	Low Voltage
LVDS	Low Voltage Distribution System
MIGA	Multilateral Investment Guarantee Agency
M&E	Monitoring and Evaluation
MHI	Manitoba Hydro Inc.
MIS	Management Information System
MO	Market Operator
MPN	Mobil Producing Nigeria Unlimited
MTR	Mid-Term Review
MYTO	Multi-Year-Tariff-Order
NBET	Nigerian Bulk Electricity Trading PLC
NDDC	Niger Delta Development Corporation
NEDP	National Energy Development Project
NEEDS	National Economic Empowerment and Development Strategy
NEGIP	Nigeria Electricity and Gas Improvement Project
NEPA	National Electric Power Authority
NERC	Nigerian Electricity Regulatory Commission
NIPP	National Integrated Power Project

NNPC	Nigerian National Petroleum Company
O&M	Operations & Maintenance
OCGT	Open Cycle Gas Turbine
OPEX	Operating Expenditures
PACP	Presidential Action Committee on Power
PAD	Project Appraisal Document
PAI	Power Africa Initiative
PAIF	Power and Aviation Intervention Fund
PCOA	Put Call Option Agreement
PDO	Project Development Objective
PHCN	Power Holding Company of Nigeria
PMU	Project Management Unit
PPA	Power Purchase Agreement
PRG	Partial Risk Guarantee
PS	Performance Standards
PSR	Project Status Report
PTFP	Presidential Task Force on Power
QIPP	Qua Iboe Independent Power Project
REA	Rural Electrification Agency
ROW	Rights of Way
RPF	Resettlement Policy Framework
SCADA	Supervisory Control and Data Acquisition
SDR	Special Drawing Rights
SO	System Operator
SPDC	Shell Petroleum Development Corporation
SPV	Special Purpose Vehicle
TA	Technical Assistance
TCN	Transmission Company of Nigeria
TOR	Terms of Reference
TSP	Transmission System Provider
USG	Unites States Government
WACC	Weighted Average Cost of Capital
WAGP	West Africa Gas Pipeline
WAPP	West Africa Power Pool
WBG	World Bank Group
WHT	Withholding Taxes

World Bank (IBRD):	
Regional Vice President:	Makhtar Diop
Country Director:	Marie Francoise Marie-Nelly
Sector Director:	Jamal Saghir
Sector Manager:	Meike van Ginneken
Guarantees Manager:	Pankaj Gupta
Task Team Leader:	Erik Fernstrom
Co-Task Team Leader (Guarantees):	Katharine Baragona

NIGERIA
POWER SECTOR GUARANTEES PROJECT (PSGP)

TABLE OF CONTENTS

Page

NIGERIA: POWER SECTOR GUARANTEES PROJECT (PSGP)

PROJECT APPRAISAL DOCUMENT (PAD)

AFRICA
AFTG2

Basic Information

Date:	April 14, 2013	Sectors:	Power (100%)
Country Director:	Marie Francoise Marie-Nelly	Themes:	Infrastructure services for private sector development (100%)
Sector Manager/Director:	Meike van Ginneken /Jamal Saghir	EA Category:	A (Full Assessment)
Project ID:	P120207		
Lending Instrument:	IBRD Guarantee		
Team Leader:	Erik Fernstrom		
Joint IFC: Yes			

Borrower: Federal Republic of Nigeria

Responsible Agency: Nigerian Bulk Electricity Trading PLC

Contact:	Rumundaka Wonodi	Title:	Managing Director and CEO
Telephone No.:	+ 234 803-685-6383	Email:	rumundaka.wonodi@nbet.com.ng

Project Implementation Period:	Start Date:	May 1, 2014	End Date:	December 31, 2029
Expected Effectiveness Date:	July 1, 2014			
Expected Closing Date:	December 31, 2019			

Project Financing Data(US$M)

[ ]	Loan	[ ]	Grant	[ ]	Other
[ ]	Credit	[X]	Guarantee		

For Loans/Credits/Others

Total Project Cost:	N/A	Total Bank Financing :	N/A
Total Co-financing :	N/A	Financing Gap :	None
Terms of Financing:	IBRD Guarantees:	up to US$395 million	
	Final Maturity:	Up to 20 years from effectiveness of each PRG	
	Amortization Profile:	N/A	
	Grace Period:	N/A	

Bank Group Participation	[X] IFC [X] MIGA (i) IFC ‘A’ Loan of up to US$125 million is proposed for Azura IPP. (ii) IFC ‘C’ Loan of up to US$30 million (with an aggregate exposure of IFC’s ‘A’ and ‘C’ Loans not to exceed US$125 million) is proposed for Azura IPP. (iii) IFC hedge instruments representing a loan equivalent exposure of up to US$8 million in Azura Power West Africa Limited is proposed for Azura IPP. (iv) MIGA Guarantee of up to US$658 million to Azura-Edo Limited and a group of commercial lenders and hedge providers is proposed for Azura IPP. (v) MIGA Guarantee is also proposed for Qua Iboe IPP (negotiation of amount is pending).

Financing Source Amount (US$M)	Azura IPP*	Qua Iboe IPP*
Equity	223.8	1,136
- Equity Capital	16.2	1,136
- Shareholder's Loan	146.2	-
- Subordinated Debt	61.3	-
Debt	589.1	-
- DFI	239.1	-
- Overseas Commercial Banks	200.0	-
- Local Commercial Banks	150.0	-
Total	**813.0**	**1,136**

(financial figures are based on estimates available at the date of the PAD)*

Expected Disbursements (in USD Million) NA

Fiscal Year		FY14	FY15	FY16	FY17	FY18	FY19		
Annual		NA	NA	NA	NA	NA	NA		
Cumulative		NA	NA	NA	NA	NA	NA		

Project Development Objective(s)

The project development objective is to increase the supply of electricity received by Nigerian consumers.

Components

Component Name	**Cost (USD Millions)**
(i) PRG Series - Transaction 1: Azura IPP - Transaction 2: Qua Iboe IPP	**up to 395** up to 245 up to 150

Compliance

Policy

Does the project depart from the CAS in content or in other significant respects?	Yes []	No [X]
Does the project require any waivers of Bank policies?	Yes [ ]	No [X]
Have these been approved by Bank management?	Yes [ ]	No [ ]
Is approval for any policy waiver sought from the Board?	Yes [ ]	No [X]
Does the project meet the Regional criteria for readiness for implementation?	Yes [X]	No [ ]

Performance Standards (PS) - for Azura IPP	**Triggered**
PS 1. Assessment and Management of Environmental and Social Risks and Impacts	**YES**
PS 2. Labor and Working Conditions	**YES**
PS 3. Resource Efficiency and Pollution Prevention	**YES**
PS 4. Community Health, Safety and Security	**YES**
PS 5. Land Acquisition and Involuntary Resettlement	**YES**
PS 6. Biodiversity Conservation and Sustainable Management of Living Natural Resources	**NO**
PS 7. Indigenous People	**NO**
PS 8. Cultural Heritage	**YES**

Safeguard Policies Triggered - for Qua Iboe IPP	**YES**	**NO**
Environmental Assessment OP/BP 4.01	X	
Natural Habitats OP/BP 4.04	X	
Forests OP/BP 4.36		X

Pest Management OP 4.09		X
Physical Cultural Resources OP/BP 4.11	X	
Indigenous Peoples OP/BP 4.10		X
Involuntary Resettlement OP/BP 4.12	X	
Safety of Dams OP/BP 4.37		X
Projects on International Waterways OP/BP 7.50		X
Projects in Disputed Areas OP/BP 7.60		X

Legal Covenants - Standard Covenants, Representations, and Warranties for Guarantees are proposed to be included in the legal documentation. In addition, the following covenants will be negotiated prior to signing of the IBRD Guarantees.

Name	Recurrent	Due Date	Frequency
Reimbursement and Credit Agreement	No	TBD	

Description of Covenant
Conclusion of a satisfactory Reimbursement and Credit Agreement between NBET L/C Bank, and IBRD with prioritization of the PRG supported transaction payments within the NBET cash waterfall.

Name	Recurrent	Due Date	Frequency
Procurement Under NIPP	No	TBD	

Description of Covenant

Satisfactory progress of 'Lot 18T (T/L, Ikot Abasi, Ikot Ekpene)' contract under NIPP projects for extension of a 330 kV transmission line for evacuation of power from Ikot Abasi to Ikot Ekpene (applicable to the Qua Iboe IPP / MPN related PRG only).

Team Composition

Bank Staff

Name	Title	Specialization	Unit
Erik Fernstrom	Lead Energy Specialist	Task Team Leader (TTL)	AFTG2
Katharine Baragona	Sr. Infrastructure Finance Specialist	Co-TTL/IBRD Guarantees	TWIFS
Rahul Kitchlu	Energy Specialist	Nigerian Energy Sector	AFTG1
Arnaud Braud	Energy Finance Specialist	Financial Analysis	TWIFS
Bassem Abou Nehme	Energy Finance Specialist	Sector Financial Analysis	AFTG2
Sameh Mobarek	Senior Counsel	Energy Law	LEGPS
Anthony Molle	Senior Counsel	Legal (PRG)	LEGSO
Ximena Talero	Advisor	Legal (PRG)	LEGSO
Amos Abu	Sr. Environmental Specialist	Environmental Safeguards	EASNS
Thomas E. Walton	Consultant	Environmental Safeguards	EASNS
Paula F. Lytle	Sr. Social Development Specialist	Social Safeguards	AFTCS
Ogochukwu Joy Medani	Team Assistant	Project Processing	AFCW2
Chita Oje	Program Assistant	Project Processing	AFTG1

Locations

Country	First Administrative Division	Location	Planned	Actual	Comments
Nigeria					Nation wide

I. STRATEGIC CONTEXT AND RATIONALE

1. **Nigeria is one of the world's largest oil exporters in the world and endowed with abundant domestic energy resources, yet access to energy services is low.** The Federal Government of Nigeria (FGN) is undertaking a bold Power Sector Reform Program encompassing the entire power sector value chain - from upstream gas development, through generation and transmission, to distribution and end-user tariffs. The 2010 Power Sector Reform Roadmap aims to expand power generation from about 4,000 MW to 40,000 MW by 2020 while dramatically improving service delivery, revenue recovery and efficiency. The reform is starting to result in tangible improvements in energy services.

2. **IBRD, IFC, and MIGA have combined forces under a joint Energy Business Plan (EBP) to support the FGN to accelerate implementation of the Power Sector Reform Roadmap** by leveraging WBG products and expertise. Support under the EBP will assist with translation of Nigeria's resource wealth into significant improvements of power supply, which in turn will create jobs, reduce poverty, and boost shared prosperity.

3. **This Project Appraisal Document (PAD) presents the IBRD Partial Risk Guarantee (PRG) Series to support independent power producers (IPPs) and the privatization program for generation companies (GENCOs) and distribution companies (DISCOs)**. This PAD presents the framework for the proposed PRG Series. It presents the first two substantially negotiated PRGs in the PRG Series for Board approval. These PRGs are for two IPPs: the Azura Edo IPP (Azura) and Qua Iboe IPP (QIPP). This PAD is complementary to the combined IFC/MIGA Board Paper that describes IFC loans and MIGA guarantees for Azura.[1] Subsequent transactions to be supported in the PRG Series will be submitted as additional financing requests for PSGP when they are sufficiently developed.[2]

A. Country Context

4. **The Federal Republic of Nigeria has experienced stable economic growth averaging 8 percent over the past decade and 7.4 percent in 2013.** In the context of high economic growth, Nigeria's key challenge is to make its growth more inclusive. Of the millions of Nigerians who enter the labor market each year, only 10 percent are able to find formal jobs. As a result, (formal) unemployment grew from 19.7 percent to 23.9 percent between 2009 and 2011, affecting principally the young (15-24 age group) with a rate rising from 25 percent in 2009 to 37.7 percent in 2011. A statistical rebasing of the gross domestic product (GDP) in 2014 reveals that Nigeria's GDP is estimated at close to US$500 billion (2012), making it the 26th largest economy in the world.

5. **A large and rapidly expanding population of 170 million represents an opportunity for economic development and increased employment if new markets can be unlocked.** As of 2013, service and agriculture sectors comprised the largest share of GDP, followed by trade,

[1] MIGA is also in discussions about supporting the Qua Iboe IPP.
[2] The FGN has requested support of up to US$700 million in guarantees as part the Power Sector Reform Program.

and oil and gas sectors. Greater market connectivity toward a unified domestic market is a key precondition for achieving rapid diversified growth that can promote small and medium enterprises, create jobs, and reduce poverty. By making markets more inclusive, Nigeria can extend opportunities to the poor and other excluded groups.

6. **While Nigeria is currently in an advantageous position for accelerating economic development, the country still faces a number of major challenges.** Despite the economic growth, Nigeria has yet to find a formula for translating its resource wealth into significant welfare improvements for the population. Job creation and poverty reduction are not keeping pace with population growth. Nigeria's progress toward the Millennium Development Goals (MDGs) has been slow, with indicators in some areas resembling those in the poorest countries in Africa. With a fiscal reserve of less than US$10 billion, the macroeconomic picture in Nigeria is also still quite vulnerable to an oil price shock. The country is also facing complex conflict and security challenges.

7. **Nigeria's population size makes its progress in reducing extreme poverty very important for achieving the global target of 3 percent by 2030**. Nigeria is the most populous country in Africa and the seventh most populated in the world. Using the official national poverty line and per adult equivalent consumption[3], the poverty rate declined from 48.5 percent in 2004 to 45.7 percent in 2010.

8. **The growth and poverty reduction strategy for Nigeria has to be built on the broader comparative advantages which include a diverse population, a focal point of connectivity for Northern and Southern cultures on the Africa continent and a gateway to Central Africa.** Economic diversification through improvements in governance and service delivery, increasing productivity, improved infrastructure and human capital, and a progressive regional policy will unlock the development potential and support strong and inclusive growth and accelerated job creation. The growth and poverty reduction strategy for Nigeria also has to respond to the acute needs of the poor while boosting shared prosperity.

B. Sectoral Context

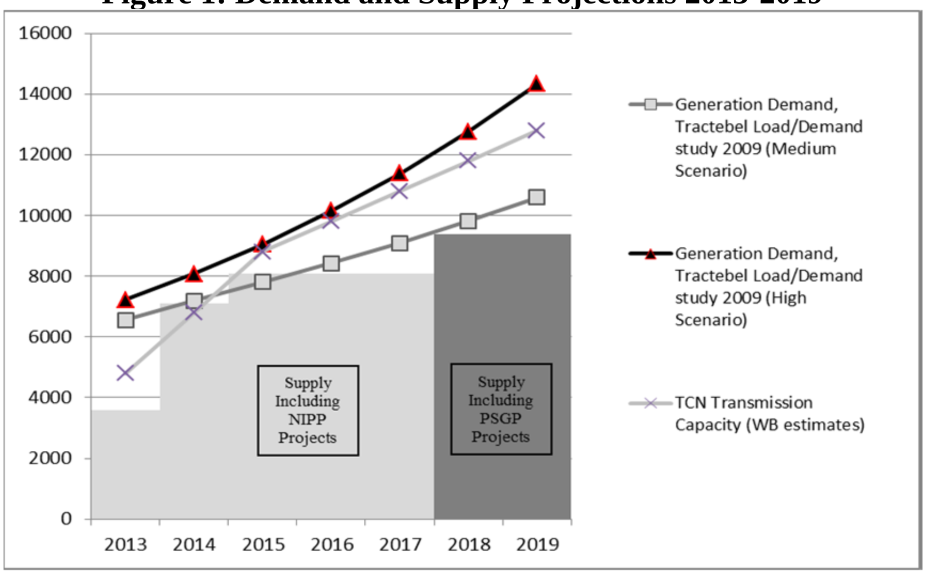
9. **Nigeria is one of the world's largest oil exporters and is endowed with abundant domestic energy resources, including the eighth largest reserves of natural gas and significant untapped hydropower potential along the Niger River**. Despite these favorable conditions, access to energy services is low: only a third of the demand for power is supplied from the national grid, those connected to the grid face multiple daily power cuts, and more than 100 million citizens (approximately 65 percent of the population) are left entirely without access to electricity. This power crisis is an obstacle to economic growth and has a negative impact on the everyday lives of Nigerians. In the 2010 Nigeria Investment Climate Assessment, 83 percent of Nigerian business owners consider a lack of electricity the biggest obstacle to doing business (compared to 14 percent of Indonesian businesses and 28 percent of Kenyan businesses).

[3] The national poverty line is about 53,710.48 Naira, equivalent to US$1.08 per capita per day at 2010 average exchange rate. Per adult equivalent measures are used instead of per capita measure to take into account differences in household composition. Children are weighted less than adults since they consume relatively less.

Supply and Demand of Electricity

10. **The demand for electricity in Nigeria vastly outpaces supply.** Over the past decade, Nigeria's publicly owned and operated electricity system has been failing to meet Nigeria's power needs. In early 2013, the total available capacity was around 3,500 MW which was significantly below the suppressed demand estimated to exceed 6,000 MW. The demand in the Nigerian power sector is expected to continue to increase at around 10 percent per annum in the medium term, reaching 10,000 MW (medium growth rate scenario) to 14,000 MW (high growth scenario) by end of the decade. However, at the current commissioning rate, the supply would barely reach 9,500 MW by 2020 (Figure 1 below). The supply shortfalls are further marred with generally inefficient technical and commercial management of the grid system, leading to frequent interruptions and poor service quality.

Figure 1: Demand and Supply Projections 2013-2019



11. **Nigerian businesses experience an average of 239 hours of power outages per month, accounting for nearly 7 percent of lost sales.** As a result, most private enterprises are forced to resort to self-generation at a high cost to themselves and the economy (about US$30-50 cents per kWh as compared to the current grid based tariff of US$0.13 per kWh). By some estimates self-generated power now substantially exceeds grid-based power in Nigeria. Many people rely on generators for either their primary source of electricity or as a back-up for the grid. Aside from the health, environmental and efficiency implications of self-generation, the practice has forced firms to divert financial resources away from productive uses, lowering productivity and competitiveness. The limited electricity that is generated from Nigeria's ailing power plants is often trapped by capacity constraints in the transmission and distribution networks, which has been exacerbated by years of poor maintenance brought about by inadequate funding from tariffs and poor revenue collection rates. Much of the electricity generated is lost due to high aggregate technical, commercial, and collection (ATC&C) losses, estimated at about 35 percent, and outright theft, that occur before the revenues are collected and re-injected into operations and maintenance.

12. **Power generation is also constrained by the inefficient exploitation of Nigeria's abundant natural gas resources.** Natural gas is an affordable, large-scale energy resource and can play a critical role in the primary energy portfolios of many African nations. However, the investment and associated gas price required for stable gas supply to develop the Nigerian power sector is not keeping pace with demand. Nigeria can also play a key role in the regional markets as an exporter of natural gas and power, should this limitation be addressed. Nigeria is already a participant in the West Africa Power Pool (WAPP) and the West Africa Gas Pipeline (WAGP) - key infrastructure that can assist regional power trade.

Financial Health of the Sector

13. **The historic problems of the Nigerian power sector can be attributed to a mutually reinforcing negative spiral of poor governance and accountability.** This has served to compromise the financial health of the sector. The resultant inefficiency has led to underfunding of utilities and a dependence on recurrent government budget transfers to stay afloat and detracted attention away from the utilities' main business purpose and revenue source which is to provide quality services to its consumers.

14. **Inefficient tariff structures combined with high ATC&C losses have worsened the financial viability of the sector.** Historically, tariffs structures have not remained cost reflective and revenue collection rates have been allowed to stay well below the levels needed to sustain sound operation and maintenance, further reinforcing the cycle of decline. The lack of reliable supply and inefficiency of the sector not only has a direct fiscal impact on the FGN with sector losses amounting to over US$80 million a month, but it also has a broader macro-fiscal impact on the economy as a whole due to loss of productivity.

Policy Framework and Reform

15. **Over the past few years, the FGN has embarked on an ambitious energy sector reform process that is resulting in tangible improvements in energy services.** The reform program has sustained political commitment. Implementation is being led at the highest level of government. The Presidency, together with the Presidential Task Force for Power (PTFP), the Ministry of Power (MOP), the Bureau of Public Enterprise (BPE), utility parastatals and agencies, provide hands-on strategic leadership, direct decisions, and coordination through the Presidential Action Committee on Power (PACP), chaired regularly by the President**.**

16. **In 2009, Nigeria's 'Roadmap for Power Sector Reform' outlined a comprehensive reform program across the power sector value chain.** The Roadmap was launched by H.E. President Goodluck Ebele Jonathan on August 26, 2010 and updated with Revision 1.0 in August 2013. The Roadmap operationalized the National Electric Power Policy (2001) and the Electric Power Sector Reform (EPSR) Act (2005). The Roadmap outlined specific short, medium, and long term actions to expand supply and open the sector for private investment, recognizing the poor historical performance of state-owned generation plants, while addressing the chronic sector issues hampering improvement of service delivery. Revision I of the Roadmap (2013) refines the strategy to complete power sector reforms and resets projections in a manner which would re-commit the new asset owners to the undelivered portions of the milestones in the Roadmap.

17. **The Roadmap aims to expand power generation from 4,000 MW to 40,000 MW by 2020 while dramatically improving service delivery, revenue recovery and efficiency.** Key areas of focus include: (i) reforming the vertically integrated sector; (ii) addressing broken institutional and regulatory systems; (iii) establishing an appropriate pricing regime; and (iv) scaling-up private sector investment.

18. **Reforming the vertically integrated sector*: An important step in the reform program has been the unbundling and privatization of the Power Holding Company of Nigeria's (PHCN) generation and distribution utilities.*** The takeover of the assets by private owners in November 2013 was a significant milestone in the reform program. All of the 6 generation companies (GENCOs) and 11 distribution companies (DISCOs) were unbundled and offered for sale. A request for proposal was released in September 2011 by the Bureau of Public Enterprises (BPE), bids were submitted in July 2012 and preferred bidders selected by November 2012. Most of the preferred bidders have now completed payment of the purchase price and have taken over the companies. Annex 2 provides further detail on the outcome of the bidding process. The FGN is winding-down PHCN by moving existing liabilities to the Nigeria Electricity Liability Management Limited (NELMCO) and has established the Nigerian Bulk Electricity Trading PLC (NBET) to serve as the central power trader in the Nigerian Electricity Market. The Transmission Company of Nigeria (TCN) has remained as a public utility (Para 20).

19. **Addressing broken institutional and regulatory systems: The reform program also clarified roles and responsibilities of key sector institutions to improve the transparency, accountability, corporate governance, and general oversight of the sector.** High-level strategic oversight is provided by the Presidency, the PTFP, PACP, MOP, and BPE while day-to-day supervision and operational implementation (including issues related to regulations, licensing, and tariff setting) is carried out by the Nigerian Electricity Regulatory Commission (NERC), NBET, TCN, GENCOs, and DISCOs. Each participating entity plays its role and is held accountable for delivering the highest possible quality of service. While a strong institutional structure is now in place, it is important to recognize that many of these institutions are new and will, together with the recently privatized utilities need time and significant capacity building to succeed in fulfilling their mandates.

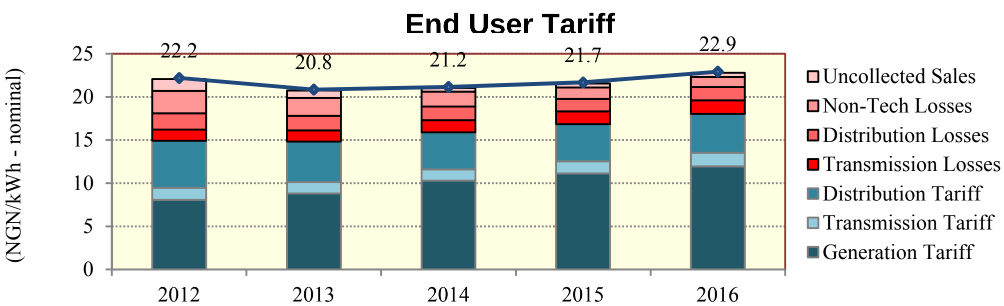
20. **An internationally reputed management contractor (Manitoba Hydro International) is in place in order to build capacity and improve the overall efficiency of the national grid operator, TCN**. FGN's objective was to reform TCN including its core Market Operator (MO) and System Operator (SO) functions. FGN also intends to combine TCN's reform with a major investment program to increase the capacity of the national grid and reduce the technical losses. The management contractor has identified several areas of critical investment that are needed for the transmission system (estimated at about US$8 billion) to achieve a wheeling capacity of at least 20,000 MW by the year 2020.

21. **Establishing an appropriate pricing regime: A critical step towards realizing the transformational change outlined in the Roadmap was the establishment of an appropriate pricing mechanism to ensure the sector's financial viability.** A Multi Year Tariff Order (MYTO) has been implemented (with revisions made on June 1, 2012 - MYTO2) and is based on a set of principles designed to reflect efficient and realistic cost levels for each of the generation, transmission, and distribution (including retail) sectors, taking into account: (i) cost recovery/financial viability; (ii) signals for investment; (iii) allocation of risk; (iv) incentives for

improving performance; (v) transparency/fairness; and (vi) social and political objectives.

Box 1: Nigeria Multi Year Tariff Order (MYTO 2) and Sector Revenue Projections

NERC adopted electricity tariffs that allow full recovery of efficient operating costs, including a reasonable rate of return and give incentives to sustain improvement in efficiency and quality. NERC adopted an incentive-based, 2-part tariff methodology in the first MYTO in 2008. The method was originally pioneered by the United Kingdom in 1980s/1990s and widely adopted in many countries since. The MYTO's assumptions are subject to a minor annual review to reflect changes in inflation rate, gas price, and foreign exchange assumptions, and a major review of all the assumptions every 5 years to keep the tariff in line with then-current circumstances. While minor revisions have been implemented annually by NERC since 2008, it agreed to accelerate the major review due in 2013 upon request from distribution companies to reflect major changes in the companies' operating environment and the anticipated reform process outlined in the Roadmap. The revised MYTO2 was implemented and in effect from June 1, 2012. This MYTO2 reflects a realistic market-based cost of new generation supplies and the large need for transmission and distribution system rehabilitation and capacity expansion. The aggregate retail tariff has more than doubled going from 10 Naira per kWh (US$0.06/kWh) to an average of 22 Naira per kWh (US$0.13/kWh).



The tariff schedule also includes the R1 residential tariff class with "life-line" social safety net features including no fixed charge and a low energy charge of approximately Naira 4/kWh (Approximately US$0.025/kWh) making this one of the lowest tariffs charged in the region. The funding of the R1 tariff class is levied through cross subsidies from the other tariff classes and therefore will have to be well targeted and defined to include only the most vulnerable and poorest consumers. The main residential class R2 (as well as the lowest commercial and industrial tariff groups) benefit from transitional subsidies from annual budget allocations to distribute the burden of the tariff increases over 2 years (due to be gradually phased out from 2014).

22. **Cost-reflective end-user tariffs and 'life-line' mechanisms to protect the most vulnerable consumers are at the heart of the reform process.** Tariff reforms are combined with a tangible improvement in the reliability of power supply, and a reform of utility commercial practices. The utility reform program includes an accelerated roll-out of new meters to unmetered consumers, the introduction of better customer care and service programs, and improved revenue management. DISCOs have increased incentives to undertake demand side management programs such as accelerated distribution of low energy light bulbs.

23. **Scaling-up private sector investment: The establishment of NBET as a central buyer ensures increased transactional efficiency of the power market.** NBET will enter into power purchase agreements (PPAs) with private sector parties - IPPs - and manage the contractual risks. FGN realizes that IPPs, when entering into PPAs, will require a creditworthy off-taker with which to contract. However, it could take many years before some of the new sector companies (GENCOs and DISCOs) become creditworthy. Therefore, in order to accelerate private sector investments in power generation, the FGN has decided that transitional support to NBET is

necessary; such support would be primarily achieved through use of a 'central buyer' model, supported with credit enhancement mechanisms (such as the use of IBRD and AfDB supported payment guarantees). Direct contracting between GENCOs and DISCOs is also envisaged over time, thereby reducing the reliance on the single buyer. In the long term, the FGN hopes to wind down the activities of the central buyer based on the overall creditworthiness of the sector and market development.

24. **Public investment in parallel with private sector promotion**: Recognizing the inherent lag before benefits from the private power generation begin to materialize, FGN has launched the National Integrated Power Plant (NIPP) Project to commission around 1,000 MW of additional supply capacity per year during 2013-15 adding another 3,700 MW to the national installed generation capacity. By end of 2015, total installed NIPP generation capacity would reach 4,700 MW. NIPP projects will also add about 2,000 MVA of distribution and approximately 3,000 MVA of transmission capacity in the coming 2 years. The first plant, Olorunsogo, was commissioned in late 2010 and is now producing 315 MW.

Challenges in the Coming Years

25. **Significant progress has been achieved on many fronts of the reform program with tangible improvements in the power supply situation**. Accelerated project implementation of ongoing NIPP projects are expected to bring the available capacity to nearly 4,500 MW in 2014 - a record high for Nigeria. Improvement in sector accountability and transparency has advanced bilateral negotiations with investors under the privatization process concluding with the takeover of the GENCOs and DISCOs by new owners in November 2013.

26. **However, the results of the initial 18 months of implementation of the tariff reform have been mixed**. Consumers have accepted that they will pay more for power. On the other hand, revenues of DISCOs have increased at a slower pace than foreseen due to continued poor revenue collection as well as lack of efficient governance. Many of these transitional challenges are expected to be addressed in the coming years. But, the new DISCO owners have expressed concern over the need for significant additional tariff adjustments in the wake of the joint loss verification process that may identify that the ATC&C losses are higher than what was previously assumed (see financial projections in Annexes 8 and 9).

27. **The ability of the new DISCO owners to deliver on their proposals on reducing ATC&C losses in the early years of the reform will be critical**. The MYTO was based on estimates that the ATC&C losses are at 25.6 percent as of 2012 and set targets for these losses to be brought down to 13.4 percent by 2017. However, the new DISCO owners have challenged these figures arguing that the current levels of ATC&C losses are around 35 percent. NERC, is in the process of independently quantifying and verifying losses. This verification will not only establish a revised baseline of losses but also loss reduction targets with a tariff regime (MYTO revisions) that leads to a financially sustainable sector.

28. **DISCO bidders were selected by the FGN on the basis of their plans for reducing ATC&C losses**. Plans submitted by the individual DISCOs bidders to reduce losses formed a key element of the FGN's asset sale decision. As part of the competitive bidding process, some bidders might have exaggerated estimated loss reductions (e.g. some bidders claim loss reduction

in their respective zones from 40 percent to 12 percent in five years). The bidders' estimations are reported 'as is' in the PAD and do not form the basis of the financial analysis in Annex 8.

29. **The risk perception of private investors remains high primarily due to the nascent nature of the emerging Nigerian electricity market.** NBET is making steady progress in PPA negotiations with the front-runner IPPs including Azura and Qua Iboe. These transactions (see details in Annex 2) are expected to reach financial close and start of construction by second half of 2014. However, the viability of these new arrangements remains to be proven and NBET is yet to establish a performance track record. Moreover, scaled-up private investment in critical upstream (gas supply) and downstream (transmission) segments would require continued improvement in the investment climate.

Natural Gas Supply: Opportunity for Domestic Growth and Regional Participation

30. **Natural gas is produced in large quantities in oil and gas wells in Nigeria.** Despite ample resources with some developed for export in the form of liquefied natural gas, a large percentage of the supply is being either re-injected back into wells or flared, thereby resulting in wastage and causing adverse environmental side-effects. It is estimated that Nigeria currently flares around 1.4 billion cubic feet of gas a day - roughly equivalent to the entire volume of gas available to the domestic gas market. The main reasons for flaring are: (i) low quality of 'associated gas' emanating from the oil production wells; (ii) remote locations of the production wells with insufficient gathering, transmission and distribution systems; and (iii) the lack of effective market mechanisms in the gas sector.

31. **Gas supply amounting to about 1,500 mmscf per day is available for the power sector in Nigeria; however, the amount varies sharply, at times dipping down to about 800-900 mmscf per day.** This equates to a current gas to power production of 3,200 MW (March 2014). In contrast the deliverable installed generation capacity (gas fired only) stands at over 4,500 MW (March 2014) leaving a large portion of installed capacity as stranded assets. Over the next two years, an increase in thermal generation capacity is expected to come from soon to be commissioned NIPP plants and from additions to currently in-situ IPPs. All these parties will be competing with each other for the limited supply of available gas.

32. **Unlocking the flow of Nigerian abundant cheap gas would not only benefit Nigeria, but West Africa as a whole.** Already fueling a majority (70%) of Nigeria's power generation capacity, natural gas could also have a significant impact within the sub-region through gas exports (WAGP) and possibly power exports (WAPP), in the long term. Efforts to improve availability of adequate gas supplies and related transportation infrastructure are ongoing. The FGN's Gas Master Plan, launched in 2009 with the support of the IDA-funded Nigeria Electricity and Gas Improvement Project (NEGIP) has achieved a number of significant milestones towards the establishment of a commercially balanced domestic gas market (see Box 2). But, progress on overall market development has been slow putting additional gas volumes at risk due to lack of viable off-takers.[4] If successful, these market reforms will be beneficial in

[4] The Roadmap (Revision 1.0) estimates that 40% of the projected increase in gas volumes up to 2020 remain at risk due to lack of viable off take (including signed commercial agreements and bankable security structure).

reducing gas flaring in Nigeria; however, it is easy for unreasonable expectations to develop as to the direct contributions of specific transactions towards flaring. While the market develops, most initial IPPs will have to rely on already developed commercial supplies rather than associated gas currently flared[5].

Box 2: IDA Support for the Nigerian Gas Sector (NEGIP Project)

The IDA-backed NEGIP Project (P106172 and P126182) includes a US$600 million PRG Series designed to improve the availability and reliability of gas supply to increase power generation in existing public sector power plants. The guarantees seek to enhance the credit worthiness of Government entities for commercially viable gas off take (obligations under gas supply agreements, GSAs) in order to facilitate availability of adequate volumes of high quality gas required to operate power plant assets at their design capacity.

The NEGIP Project has supported significant progress towards the establishment of a commercially balanced domestic gas market. Gas price has increased from US$0.10 per mmbtu to US$2.0 per mmbtu in 4 years, which is an incentive to increase gas production and processing for domestic consumption.

NEGIP PRGs were made available to support gas purchase arrangements with private sector suppliers (such as Shell Petroleum Development Corporation (SPDC), and Chevron Nigeria Limited (CNL)). Although the documentation for the SPDC and CNL guarantees was substantially negotiated, changes in market structures have made these transactions unable to reach effectiveness. The next transaction in the NEGIP Series is a US$127 million PRG to support the GSA between Accugas Limited and Calabar Electricity Generation Company which will be presented to the World Bank Board for approval shortly.

33. **Efficient revenue management from the production of oil and gas would improve transparency, and governance, as well as improve the macro financial status of the economy**. The FGN faces challenges in disaggregating and calculating the revenue flows that stream from production of oil and gas. The Bank is supporting the FGN in development of a financial model which will reflect applicable fiscal provisions, whether contained in legislation or individual contracts with investors. The model will be able to assess the sector-wide impact of petroleum fiscal regimes proposed under the Petroleum Industry Bill.

34. **Unlocking Nigeria's power sector holds tremendous potential for economic growth in the country.** The FGN-led power sector reform program requires ongoing support to overcome challenges. The proposed operation will address issues relating to the promotion of private sector participation. Improving electricity supply can go a long way to spurring economic growth domestically and making Nigeria a powerhouse of Africa.

C. Higher Level Objectives to which the Proposed Project Contributes

35. **In 2009, Nigeria presented the *Vision 20:2020* outlining the country's ambition to become one of the top twenty economies in the world by 2020 by:** (i) optimizing the country's human and natural resource potential to achieve rapid and sustained economic growth, and (ii) translating economic growth into equitable social development that guarantees a dignified and meaningful existence for all its citizens. The 2011 Transformation Agenda lays out the initial

[5] Associated gas typically flared is often of low quality, low pressure, high moisture that requires significant investments in gas gathering and gas treatment infrastructure to be commercialized.

steps towards realizing the *Vision 20:2020*, by assigning top priority to job creation and addressing infrastructure constraints to growth, notably in power and transportation sectors together with reforms in agriculture and oil and gas industries.

36. **The proposed PRG Series is aligned with the Transformation Agenda's identified need for massive improvements in infrastructure provision to achieve the *Vision 20:2020***. In order to reach a target of over 40,000 MW by 2020, the Roadmap estimates a need for private sector investments of US$10 billion (Naira 1.6 trillion) annually, which if the funds were to be raised through budget allocations would exceed the entire FGN 2012 capital expenditure budget[6] - clearly an impossible feat for any government. The proposed PRG Series will assist FGN in leveraging scarce budget resources by mobilizing private investment and commercial lending through a tailor made package of risk mitigation instruments such as IBRD PRGs, IFC investments, and MIGA guarantees.

37. **The proposed PRG Series is fully aligned with the FY14-17 Country Partnership Strategy (CPS), which focuses on three strategic clusters in support of inclusive economic growth.**[7] The WBG's support to improving Nigeria's power supply is a critical part of the CPS. Many outcomes of the CPS are directly linked to improving power generation and transmission capacity, and efficiency of power supply to consumers. Given the magnitude of investments needed, leveraging private sector participation is and will continue to be vital to achieving these objectives. The proposed PRG Series is also aligned with WBG's Africa Strategy and the WBG's twin goals of eradicating extreme poverty and boosting shared prosperity. By improving the energy supply situation, the PRG Series assists in also improving access to markets and improving competitiveness.

38. **The PSGP will be implemented as an integral part of the coordinated donor support to the power sector** that includes significant investment and technical assistance (TA) programs from both multilateral partners such as: the African Development Bank (AfDB), as well as bilateral partners such as: Agence Francaise de Développement (AFD), Department for International Development (DFID), Japan International Cooperation Agency (JICA), and the United States Government (USG) under the Power Africa Initiative (PAI).

39. **The World Bank has been deeply involved in power sector financing and reform in Nigeria over the past 15 years**. The proposed PRGs are part of a suite of instruments supporting the energy sector, including a strong sectoral dialogue with the authorities. Within this broader suite of ongoing investment, technical assistance, and capacity building support, PRGs are used as an instrument to crowd in private investment and contribute to restoring investor confidence in the energy sector in Nigeria. World Bank support to the Nigerian power sector includes the recently closed National Energy Development Project (NEDP), the ongoing NEGIP, and the proposed PSGP. In the coming years, the Bank plans to increase its support to strengthen the transmission and distribution networks and enhanced electricity access.

[6] 2012 Approved budget, Capital/Investment expenditures: US$8.65 billion.
[7] The FY14-17 CPS will be presented to the Bank Board in April 2014.

40. **The proposed PRG Series is part of a suite of instruments under the WBG's Joint EBP for Nigeria** (see Box 3 below)**.** While IBRD has taken a lead role on the overall sector dialogue, due diligence with regard to the power sector reform program, and the power sector's financial situation and prospects, IFC has played a leading role ensuring the bankability of projects from a lender perspective (in the case of the Azura Edo IPP, in its capacity as a co-lead arranger of the DFI tranche, Co-Documentation Bank, Technical Bank and E&S Bank), and MIGA has participated in the insurance dialogue.

Box 3: The Joint Bank Group Energy Business Plan for Nigeria (EBP)

The Power Sector Reforms in Nigeria encompass the entire power sector value chain – from upstream gas development, through generation and transmission, to distribution and end-user tariffs. It is more comprehensive and ambitious than any power sector reform thus far undertaken in Africa.

The EBP for Nigeria was designed to provide a comprehensive solution of WBG expertise and financing under a joint task team to support the FGN's Power Sector Reform Program. The EBP focuses on maximizing WBG resources and support to the FGN to accelerate implementation of the Reform Roadmap by leveraging WBG products and expertise to attract private investment in new power generation capacity. The EBP is assisting the FGN with policy level issues such as tariff setting, regulatory improvements, sector financial viability, etc. In addition the EBP has mobilized appropriate advisory and technical and capacity building support not only for individual transactions, but also for cross cutting challenges related to the Reform Program.

In terms of support to individual transactions, the joint solutions by IBRD/IDA, IFC and MIGA for the first set of IPPs / GENCOs / DISCOs to be launched under the power sector reforms is expected to have a measurable impact on the sector - especially due to fast-tracking of key projects to financial close, enabling the Nigerian power sector to attract some of the most experienced and capable private sector investors while removing duplicative due diligence steps across WBG, making it easier to do business and deliver results. Targeted transactions may benefit from a mix of different types of IBRD partial risk guarantee support (e.g. credit enhancement/governmental payment, debt mobilization, and/or regulatory) as well as joint Bank Group support, e.g., IFC equity and lending participation and MIGA guarantees) where the relevant transaction justifies the need for such a mix, and there is no duplication of WBG coverage. While IBRD has taken a lead role on the overall sector dialogue, due diligence with regard to the power sector's financial situation, and prospects for improvement, and provision of critical risk mitigation through guarantees, IFC is playing a leading role in ensuring the bankability of projects from a lender perspective (in the case of the Azura Edo IPP, in its capacity as a co-lead arranger of the DFI tranche, Co-Documentation Bank, Technical Bank and E&S Bank). MIGA's value added is expected to be credit enhancement through termination guarantees, regulatory risk and other investment guarantees paired with vast knowledge and experience in developing political risk insurance instruments for power sectors in other countries with similar types of reform.

II. PROJECT DEVELOPMENT OBJECTIVES

A. PDO

41. The project development objective is to increase the supply of electricity received by Nigerian consumers.

B. Project Beneficiaries

42. *Direct beneficiaries*: The proposed PRG Series' direct beneficiaries are current electricity consumers (no new connections are financed under the supported IPP transactions), including the poor, who are provided an unreliable service due to poor quality of supply, high losses, and a lack of sufficient generation capacity to service the demand. By strengthening the power sector's technical and financial base, the PRG Series also helps lay the foundation for a future increase in access to electricity to the 65 percent of Nigerians not connected to the grid.

43. *Indirect beneficiaries*: Additional power generated by the transactions under the PRG Series will help increase productivity and spur economic growth. This benefits not only the electricity consumers but the country's population as a whole by assisting with translation of Nigeria's resource wealth into significant improvements in the power supply situation, assisting with job creation, poverty reduction, and improving the prospects for shared prosperity.

C. PDO Level Results Indicators

44. The proposed PDO indicators are (detailed results monitoring framework in Annex 1):
(i) Energy supplied to consumers (GWh) by first two IPP transactions (Azura and QIPP) supported under the PRG Series;
(ii) Installed capacity (MW) by first two IPP transactions (Azura and QIPP) supported under the PRG Series; and
(iii) Direct project beneficiaries (number), of which female (percentage).

III. PROJECT DESCRIPTION

A. Description of the PRG Series

45. The proposed PRG Series will support the implementation of the Roadmap for Power Sector Reforms. Each PRG will support a specific transaction, such as a greenfield IPP, a GENCO privatization, or a DISCO privatization. Each of the transactions supported will fall under one of the PRG Series Sub-Components (described below) and the commercial, technical, economic, financial, safeguards due diligence will be similar for each transaction as described in this PAD. The PRG Series will support transactions on a first-come-first-served basis. As per the FGN's request and FGN's borrowing plan with the Bank, the proposed PRG Series is initially estimated to be up to US$700 million in the form of IBRD PRG support. Guarantees will be provided in support of private transactions, as and when such transactions are ready. The proposed support (up to an aggregate of US$395 million) for Azura Power and Exxon QIPP will form an integral part of the PRG series. Subsequent transactions will be presented to the Board for approval as additional financing to the PSGP PRG Series.

B. Components of the PRG Series

46. The proposed project contains: **Component 1: PRG Series** with three sub-components based on the type of transactions supported:
(i) **Sub-Component 1**: Greenfield IPP Transactions;
(ii) **Sub-Component 2**: Privatization of GENCOs; and
(iii)**Sub-Component 3**: Privatization of DISCOs.

47. **Sub-Component 1: Greenfield IPP Transactions**: Support to greenfield IPPs will include the option of both credit enhancement for NBET and private debt mobilization support, i.e.: (a) the NBET credit enhancement guarantee, with or without Letter of Credit; (b) the commercial debt mobilization guarantee; or (c) a combination of both forms of guarantees. The first generation of fully project financed IPPs will need a reasonable securitization package to close, as most of the key agreements with responsible government institutions (such as NBET, Market Operator, NERC) have yet to be tested. The FGN has agreed to provide a backing of

NBET's obligations and a combination of termination and liquidity cover through MIGA/IBRD. As the commercial framework and market performance is confirmed, subsequent pipeline transactions should expect gradually lower securitization support both in terms of outright FGN support to NBET as well as WBG guarantee instruments until the market develops to the point where willing buyer-willing seller transactions are possible. Annex 2 provides a brief description of the pipeline for greenfield IPPs. Two greenfield IPP transactions have been identified for PRG support (the Azura Edo and the Qua Iboe IPPs). These are described below in more detail. Additional IPPs are being identified for support as transactions mature.

48. **Sub-Component 2: Privatization of GENCOs:** The structures of the PRGs in support of the GENCOs will be similar in terms to greenfield IPPs. The PRGs could support the initial capital mobilization that is anticipated to be carried out by the new owners of the 6 new GENCOs. New finances could be used for expansion of the available capacity of the plants or for rehabilitation of the currently installed but unavailable capacity. The PRG support will be for: (a) the NBET credit enhancement guarantee, with or without Letter of Credit; (b) the commercial debt mobilization guarantee; or (c) a combination of both forms of guarantees. However, currently, the capital expenditure (CAPEX) plans are being developed by the new owners who have recently taken over the GENCOs. Annex 2 provides a description of all the privatized GENCOs (not the prioritization of transactions). The privatized GENCOs include both gas fired as well as hydropower companies.

49. **Sub-Component 3: Privatization of DISCOs:** It is important that each link in the energy value chain be fully functional for the reforms to be effective. The ability, therefore, of the DISCOs to successfully turn around dismal customer service levels and improve revenues flows to finance investments upstream in the value chain will make or break the power sector reform efforts. The PRG structures available to DISCOs may fall into one of the following categories: (a) commercial debt mobilization guarantee; and/or (b) regulatory risk guarantee. The PRGs to be provided under sub-component 3 are necessary to ensure the DISCOs are able to attract the CAPEX financing required to implement the investment plans proposed by the new owners, and provide confidence to commercial lenders that the regulatory process will not be reversed. The criteria used for selecting DISCOs will include, inter alia, their revenue potential, cost effectiveness (using population density as a proxy), industrial customer base and access to electricity generation. Out of the 11 DISCOs being privatized, four have been identified as advanced stage candidates: Abuja DISCO, Benin DISCO, Eko DISCO, and Ikeja DISCO. Annex 2 provides a description of the four DISCOs.

C. The First Two IPP Transactions in the PRG Series (Under Sub-Component 1)

50. The first two front-runner transactions (up to US$395 million) are fully described in this PAD. By mitigating the uncertainty that these frontrunner transactions face, the PRG Series will augment the reforms and build market confidence and set industry benchmarks. The successful implementation of the first set of transactions will be critical to the success of the power reform agenda, as it will confirm the viability of the financial, transactional and regulatory systems put in place under the reform program. In the longer term, as Nigeria's power sector reforms progress through the transitional phase, it is expected that the need for risk mitigation will decrease, as NERC, NBET, and TCN establish track records of successful financial and

operational performance. The FGN has nominated, as transactions that require credit enhancement and debt mobilization support in the short to medium term, a total of 18 new greenfield IPPs, 6 privatized GENCOs, and 11 privatized DISCOs. This PAD presents the complete PRG Series design and appraises the overall scope of the universe of transactions to be supported. It also presents the first two greenfield IPP transactions for Board approval.[8] A pipeline of IPPs, GENCOs, and DISCOs that are in advanced stage of preparation has been established and will be considered for PRGs when mature. Subsequent PRGs will be presented to the Board as additional financing to the PSGP.

51. The first two IPP transactions will increase the installed power generation capacity by around 1,000 MW, and deploy nearly US$2 billion in financing, which includes about US$1.7 billion of private capital. The initial set of greenfield IPP transactions proposed for PRG coverage are as follows: Azura Edo IPP (Azura) and Qua Iboe IPP (QIPP). These initial transactions inherently possess a higher level of risk and require diligent support in order to achieve success. In the long term, the risks as well as costs of such transactions are expected to reduce. The two greenfield IPP transactions that have been identified for PRG support under Sub-Component 1 are described as follows (draft Term Sheets in Annex 10):

(a) ***Transaction 1: Azura Edo IPP (up to US$245 million):*** The Azura Edo IPP includes: (a) The NBET credit enhancement guarantee (up to US$120 million), and (b) The commercial debt mobilization guarantee (up to US$125 million). This open-cycle gas-fired power plant is being developed by Azura Power West Africa Limited (the "Company"), which is a Special Purpose Vehicle ("SPV") incorporated in Nigeria, with the sole purpose of developing a 459 MW open-cycle gas power plant located in the vicinity of Benin City, in Edo State, Nigeria. The sponsors are: (a) Amaya Capital Ltd., a principal investment firm and majority investor in Azura Power Holdings Ltd., its dedicated vehicle for investing in IPPs and the power distribution sector in Africa, jointly owned with the American Capital Energy and Infrastructure Fund, a fund managed by American Capital Ltd.; (b) Aldwych International Ltd. ("Aldwych"), an international power developer focusing on Sub-Saharan Africa; (c) African Infrastructure Investment Fund 2 ("AIIF2"), an Africa-focused fund managed by the Macquarie Group and Old Mutual which will invest through both its Rand-denominated and US$-denominated vehicles; and (d) Asset and Resource Management Ltd., a leading Nigerian asset manager. The sponsors are investing in the company through Azura Edo Ltd. (the "Shareholder"), an SPV incorporated in Mauritius. The Edo State Government, the local State authority, is also expected to have a 2.5 percent shareholding in the Company. The Power Plant will be located in Edo State and will have an installed capacity of about 1,000 MW, developed in two phases (a first phase of 459 MW and a second phase of 500 MW). It is possible that the company later converts the first phase project into a combined cycle plant and then adds 'Phase 3' thus the total capacity could reach 1,500MW). The plant is expected to include 4 high voltage (15 kV to 330 kV) transformers, one for each of the generator sets and a switchyard that is designed to accommodate

[8] The Azura Edo IPP (Azura) and Qua Iboe Power Project (QIPP). The Azura Edo project will also be supported by IFC and MIGA, see IFC /MIGA joint Board Paper.

additional capacity in the event that plant is converted into combined-cycle. Power will be evacuated from the switchyard through a single tower on a new 330 kV transmission line connecting the plant to the adjacent 300/132 kV new Benin North substation, currently under construction. Total transaction costs are estimated at US$813 million, expected to be financed on 72.5:27.5 debt-to-equity ratio. The most advanced of the IPPs, Azura has already executed its PPA with NBET as part of the Presidential Signing Ceremony held on 22 April 2013 in Abuja, although certain aspects, such as the security package provided by NBET under the PPA, and termination provisions under the Put Call Option Agreement (PCOA), including the final PRG terms, are being finalized.

(b) ***Transaction 2: Qua Iboe IPP (up to US$150 million):*** The Qua Iboe IPP includes the NBET credit enhancement guarantee (up to US$150 million). This 533 MW combined-cycle gas-turbine (CCGT) power plant is being developed by a Joint Venture (JV) between Mobil Producing Nigeria Unlimited (MPN) and the Nigerian National Petroleum Corporation (NNPC). MPN is a wholly owned indirect affiliate of Exxon Mobil Corporation, and is the operator of the JV. The JV is involved in the exploration, development, and production of several oil and gas concessions in Nigeria. The power plant will be constructed in Ibeno, Akwa Ibom State, on the south-eastern coast of Nigeria. The JV will also be responsible for the construction of a new, 58-km, 330 kV double-circuit transmission line connecting the plant to the new Ikot Abasi substation. The new substation at Ikot Abasi is part of a larger plan being progressed by the Transmission Company of Nigeria and the Niger Delta Power Holding Company Ltd. to extend the grid from Ikot Ekpene to Ikot Abasi through a new 78 km transmission line that is scheduled to be completed by mid-2014. Selection of EPC contractors for the power plant and the transmission line is being finalized. QIPP has met the disclosure and consultation requirements for its power plant ESIA. The Nigerian Electricity Regulatory Commission has issued MPN the requisite power generation license. Total cost of the power plant is estimated at US$1 billion. Transmission line is estimated to cost US$136 million. Major agreements underpinning the project, including the PPA and Put/Call Option Agreement (PCOA), are being finalized.

D. Financing and Bank Group Instruments

Lending Instruments

52. The proposed lending product is an IBRD PRG. Detailed terms and conditions for the proposed PRGs are provided in Annex 10. The transactions are also to be supported by IFC financing and MIGA guarantee, as described in their respective Board documents.

IBRD PRG Structures

53. The proposed PRG Series provides for three types of PRG support which address three key areas of investor concern. These guarantee structures are: (i) credit enhancement/ governmental payment structure; (ii) commercial debt mobilization support structure, and (iii) regulatory risk structure.

54. ***Credit Enhancement/Governmental Payment Structure***: The credit enhancement structure provides for an IBRD PRG to backstop certain payment obligations undertaken by Nigerian governmental agencies. The credit enhancement PRG can support a revolving standby Letter of Credit (L/C).[9] Under the L/C structure, NBET would provide security under the PPA in the form of an L/C, issued through a commercial bank, in favor of the IPP, for an agreed amount of coverage, corresponding to either: (i) certain upstream payment obligations, or (ii) a number of monthly payments representing NBET's periodic payment obligation under the PPAs. The L/C could be drawn in the event NBET, or the FGN, fails to make timely payments to a covered IPP, or GENCO, under the PPA, subject to certain grace periods, for the undisputed unpaid amount. Following a drawing, NBET would be obligated under the Reimbursement and Credit Agreement (to be entered into between NBET and L/C bank) to make a repayment to the L/C bank for the amounts drawn (plus accrued interest) within a period of one year. If NBET makes a payment within a determined time period (generally no less than 1 year), the L/C would be reinstated to the amounts repaid. However, if NBET fails to repay the L/C bank within such period, the L/C bank would have recourse to the IBRD PRG for the drawn amounts, plus any accrued interest, under the Guarantee Agreement (to be entered into between IBRD and L/C bank).

55. In such case, the maximum L/C amount would be reduced by the amount of payment made by IBRD under the PRG. Payments by IBRD under a PRG would trigger the obligation of FGN under the Indemnity Agreement (to be entered into between IBRD and FGN), which requires that FGN repay IBRD on demand, or as IBRD may otherwise direct. Each PRG L/C in support of the greenfield IPPs and GENCOs will be for an agreed maximum term of years from the effectiveness of each PRG, comprising the L/C term, plus NBET's one year repayment period, plus 60 day IBRD claim period within which IBRD would be obligated to pay the L/C bank. The credit enhancement structure outlined above could also be applied, in certain circumstances, to DISCOs where a significant portion of its electricity sales are to governmental agencies, and therefore, the DISCOs' success is dependent upon the timely collection of payments from those governmental agencies. It is possible an IPP, or GENCO, may seek credit enhancement against NBET's failure to pay under a PPA, but elect not to use the L/C structure, with its intermediary L/C Bank. In this case, the IPP, or GENCO, would be the direct beneficiary of a PRG for an agreed amount of coverage, similar to the L/C structure. If NBET fails to make an undisputed payment, and such payment remained outstanding for a period of, say, 12 months, the IPP, or GENCO, would have recourse to the PRG for the amount owed, plus any accrued interest.

56. ***Commercial Debt Mobilization Support Structure***: The commercial debt mobilization PRG provides direct support to a transaction's covered commercial lenders in the event of a debt payment default caused by NBET's failure to make undisputed payments under the PPA, or FGN under a termination of the relevant PPA, or in the case of DISCOs, a covered off-take agreement. Under the Guarantee Agreement (to be entered into between IBRD and the covered commercial lender(s)), the failure of NBET, or FGN, or the governmental agency guaranteed by FGN, to pay

[9] Note that the PRG L/C structure may not necessarily require that an L/C be provided so long as the payment security proposed in lieu of the L/C is in form and substance acceptable to IBRD.

undisputed amounts due under the covered PPA, or off-take agreement, entitles the covered commercial lender(s) to recourse under the IBRD PRG. As contemplated under the WBG's EBP for Nigeria, termination support to commercial lenders is also expected to be provided by MIGA. The coverage provided by MIGA will be complimentary to the IBRD support and not duplicative. The joint IBRD/MIGA guarantees would be structured to cover different risks or different tranches of debt.

57. ***Regulatory Risk Structure****:* To address DISCO concerns in respect of MYTO 2 implementation, the newly privatized DISCOs have the possibility of an additional PRG structure focused on regulatory risks faced during the transitional period. The support for regulatory risks will be designed to backstop only those clearly identifiable risks associated with implementation of the new MYTO 2 tariff and FGN's agreement to provide subsidies. The MYTO 2, adopted in June 2012, has introduced tariff at cost-reflective levels. It provides for adjustment of these levels through bi-annual minor reviews to account for changes in a set of agreed parameters - inflation, exchange rate, gas price and actual daily generation capacity, and major reviews every five years involving a comprehensive review and overhaul of all the assumptions in MYTO 2. The PRG regulatory risk coverage will be confined to the revenue gap stemming from the failure of NERC to abide by the identified parameters for minor and major review of the retail tariffs as provided under MYTO 2, to the extent the DISCOs relied upon such identified parameters when making their investment decision, and/or FGN's failure to provide the subsidies promised to the DISCOs. It will cover only the retail portion of the tariff, after deducting amounts corresponding to the bulk purchase tariff and transmission costs. More specifically, the gap will be subject to the difference between the actual level of revenues collected by the DISCO at any point in time, and the revenues the DISCOs would have otherwise been legally entitled to generate, excluding any portion lost due to commercial losses. This way the PRG will support the DISCOs only for regulatory risks and not commercial risk, which is expected to be managed by private investors.

Table 1: PRG Structures by Sub-Component

	NBET Credit Enhancement	*Commercial Debt Mobilization*	*Regulatory Risk*
Sub-Component 1			
IPPs	✓	✓	N/A
Sub-Component 2			
GENCOs	✓	✓	N/A
Sub-Component 3			
DISCOs	N/A	✓	✓

58. To ensure success, there are various mitigation and risk sharing arrangements being designed. The idea that risks should be allocated to the party most capable of managing the risk, has been a guiding principle in the risk sharing design. The credit enhancement feature is proposed to provide an agreed amount of coverage that corresponds to: (i) certain upstream payment obligations, such as gas, or fixed and variable expenses, or (ii) a number of monthly PPA payments, representing NBET's periodic payment obligation under the PPAs with IPPs. Commercial debt mobilization support provided by the PRG is proposed to cover private commercial debt from certain events of default that result from an NBET payment failure that leads to termination of the PPA or FGN's failure to make payments under the PCOA. Regulatory

guarantee backstops only those clearly identifiable risks associated with implementation of FGN’s policies. The risk sharing arrangement is presented below.

Table 2: Risk Sharing Arrangements

Phase	*Risk*	*Sponsor*	*Lender*	*FGN*	*World Bank Group Mitigation Support*
Pre-Construction	Design	✓			
	Debt/equity financing	✓	✓	✓	✓
Construction	Cost overrun	✓	✓		
	Construction delay	✓	✓		
	Implementation of ESIA	✓	✓		
	Implementation of RAP	✓	✓		
Operation	Adequately efficient O&M	✓	✓		
	Output and reliability	✓	✓		
	Payments under contracts (PPA/GSA)	✓	✓	✓	✓
Concession Term	Currency devaluation			✓	
	Currency convertibility/transferability	✓	✓	✓	✓
	Political force majeure			✓	✓
	Changes in law			✓	✓
	Natural force majeure	✓	✓	✓	

PRG Pricing

59. Each of the PRGs under the proposed PRG Series would usually be priced at 50 basis points per annum[10] on the highest annual guaranteed amount, payable every six months in advance. In respect of the greenfield IPPs, because PRG support does not cover construction risk, PRG coverage would commence from the commissioning date of the relevant greenfield IPP. In addition, there would be (i) a Front-end fee of 25 basis points on the maximum exposure of the guarantee, (ii) an Initiation Fee of 15 basis points or US$100,000 whichever is higher, and (iii) a Processing Fee determined on a case by case basis (usually 50 basis points of the guaranteed amount) for the reimbursable expenses of each transaction. All PRG-related fees are per transaction, payable by the transaction sponsors, in accordance with the IBRD pricing policy for guarantees.

Optimization of World Bank Group Instruments

60. The joint WBG support to transactions in the power sector (e.g. IBRD PRGs, IFC financing and MIGA guarantees) could be deployed where relevant transactions justify the need for such a comprehensive mix and there is no duplication of WBG coverage. In this regard, to optimize the available envelope of IBRD PRG support, and ensure efficiency gains envisioned under WBG’s EBP, transactions may benefit from a mix of the three types of PRG support (i.e. credit enhancement for power off-taking payments, commercial debt mobilization, and/or regulatory risk). For example: in mobilizing commercial debt tranches, MIGA and IBRD can provide parallel guarantees against the FGN’s obligations under PCOA. This combined WBG coverage provides assurances to sponsors and lenders that IBRD and MIGA have adequate rights

[10] FY14 pricing (subject to change) if guarantee based on average maturity of up to 12 years. For IBRD guarantees, the guarantee fee includes an annual maturity premium of 0.10% for maturities greater than 12 and up to 15 years, and 0.20% for maturities greater than 15 and up to 18 years.

for intervention in the event of an off-taker default by NBET, and/or a reversal of Nigeria's nascent power sector reforms. In offering this combined form of commercial debt coverage, transactions become more sustainable; stronger risk allocation between the private sector investors, lenders, FGN and the WBG can be achieved; and WBG resources can be used more efficiently. Such guarantees are required to mobilize equity and debt financing for the transaction until a track record is set. These principles of efficient deployment of WBG instruments will be applied for each transaction supported under PSGP. In addition, the use of IFC's lending instruments enhances bankability of projects from a lender perspective - for example, in the case of the Azura Edo IPP, in its capacity as a Co-Lead Arranger of the DFI tranche and Co-Documentation Bank.

Total Cost and Financing Summary

61. The proposed IBRD PRG support for the first two IPP transactions in the PRG Series is up to US$395 million. This includes up to US$120 million for NBET credit enhancement and up to US$125 million for commercial debt for the Azura Edo IPP and up to US$150 million credit enhancement for Qua Iboe IPP. This PRG support will deploy nearly US$2 billion in financing, which includes about US$1.7 billion of private capital. This means that the first two transactions will have a leverage ratio (for capital deployed) of about 1:5. Details of financing arrangements for each transaction are below:

Table 3: Financing Plan for Azura Edo IPP

Item	*Amount (US$M)*	*% of Total*
Equity	**223.8**	**27.5**
1. Shareholder's Loan	146.2	18.0
2. Equity Capital	16.2	2.0
3. Mezzanine Debt	61.3	**7.5**
Debt	**589.1**	**72.5**
1. DFI (Proposed Loan)	239.1	29.4
2. Overseas Commercial Banks	200.0	24.6
3. Local Banks	150.0	18.5
Total Cost (Debt and Equity)	**813.0**	**100.0**

Table 4: Financing Plan for Qua Iboe IPP

Item	*Amount (US$M)*	*% of Total*
Equity	**1,136.0**	**100%**
1. Shareholder's Funds	1,136.0	100%
Total Cost (Equity)	**1,136.0**	**100.0**

E. Lessons Learned and Reflected in the PRG Series Design

62. The key lessons learned from the WBG's energy sector operations and project finance transactions, which are applicable to this proposed PRG Series, include the following:

(i) Comprehensive power sector *reform program* has to be initiated in advance of major new investments. Implementation of reforms has to be followed through while investments come into the sector. This approach helps to establish a sound legal and regulatory framework and underpin the financial viability and sustainability of the power sector and new investments. In Nigeria, the Electric Power Sector Reform (EPSR) Act (2005) has helped in achieving a sound legal and regulatory framework and established a power sector regulatory body. Achieving sound institutional and governance arrangements have been a key focal point of the reform program;

(ii) The *financial viability* of the power sector is being enhanced by commercializing power sector operations and through private participation in the ownership and management of generation and distribution facilities, whereby the private sector is provided with a suitable incentive and penalty structure for enhancing performance and achieving efficiency targets. The cash flow modeling of the sector demonstrates the significant improvements (revenues) that can be achieved by reducing losses and improving the efficiency of sector utilities which in turn can improve the overall financial situation;

(iii) Due to the size of the investment needed in the Nigerian power sector, coupled with the scarcity of government budget resources and donor funding available for such large and complex infrastructure projects, World Bank Group support will be dedicated to helping catalyze long term *private sector financing* for capital intensive projects by mitigating certain political and transactional risks where the power sector has not yet developed a consistent track record of positive performance;

(iv) In order to ensure a transaction's long-term sustainability, it is important that there is an equitable *allocation of risks* between the various participating parties (for example: the government, private sponsors, lenders, consumers, and other stakeholders). This principle has been followed during the negotiation of PPAs and other commercial contracts pertaining to the power sector privatization process;

(v) Implementation delays experienced in past PRG Series can be avoided by *advanced preparation* of core commercial contracts and related legal documents for the transaction. The current Bank operation in the Nigeria power sector, NEGIP, is providing a PRG Series to enhance the gas supply to publicly-owned power plants in Nigeria. Being the first such operation, it suffered delays in making these PRGs effective due to the time required to develop and negotiate many of the benchmark commercial documents that make up the transactional structure. In the current PSGP PRG Series, model forms of these documents (such as draft PPA, PCOA, GSA, GTA, etc.) have already been developed with the input of industry participants, and, in the case of the front-runner transactions, substantially agreed. This should assist in timely effectiveness of individual PRGs proposed under PSGP;

(vi) Improving *sector governance* requires policy reforms and that policies be applied through pilot investment projects. WBG instruments can support good governance through technical assistance to reform minded governments but also importantly to the support to specific transactions. WBG presence can attract credible investors and enhance transparency in selection and contracting processes; and

(vii) In an evolving market landscape, it is necessary that the PRG instruments are designed with sufficient *flexibility*. The adaptability of such instruments can in fact be an important aspect of risk mitigation of the design obsolescence. The proposed PRG Series reflects this philosophy by presenting a menu of PRG approaches that can support various types of transactions under the ongoing reform and privatization program.

F. Partnership Arrangement

63. The operation focuses on supporting private sector sponsors and financiers. Transactions support will be carried out in partnership with other donor agencies which are partnering and assisting the FGN towards the sector reforms. These include AfDB, AFD, DFID, EIB, EU, FMO, GIZ, JICA, KfW, and others. Nigeria is a focus country under President Obama's Power Africa Initiative. The WBG and USG agencies are working together to mobilize private sector financing to maximize impact through the deployment of different instruments in coordination with each other. The technical assistance from WBG and USAID supports the overall reform program as well as specific transactions.

64. Donor activities are coordinated through an Energy Sector donor working group, co-chaired by EU and UNIDO with regular meetings with the Ministry of Power and relevant FGN sector stakeholders. As the demand for securitization is expected to be considerable during the transitional period of the reform process, AfDB is supporting an additional PRG Series focusing on a separate set of nominated IPPs. The additional securitization will help to further boost NBET transactional capacity in the short to medium term.

IV. IMPLEMENTATION

A. Institutional and Implementation Arrangements of the First Two IPPs

65. ***Azura IPP:*** Azura Power West Africa Ltd (Azura IPP) is a special purpose vehicle incorporated and registered in Nigeria in 2010 to develop, build, own, operate and maintain the Azura project. The construction of the plant will be implemented through an Engineering, Procurement, and Construction (EPC) contract. The sponsors are finalizing the EPC contract with Siemens AG, Siemens Nigeria Ltd. and Julius Berger PLC. PIC Group, Inc., a US-based company wholly-owned by Marubeni, Japan's leading conglomerate and largest power producer will be responsible for the operation and maintenance of the plant. Azura is currently finalizing a Gas Supply Agreement (GSA) with Seplat Petroleum Development Company PLC (details in Annex 2).

66. ***Qua Iboe IPP:*** Qua Iboe IPP is a joint venture (JV) between Nigerian National Petroleum Corporation (NNPC) and Mobil Producing Nigeria Unlimited (MPN). MPN is a wholly owned indirect affiliate of Exxon Mobil Corporation. The FGN has a 60 percent interest in the JV, with the remaining 40 percent owned by MPN including operating rights. As such, the project commercial and operational arrangements will be consistent with the JV's current practice. The JV expects QIPP to be constructed under three EPC contracts, one for the power plant, one for the transmission line between the plant and a substation in Ikot Abasi, and one for the gas pipeline. Gas for QIPP will be supplied from the off-shore Oso field, a JV asset operated

by MPN. The JV expects to retain the EPC contractor as operator to operate and maintain the plant for a three-year term after the plant's commercial operations date, followed by MPN taking over the plant's operations (details in Annex 2).

67. ***Project Management:*** NBET is wholly owned by the FGN and was incorporated in 2010 as part of the ongoing Nigeria power sector reforms. NBET, as the primary off-taker of power from IPPs, is responsible for developing and implementing the commercial arrangements for bulk power trade. NBET has been negotiating the first PPAs with front-runner project sponsors under the MYTO 2 New Entrant Model PPA price benchmarks. In the transition phase, NBET will be entering into PPAs with new IPPs which intend to sell power to local distribution companies through the national grid. It will also sell power to the privatized PHCN successor (distribution) companies (additional information on NBET organizational structure and monitoring systems can be found in Annex 2 and 3). In addition to the contractual obligations projects sponsors will have with NBET, each power plant will be operating under a license issued by NERC detailing the rights and obligations of the individual IPPs under the existing regulatory code. Compliance with the operating license, including hearings with consumers and other sector stakeholders will be monitored continuously by NERC. Privatized GENCOs and DISCOs will also be supervised by BPE, as representative of the Federal Government under the Share Purchase Agreements. This will include adherence to the agreed business plans, including obligations to mobilize investment capital to reduce losses and rehabilitate the assets.

68. ***Transitional Electricity Market:*** The February 2009 Market Rules provided for evolution of the Nigerian Electricity Supply Industry (NESI) through three (3) stages: Pre-Transitional, Transitional, and Medium Term stages. The Pre-Transitional stage was intended to facilitate privatization of the generation and distribution assets of the PHCN as well as to develop the grid code and market rules needed for operation of the electricity market. The Transitional stage (otherwise known as the 'Transitional Electricity Market' or 'TEM') is anticipated after completion of 14 conditions precedent to operation of the electricity market. TEM is characterized by development of contract-based new generation capacity and arrangements for electricity flows until the underlying market systems are sufficiently mature to introduce spot market trading that would mark commencement of the medium term stage. The FGN and relevant stakeholders are currently working on the process to operationalize the pre-transitional stage market while work continues on the conditions for TEM's commencement, many of which are already in an advanced stage.

B. Results Monitoring and Evaluation

69. Data for monitoring project outcomes and results indicators (see Annex 1) will primarily be generated by the implementing agency, NBET, through progress reports, annual reports, etc. Evaluation of results indicators will be part of regular IBRD supervision missions. The proposed PRG Series' mid-term review will thoroughly review project implementation and the indicators. The main indicators are aligned with key trading parameters of the sector that are generated and monitored monthly. The PRGs will be monitored through regular supervision until the expiry of each PRG as well as notification and reporting requirements by the L/C Bank, NBET, and FGN under the Project, Guarantee, and Indemnity Agreements.

70. FGN will also organize stakeholder forums with participation from the Ministry of Power

and other relevant government agencies, NGOs, civil society organizations and industry representatives to discuss project implementation issues and provide a platform to articulate and address concerns about community, social and environmental aspects of project implementation. These interventions will leverage the platform already established by the NEGIP program to support ongoing dialogue, transparency, information sharing, and community outreach programs, particularly in the gas rich regions of Nigeria. Beneficiary surveys, at inception and the mid-point of implementation, will also provide information of outcomes.

C. Sustainability

71. The sustainability of the Nigerian power sector reforms as well as that of investments under this proposed Series will depend upon: (a) the financial health of the power sector and its ability to generate sufficient revenues to fully cover costs, including capacity payment obligations to the proposed Series; and (b) the FGN's continued commitment to supporting the comprehensive power sector reform program which has been implemented over the past few years. Cost recovery in the power and gas sectors will ultimately be essential for sustainability and the phasing out of requirements for FGN budgetary support. Investments in the power sector under the proposed Series are designed to promote cost recovery through increased capacity and efficiency through reduction of technical and commercial losses. As the sector's losses are reduced and its commercial viability improves, the risk perception of NBET will also improve. Certainty of payments by a credible off-taker, NBET, will also motivate IPPs, GENCOs, and DISCOs, to invest in maintenance and upkeep of technical equipment, construction of spur lines, etc. in order to meet their contractual obligations.

72. The outlook for the economic and financial sustainability of the Series is also reinforced by: (a) strong forecasts of demand growth for electricity driven by positive economic growth performance; (b) cost-reflective tariff levels that are consistent with the electricity prices underlying the demand forecasts (MYTO); and (c) the fact that in the residential sector, maintenance of an 'affordable' share of expenditure on electricity, relative to projected total household expenditure. Long term sustainability of the electricity infrastructure is enhanced by the fact that the companies will be managed and operated by experienced and professional operators with an incentive to maintain, upgrade, and keep plants/systems running smoothly.

V. KEY RISKS AND MITIGATION MEASURES

A. Risk Rating Summary

Table 5: Risk Rating Summary Table

Risk	*Rating*
Stakeholder Risk	M
Implementing Agency Risk	
- Capacity	S
- Governance	H
Project Risk	
- Design	L
- Social and Environmental	M

- Program and Donor	M
- Delivery Monitoring and Sustainability	M
- Gas Supply	H
- Financial Viability	H
Overall Implementation Risk	**H**

B. Overall Risk Rating Explanation

73. Given the overall scale of the reform agenda and the sheer volumes of transactions being supported under the PRG Series, the overall risk rating is considered '**High**'. Other than the key risks highlighted above, there remain other challenges to the success of the PRG Series, such as, the overall governance risk in Nigeria; capacity of the newly established NBET to manage transactions; and technical risks such as transmission system capacity bottlenecks. A detailed analysis of these risks is provided in Annex 4. The potential major risks and possible mitigation measures are discussed below:

74. ***Gas supply risk***: The shortfall of gas supply remains a considerable risk for power generation in Nigeria. Investment in exploitation of the gas resources is not keeping up with demand. Furthermore, the risk to major gas pipelines due to vandalism and general unrest is also significant. ***Mitigation***: Transactions supported under the PRG Series are in locations where gas resources are reliably available, either next to a major gas pipeline, or next to a treatment plant. Confirmed and dedicated gas supply will continue to be a selection criterion for future transactions supported under the PRG Series. Furthermore, IDA, under the ongoing NEGIP Project, is supporting the improved incentives and increased attractiveness of investment to gas suppliers by supporting the development of a commercial framework for gas supplies under the FGN's revised pricing policy as well as a PRG for backing the FGN's obligations under a gas supply agreement (GSA).

75. ***Financial viability concerns for the sector***: There is a high risk of the sector facing financial viability challenges, given that the sector cash flows are not expected to be adequate to meet all sector obligations during the transitional period. ***Mitigation***: The revised MYTO2 was implemented on June 1, 2012 and is based on a set of principles designed to reflect efficient and realistic cost levels for each of the generation, transmission, and distribution (including retail) sectors, taking into account (i) cost recovery/financial viability; (ii) signals for investment; (iii) allocation of risk; (iv) incentives for improving performance; (v) transparency/fairness; and (iv) social and political objectives. Recognising the weak base for distribution loss data in the current MYTO 2 model, NERC has agreed to launch a joint loss verification exercise with DISCO bidders post hand-over. The results will be used in determining revised loss baselines with corresponding adjustment in tariffs. The WBG is also providing technical assistance to the NBET and FGN to analyse future sector cash flows and prepare corresponding mitigation measures to address revenue shortages including priority payment order, subsidy levels and management of remaining public assets.

76. ***Inability of sponsors / bidders to mobilize financing***: Most of the project sponsors and bidders of IPPs, GENCOs, and DISCOs supported under this PRG Series have completed asset acquisition. However, there remains a risk for new owners in attracting additional financing for

capital expenditures in order to rehabilitate their assets under the business plans. ***Mitigation***: Based on the due diligence performed, the WBG is satisfied with the viability of the financial models for the proposed front-runner transactions, and the ability of NBET to successfully manage the technical and financial aspects of the transactions. This level of due diligence will be maintained for each transaction supported under the PRG Series.

77. ***Delays in construction and cost overruns***: There remains a risk that the construction of the IPP projects may not complete on time and may incur additional costs than previously estimated. ***Mitigation***: the EPC contracts are designed to be fixed price turnkey contracts. Based on the due diligence performed by the sponsors and the World Bank (of the leading two IPP transactions), the contractors and sub-contractors have adequate experience of undertaking similar projects. Changes in EPC contract prices are only allowed under very specific circumstances, such as changes in law, change orders instructed by NBET, and for technical conditions being worse than the baseline.

78. ***Change in government / political support***: The advances made in the power sector reform under the current government could be reversed by subsequent administrations, especially, in the light of the upcoming national elections to be held in 2015. ***Mitigation***: The government has taken significant and irreversible steps to implement a comprehensive power sector reform program. There is broad public support and political consensus (from governing and opposition parties) around the overall goals outlined in the Presidential Roadmap including the privatization of the GENCOs and DISCOs, the reliance on IPPs for future generation addition and the appointment of the management contractor (MHI) for TCN. There are many other interested stakeholders who are following the reform process and will push to keep it on track (e.g. donors, investors, media, CSOs). World Bank Group presence in the sector will support reformers in the FGN to stay the course. Perhaps the best mitigation measure in the sector will be to create visible results that would generate continued political support for the reforms.

79. ***Macro-economic environment***: The success of the transactions may be affected by risks to macroeconomic stability. These may include fluctuations in the price of crude oil (and consequently, of the Nigerian Naira) which accounts for a large portion of Nigeria's foreign exchange earnings. ***Mitigation***: The proposed PRG Series will assist in providing reliable electricity supply that will remove supply constraints and improve the overall efficiency of the sector. The PRG Series is expected to improve Nigeria's ability to handle future exogenous shocks and maintain satisfactory macro-economic performance by reducing the reliance on imported fuel and self-generation to power domestic industry and commercial activities. Macro-performance and progress on power sector reform are underpinned by the World Bank and IMF[11] dialogue.

80. ***Slower than expected demand growth***: Further to the macro-economic and financial viability risks, slower than expected demand growth may affect the success of the transactions supported under the project. ***Mitigation***: There is significant suppressed demand in the Nigerian power sector which is estimated to exceed 6,000 MW. The growth in demand in the Nigerian

[11] Further information on the IMF Nigeria assessment: http://www.imf.org/external/pubs/ft/scr/2013/cr13116.pdf

power sector is expected to continue to increase at around 10 percent per annum in the medium term. Based on the supply-demand analysis carried out by the World Bank, the risk to the initial set of transactions due to lack of demand is expected to be low.

VI. APPRAISAL SUMMARY

A. Economic and Financial Analyses

Economic Analysis

81. ***Development impact***: A traditional cost-benefit analysis of the proposed PRG Series shows that the PRG Series is economically viable. IPP investments supported by the PRG Series will significantly improve Nigeria's power supply capacity. In particular, 'incremental consumption', as a result of the PRG Series was estimated. The analysis includes the impact of the current power shortages on the economy, electricity demand growth and cost of unserved electricity, the end-user tariff path (via the cost reflective MYTO 2), consumer's willingness to pay (WTP), and the overall macro-economic impact of the reforms. Based on the methodology and assumption described in Annex 7, the estimated Economic Internal Rate of Return (EIRR) of the PRG Series is 33 percent and the Net Present Value (NPV) is US$3,628 million (at 10 percent discount rate). At 12 percent discount rate, the NPV is US$2,719 million. Sensitivity analysis was also conducted to test the robustness of the profitability of the project to changes in key parameters of project costs and benefits.

82. ***Appropriateness of public sector financing:*** The objective of the PRG Series is to increase the supply of energy to the Nigerian consumers. Given the scale of financing needed for the sector, this PRG Series will provide public sector financing to promote private sector investment and to support FGN's efforts by addressing the huge financing gaps. The WBG investment and risk mitigation framework for this PRG Series is designed with complementary and efficient use of IBRD PRGs, IFC Investments, and MIGA Guarantees to support the FGN's agenda of increasing electricity generation and private sector participation in the sector. This PRG Series assists the FGN in achieving its goals of investment promotion by the private sector by an economically suitable mechanism - the PRG structure helps to conserve IBRD resources through the provision of minimal amounts of security to lenders and investors, while at the same time making projects bankable. PRGs have a significant leveraging impact - for the first two IPP transactions of the PRG Series, US$395 million in PRGs will mobilize over US$1,700 million of investment.

83. ***World Bank's value added:*** Given the risk perception of some investors towards the Nigerian power sector, and the fact that the new sector institutions are yet to build up credit histories, the anticipated scale-up in private investment would not be feasible without the intervention of credit enhancement and debt mobilization instruments (PRGs). WBG's support is critical for providing confidence to investors in the sector. Not only is the project helping crowd in much needed private capital, but it is also aligned and embedded in a strong sectoral dialogue with the authorities. In addition, WBG's technical assistance and overall support in bringing transactions to financial closure adds significant value to the sector and assists in the goal of increasing the supply of energy.

Sector Financial Analysis

84. A cash flow model has been developed by the Bank team and NBET in order to assess the financial risks associated with the sector over the period 2014-2017. Financial shortfalls would be driven in large part by two factors: (i) higher transmission and ATC&C losses than what MYTO 2 has provisioned for; and (ii) lower energy injected on the grid than MYTO 2 projections impacting negatively the DISCOs' ability to recover their fixed costs. Under such a scenario, the model estimates that DISCOs would be able to pay on the average only about 50 percent of their invoices at takeover.

85. Payments from DISCOs are expected to improve significantly post-privatization, even before the core investment program has been completed. Private sector operators can immediately address transitional issues such as low staff morale, poor management oversight and limited resources even for basic operations and maintenance. The remittance level is expected to increase up to 81 percent by 2017 as the investments made by TCN and new private owners of DISCOs in reducing losses and improving commercial performance start yielding results. Despite this improvement, a 19 percent shortfall in the sector cash-flows would still be incurred by 2017 if no additional measures are taken. Over the period 2014-2017, sector liabilities would aggregate to about US$4 billion, in average US$1 billion a year. These sector liabilities are essentially covering the remaining revenue shortfall to pay for some of the generation, TCN wheeling charges, and various administrative charges.[12] The analysis included two alternative scenarios:

(i) ***Aggressive loss reduction scenario****:* This scenario was modeled to emulate the uncertainty on the level of losses that could be reduced within the next 4 years, in particular by the DISCOs' new owners. In the event where the new owners are successful in reducing these losses down to 22 percent [13] and transmission losses are capped at 7.7 percent by 2017, DISCOs would be able to remit 93 percent of their invoices. By 2016, GENCOs would be made whole under their PPAs while TSP would have to wait until 2017 until it is made whole. Sector liability under this scenario falls short of US$2.8 billion that is equivalent to US$700 million per year.

(ii) ***Adjusted tariff scenario*****:** In the context of the projected sector deficit, NERC has agreed it would adjust tariffs to reflect actual level of losses following an independent assessment that is being carried out by an independent technical auditor on behalf of the regulator and the DISCO prior to the initiation of TEM. If these losses turn out to be higher than what is actually projected in MYTO 2, the team's analysis highlights that an increase in tariff by about Naira 4 per kWh to the current tariff as of 2014 would allow the sector to become financially whole as of 2015. In this case, government's support to the sector becomes significantly reduced. The risk associated with this scenario is whether the tariff increase will be politically palatable, especially

[12] The cash flow model gives priority payment from the cash collected by discos to private sector operators: DISCOs come first, then IPPs and privatized GENCOs, TCN and finally rest of administrative agencies.

[13] In the base case, level of ATC&C losses targeted is 28 percent by 2017 down from 35 percent in 2014. This would require reducing losses by 8 percent per annum as of 2014.

given that the tariff has been doubled in June 2012 with no substantial improvement in delivered power on the grid. Sector liability falls under the threshold of US$1 billion over the 4-year period, equivalent to US$250 million.

IPP Financial Analysis

86. The following are the main financial indicators from the financial analysis conducted for each transaction. Detailed analysis for the Azura and Qua Iboe transactions is in Annex 9.

87. ***Azura Edo IPP:*** Financing of the Azura Edo IPP is conducted based on a 72.5:27.5 debt-to-equity ratio. The financial analysis of Azura's cash flows shows a robust project based on sound financial structure and projected stream of cash flow. Based on Azura's approved tariff under the PPA, the unlevered internal rate of return (IRR) is 13.5 percent. Senior Debt service coverage ratio (DSCR) remains above 1.71 throughout the life of the project limiting risk of debt service default, in addition to a debt service reserve account of 6 months. A sensitivity analysis highlighted that the project can sustain variations in the range of 30 percent to 35 percent for key variables such as net capacity and availability factors.

88. ***Qua Iboe IPP****:* Financing of the Qua Iboe power plant is expected to be conducted on an equity finance basis by the NNPC/MPN Joint Venture. The financial analysis of Qua Iboe IPP shows a robust project based on sound financial structure and projected stream of cash flow. Furthermore, the project can rely on the support of Tariff negotiated with NBET under the PPA resulting in the QIPP's IRR estimated at 13.8 percent. A sensitivity analysis highlighted that the project can sustain variations in the range of 15 percent to 20 percent for key variables such as net capacity and availability factors assuming no additional cash infusion from sponsors. The table below provides a summary of the main financial indicators for all IPP sub-projects:

Table 6: IPP Financial Analysis

	Azura Edo	*Qua Iboe*	*MYTO 2 New Entrant in 2017**
Installed Capacity	459 MW	533 MW	250 MW
Technology	Open cycle	Combined Cycle	Open Cycle
Total Cost	813 M$	1136 M$	358 M$
EPC cost	416 M$	850 M$	
Total cost per kW	1,771 US$ /kW	1,876 US$/kW**	1,433 US$/kW
Electricity tariff			
Capacity Charge	5.05 c$/kWh	5.86 c$/kWh***	4.65 c$/kWh
Energy Charge	5.00 c$/kWh	2.13 c$/kWh[14]	3.77 c$/kWh
Total Tariff	10.05 c$/kWh	8.64 c$/kWh	8.42 c$/kWh
Project IRR	13.5%	13.8%	15.0%

** Structure for IPPs provided under MYTO 2*

** $1876/kW excludes transmission line cost of $136M ($2131/kW if transmission line is included)

*** In addition, QIPP transmission line tariff is 0.65 c$/kWh bringing the total to 8.64 c$/kWh

B. Technical

89. ***Design and Layout of Power Plants*****:** The first two plants covered by the proposed PRG Series are designed with 2-4 Gas turbines in straight-line configuration. The Azura plant is not

[14] Based on a gas price of US$2.0 /mmbtu

configured for combined-cycle operation in the initial stage but has been prepared to accommodate conversion by adding appropriate heat recovery steam generators (HRSGs) to space that will be made available at the inlet exhaust ducts of the gas turbines. The conversion will take place only when gas and power prices in the Nigerian market justify the additional investment. The fact that NNPC/MPN JV proceeds with a CCGT design already at the outset reflect the integrated nature of the QIPP development, as the gas quantities saved from the increased efficiency of the plant can be made available to the domestic market under NNPC/MPN JV's domestic supply obligation (DSO).

90. ***Generation Equipment*:** The plants are using similar Frame E type gas turbines with a capacity (at site conditions) of between 110 MW and 160 MW per turbine depending on the manufacturer. Selection of this turbine type was based on an analysis of the technology's associated construction costs, thermal efficiency, and operating versatility. It was also based on availability of multiple equipment manufacturers that provide the machines (currently, Frame E machines manufactured by General Electric, Alstom, and Siemens are operating in Nigeria), and the fact that the new, FGN-funded NIPP-funded projects operate 18 of these machines, which is likely to ease availability of spare parts in the country. The technology is to be considered fully mainstreamed and thoroughly tested for similar environments.

91. ***Transmission System Power Evacuation*:** The Nigerian Transmission system is expected to continue to struggle with capacity constraints in the near term while ongoing projects managed by TCN and NDPHC/NIPP are being completed. Therefore the plants have chosen locations close to major demand centers - Azura is located in proximity to a critical transmission node in Benin City allowing easy evacuation of the added power supply in multiple directions. For the QIPP the location in Qua Iboe represents some challenges in terms of evacuation as the transmission system needs to be extended there and several other transmission line projects are on the critical path to decongest the system and allow the quantum of power to reach key demand centers. MPN has therefore, in addition to the compulsory TCN load evacuation study, commissioned a detailed grid evacuation study made by consultants PB power. The study confirms that, beyond completion of the lines connecting the plant to the grid, progress on decongestion of the network in the South-East is sufficiently advanced that it poses minimal risk to the expected project first power time in 2017/early 2018.

92. ***Gas Supply*:** Azura will receive its gas supply through the main Escravos-Lagos Pipeline System (ELPS) supplying gas from the Escravos area in the south to Lagos in the South West. With the doubling of the capacity of this pipeline well underway (expected to be completed by end 2014/15) and firm gas supply agreements in place both the gas availability and delivery system capacity is expected to be assured by project completion. Gas for QIPP will be supplied via a new pipeline (to be constructed by the NNPC/MPN JV) delivering gas from the off-shore Oso platform (an existing facility owned by the NNPC/MPN JV) to the on-shore plant location at the Qua Iboe Terminal.

93. ***Operations and Maintenance*:** Both Power Plants will be operated by a third party O&M contractor (For QIPP, the third party O&M contractor is expected to operate the plant for the first three years only. MPN plans to operate the plant thereafter). It is also expected that each plant will have a Long Term Service Agreement (LTSA) with the equipment supplier or other

professional party, selected as part of the EPC process for construction of the plant. For a detailed and plant specific account of the plant configurations, O&M arrangements, supply and evacuation details please consult Annex 2.

C. Financial Management

94. The IBRD PRG is providing a guarantee to the commercial lenders. As such, there are no anticipated financial management (FM) issues as there will be no procurement or procurement-related disbursements under the proposed PRG Series. Should the IBRD PRG be called, IBRD would disburse to the beneficiary and the FGN would then be obligated to repay IBRD in accordance with the terms of the Indemnity Agreement between the FGN and IBRD. The overall financial management of the transactions will be undertaken by a private entity according to commercial practices acceptable to the lenders.

95. Within NBET, the organization includes a finance department, charged with accounting, financial management, and control, reporting, internal audit, and other financial management tasks. Given that NBET will handle significant amounts of money that would flow through its accounts, the proposed financial management (FM) measures would also support mitigation of governance risk. A continuation of periodic external FM audit would further enhance the mitigation of this risk. FGN has enhanced the capital reserves of NBET to increase its credit worthiness under the numerous PPAs it will be entering into and provide a buffer in the event of contingencies. US$350 million from the Eurobond sales[15], US$325 million from the sale proceeds of Egbin Power Plant, US$20 million from the sales proceeds of Olorunsogo and Omotosho power plants, US$145 million from budget appropriations as well as a security deposit of 3 months of revenues (irrevocable L/C) required from the DISCO owners.

96. A securitization arrangement has been developed where market participants can tap into these accounts under an Escrow Account arrangement, in the event of shortfalls; these accounts are then replenished by the party responsible for the shortfall. This arrangement is contingent upon having a financially sustainable sector. It would require, as highlighted by the sector financial analysis, an achievement of the ATC&C loss reduction projections by the private sector, transmission loss reductions by the government-owned though privately managed TCN over the 5-year regulatory period as well an adjustment of tariffs by NERC prior to or at the initiation of the transitional electricity market.

D. Procurement

97. The Bank has taken several steps to verify that costs for the projects supported by the Sereies are reflective of current market conditions, based on: (i) established best practices, (ii) study and evaluation of the respective analyses conducted by sponsors prior to their selection of preferred EPC contractors, (iii) assessment of the choice of EPC contractor as a sound and defensible one in terms of overall economy, efficiency, bankability and risk-mitigation. Since the IPP transactions did not undergo standard Bank procurement guidelines, the Bank carried out an independent assessment of the sponsor submitted proposals to ascertain adherence to principles

[15] The bond proceeds would have to be repaid with a 5-year bullet repayment profile at 4.5% interest rate annually.

of economy and efficiency under the proposal contracts (such as: EPC, LTSA, O&M). The analysis summary is presented below (with further details in Annex 6):

(i) *Azura Edo IPP* issued an international request for Expression of Interest (EoI) for implementation of the project on a 'turnkey' basis, and the scope of work included engineering, procurement, and construction and commissioning of all foundations, buildings, power generating equipment, auxiliaries, HV sub-station, local infra-structure, and connection to the existing HV substation and distribution facility adjacent to the planned Azura site. The project was to be implemented on a date-certain, guaranteed performance mandate with liquidated damages included for schedule, net output, and thermal efficiency. Following a rigorous process, Azura selected Siemens as the preferred EPC Contractor. Azura has been proactive in reducing their exposure to the numerous risks associated with implementation of a major power generating facility. Azura has acted to select proven equipment which is marginally more efficient than competitive offerings, and which will be installed and commissioned by the EPC Contractor with the best record of achievement in recent power projects in Nigeria. Combined cycle gas turbine technology could be considered for the Azura project, however, analysis shows that neither a plant of similar output to the proposed configuration (three gas turbines), or a plant with three gas turbines plus the heat recovery steam generators and steam turbine generator, would show economic advantage over the open cycle technology proposed. Given that open cycle gas turbine technology is the most cost effective technology for major power generation in the Nigerian context and cost structure it is, therefore, reasonable to conclude that Azura has acted in a manner consistent with the WB guidelines for selection of the lowest overall cost alternative consistent with efficiency and appropriate technology.

(ii) *Qua Iboe IPP* issued an EoI for a turnkey contract for the construction of the power plant. The proposals were evaluated in terms of their estimated overall cost (including capital, estimated LTSA, fixed O&M, variable O&M, and fuel) and discounted to present value at an annual discount rate of 15 percent. These costs were used with an assigned project Internal Rate of Return (IRR) of 15 percent to determine the lowest present value (PV) price for power generation. Following a rigorous process, the preferred EPC Contractor was identified and the power plant configuration would be based on combined cycle (the identity of the preferred EPC Contractor is being kept confidential until NNPC Board issues approval). A separate EPC project has been identified for development of the 330 kV, 58 km transmission line required to connect the new power plant to the Nigerian power grid at Ikot Abasi substation. The power plant EPC Contractor will also be responsible for construction of two additional 330 kV bays in the Ikot Abasi substation for connection of Qua Iboe to the Nigerian regional grid. Overall, the analysis concludes that Qua Iboe has acted in a manner consistent with the World Bank guidelines for selection of the lowest overall cost alternative consistent with efficiency and technology appropriate for the location.

E. Environmental and Social Safeguards

1. PRG Series

98. The PRG Series is classified as 'Category A' because of its geographical extent and the power sector investments it will support a number of which have major environmental impacts. World Bank Performance Standards (PSs) for Projects Supported by the Private Sector are applied to the Azura IPP and subsequent transactions in this PRG Series. For QIPP, the World Bank's Operational Policies on safeguards apply (see Para. 101 below). Environmental and safeguards appraisal has been carried out by the joint WBG team. The safeguards preparation approach for PSGP is consistent with the overall project processing arrangement, in which two PRGs are presented for Board approval now, and subsequent investments for which PRGs are being sought will be presented to the Board as additional financing. A prerequisite for Board presentation of any investment will be completion and disclosure of the appropriate safeguards instruments satisfactory to the Bank. In Nigeria, ESIA drafts are disclosed in the project-affected area as part of the FMEnv review process that includes a public hearing and comment period. If the draft disclosed by FMEnv has already been cleared by the Bank, this disclosure will also satisfy the disclosure requirement of OP 4.01 and PS 1; otherwise, the proponent will make a separate in-country disclosure after Bank clearance. Depending on investment type and setting, the main environmental impact management instrument to satisfy OP 4.01 and PS 1 requirements will be one of the following:

(i) ***For new IPPs – a full ESIA***: The IPPs nominated by FGN are all gas-fired generation plants of moderate size, many if not all of which would be classified in Category B if they were being supported as individual transactions. None of the power plants under consideration is expected to be located on or near critical natural habitats. However, FMEnv has been requiring full ESIAs for these plants, and the Bank will do the same. Ancillary facilities, the most significant of which are gas pipelines and power transmission lines, will be covered in the IPP ESIA when they are being constructed by the developer. When they are being constructed by NGC or TCN and thus have separate ESIAs in accordance with Nigerian regulations, those ESIAs will also have to be acceptable to the Bank, disclosed, and included in the documentation for Board presentation. Where a new IPP requires land acquisition, a RAP will also have to be acceptable to the Bank, disclosed and included in the Board presentation.

(ii) ***For privatization of existing generating facilities:*** Depending on the characteristics of the individual transactions, GENCO privatizations (which may be gas fired or hydropower plants) will be treated as Category A or B under PSGP. An environmental audit acceptable to the Bank, including a remedial action plan to address deficiencies, risks, or legacy issues identified in the audit. The decision on disclosure of an audit will be made on a case-by-case basis with the client; some audits contain information that is sensitive from a security standpoint, and others do not. Clear responsibilities for implementation of the various elements of the action plan will have to be spelled out in the legal agreements for the privatization.

(iii) ***For privatization of distribution companies:*** Privatization of distribution companies would be classified in Category B if it were being financed as a separate transaction. The investments the DISCOs will need to make in their respective systems may not be known with certainty at the time a PRG is issued. They are unlikely to require full ESIAs under World Bank or Government procedures, but new infrastructure investments by the DISCOs will need some level of environmental assessment culminating in formulation of environmental and social management plans (ESMP). For work at existing substations or other facilities that may be included in a DISCOs program, an environmental audit will be conducted as a first step in the implementation process to determine the physical state of the facilities, the viability of investing in their rehabilitation from an environmental management perspective, and the potential environmental and social impacts associated with the rehabilitation project. Under these circumstances, an Environmental and Social Management Framework (ESMF) has been prepared to guide DISCOs in carrying out the necessary environmental and social assessments or audits and preparing the appropriate safeguards instrument for each distribution system PRG. The level of detail and rigor in the assessment or audit should be consistent with Category B.

99. In addition to the safeguards instruments for individual investments, FGN will undertake a Sectoral Environmental and Social Impact Assessment (SESIA) for development of gas-fired generating plants in Nigeria. The terms of reference for the SESIA have been drafted by the Environment, Resettlement and Social Unit (ERSU) in PHCN, approved in draft by the Bank, and presented for stakeholder consultation at a workshop conducted by ERSU on 24 October, 2012. Comments and recommendations from the stakeholders have been taken into consideration in the final terms of reference. The SESIA will be conducted early in PSGP implementation, reviewed and approved by the Bank, disclosed, and made available to IPP developers to inform the ESIAs for their respective investments.

2. First Two IPP Transactions

100. *The Azura Edo site* disturbs areas that would not be considered natural habitat. Azura is acquiring land from three communities and has prepared a Resettlement Action Plan (RAP) approved by the Bank for this purpose. The Azura Edo plant will receive gas through a short pipeline spur from the ELPS (the ELPS itself has already been the subject of a Pipeline Integrity Study conducted for WAGP and updated for NEGIP). The plant will evacuate power to the adjacent Benin North Substation through a short transmission line of less than 1 km in length that will not need to cross any land other than that which is already owned by Azura and TCN (the Benin North Substation has recently been built by the FGN through the NIPP program and will soon be handed over to and run by TCN). PS 8 applies to the project because the land being acquired for Azura Edo contains some shrines and sacred areas of local cultural importance. In addition, the excavation of the power plant's sites and ancillary activities relating to gas pipelines and mounting of the transmission lines may lead to chance finds of physical cultural properties. The Azura Edo ESIA and RAP provide for protection of known cultural resources, and the ESMPs for all plants will include measures to protect chance finds. PS 2, 3, and 4 also apply to the project because of the industrial nature of the power plant workplaces, their emissions of air pollutants and greenhouse gases, and the risks, albeit minor, that gas-fired power plants and gas pipelines pose to nearby communities. The requirements of all triggered performance standards

are met in the ESMPs included in the ESIAs with the exception of PS 5, for which RAPs are prepared. The Azura Edo ESIA and RAP were disclosed respectively on 5 March 2012 and 6 March 2012. The ESRS was disclosed on September 5, 2013.

101. *QIPP Plant* will receive gas from the offshore Oso platform via a pipeline which will land at the NNPC/MPN's Qua Iboe Terminal that abuts the plant site. Its power will be transmitted to TCN's Ikot Abasi Substation through a 58-km line that will be operated by TCN. The QIPP transmission line crosses small amounts of swamp forest and other wetland, and also affects crops and productive trees. The routing of the line was designed to minimize impact on populated areas. For QIPP, the World Bank Operational Policies on safeguards apply, as the ESIAs for the power plant and transmission line and draft RAP were prepared before OP 4.03 was approved by the Board and published. The QIPP plant site abuts the company's oil terminal. OPs 4.01, 4.04, 4.11, and 4.12 are triggered because of the project's overall environmental and social impacts; in addition, gas pipelines or transmission lines pass through some natural habitats, the project may involve or affect physical cultural resources, and will also require acquisition of land used for agricultural production. ESIAs for the QIPP plant and QIPP transmission line were disclosed respectively on 19 June 2012 and 13 December 2012. The RAP for the QIPP transmission line was disclosed on 1 November 2013.

102. The ESMPs for the two plants and the QIPP transmission line indicate that nearly all potential adverse environmental, social, and health and safety impacts can be mitigated to low levels. None of the residual impacts are considered major, and the few that are predicted to be moderate after mitigation are: short-term impacts on water quality caused by dredging, reduction in local biodiversity due to site clearing (Azura), and short-term noise impacts during construction. Loss of wetland associated with the NNPC/MPN QIPP transmission line is being minimized by modification of the originally-proposed alignment. Quantitative models were employed to analyze impacts on air quality and noise levels during plant operation - a process that involved consideration of cumulative impacts for the Azura Edo plant because of the proximity of another emission sources (the adjacent Ihovbor power plant). Modeling results predicted no violations of WBG or WHO guidelines. The two plants would contribute to greenhouse gas emissions but to a much smaller extent than the most likely alternative power sources (fuel oil, coal, or individual diesel generators). Moderate positive impacts would occur in the form of short-term employment during construction, service contracts for local firms during construction and operation, and training for local people to prepare them for possible longer-term employment at the plants. NBET will rely on the Environment, Resettlement and Social Unit (ERSU) of the project implementation unit for NEGIP and NEDP for the management of safeguard policies. ERSU has demonstrated satisfactory capacity to address the impacts of power project and associated facilities; in fact, the ERSU prepared both the ESMF and the RPF for NEGIP. NEGIP, TDP and NEDP supervision missions have shown that the ERSU's capacity to implement the ESMF properly for those projects is fully adequate. ERSU has overseen audits of substations, prepared ESMPs, and supervised preparation of RAPs and implementation of ESMPs for substation and distribution line improvements and extensions.

Annex 1: Results Framework and Monitoring

Nigeria: Power Sector Guarantee Project

Project Development Objective (PDO): The project development objective is to increase the supply of electricity received by Nigerian consumers.

PDO Level Results Indicators	Core	Unit of Measure	Baseline	Cumulative Target Values[16]					Frequency	Data Source/ Methodology	Responsibility for Data Collection	Description (indicator definition etc.)
				2014	2015	2016	2017	2018				
1. Energy supplied to consumers by first two IPP transactions (Azura and QIPP) supported under the PRG Series	☐	GWh	0	0	0	0	3,200	6,800	Annually	NBET statistics and IPP reports	NBET	Energy supplied to the grid by Azura and QIPP Power Plants
2. Installed capacity by first two IPP transactions (Azura and QIPP) supported under the PRG Series	☐	MW	0	0	0	0	500	950	Annually	NBET statistics and IPP reports	NBET	Installed generation capacity of gas turbines of Azura and QIPP
Beneficiaries												
3. Project beneficiaries	☒	Number	0	0	0	0	27,000,000	54,000,000	Annually	NBET statistics	NBET	Current electricity customers receiving improved services
4. Of which female (percentage of total)	☒	%	0	0	0	0	50	50	Annually	NBET statistics	NBET	Current electricity customers receiving improved services
INTERMEDIATE RESULTS												
Intermediate Result (Sub-Component 1, Transaction 1): Azura Edo IPP												
Construction of Azura Power Plant completed	☐	Y/N	N	N	N	N	Y	Y	Quarterly	Progress reports	Azura, NBET	Progress of EPC Contractor of Azura
Commissioning test completed	☐	Y/N	N	N	N	N	Y	Y	Quarterly	Progress reports	Azura, NBET	Acceptance tests for producing power
Private capital mobilized	☐	US$	0	0	200	300	400	450	Quarterly	Progress reports	Azura, NBET	Investment in generation
Intermediate Result (Sub-Component 1, Transaction 2): Qua Iboe IPP												
Construction of QIPP Power Plant completed	☐	Y/N	N	N	N	N	N	Y	Quarterly	Progress reports	Qua Iboe, NBET	Progress of EPC Contractor of QIPP
Commissioning test completed	☐	Y/N	N	N	N	N	N	Y	Quarterly	Progress reports	Qua Iboe, NBET	Acceptance tests for producing power
Private capital mobilized	☐	US$	0	0	200	500	800	1,000	Quarterly	Progress reports	Qua Iboe, NBET	Investment in generation

[16] The target values are for the Azura Edo Gas Power Plant PRG and the Qua Iboe Gas Power Plant PRG. Targets will be updated to include other PRGs in the PRG Series in subsequent project papers for additional financing.

Annex 2: Detailed Project Description

Nigeria: Power Sector Guarantee Project

I. Strategic Context

1. Nigeria is Africa's most populous country with a population of 170 million, estimated as of July 2012, covering a land mass of 923,768 sq. km. A large portion of this population is very young (44 percent between the ages of 0-15, 53 percent between the ages of 15-64, and 3 percent are 65 and over), 45.6 percent of which are below the poverty line (adult equivalent). The country's Gross Domestic Product (GDP) is estimated to be approximately US$456 billion (2012 est.), making it among the largest on the continent, behind only South Africa and Egypt. Real GDP growth is estimated to be 6.58 (2012 est.) percent, making the economy among the fastest growing in Africa. The country's labor force is estimated to be approximately 54 million (2012 est.), largely concentrated in the agricultural sector, which employs about half of the workforce, and unemployment stands at 24 percent (2011 estimate).

2. Nigeria has the 10th largest oil reserves in the world, estimated at 37.2 billion barrels (2012 proven estimates). At the current OPEC allocation of 1.67 million barrels per day, these reserves will last approximately 60 years. However, Nigeria exceeds this production allocation when output is not disrupted by insurgency activities, which, until recently, was a significant factor affecting the sector. Nigerian crude output is of very high quality, with low sulphur content; Nigerian 'Bonny Light' regularly sells at a premium to other oil designations. The country's reserves rest along the coast and in the Niger Delta. Currently, Nigeria does not have enough operational refinery capacity to meet domestic needs. As a result, despite being the fourth largest OPEC crude oil producer, Nigeria is also a net importer of refined petroleum products.

3. Nigeria also benefits from large gas reserves. In recent years, oil and gas account for over 95 percent of exports, about 75 percent of consolidated Government revenues, and over 30 percent of GDP (at current prices). Proven gas reserves amount to 5.11 trillion cubic meters, additional reserves, reportedly, could significantly increase this amount. Average gas production stands at 29 billion cubic meters per day, around 40% of which is flared because of a lack of a domestic gas market and insufficient infrastructure to transport the gas to domestic customers. Flaring results in billions of dollars of lost potential revenue and creates many environmental complications. As a result, Nigeria is participating in a number of projects intended to curtail flaring, including the West Africa Gas Pipeline Project (WAGPP) and the Nigeria LNG Project at Bonny Island. As these projects become operational, gas exports will boost Nigeria's revenue and foreign exchange earnings. Nigeria is also accelerating development of a domestic gas market, support by the World Bank-financed Nigeria Electricity and Gas Improvement Project (P106172) and increasing development of the power sector to both create a domestic market for gas and increase access and reliability of electricity supplies in the country.

Power Sector Background

4. Although Nigeria is one of the largest oil producers in the World and has the eight largest gas reserves, the country continues to suffer from a chronic shortage of power. With approximately 3,500 MW of available generation supplied through the grid against an estimated suppressed demand estimated to exceed 6,000 MW. The growth in demand in the Nigerian power sector is

expected to continue to increase at around 10 percent per annum in the medium term, reaching 10,000 MW (medium growth rate scenario) to 14,000 MW (high growth scenario) by end of the decade. On aggregate, nearly one out of every two units[17] of electricity generated is lost due to technical and commercial losses and outright theft before the revenues are recovered and re-injected into operations and maintenance. These deficiencies have resulted in approximately 65 percent of the country's population living without access to electricity and the remaining 35 percent suffering from poor quality of service with multiple power cuts each day.

5. In the recently released Nigeria Investment Climate Assessment, 83% of Nigerian business owners consider a lack of electricity the biggest obstacle to doing business.[18] Nigerian businesses experience an average of 239 hours of power outages per month, accounting for nearly 7% of 'lost sales.'[19] As a result, most private enterprises are forced to resort to self-generation at a high cost to themselves and the economy (about US$0.3-0.5 per kWh as compared to the current grid based tariff of US$0.13 per kWh). By some estimates, self-generated power now substantially exceeds grid-based power in Nigeria.[20] Aside from the environmental and efficiency implications of self-generation, the practice forced firms to divert financial resources away from productive uses, lowering productivity and competitiveness. In addition, the transmission and distribution networks suffer from severe capacity constrains exacerbated by years of poor maintenance brought about by inadequate funding from tariffs and poor revenue collection rates.

6. This situation has developed over a long period that started in the 1980s. Chronic underinvestment in the sector's development for two decades limited the sector's growth to meet the country's demand for power and adversely affected the sector's ability to maintain its assets. Weaknesses in the sector's institutional structure also limited accountability for budget allocations and investment projects, thus eroding the impact of what little funds were set aside for the sector's development and operations. Moreover, the sector's ability to support itself was also constrained by the prevailing public policies that artificially depressed retail tariffs for both electricity and domestic natural gas. Aside from the underinvestment in new infrastructure and maintenance of existing assets, these policies echoed the wrong pricing signals for private sector development of upstream gas supply, gathering, and processing assets, further reducing availability of gas supplies for domestic consumption despite Nigeria's natural resource endowment. The culmination of these circumstances led to the sector's heavy reliance on federal government support that created an increasing burden on the country's finances.

[17] Average Technical losses are estimated to 21% of energy sent out; Non-technical losses such as electricity theft estimated to 11% and; commercial losses estimated to 12% of billed amounts (Roadmap 2010).
[18] Compare this to 14% of Indonesia businesses and 28% of Kenya businesses.
[19] Investment Climate Assessment (2011).
[20] Studies estimate self-generation at 6,000 MW against 3,500 - 4,000 MW available in the grid.

Figure 1: Government Investments in the Nigerian Power Sector

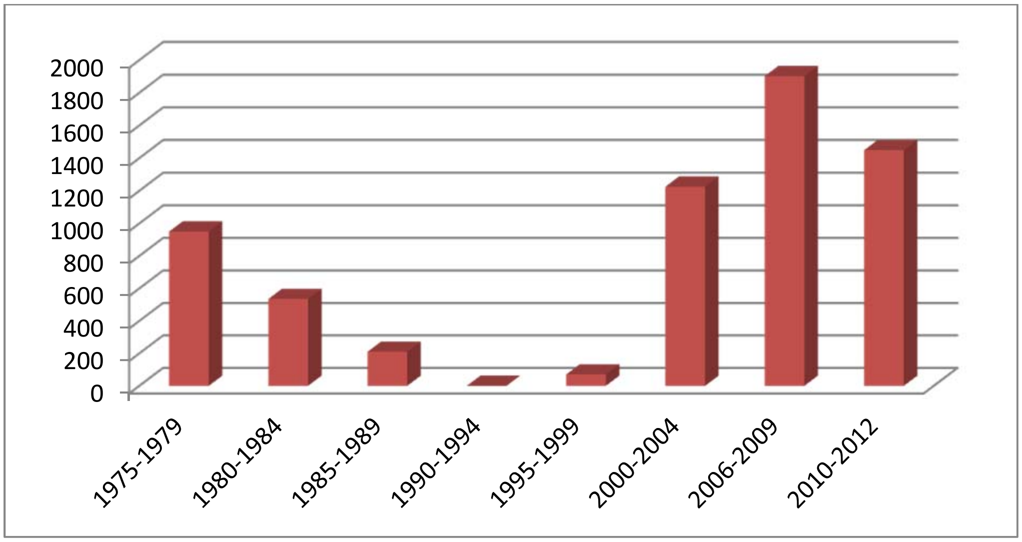
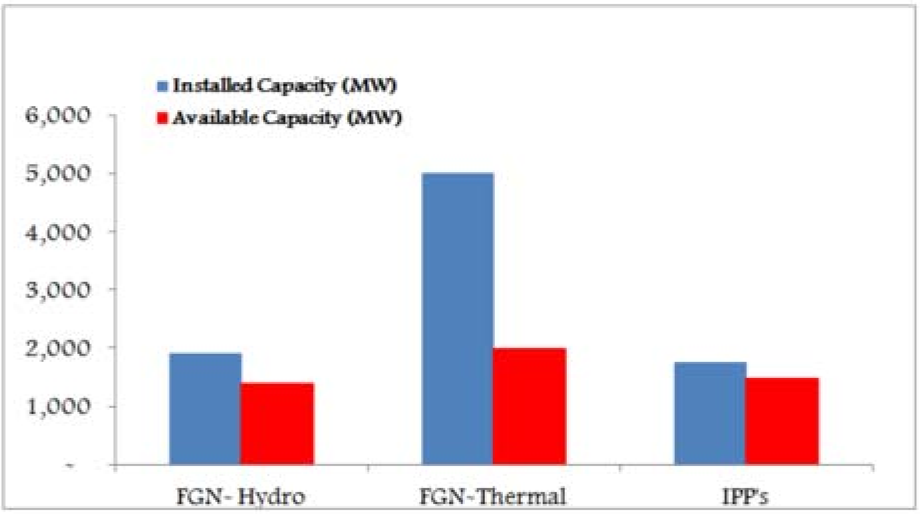


Figure 2: Current Performance of Nigeria's Power Generation Assets



7. In an effort to address some of these issues, the FGN promulgated the Electricity Power Reform Act (EPSR) in 2005 based on the 2001 National Electric Power Policy (2001). EPSR sought to restructure the power sector and open it to private sector investment and know-how by establishing a framework for wide-ranging sector reforms to commercialize sector operations and establish a market-oriented industry structure. The law required the breakup of the National Electricity Power Authority (NEPA) – the vertically-integrated, state-owned monopoly that was formed in 1972 by merger of the Niger Dams Authority and the colonial-era Electricity Company of Nigeria. NEPA was split into 18 companies (6 generation companies (GENCOs), the Transmission Company of Nigeria (TCN), and 11 distribution companies (DISCOs)) under a new holding company called the Power Holding Company of Nigeria (PHCN).

8. This move was intended as the first step in a sector restructuring plan that would ultimately result in privatization of the GENCOs and DISCOs. EPSR also required opening access to the grid on a nondiscriminatory basis to facilitate bilateral contracts between power producers and bulk consumers, and to spur competition among producers. To facilitate open access and stimulate private sector transactions, the FGN established the Nigeria Electricity Regulatory Commission (NERC) as an independent regulatory agency to ensure efficient and equitable growth of the electric power sector.

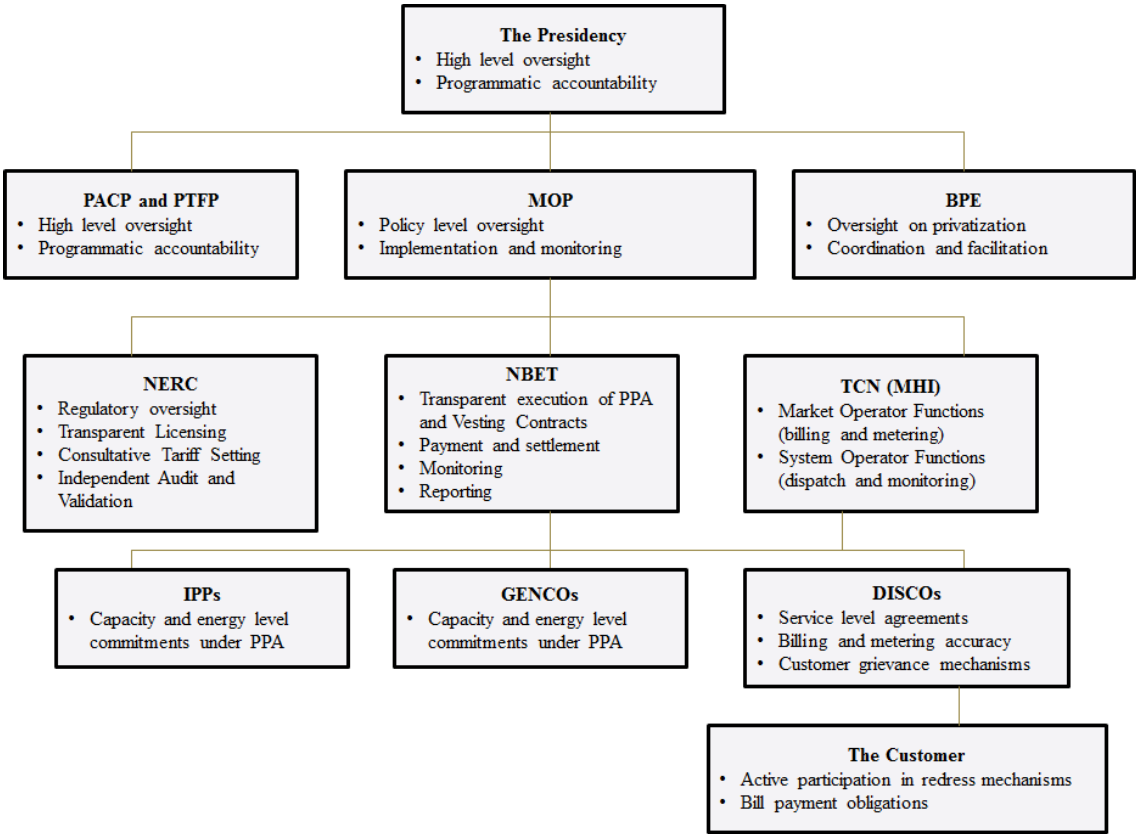
9. In discharging its obligation, NERC adopted an incentive-based, 2-part tariff methodology in the first Multi-Year Tariff Order (MYTO) in 2008 that was originally pioneered by the United Kingdom in 1980s/1990s and widely adopted in many countries since. The MYTO's assumptions are subject to a minor review to reflect changes in inflation rate, gas price, and foreign exchange assumptions, and a major review of all the assumptions every 5 years to keep the tariff in line with then-current circumstances.

10. While bi-annual minor revisions have been implemented annually by NERC since 2008, it accelerated the major review due in 2013 upon request from distribution companies to reflect major changes in the companies' operating environment and the anticipated reform process outlined in the Roadmap that was released in August 2010. NERC further revised MYTO's assumptions in 2012 in anticipation of private sector participation in both the generation and distribution sub-sectors, and in recognition of the sector's investment needs. Annexes 8 and 9 provide a more detailed discussion of this 2012 MYTO revision and the tariff structure and methodology on which it is based.

11. The FGN was also keen on addressing other sector weaknesses so it undertook an extensive overhaul of its natural gas pricing policies. The FGN recognized the need to reform its gas industry and incentivize additional private sector investment in upstream gas infrastructure to expand available capacity for domestic consumption. The Government sought to capitalize on availability of gas associated with current oil production, which was largely flared or re-injected, to provide much needed supplies in the short-term to existing generation facilities.

12. Aside from availability of this associated gas without extensive investment in, and time required for, exploration and production of new fields, the byproduct nature of this resource implied lower fuel supply costs and greenhouse gas emissions in comparison to the imported diesel and fuel oil that it would replace. In the medium-term, available generation capacity is projected to outstrip gas supplies to generators and, therefore, requires new investments in exploration, production, and processing infrastructure to ensure availability of adequate gas volumes. Consequently, the FGN, with support from IDA under NEGIP, embarked on reforms to its gas pricing policy and has already increased the domestic price of gas by 900 percent from US$ 0.1 per million British Thermal Units (mmbtu) to US$1 per mmbtu. The Government plans to continue increasing the price of gas to near commercial levels of US$2 per mmbtu by 2014, and is considering other policy initiatives to further incentivize upstream investments.

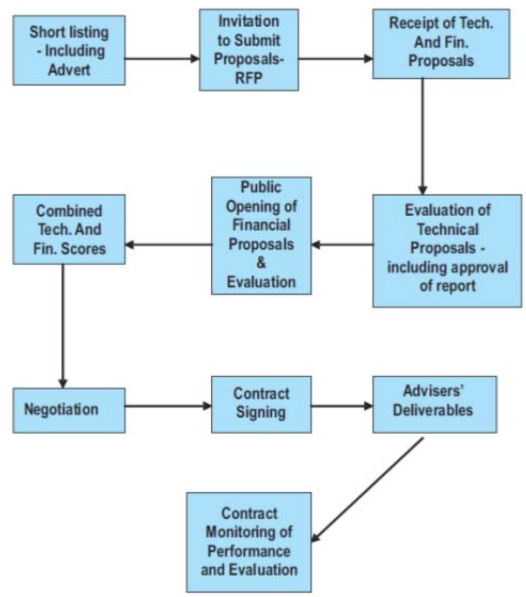
Box 1: Accountability and Roles of Sector Institutions (Post Reform)



13. The FGN further recognized the need to reform TCN. Manitoba Hydro Inc. (MHI) was selected in July 2012, through an international bidding process, to take over management of TCN for a 5-year period. British Power International (BPI), funded through the Bank's NEDP, advised the Government in developing, selecting, and negotiating a management contract with MHI that set specific key performance indicators for reforming, rehabilitating, and expanding the transmission network and its management. One of MHI's early deliverables is an investment plan for the network to be financed by the FGN through a new fund, called the Transmission Network Development Fund. The Fund will raise long-term financing from the private and public sectors, possibly through domestic and international bond issuance. Repayment of these funds is expected to be made over time from NERC-approved Transmission Use of System (TUOS) charges, which are accounted for in the MYTO and levied by TCN for wheeling electricity between generators and distributors.

14. The FGN, through the Bureau of Public Enterprises (BPE), commenced the long-awaited process of privatizing the GENCOs and DISCOs. BPE, NERC, TCN and other stakeholders collaborated in the development of a transparent and efficient framework for sector operations in anticipation of increased private sector participation. For example, the parties developed grid and metering codes to provide the minimum technical specifications for sector operations; market rules that provides for management of transmission service by an independent system and market operators that are already in place and temporarily housed at TCN; and standardized agreements for interconnection and transmission service to be used by independent power producers. BPE

also engaged labor unions and other stakeholders in discussions to agree on a constructive approach to the privatization process that would not unreasonably jeopardize the interests of staff or the privatization process' objectives. The FGN created Nigerian Electricity Liability Management Company (NELMCO) to hold post-privatization liabilities from PHCN's non-core assets that were not included in the privatized entities, and budgeted funding of ₦ 200 billion (approximately US$1.3 billion) to cover, among other things, liabilities related to severance and other benefits to workers that are laid off post-privatization.



15. BPE retained transaction and legal advisors to advise it in developing the international bidding documents, as well as the underlying contractual framework that will govern the privatized entities' relationship with other stakeholders in the sector. The bidding process was structured in two stages: a prequalification process to ascertain both the technical and financial capabilities of interested bidders and a formal bidding stage. The bidding stage was further divided into two parts. The first part involved evaluation of bidders' technical proposal, and the second part involved opening of the financial bid of only the first-ranked bidders. Between the prequalification process and the formal bidding stage, BPE allowed bidders access to a data room that contained information on the assets included in the privatization process, and arranged site visits to the various assets. BPE issued draft versions of most of the documents for several rounds of public comments and held public consultations to ensure that input from the private sector and local and international financing institutions is considered in finalizing the documents. The final invitation to submit bids was issued on May 11, 2012.

16. Highlighting investor confidence in the Nigerian market, in general, and the seriousness of the FGN's resolve to reform the sector, in particular, 87 companies were prequalified for 6 thermal assets, 40 companies for 3 hydro plants, and 80 companies for the 11 DISCOs. Of these companies, 54 submitted bids for the 11 DISCOs. BPE evaluated the submissions and, after approval of the rankings by Nigeria's National Commission on Privatization, announced on September 25, 2012, the first-ranked bidders of both thermal and hydro plants, and on October 10, 2012, the first-ranked bidders for the DISCOs. Financial bids of these first-ranked bidders were opened in a public forum at that time. Bidders for two of the DISCOs were disqualified on various grounds, but BPE is in active negotiations with the remaining bidders for all of the generation plants and 9 of the DISCOs.

17. The FGN recognized that the DISCOs current financial performance is unlikely to provide the requisite comfort for private generators to directly contract with them for the sale of power. Accordingly, the Government established the Nigerian Bulk Electricity Trading Co. (NBET or "Bulk Trader") as a "Central Buyer" to enter into power purchase agreements (PPAs) with Independent Power Producers (IPPs) from Greenfield projects and GENCOs once privatization is completed. The Bulk Trader would purchase power on behalf of the DISCOs until the

industry develops adequate revenue streams and the settlement, accounting, managerial, and governance systems required for successful direct bilateral contracting between IPPs and the DISCOs. Because the Bulk Trader is a new entity and does not yet have sufficient credit history to provide the level of comfort IPPs need of the bankability of the PPA, the Bulk Trader will need credit support to provide such assurance. Towards that end, the FGN requested support from the World Bank to provide credit enhancements for the Bulk Trader in the form of a Series of partial risk guarantees (PRGs) on specifically nominated transactions.

Figure 3: Bulk Trader Participation

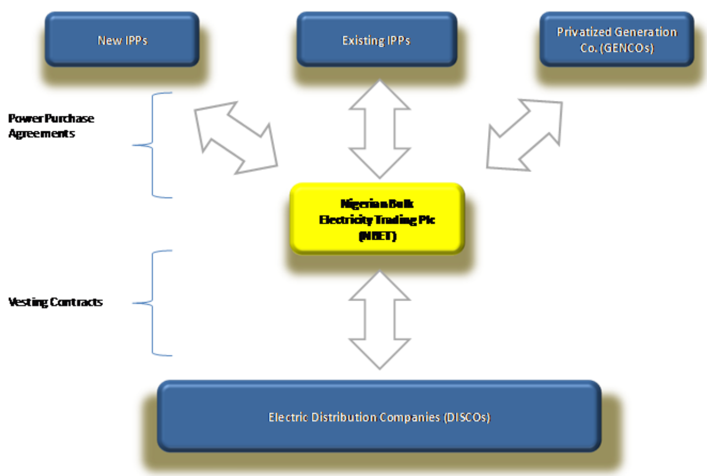
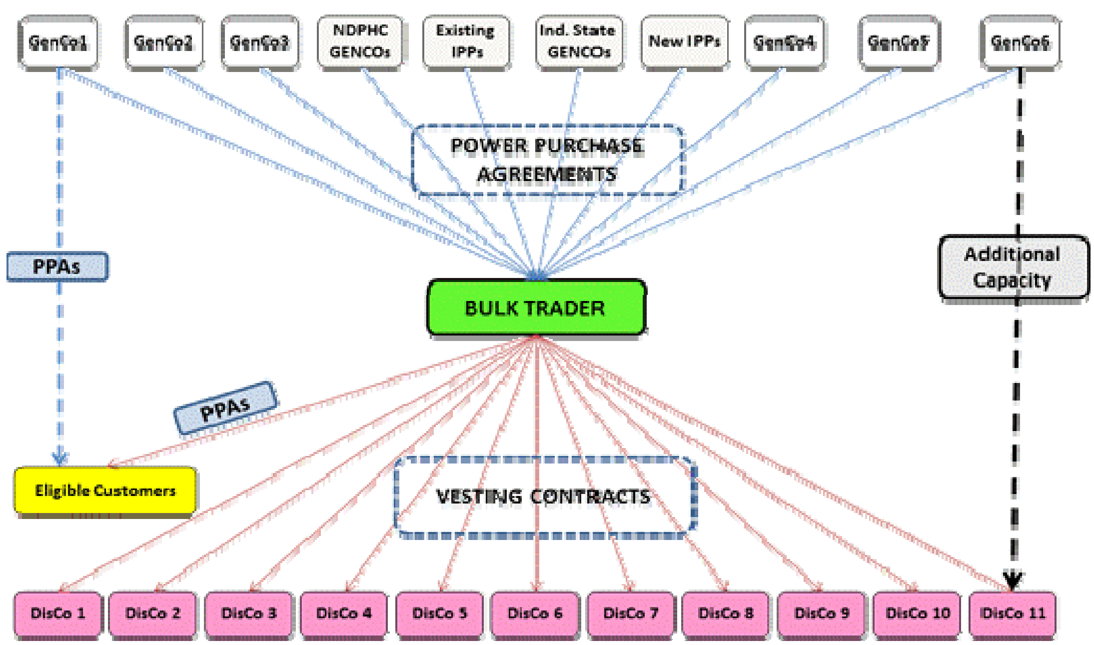


Figure 4: Transitional Market Trading Structure



18. The FGN also requested support from the Bank to catalyze the process of privatizing the DISCOs while NERC's regulatory policies take root in the sector and an adequate history of performance provides investors more confidence in the established regulatory framework.

II. Series Description

19. The proposed Series of PRGs (the Series) will support the implementation of the Roadmap for Power Sector Reforms. Each PRG will support a specific transaction, such as a greenfield IPP, a GENCO privatization, or a DISCO privatization. Each of the transactions supported will fall under one of the PRG Series Sub-Components (described below) and the commercial, technical, economic, financial, safeguards due diligence will be similar for each transaction as described in this PAD. The PRG Series will support transactions on a first-come-first-served basis. As per the FGN's request and FGN's borrowing plan with the Bank, the proposed Series is initially expected to be capped at US$700 million in the form of IBRD PRG support. Guarantees will be provided in support of private transactions, as and when such transactions are ready. The proposed support (up to US$395 million) for Azura Power and Exxon QIPP will form an integral part of the series. Subsequent transactions will be presented to the Board for approval as additional financing to the PSGP PRG Series.

20. By mitigating the high level of uncertainty the frontrunner transactions face, the PRG Series will kick start the reforms and build market confidence and set industry benchmarks. The successful implementation of the first set of transactions will be critical to the success of the power reform agenda, as it will confirm the viability of the financial, transactional and regulatory systems put in place under the reform program. In the longer term, as Nigeria's power sector reforms progress through the transitional phase, it is expected that the need for risk mitigation will decrease, as NERC, NBET, and TCN establish track records of successful financial and operational performance. The FGN has nominated, as transactions that require credit enhancement and debt mobilization support in the short to medium term, a total of 18 new greenfield IPPs, 6 privatized GENCOs, and 11 privatized DISCOs. This PAD presents the PRG design for the complete Series and appraises the overall scope of the universe of transactions to be supported.

IBRD Partial Risk Guarantee Structures

21. The proposed Series provides for three types of PRG support, aimed at providing support for three key areas of investor concern, which are inherent in each of the transactions to be supported by the proposed Series. The guarantees are designed to provide:

> (a) ***Credit Enhancement/ Governmental Payment Structure***: The credit enhancement structure provides for an IBRD PRG to backstop certain payment obligations undertaken by Nigerian governmental agencies. The credit enhancement PRG can support a revolving standby Letter of Credit (L/C).[21] Under the L/C

[21] Note that the PRG L/C structure may not necessarily require that an L/C be provided so long as the payment security proposed in lieu of the L/C is in form and substance acceptable to IBRD.

structure, NBET would provide security under the PPA in the form of an L/C, issued through a commercial bank, in favor of the IPP, for an agreed amount of coverage, corresponding to either: (i) certain upstream payment obligations, or (ii) a number of monthly payments representing NBET's periodic payment obligation under the PPAs. The L/C could be drawn in the event NBET, or the FGN, fails to make timely payments to a covered IPP, or GENCO, under the PPA, subject to certain grace periods, for the unpaid amount. Following a drawing, NBET would be obligated under the Reimbursement and Credit Agreement (to be entered into between NBET and L/C bank) to make a repayment to the L/C bank for the amounts drawn (plus accrued interest) within a determined period (generally of no less than one year). If NBET makes a payment within such period, the L/C would be reinstated to the amounts repaid. However, if NBET fails to repay the L/C bank within such period, the L/C bank would have recourse to the IBRD PRG for the drawn amounts, plus any accrued interest, under the Guarantee Agreement (to be entered into between IBRD and L/C bank). In such case, the maximum L/C amount would be reduced by the amount of payment made by IBRD under the PRG. In case of disputed events, the IPP, or GENCO, would be able to access the L/C for the disputed amounts, only after the dispute has been resolved in its favor, or receive provisional payments upon the provision of acceptable security to IBRD. Payments by IBRD under a PRG would trigger the obligation of FGN under the Indemnity Agreement (to be entered into between IBRD and FGN), which requires that FGN repay IBRD on demand, or as IBRD may otherwise direct. Each PRG L/C in support of the greenfield IPPs and GENCOs will be for an agreed maximum term of years from the effectiveness of each PRG, comprising the L/C term, plus NBET's one year repayment period, plus 60 day IBRD claim period within which IBRD would be obligated to pay the L/C bank. The credit enhancement structure outlined above could also be applied, in certain circumstances, to DISCOs where a significant portion of its electricity sales are to governmental agencies, and therefore, the DISCOs success is dependent upon the timely collection of payments from those governmental agencies. Although, under the new market rules for privatized distribution companies, DISCOs will have a right to discontinue providing electricity to late or non-paying off-takers, there will be some exceptional instances, (e.g., supplies to police, the army, or other critical governmental services) where termination of electricity supply is not an implementable solution. FGN is considering implementation of a policy to support off-take payments by its governmental agencies, and it is in those exceptional circumstances that a governmental payment PRG could be considered for DISCOs. A credit enhancement PRG for DISCOs could be offered with or without an L/C. The governmental payment PRG L/C in support of DISCOs would be for an agreed maximum term of years, from effectiveness, plus the governmental agency's one year repayment period, plus 60 days IBRD claim period. It is possible an IPP, or GENCO, may seek credit enhancement against NBET's failure to pay under a PPA, but elect not to use the L/C structure, with its intermediary L/C Bank. In this case, the IPP, or GENCO, would be the direct beneficiary of a PRG for an agreed amount of coverage, similar to the L/C structure. If NBET fails to make a covered payment, and such covered payment remained outstanding for a period of 12 months, the IPP, or GENCO, would have recourse to the PRG for the amount owed, plus any accrued interest. In such case, the maximum PRG amount would be reduced by the amount of payment made by IBRD. As with the L/C structure, the IPP, or GENCO, would be able to access the PRG for disputed amounts, only after the dispute has been resolved in its favor, or receive provisional payments upon the provision of acceptable security to IBRD. An IBRD payment under the PRG would trigger the obligation of FGN under the Indemnity Agreement. Similarly, a DISCO that is capable of supporting governmental account receivables that remain outstanding for one year under a governmental payment PRG may also elect to forego the L/C structure and be the direct beneficiary under the PRG.

(b) ***Commercial Debt Mobilization Support Structure***: The commercial debt mobilization PRG provides direct support to a transaction's covered commercial lenders in the event of a debt payment default caused by NBET's failure to make payments under the PPA, or FGN under a termination of the relevant PPA, or in the case of DISCOs, a covered off-take agreement. Under the Guarantee Agreement (to be entered into between IBRD and the covered commercial lender(s)), the failure of NBET, or FGN, or the governmental agency guaranteed by FGN, to pay amounts due under the covered PPA, or off-take agreement, entitles the covered commercial lender(s) to recourse under the IBRD PRG. The IBRD commercial debt mobilization PRG is non-accelerable; therefore principal and interest on the IBRD guaranteed commercial loan would be covered by IBRD only as and when it becomes due and payable. In the event of a dispute, the IBRD PRG would be callable only once the dispute has been resolved in the commercial lender(s)' favor, or for provisional payments, upon receipt of acceptable security to IBRD. For any payment under the debt mobilization PRG, IBRD would seek reimbursement from FGN under the Indemnity Agreement, similar to what was explained under the credit enhancement PRG above. As contemplated under the WBG's EBP for Nigeria, termination support to commercial lenders is also expected to be provided by MIGA. The coverage provided by MIGA will be complimentary to the IBRD support and not duplicative. The joint IBRD/MIGA guarantees would be structured to cover different risks or different tranches of debt.

(c) ***Regulatory Risk Structure:*** To address DISCO concerns in respect of MYTO 2 implementation, the newly privatized DISCOs have the possibility of an additional PRG structure focused on regulatory risks faced during the transitional period. The support for regulatory risks will be designed to backstop only those clearly identifiable risks associated with implementation of the new MYTO 2 tariff and FGN's agreement to provide subsidies until mid-2014. The MYTO 2, adopted in June 2012, has introduced a retail tariff at cost-reflective levels. It provides for adjustment of these levels through bi-annual minor reviews to account for changes in a set of agreed parameters, such as inflation, exchange rate and gas price. Major tariff reviews, which will include review of all inputs and assumptions, are conducted every 5 years. To ease the burden on SMEs and households from the tariff increases, the FGN has undertaken to provide transitional subsidies to lower the initial increase for these groups and stagger the adjustment to cost-reflective levels. The PRG regulatory risk coverage will be confined to the revenue gap stemming from the failure of NERC to abide by the identified parameters for minor and major review of the retail tariffs as provided under MYTO 2, to the extent the DISCOs relied upon such identified parameters when making their investment decision, and/or FGN's failure to provide the subsidies promised to the DISCOs. It will cover only the retail portion of the tariff, after deducting amounts corresponding to the bulk tariff and transmission costs. More specifically, the gap will be subject to the difference between the actual level of revenues collected by the DISCO at any point in time, and the revenues the DISCOs would have otherwise been legally entitled to generate, excluding any portion lost due to commercial losses. This way the PRG will support the DISCOs only for regulatory risks and not commercial risk, which is expected to be managed by private investors.

III. Sub-Component 1 – Partial Risk Guarantees for IPPs

22. The FGN nominated 18 Greenfield IPPs in various stages of development for possible coverage by the Bank through a Series of PRGs. The proposed support to the Azura Edo IPP (459 MW); and the Qua Iboe IPP (533 MW) (described in more details below) would be provided under Sub-Component 1. In addition, a project pipeline for potential future Bank support under this PRG Series has been defined and an overview is provided below.

Agura Independent Power Project

Project Sponsors

23. The Agura Independent Power Project (AIPP) is being developed by Chevron Nigeria Limited (CNL), a wholly-owned subsidiary of Chevron Corporation, on behalf of a joint venture between Chevron (40 percent) and NNPC (60 percent). NNPC's interest in the joint venture is managed by its subsidiary, National Petroleum Investment Management Services (NAPIMS). AIPP will be fully funded by the NNPC/Chevron joint venture and administered by CNL. No project debt is envisaged.

Project Site

24. AIPP will be implemented on a 155-hectare site located on the northern shore of the Lagos Lagoon, approximately 25 km northeast of Lagos, adjacent to the operating 1,320 MW LTS-Egbin Power Station (Egbin). The site was purchased in 2007 by CNL, in its capacity as operator of the NNPC/Chevron joint venture, primarily from Power Holding Company of Nigeria (PHCN) and host communities. Agreement was reached with PHCN and the communities separately, payments made and transfers of land title have been completed and approved by the Lagos State Government (LASG). CNL has continued to pay the annual ground rent statutorily required by the LASG.

Project Construction and EPC Contractor

25. The first phase of the power plant is designed to produce 300 MW (ISO) from two (2) Gas Turbine Generators (GTGs) in simple-cycle mode. The project will add two additional phases at later stages that may be considered for Bank support through additional financing under the proposed PRG Series. The second phase will increase the plant's nominal capacity to 495 MW

(ISO) by adding one additional GTG. The third phase is expected to add heat recovery steam generators (HRSGs) and a steam turbine generator to bring the capacity of the plant to 720 MW (ISO).

26. The plant will use heavy frame industrial outdoor packaged type GTGs with Dry Low Emission Combustors (without any ancillary equipment, such as chiller, water/steam injection, etc. for increasing power output/ NO_X reduction). The fully packaged GTGs will be complete with control systems and integrated Distributed Control System (DCS), Balance of Plant (BOP) equipment, Gas Conditioning Facilities, Plant Sub-station/utility interconnections and associated equipment and materials. A Power Block EPC contract was competitively tendered in 2010 to five (5) contractors, and final approval of the award was given by the NNPC Executive Board in March 2012. The contracting process for the project was governed by NNPC's contracting guidelines, which require that all capital projects are competitively bid through an open and transparent process.

BOX 2: NNPC'S CONTRACTING PROCESS

NNPC contracting process involves three phases:

- *Prequalification*

The solicitation/prequalification process for NAPIMS contracts begins with the publishing of the advertisement approved by NAPIMS. The advertisement is published on the NIPEX website and in three national newspapers and remains open for three weeks starting from the day the advertisement was placed.

- *Technical Tendering*

The objective of the technical phase in the NAPIMS process is to evaluate the capability of the competing contractors to ensure only technically qualified/competent contractors are eligible to participate in the commercial phase.

- *Commercial Bid*

The NAPIMS commercial phase is initiated after the evaluation of the bids submitted at the tender phase. For AIPP, five (5) companies were deemed technically qualified and participated in the commercial bid.

Fuel Supply and Transportation

27. Phase 1 of the AIPP requires 75 mmscf/day of gas that will be supplied from CNL's existing Escravos gas plant. This gas will be transported through ELPS to the plant through an existing 30-inch lateral extending from the ELPS to Egbin pursuant to a GTA with NGC, which owns and operates the ELPS. The existing lateral is approximately 4 km from the AIPP site boundary and currently supplies fuel gas for nearby PHCN and AES power plants. AIPP will connect to the lateral through a tie-in upstream of the NGC gas conditioning facility at Egbin.

28. A new 4 km pipeline lateral will be constructed from the tie-in point to the AIPP site with associated gas conditioning facilities directly outside the AIPP site. The gas conditioning facilities includes gas cleaning (scrubbers), gas conditioning (heaters) and gas metering (meters). FEED design for these gas conditioning facilities has been completed, and detailed engineering is included in the pipeline EPC contractor's scope. The new 4-km gas pipeline to the AIPP site will be 16-inches in diameter with a 100 bar (g) design pressure and installed underground. The

pipeline itself will be constructed from corrosion-protected carbon steel. NGC will undertake construction and commissioning of the new gas infrastructure required for AIPP (16-inch gas pipeline lateral and gas conditioning facility). A solicitation for qualified contractors to construct the pipeline was initiated, with technical bids evaluated and 3 pre-qualified bidders recommended for approval by the Board of NNPC, NGC's parent company. The commercial bids are expected to be opened by the end of 2012. CNL will fund the project under a Project Management Agreement (PMA) with NGC and recover the costs through a proportional discount in the gas transmission tariffs.

Interconnection and Transmission Service

29. The AIPP project will evacuate its generated power through a new 4 km overhead transmission line from project site to the existing Egbin sub-station. The Egbin substation will be expanded to accommodate the generated power from AIPP. The overhead transmission line and Egbin substation expansion will be undertaken as a separate work package to be managed by CNL in close cooperation with Transmission Company of Nigeria (TCN). Prequalification of bidders have been concluded and tender documents for bidding is currently being finalized. The bidding package was issued to prequalified bidders in Q4 of 2012 with actual construction is underway and will continue for 18 months thereafter.

30. CNL has completed negotiation of three (3) cooperation agreements that will define the terms and conditions under which TCN will participate in activities related to, among others, construction of the transmission line and expansion of the Egbin substation. The three cooperation agreements cover the following areas - (1) right-of-way, (2) environmental impact assessment of the proposed activities, and (3) construction of the AIPP-to-Egbin transmission line and Egbin substation expansion.

Environmental and Social Impact

31. AIPP has completed an ESIA for the project in line with the FMEnv, the World Bank, and Chevron's corporate policy on Environmental, Social and Health Impact Assessment (ESHIA). The assessment covered the entire scope of the project including the power block, gas pipeline and electric transmission lines. AIPP received comments on the ESIA from the World Bank in April 2011 and from the FMEnv in September 2012. Public hearings were carried out in July 2012 with participation from representatives of the FMEnv, the World Bank, independent environmental consultants, non-governmental organizations, and host communities. AIPP has commenced data gathering and analysis required to close all gaps in the ESIA identified by FMEnv and other stakeholders.

Operations and Maintenance

32. AIPP will be operated by a third party O&M contractor working under a small team from CNL. O&M contractor will be selected through a competitive tender process. AIPP has commenced discussions with potential O&M contractors. In addition, AIPP expects to enter into a long term Long Term Service Agreement (LTSA) with the equipment supplier selected as part of the EPC process for construction of the plant.

Construction and Operating Insurance

33. AIPP is currently prequalifying companies to provide a Construction All Risk Insurance Policy to cover the risk associated with construction activities. In addition, AIPP expects to obtain and maintain a Commercial/General Liability insurance to cover legal liability to third parties for bodily injury or damage to property arising out of the construction, testing, commissioning, ownership, operation and maintenance of the plant.

Geometric Aba Power Limited

34. Geometric Aba Power Ltd. (GAPL) is currently constructing a 140 MW plant at Aba to serve captive load nearby, but expect to have 50 MW of night-time capacity from this plant available for sale to the grid on an interruptible basis. This portion of the plant is 70 percent complete and is expected to be commissioned by end 2014. In addition, GAPL designed this plant with a view to adding an additional turbine to sell power into the grid on a firm basis. This supplementary turbine will increase the plant's capacity by 47 MW to 187 MW. The existing gas supply agreement with SPDC can accommodate the fuel requirements of all 187 MW. Gas will be delivered to the plant through a dedicated 12 inch, 27 km lateral connecting the power plant with SPDC's facility. Most of this new pipeline will run parallel to an existing pipeline and make use of the existing right-of-way (ROW). Only 7 km will be built on a new ROW. EIA for the plant is completed and available for review by the Bank. EIA for the gas pipeline has been completed. GAPL has commenced discussions with the NBET on a PPA for 97 MW.

Century Power Generation Limited

35. Century Power Generation Limited (CPG) plans to build and operate a 495MW combined cycle power plant using natural gas as its primary source of fuel. The plant will be located in Okija in Ihiala Local Government Area of Anambra which is about 20 Kilometers from the Oguta-Egbema oil field. CPG has obtained a registered Title deed for the project site land, a provisional approval from TCN to connect the 495MW gas power plant to the grid via the proposed Nnewi 330/132Kv sub-station in Anambra State and an Environmental and Social Impact Assessment (ESIA) Approval Certificate from the Federal Ministry of Environment. CPG has passed the preliminary due diligence requirements for Gas Aggregation Company of Nigeria (GACN) and is expecting to be issued a Gas Purchase Order (GPO). In addition, Century Power is exploring other options of securing a gas supply from an independent supplier. Century has also commenced discussions with NBET for a PPA for 495MW.

Ikot Abasi Power Plant Limited

36. Ikot Abasi Power Plant Limited (IAPPL) plans to build two floating barges mounted with two GE Frame 9E turbines to give a total output of about 250 MW. The plant will be located along the JAJA CREEK in Ikot Abasi Local Government Area (LGA). The Akwa Ibom State Government has issued Certificate of Occupancy with the number IA/269/2013 to IAPPL for the 4.05 hectares project site land. TCN has issued a provisional approval to IAPPL giving the project till 2015 to connect to the grid via the Ikot Abasi 330kv sub-station. IAPPL has received the final EIA approval from the Federal Ministry of Environment, secured a permit from the Nigerian Inland Waterways Authority to utilize the waterways for the occupation of 250MW barge mounted power plant and a confirmation of intent from Accugas Ltd Seven Company for

gas supply. IAPPL is also currently in negotiations with NBET towards execution of a PPA for the 250MW plant.

Nigerian Solar Capital Partners

37. Nigerian Solar Capital Partners (NSCP) plans to develop 100MW solar photovoltaic power plant in Ganjuwa Local Government Area of Bauchi State with a configuration of 344,000 panels in the field with each one having a 290Wp rating. NSCP was incorporated as a joint venture between Gigawatt Global, a leading utility scale solar PV developer and Industry Capital, a $1.4bn private equity firm based in San Francisco. NSCP has acquired 400 hectares of land from the Bauchi State government and the Certificate of Occupancy is currently being processed by the State Ministry of Lands and Survey. Further, NSCP has obtained a provisional approval from TCN to connect the 100MW power plant to the grid via a turn-in-out of the Gombe – Bauchi 132kv single circuit line. A solar irradiation study has been carried at the project site and key measurements have been obtained for a one year period. NBET is currently finalizing its draft form solar PPA and will share with NSCP in the short term so as to commence PPA negotiations for the 100MW plant.

JBS Wind Power Limited

38. JBS Wind Power Limited (JWPL) plants to develop a 100MW power plant utilizing 50 X 2MW Wind Turbine Generators (WTG) generating approximately 342,000MWH of electricity per year. The project site is located on the uncultivated rough rolling hills at Maraban Pushit in Mangu Local Government Area of Plateau State. JWPL has obtained a 45 year lease agreement for the 4 hectare project site and a provisional approval from TCN to evacuate the 100MW power via a 132kv substation at Makeri, Plateau State. Further, JWPL has conducted and submitted required Environmental Impact Assessment Studies (EIA) studies and obtained an interim EIA approval from the Federal Ministry of Environment and a provisional Independent Power Producer (IPP) license has been obtained from the National Electricity Regulatory Commission (NERC) in acknowledgment that JBS Wind Power Limited has met all regulatory requirements to commence operation. NBET is currently finalizing its draft form wind PPA and will share with JWPL in the short term and so as to commence PPA negotiations for the 100MW plant.

IV Sub-Component 2: GENCO PRGs

39. The FGN elected to privatize existing generation plants that are operating at far below their installed capacities (see Table 1). The objective of privatization is not just to transfer ownership and/or control of the assets, but also to incentivize rehabilitation/modernization of these plants to bring them up to their installed capacities. This effort will be facilitated by the fact that, although the plants are operating at far below their potential, their existing transmission and fuel supply and transportation infrastructure is already sized to handle their installed capacity. Once privatized, the plants' current output will be sold to the NBET through PPAs while work on rehabilitating the facilities takes place. The FGN requested the Bank's support, similar to that requested for Greenfield IPPs, in the form of PRGs to backstop the NBET's obligations in those agreements. The increased capacity after rehabilitation will also be sold to NBET either under the same PPA entered into for the current output or a new PPA. Depending on the contractual

agreements reached, Bank support for this increased capacity may need to be accounted for in the initial PRG coverage or provided later as the rehabilitation work is completed through requests for additional financing submitted for Board approval.

40. Privatization of the GENCOs is structured differently for each type of plant. Control of the hydroelectric plants is to be transferred to the private sector under concession agreements with a term of not less than 15 years, which can be extended for the terms of extensions of the generation licenses associated with the relevant plant. The plants' assets are expected to be leased to the concessionaire for the term of the concession. Award of the concessions to bidders who passed the technical evaluation stage of the bidding process will be made on the basis of concession fees offered by each bidder for the life of the concessions, taking into consideration NERC's MYTO parameters and the plants' rehabilitation and operation/maintenance needs. The thermal plants, on the other hand, are to be privatized through the sale of 100 percent of the shares of the special purpose vehicles (SPVs) that were formed specifically to own the plant assets. Once finalized, the sale agreements are expected to require the new private sector owners to rehabilitate the plants and raise all of the financing necessary to complete this work. Award of the shares of the SPVs will be made solely on the basis of the purchase price offered for the SPV shares by the bidders who passed the technical evaluation stage.

41. The heart of the commercial arrangements underpinning the foregoing transactions for both hydroelectric and thermal assets are the revenues generated from the sale of electricity from the plants under PPAs to be entered into with the NBET. As discussed above, the FGN requested the Bank's support in providing credit enhancement for NBET in the form of a PRG similar to those proposed for Greenfield IPPs. The final structure, amount, and scope of the PRGs will depend on the outcome of the FGN's current negotiations with the announced first-ranked bidders for each of the GENCOs, the financing structure of the acquisition, and approach on the required rehabilitation work. Once the PRGs are finalized and the structure of the applicable transactions agreed, the package will submitted to the Board, on a no-objection basis.

Table 1: GENCOs offered for Privatization

	Afam	***Geregu***	***Kainji***	***Sapele***	***Shiroro***	***Ughelli***
Location	River State	Kogi State	Niger State	Delta State	Niger State	Delta State
Plant Type	Gas	Gas	Hydro	Gas	Hydro	Gas
Installed Capacity	776 MW	414 MW	760 MW	1,020 MW	600 MW	900 MW
Available Capacity [2011]	57 MW	270 MW	258 MW	103 MW	372 MW	225 MW
Energy Generated [2011]	416 GWh	1,698 GWh	1,769 GWh	697 GWh	2,374 GWh	1,493 GWh
GENCO revenues [2011]	$11.8 M	$74.4 M	$53 M	$53 M	$78 M	$45.4 M
GENCO OPEX [2011]	$3.6 M	$22 M	$16.4 M	$15.2 M	23.2 M	$13.6 M
Staff [2009]	281	48	413	433	447	462

V. Sub-Component 3: DISCO PRGs

42. The power sector value chain elements (gas development, generation, transmission, and distribution) are concomitant. Therefore, it cannot be over emphasized how important it is that each link in the chain be fully functional for the reforms to be effective. The ability, therefore, of the DISCOs to successfully turn around dismal customer service levels and revive fledgling revenues flows to finance investments upstream in the value chain will make or break the power sector reform efforts. The FGN's current privatization effort includes divestiture of the country's

11 DISCOs. These companies at the heart of the sector's financial performance have suffered chronic technical and operating difficulties that the FGN expects would be addressed by private-sector ownership. These difficulties require significant capital investments in upgrading/rehabilitating the distribution networks and commercial systems in all of the companies to improve the quality and reliability of service. NERC has anticipated this need in the investment targets that were adopted in its recently announced MYTO tariff revision. NERC also expects to revise them further once the privatization process has concluded and the new private-sector owners have had the opportunity to take full stock of the investment needs. As such, stability of the revenue derived from the MYTO tariff and the overall regulatory process will be the key to bankability of the companies and their ability to raise financing for the requisite capital projects. Furthermore, as noted above, the Government began preparations for the privatization effort by tackling the difficult issues of labor, stranded assets and liabilities, and other issues that normally dampen interest in private-sector participation in the companies' privatization. Discussions with labor unions are at an advanced stage, and the FGN has already begun the process of transferring non-performing assets, including liabilities to staff, to NELMCO. NELMCO was specifically created for the purpose and capitalized with approximately US$1.3 billion to provide sufficient support for the transferred liabilities.

43. The FGN's privatization process for the DISCOs followed a similar two-stage approach adopted for the GENCO bidding process. Valuations of, and, therefore, the asset price to be paid for all DISCOs were fixed in the beginning of the process and used as the basis for regulated rates approved by NERC in the MYTO. As such, bidders' commercial proposals focused on committed improvements in Aggregate Technical, Commercial, and Collections (ATC&C) Losses to be achieved within the initial 5-year MYTO tariff period post-privatization. These losses are based on the percentage difference between the amount of electricity received by a DISCO from the transmission system and the amount of electricity for which this DISCO is able to collect revenue from customers.

44. NERC assumed a certain downward trajectory for these losses in the MYTO's 5-year assumptions that corresponds to NERC's estimate of the amount of CAPEX required achieving these estimates. The focus on improving ATC&C losses reflects the FGN's desire to improve service delivery on the retail end of the electricity value chain and deal with the chronic under-performance of the distribution networks in the country.

45. BPE launched the DISCO privatization process concurrently with the privatization process for the GENCOs. It engaged in discussions and consultations with stakeholders throughout the process of developing the privatization structure and bidding documents to ensure that market and stakeholders' concerns are appropriately considered. Potential bidders were initially pre-qualified and provided access to an electric data room with data on the different assets offered for privatization. BPE also arranged site visits to the various companies. Bidding documents were released in May 2012 and bids were received in July 2012. BPE announced on October 10, 2012, the first-ranked bidders for 9 of the 11 DISCOs, with bidders involved in bids for the remaining 2 DISCOs disqualified on technical or other grounds, and began individual negotiations of the legal documents with each of these bidders. As noted above, a critical aspect underpinning the privatization process are the risks affecting DISCO revenue.

46. While many of these risks are typical commercial risks whose mitigation is within the ambit of the soon-to-be privatized DISCOs, some risks are more in the control of the FGN. This is particularly true with respect to NERC's adherence to requirements and parameters of the MYTO for minor periodic reviews of the retail tariff to reflect changes in, for example, inflation, exchange rates, and working capital requirements. Because NERC has not yet developed a sufficient track record of performance as an independent regulator in a market that involves both private and public sector companies and because the MYTO is still in a nascent stage, the FGN requested the Bank's support to provide risk mitigation measures in the form of a Series of PRGs to provide investors some assurance of stability in expected regulatory actions.

47. In response to the FGN request, the proposed PRG Series is to provide PRGs to support the DISCO privatizations. The PRGs to be provided are necessary to ensure the DISCOs are able to attract the CAPEX financing required to implement the investment plans proposed by the preferred bidders, and provide confidence to commercial lenders that the regulatory process will not be reversed. The risk mitigation instruments offered under sub-component 3 will be similar to those being considered for both sub-components 1 and 2, in respect of credit risks associated with governmental non-payment, but may include an additional element of risk mitigation focused on the regulatory risks DISCOs face during the transitional period. The regulatory risk mitigation element will be designed to backstop risks associated with implementation of the new MYTO 2 tariff and any FGN's agreement to provide subsidies beyond to current sunset date of mid-2014, as well as protect against the risk of reversal of recent governmental reforms. Given that WBG cannot conceivably engage with and support all 11 DISCOs, the proposal is to support a limited number of early market leaders in becoming "centers of excellence" for other operators in the industry to emulate, and, thus, achieve EBP objectives. The PRG regulatory risk coverage is proposed to be confined to the revenue gap stemming from a failed or delayed NERC minor review of the retail tariffs as provided under MYTO 2 and/or FGN failure to provide the subsidies promised to the DISCOs. It will cover only the retail portion of the tariff, after deducting the bulk tariff and transmission costs. More specifically, the gap will be subject to the difference between the actual level of revenues at any point in time, and the revenues that DISCOs are legally obliged to generate (excluding the portion lost due to commercial losses).This way the PRG will support the DISCOs only for regulatory risks and not commercial risk, which is expected to be managed by the part of the privatization process. The criteria used for pre-selecting these DISCOs included, inter alia, their revenue potential (household income and electricity consumption per capita used as proxies), cost effectiveness (population density used as a proxy), industrial customer base and access to electricity generation. Out of the 11 DISCOs being privatized, following four have been identified as advanced stage candidates: Abuja DISCO, Benin DISCO, Eko DISCO and Ikeja DISCO:

(i) ***Abuja DISCO*: ** The preferred bidder is the KANN Consortium, a joint venture between Copperbelt Energy Corporation (CEC PLC) of Zambia and the Nigerian private equity fund Xerxes Global Investments. For technical competency, the Consortium has signed a services agreement with Aurecon, a global engineering and technical consultancy services company with extensive electric distribution experience in Tanzania and South Africa. Abuja DISCO is located in Nigeria's Federal Capital Territory, which may be considered symbolic for the success of the reforms. The Bank has already invested in the Abuja DISCO (IDA financed NEGIP

Project) in a Series of programs focusing on distribution grid rehabilitation, capacity de-congestion and distribution of pre-payment metering for households in the Abuja DISCO in the recent past. Abuja is also unique in that a significant percentage of its revenues (more than 40 percent) are derived from governmental agencies (e.g., the military, the police and similarly critical FGN agencies), which, historically, have not paid for electrical services in a timely manner. While the market rules provide that a DISCO will be within its contractual rights to stop providing electricity to such agencies when they are in arrears on their electricity bills, this would be an impractical solution. To address the concern of DISCOs, the FGN is considering implementing a policy of support for off-take payments by some of its agencies. If such an FGN policy is implemented, a PRG could provide Abuja DISCO's investors and lenders comfort that such governmental obligation would result in payments when required. The Abuja DISCO owners consortium has committed to reducing ATC&C losses for Abuja DISCO to 12.8 percent (down from 35 percent) during the first five-years post-acquisition.

(ii) ***Benin DISCO*:** Benin DISCO distributes electricity to users in four South West States (Edo, Ekiti, Ondo, Delta). The preferred bidder is Vigeo Power Limited. The Vigeo consortium consists of the following shareholders: Vigeo Holdings Limited (82.33 percent) and Africa Finance Corporation (17.67 percent). The consortium's key technical partner is Tata Power Delhi Distribution Limited (TPDDL), a 51/49 joint venture between Tata Power, part of the Tata Group, and State Government of Delhi, India. Tata has a strong track record in loss reduction, as it successfully reduced ATC&C losses in its licensed area from 53 percent to 11 percent between 2002 and 2012. Benin DISCO is situated at the sweet spot of the transmission grid, in a region crossed by multiple transmission lines and no apparent transmission constraints. This ideal position, if fully harnessed by the preferred bidder, should be instrumental in reducing technical losses. Also, the Azura IPP is located at the outskirts of Benin City, the main load center. The loss reduction proposal for Benin Disco targets loss levels falling to 12.19 percent (down from 40 percent) over the five year period.

(iii) ***Eko DISCO*:** West Power and Gas (WPG) has been designated preferred bidder for Eko Disco. Eko DISCO covers the southern-most part of the Lagos metropolis which is the main industrial and commercial hub, accounting for 12 percent of Nigeria's GDP. The prior to taking possession of the company, WPG has established a project takeover office, which KPMG advising and international experts leading in the best way to maintain the DISCOs successful performance and develop a fast-track plan to address metering and system distribution. First actions post takeover will be to install meters for all industrial customers, confirm the correctness of TCN meters measuring power delivery to Eko, and the transition of all residential customers to AMR. Currently, Eko DISCO receives 65 percent of its revenue from a maximum demand, high-density industrial customer base using estimated billing methods. This is the only distribution company in Nigeria with a 100 percent collection rate. As a result of Eko's positive pre-privatization performance, the new owners have indicated they will keep Ekos current CEO post-takeover, and have already identified key employees to keep past the 6-month probation period.

(iv) ***Ikeja DISCO*:** Ikeja DISCO has been awarded by BPE to New Electricity Distribution Company (NEDC), a Special Purpose Entity jointly owned by the Sahara Group (c.87 percent) and KEPCO (c.13 percent). Since 2007, KEPCO and Sahara, through their KEPCO Energy Resources Limited (KERL) Joint Venture, have refurbished, operated and largely managed the 1.3 GW Egbin Thermal Power Plant – Nigeria's largest thermal power plant. Note that KEPCO and Sahara are also in the process of jointly acquiring the Egbin Power Plant from FGN. KEPCO appears to be as strong a technical partner as Sahara could get in the electricity distribution space. The Sahara Group is the only entity that has a virtually integrated utility (generation and distribution) in the emerging Nigerian Power Sector. By acquiring Egbin Power Plant and Ikeja DISCO, the Group will own the largest electricity generation and distribution companies in Nigeria.

Table 2: Summary of DISCOs

	Abuja	***Benin***	***Eko***	***Ikeja***
Area ('000 sq.km)	133	58	1.8*	1.8*
Population (millions)	10.5	13.2	4.6*	4.6*
Population Density per km^2	79	229	2,531**	2,531**
# of Customers in '000	478	745	320	593
Power sold [2011]	2,025 GWh	2,444 GWh	1,969 GWh	2,758 GWh
DISCO revenues [2011]	$ 144 million	$135 million	$170 million	$222 million
Staff [2010]	2,584	4,684	3,713	3,370
Losses ***	35%	40%	35%	35%
Annual peak load demand	865 MW	1,000 MW	1,105 MW	1,335 MW

*: assuming Eko and Ikeja Discos each serve half of Lagos
**: Data for the entire Lagos State
***: As stated in the individual DISCO business plans (To be verified post acquisition)

The First Two Greenfield IPP Transactions:

48. The first two greenfield IPP transactions are presented for Board approval.[22]

49. The first two IPP transactions will increase the installed power generation capacity by around 1,000 MW, and deploy nearly US$2 billion in financing, which includes about US$1.7 billion of private capital. The initial set of greenfield IPP transactions proposed for PRG coverage are as follows: Azura IPP (Azura) and Qua Iboe IPP (QIPP). These initial transactions inherently possess a higher level of risk and require diligent support and increased risk appetite of the WBG instruments in order to achieve success. In the long term, the risks as well as costs of such transactions are expected to reduce.

[22] The Azura Edo project (Azura) and Qua Iboe Power Project (QIPP). The Azura Edo project will also be supported by IFC and MIGA, see IFC IRM Memorandum and MIGA Underwriting Paper.

Azura Edo IPP (459 MW OCGT)

Project Sponsors

50. The Azura Edo IPP includes: (a) The NBET credit enhancement guarantee (up to US$120 million), and (b) The commercial debt mobilization guarantee (up to US$125 million). This open-cycle gas-fired power plant is being developed by Azura Power West Africa Limited (the "Company"), a Special Purpose Vehicle ("SPV") incorporated in Nigeria, with the sole purpose of developing a 1,000 MW open-cycle gas power plant located in the vicinity of Benin City, in Edo State, Nigeria. The Sponsors are: (a) Amaya Capital Ltd., a principal investment firm and majority investor in Azura Power Holdings Ltd., its dedicated vehicle for investing in IPPs and the power distribution sector in Africa, jointly owned with the American Capital Energy and Infrastructure Fund, a fund managed by American Capital Ltd.; (b) Aldwych International Ltd. ("Aldwych"), an international power developer focusing on Sub-Saharan Africa; (c) African Infrastructure Investment Fund 2 ("AIIF2"), an Africa-focused fund managed by the Macquarie Group and Old Mutual which will invest through both its Rand-denominated and US$-denominated vehicles; and (d) Asset and Resource Management Ltd., a leading Nigerian asset manager. The Sponsors are investing in the Company through Azura Edo Ltd. (the "Shareholder"), an SPV incorporated in Mauritius. The Edo State Government, the local State authority, is also expected to have a 2.5 percent shareholding in the Company. The Power Plant will be located in Edo State and will have an installed capacity of about 1,000 MW, developed in two phases (a first phase of 459 MW and a second phase of 500 MW. It is possible that the Company later converts the first phase project into a combined cycle plant and then adds 'Phase 3' thus the total capacity could reach 1,500 MW). The Plant is expected to include 4 high voltage (15 kV to 330 kV) transformers, one for each of the generator sets and a switchyard that is designed to accommodate additional capacity in the event that plant is converted into combined-cycle. Power will be evacuated from the switchyard through a single tower on a new 330 kV transmission line connecting the plant to the adjacent 300/132 kV new Benin North substation, currently under construction. Total transaction costs are estimated at US$813 million, expected to be financed on 72.5:27.5 debt-to-equity ratio. The most advanced of the IPPs, Azura has already executed its PPA with NBET as part of the ceremonial Presidential Signing Ceremony held 22 April 2013 in Abuja, although certain aspects, such as the security package provided by NBET under the PPA, and termination provisions under the Put Call Option Agreement (PCOA), including the final PRG terms, are being finalized.

Project Site

51. The 459 MW Azura Edo IPP will be implemented on a 100-hectare site in Edo State and is the first of two similarly-sized phases that will provide 1000 MW of combined Greenfield capacity at the site. In addition, the site has been sized to allow for further expansions at a later date (via the addition of heat recovery steam generators). The site is near a major load center, an inland port with proven capacity to handle shipment of heavy equipment and a major gas trunk line.

52. Azura entered into a Memorandum of Understanding with the government of Edo State to acquire the site and secure the necessary regulatory approvals to perfect title. Resettlement will be subject to a Resettlement Action Plan (RAP) and an Environmental and Social Impact

Assessment (ESIA) both of which have been reviewed by the FGN and have been disclosed in the World Bank's InfoShop on March 6th 2012 and March 5th 2012 (respectively).

Project Construction and EPC Contractor for Phase I

53. The first phase of the project, which will be covered by the proposed PRG, consists of open-cycle Frame E gas turbines with a tendered capacity (at site conditions) of 459 MW. Selection of this configuration was based on an analysis of the technology's associated construction costs, thermal efficiency, and operating versatility. It was also based on availability of multiple equipment manufacturers that provide the machines (currently, Frame E machines manufactured by General Electric, Alstom, and Siemens are operating in Nigeria), and the fact that the new, (FGN-funded) NIPP projects operate 18 of these machines, which is likely to ease availability of spare parts in the country. The plant will be designed to accommodate conversion to a combined-cycle configuration by adding appropriate heat recovery steam generators (HRSGs) to space that will be made available at the inlet exhaust ducts of the gas turbines. However, the conversion will take place only when gas and power prices in the Nigerian market justify the additional investment.

Table 3: NIPP Plants Commissioned or Under Construction

NIPP Plant	*Capacity (MW)*	*Available (MW)*	*End 2013 (MW)*
Alaoji	1,074	225	510
Calabar	561	0	0
Egbema	338	0	0
Gbarain	225	0	0
Geregu Phase II	434	144.7	217
Ihovbor	450	0	450
Olorunsogo II	562.5	315	450
Omoku	250	0	0
Omotosho Phase II	450	225.5	225.5
Sapele	450	157.5	450
Total	**4,794.5**	**1,067.7**	**2,302.5**

54. Construction of the first phase of the plant is expected to commence by the second half of 2014, with commissioning and commercial operations reached 30 months thereafter (i.e., in late 2016). Azura undertook a competitive bidding process to select a qualified EPC contractor. The process began in October 2011 with the issuance of a general procurement notice in the local and international press, concurrently with publication of an invitation to submit expressions of interest (including pre-qualification criteria) in the same media. The company then issued the invitation to bid to pre-qualified bidders on November 21, 2011. First round (commercial and technical) bids were received from 8 bidding consortia on March 23, 2012.

55. From these 8 bidders, 5 were shortlisted to progress to the second round. The countries of origin of these bidders were: China (1 bidder); Germany (1 bidder); Korea (2 consortia); South Africa (1 bidder). The company awarded the bid to a consortium consisting of Siemens AG, Siemens Nigeria Ltd and Julius Berger, and is currently finalizing the construction contract and the long-term service agreement with Siemens.

Fuel Supply and Transportation

56. On 1 April 2014, Azura signed a 15 year Gas Sale and Purchase Agreement (GSPA) with Seplat Petroleum Development Company PLC (Seplat). Seplat is an indigenous Nigerian oil and gas company, 70% of whose ownership currently resides with two Nigerian exploration and production companies (Platform Petroleum Limited and Shebah Petroleum Development Company Limited) and MPI S.A. (formerly Maurel Prom Nigeria S.A). On 28th March 2014, Seplat launched an Initial Public Offering on the London and Lagos Stock exchanges.

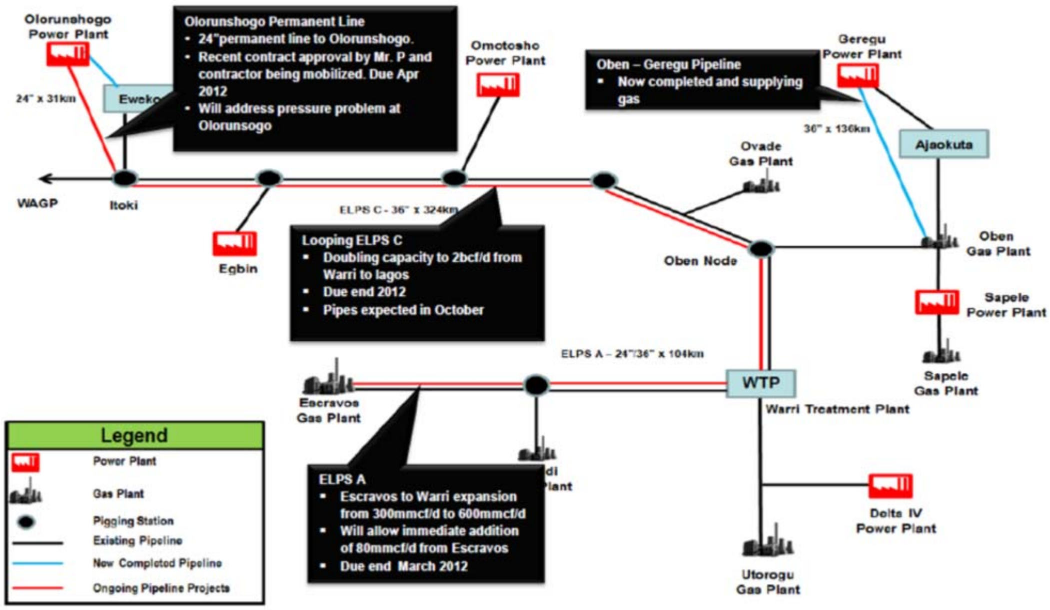
57. Seplat currently plans to meet Azura's 115,909 mmbtu per day gas requirements (equivalent to circa 113 million standard cubic feet per day (mmscfd) from OMLs 4, 38, and 41. Expanding supply from these fields also requires expansion of Seplat's existing processing and production infrastructure. Accordingly, SEPLAT is currently expanding the existing gas processing capacity at its Oben gas plant, by constructing two new processing trains with a combined capacity of 150 mmscfd, bringing the total gas processing capacity at Oben to 240 mmscfd. It has established an overall budget for this expansion of US$104 million. The scope of the initial expansion includes the installation of condensate and produced water storage tanks with ten-day working capacities to mitigate the impact of downstream interruptions on gas production. Taking into account a reasonable schedule reserve, the expanded Oben Gas Treatment Plant should be onstream at least six months ahead of the Project's need for commissioning gas. Thereafter, additional projects envisaged by Seplat include the installation of two more 75 mmscfd trains (or possibly 100 mmscfd trains) and the construction of an interconnector pipeline between Seplat's Oben and Sapele Gas Plants.

58. Gas is expected to be transported from Oben to the project through the ELPS pursuant to a Gas Transportation Agreement (GTA) with the Nigerian Gas Company (NGC), which owns and operates the ELPS. The route of the ELPS is located directly adjacent to the project site. Currently, ELPS's main 36-inch pipeline has a capacity of 1 billion standard cubic feet per day (scf/d), which is fully subscribed by supply obligations to existing power plants operated by the Power Holding Company of Nigeria (PHCN), the West African Gas Pipeline that supplies gas to neighboring West African countries, and new power plants expected to be commissioned by 2014 under the FGN-funded NIPP.

59. As such, the FGN has commenced a project to expand ELPS to provide transportation capacity to the project and other independent power projects supplying Lagos, Ibadan, and Abuja along the western axis.

60. This expansion involves construction of new pipelines in the same right-of-way as the existing ELPS, and consists of a 24-inch pipeline from Escravos to Warri, a 30-inch pipeline from Warri to OGP, and a 36-inch pipeline from the Oben Node (south of the Azura Edo IPP) to Lagos. A short spur line (less than 1 km) will be constructed connecting the ELPS to Azura's gas receiving station. This spur line will be entirely enclosed within land owned by Azura. Azura is currently finalizing the GTA with NGC and expects to complete the process in May 2014.

Figure 5 – ELPS System and Expansion



61. It is expected, based on the current progress of pipeline construction, that the ELPS loop will reach the location of the Azura Edo IPP before the facility needs commissioning gas. The project will also use diesel fuel to support Black Start capabilities through 3x3.7 MVA diesel generators.

62. These generators would be used to start and shut-down the gas turbines and to power auxiliary equipment in the event of a total transmission system collapse that prevents the plant from receiving power from the grid for such purposes. On-site diesel storage is expected to be limited to 24 hours of continuous operation.

<u>Interconnection and Transmission Service</u>

63. The Azura IPP is expected to include 3 high voltage (15 kV to 330 kV) transformers for each of the generator sets and a switchyard that is designed to accommodate additional capacity in the event that the plant is converted to combined-cycle. Power will be evacuated from the switchyard through a single tower on new 330 kV transmission lines connecting the plant to the adjacent 330/132 kV Benin North substation that was originally planned to receive power from the NIPP Ihovbor plant and has recently been completed. It connects to the major transmission node at Benin City through a new 330 kV line. Construction of this Benin North substation is part of a significant expansion of the transmission network in Nigeria that will add 5 new transmission lines to the existing 330/132 kV lines already in operation at Benin City.

<u>Environmental and Social Impact</u>

64. The project is classified as a "Category A" requiring a full Environmental and Social Impact Assessment (ESIA). Azura retained Environmental Resources Management Ltd. (ERM) as an independent consultant to undertake the ESIA based on terms of reference that have been reviewed and approved by both the FGN and the World Bank. Dry season environmental

baseline data collection commenced on March 18, 2011; wet season data collection commenced on July 24, 2011; and social baseline data collection commenced on June 20, 2011. The first draft of the ESIA was submitted to the World Bank for its review in November 2011 and the final draft was disclosed in the World Bank's InfoShop on 5th March 2012.

65. The project site is currently owned by three local communities: the Orior, Idunmwowina and Ihovbor communities. The communities consist of several small dwellings and some farm land. The residents and farmers of these communities will be resettled and/or compensated in accordance with World Bank guidelines under a Bank-approved RAP that was disclosed in the World Bank's InfoShop on March 6th 2012.

Operations and Maintenance

66. The selection of an Operations and Maintenance contractor was made pursuant to a competitive bidding process similar to that followed for award of the EPC contract and the LTSA. Specifically, Azura issued an invitation to bid on April 23, 2012, and bids were submitted by 9 pre-qualified firms. One bid was rejected because it failed to include a commercial proposal; two others were disqualified because of technical non-compliance; and one bid was rejected because of its commercial weakness.

67. After the EPC contractor was identified and the type of equipment to be used for the plant was settled, Azura narrowed the field of qualified bidders to those that possessed experience both in operating Siemens turbines and power plants in Nigeria. Ultimately, PIC Group, a wholly-owned subsidiary of Marubeni, was selected as the Operation and Maintenance (O&M) contractor for the Azura Edo IPP.

68. The company further expects to enter into a long-term service agreement with Siemens, which is supplying the plant's equipment. The selection process proceeded in parallel with, but separate from, the process to select the EPC Contractor. This agreement will cover procurement of spare parts and the periodic minor/major gas turbine maintenance required based on the equipment's operating profile.

Construction and Operating Insurance

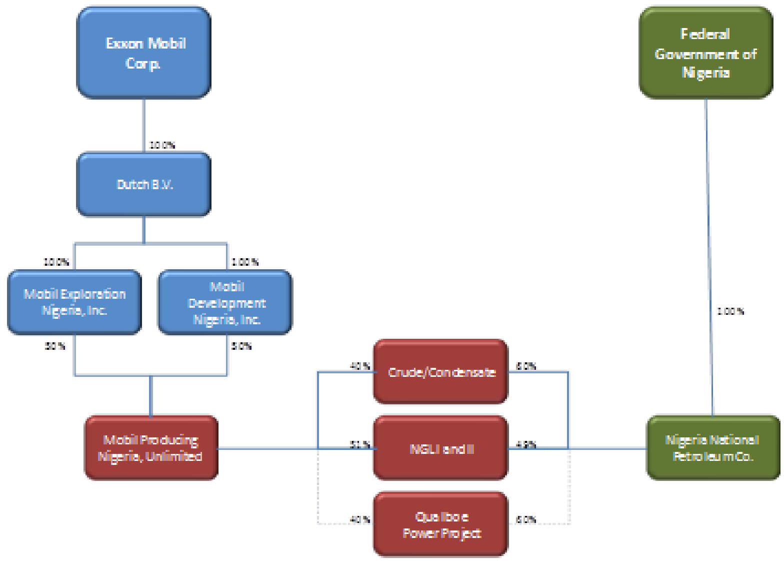
69. Azura commenced discussions with a number of insurers to get a more detailed understanding of the likely premiums that will need to be paid for, inter alia, construction, equipment, erection, and cargo insurance. The company anticipates that the project lenders may impose certain minimum criteria with regard to these insurance policies, the satisfaction of which may require a substantial portion of the insurance cover to be placed outside of the Nigerian insurance market.

70. Azura is also in the process of obtaining indicative pricing, where and to the extent available, for contingent business interruption (CBI) insurance from the Lloyds Market to help mitigate the risk of short-term interruptions to the fuel supply chain that may be occasioned by events outside of any political risk insurance secured. A final decision on CBI coverage is likely to depend on its availability in the market, the overall balance of insurance coverage, including political risk insurance, and project structure.

Qua Iboe IPP (533 MW OCGT/CCGT)

<u>Project Sponsors</u>

Figure 6 – QIPP Ownership Structure



71. Qua Iboe IPP (QIPP) is being developed by an unincorporated joint venture (JV) between Nigerian National Petroleum Corporation (NNPC) and Mobil Producing Nigeria Unlimited (MPN), a wholly owned indirect affiliate of Exxon Mobil Corporation (EMC). MPN was incorporated in Nigeria in 1969 by Mobil Oil Corporation before its merger with Exxon Corporation in 1999. MPN is currently the operator of this joint venture under a Joint Operating Agreement (JOA) for the exploration, development, and production of several oil and gas concessions in Nigeria. The JOA provides MPN powers to act on behalf of NNPC in the conduct of the joint venture's business and management of the joint venture assets.

72. The JV partners plan to fund QIPP with equity contributions in proportion to their respective equity interests. As such, the project commercial and operational arrangements will be consistent with JV's current practice. A Seller's Representative Agreement was entered into by NNPC and MPN in April 2013 to allow MPN to enter into a PPA with NBET on behalf of the JV partners.

<u>Project Site</u>

73. QIPP will be constructed on a site immediately north of JV's Qua Iboe Terminal (QIT) in Ibeno, Akwa Ibom State, on the south-eastern coast of Nigeria. QIT has an existing crude stabilization plant, including crude separation, treatment, storage, and loading facilities. The transmission line Right of Way (ROW) to be acquired for the project is approximately 58km in length and 50m wide, thereby giving a total area of about 2.9 million square meters, from QIPP to the West.

Project Construction and EPC Contractor

74. MPN completed Front-End Engineering Design (FEED) for both simple cycle and combined cycle gas turbine configurations for the Power Plant EPC tender. The award of the EPC will be based on only one power plant configuration (Simple or Combined cycle) determined from the Life Cycle Cost Analysis (LCCA) of the proposals submitted by bidders in the competitive bidding process applied to select the project's EPC contractor. This decision will take into account the plant efficiency, total life-cycle costs, gas and power prices, and overall economic viability of the project. Presently, a combined cycle configuration is being used in open book discussions with NBET; formal approval of the plant configuration (Simple vs. Combined Cycle) is pending (see the discussion below for the bid selection process and approval status).

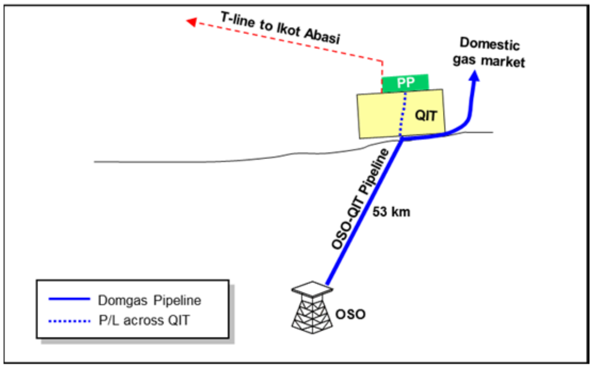
75. It is expected that the Gas Turbine Generators (GTG) will be capable of operating in simple cycle or combined cycle mode, and fired with fuel gas using Dry Low Nitrous Oxide (NOx) burners. The output of a single GTG will range from approximately 125 – 180 MW, based on ISO conditions, depending on the manufacturer of GTG units. The GTG and Steam Turbine Generator (STG) units will be installed in a common building. Each GTG package will include free standing enclosures, an air inlet filtration system, exhaust stack, accessory equipment (oil lubrication system, hydraulic system, starting motor), auxiliary equipment (fuel gas skid, cooling water package, compressor washing system) and a local control room. The generators will be equipped with a Totally Enclosed Water to Air Cooled (TEWAC) cooling system. For combined cycle, heat recovery steam generators and air cooled condensers will be installed.

76. QIPP will be constructed using three EPC contracts, one for the power plant and another for construction of the transmission line between the plant and Ikot Abasi. A third EPC contract will be executed for construction of the pipeline to supply fuel gas to the power plant; this project has been known as the Oso-QIT Pipeline Project. These EPC contracts will be awarded based on competitive bidding guidelines established by the JV. These guidelines require that all procurement packages exceeding a threshold amount be approved by NNPC and follow the process outlined and approved by the NNPC Board. MPN published the EPC advertisements seeking response from interested parties in October 2010, issued the request for pre-qualifications to screened interested bidders in December 2010 and finalized the list of pre-qualified bidders in February 2011. The Technical Invitation to Tender package was issued in September 2011 and commercial bidding/evaluation conducted September 2012 through April 2013. MPN has obtained its Nigeria Upstream Bid Committee (NUBC) approval of the award recommendations and forwarded the same to JV's partner representative, the National Petroleum Investment Management Services (NAPIMS) for concurrence in March and April 2013. The award recommendations were made for (1) the power plant EPC contract and the two associated service agreements, namely, the Long Term Service Agreement (LTSA) and the EPC Operations and Maintenance (O&M) Agreement, (2) the transmission line EPC contract, and (3) the Oso-QIT Gas Pipeline Project EPC contract. The JV expects to be in a position to make the final selection and award of the EPC contracts subject to the completion of major commercial agreements including the Power Purchase Agreement and payment securitization arrangements.

Fuel Supply and Transportation

77. Gas for QIPP will be supplied from the off-shore Oso field. The field is part of the NNPC/MPN joint venture's assets, which include other gas reserves available in production areas under the JV's control. Most of the JV's current gas production is used for gas lift and/or gas injection to maximize oil recovery from existing reservoirs.

Figure 7 – QIPP Gas Supply and Transmission Line



78. Gas production from the Oso field is expected to be developed as part of a broader plan to supply gas to domestic market in Nigeria. A new 20-inch, 53km pipeline (Oso-QIT Gas Pipeline Project) will be constructed from the off-shore JV gas production facility to the Qua Iboe Terminal (QIT). The Oso-QIT pipeline will provide fuel gas to the power plant as well as supply other domestic gas users in the future. The Oso-QIT pipeline is expected to have a maximum transport capacity of 400 mscf per day, of which up to 95 mscf per day will be available for the power plant. The gas will be processed in a fuel gas receiving station (prior to injection into the gas turbine units) to filter and meter the gas and to reduce its pressure. Gas chromatograph(s) may be required due to the expected fluctuation in the fuel gas composition and consequently, heat value.

Interconnection and Transmission Service

79. QIPP will connect to the grid through a new 58 km, 330 kV double-circuit transmission lines that will link the plant with a new substation at Ikot Abasi. Each circuit will have a minimum capacity of approximately 550 MW, thereby accommodating QIPP's entire output, and, with their double circuits, will have redundancy to allow uninterrupted power flows in the event of failure of one circuit. The new substation at Ikot Abasi is part of a larger Transmission Company of Nigeria (TCN) plan to extend the grid from Ikot Ekpene to Ikot Abasi through a new 78 km transmission line that is scheduled to be completed by mid-2014. Niger Delta Power Holding Company (NDPHC) is responsible for completing the Ikot Ekpene to Ikot Abasi transmission line. The JV will fund and build the QIT-Ikot Abasi transmission line and transfer its ownership and operatorship to TCN at start up.

Environmental and Social Impact

80. The Environmental Impact Assessments (EIA) of the proposed QIPP plant and transmission line were carried out using data obtained from two seasons (wet and dry) of sampling and measurement in the areas as well as research/literature survey on similar studies in the area. The field analyses results showed that the physical, chemical and biological characteristics of the seawater column, surface seawater and surficial sediments were consistent across the area. The composition of plankton and benthic macro fauna species indicated unique grouping with abundance that relate to the nutrients and chemical composition of the ecosystem. The potential and associated impacts of the proposed QIPP plant and transmission line project areas have been identified and evaluated using standard procedures. The assessment used various source references including past project experiences, professional judgment and knowledge of the project environment and activities as well as the Federal Ministry of Environment (FMEnv) industry guidelines. The assessment noted some adverse impacts that include, among others, some habitat fragmentation and loss of vegetation at the project sites, risk of labor-related clashes and conflicts, emissions and noise from power plant equipment operation, and increase in the water turbidity from dredging. Additional impact includes acquisition of properties that fall within the transmission line ROW.

81. To mitigate these concerns, the JV and EPC contractors will develop Environmental Management Plans, Waste Management Plans, and Spill Preparedness and Response Plans prior to the execution of the projects to ensure that adequate safeguards are in place. The JV and EPC contractors will also develop plans to address the project-specific security, safety, and health hazards, and a Sedimentation and Erosion Control Plan to address the impact to water resources, soil, and geology. The power plant EPC Contractor will develop a Community Relations Plan that is aligned with the JV's Community Relations Guidelines while the transmission line EPC Contractor will develop a Community Relations and Engagement plan to address project related socioeconomic impacts. Power Holding Company of Nigeria (PHCN) and World Bank's Standards, as captured in the Resettlement Action Plan (RAP) prepared by a PHCN-approved consultant, will be used to address the impacts on those whose properties fall within the ROW. Moreover, the JV plans to include Continuous Emissions Monitoring System (CEMS) and low NOx burners in the GTGs which are designed to cap NOx emissions to 25 parts per million. The proposed plant design also contains controls to minimize potential noise impacts.

Operation and Maintenance

82. The JV developed several options for operation and maintenance (O&M) of QIPP that range from engaging a third-party operator to direct employment of operators and maintenance technicians. The JV expects to retain the EPC contractor as operator for three years after the commercial operations date, followed by MPN taking over the plant's operations. The operator will be responsible for operating and maintaining the power plant. The O&M agreement will be executed concurrently with the EPC contract. Nonetheless, MPN will have the internal resources to take over operation of the plant should the need arises prior to the end of the contract period. MPN's worldwide affiliates have successfully operated power projects for decades, both to supply internal power requirements and to generate electricity for sale to others. ExxonMobil's extensive in-house technical capability in power generation is built upon a global network of refinery, petrochemical and production facilities.

83. To the extent that the EPC contractor's O&M arrangement is put in place for initial operations and maintenance of the plant, MPN will provide oversight of the operator and administer the various contracts as well as the relationship with NBET and other FGN agencies involved in QIPP's operations. The JV expects that, as part of the EPC contract, the contractor will deliver a training program to its own operators, line managers, supervisors, technicians, and select MPN staff to ensure that adequate experience and knowledge are available to operate and maintain the specific equipment installed. The EPC contractor, as operator, will continue to provide training to facilitate the gradual hand over of operations to MPN at the end of the three year term.

Construction and Operating Insurance

84. Construction and operating insurance policies will be consistent with existing JV insurance provisions. During construction, MPN will procure a joint Construction All Risk insurance policy on behalf of NNPC and MPN. During operation, JV partners will procure separate Operational Asset insurance policies.

License to Operate

85. Under Nigeria law, a license is required for power generation. MPN as operator of the JV engaged the Nigerian Electricity Regulatory Commission (NERC) for the procurement of the required On-Grid Generation License for QIPP. The License Application was subsequently updated to allow maximum power output (575 MW) from the plant based on EPC tender results. NERC advised MPN in September 2013 that the Application and NERC due diligence was complete and supported MPN in providing the public notice of the Application for the On-Grid Generation License Application. The 21-day period for public responses ended in early October 2013. NERC granted the On-Grid Generating License to MPN (License No. NERC/LC/110) effective December 3, 2013 and issued the terms of the License to MPN on March 27, 2014.

Annex 3: Implementation Arrangements

Nigeria: Power Sector Guarantees Project

Institutional and Implementation Arrangements for the First Two IPPs

1. ***Azura IPP:*** Azura IPP will be implemented by Azura Power West Africa Ltd., a company established in 2010. The construction of the plant will be implemented through an Engineering, Procurement, and Construction (EPC) contract. The sponsors are in the process of selecting the EPC contractor. The operation and maintenance is expected to be implemented under a third-party contractor, expected to be selected soon. The fuel supply will be provided by Seplat Petroleum Development Company PLC.

2. ***Qua Iboe IPP:*** Qua Iboe IPP is being considered for development by an unincorporated joint venture (JV) between Nigerian National Petroleum Corporation (NNPC) and Mobil Producing Nigeria Unlimited (MPN). MPN is a wholly owned indirect affiliate of Exxon Mobil Corporation (EMC). The JV partners plan to fund QIPP with equity contributions in proportion to their respective equity interests. As such, the project commercial and operational arrangements will be consistent with JV's current practice. A Seller's Representative Agreement was entered into by NNPC and MPN in April 2013 to allow MPN to enter into a PPA with the Bulk Trader on behalf of the JV partners. The JV expects QIPP to be constructed under three EPC contracts, one for the power plant, one for the transmission line between the plant and Ikot Abasi, and one for the gas pipeline. The selection of EPC contractors is currently being finalized. Gas for QIPP will be supplied from the off-shore Oso field. The field is part of the NNPC/MPN JV's assets, which include other gas reserves available in production areas under the JV's control. The JV developed several options for operation and maintenance (O&M) of the power plant that range from engaging a third-party operator to direct employment of operators and maintenance technicians. Currently, the JV expects to retain the EPC contractor as operator for a three-year term after the plant's commercial operations date, followed by MPN taking over the plant's operations. The operator will be responsible for operating and maintaining the power plant. The O&M agreement will be executed concurrently with the EPC contract.

3. ***Project Management:*** NBET is wholly owned by the FGN and was incorporated in 2010 as part of the ongoing Nigeria power sector reforms. NBET is responsible for the commercial arrangement for bulk power trade as the primary off-taker of power from IPPs. NBET has been negotiating the PPAs with the project sponsors under the MYTO 2 New Entrant Model PPA price benchmarks. NBET will be entering into PPAs with all new IPPs which intend to sell power to local distribution companies. It will also sell power to the PHCN successor (distribution) companies that are currently in the process of being privatized.

4. ***Transitional Electricity Market:*** The February 2009 Market Rules provided for evolution of the Nigerian Electricity Supply Industry (NESI) through three (3) stages: Pre-Transitional, Transitional, and Medium Term stages. The Pre-Transitional stage was intended to facilitate privatization of the generation and distribution assets of the Power Holding Company of Nigeria (PHCN) as well as to develop the grid code and market rules needed for operation of the electricity market. The Transitional stage (otherwise known as the "Transitional Electricity Market" or "TEM") is anticipated after completion of 14 conditions precedent to operation of the

electricity market. TEM is characterized by development of contract-based new generation capacity and arrangements for electricity flows until the underlying market systems are sufficiently mature to introduce spot market trading that would mark commencement of the Medium Term stage. The FGN and relevant stakeholders are currently working on the process to operationalize the Pre-Transitional stage market while work continues on the conditions for TEM's commencement, many of which are already in an advanced stage

Financial Management, Disbursements and Procurement

5. ***Financial Management***: The IBRD PRG is providing a guarantee to the commercial lenders. As such, there are no anticipated financial management issues as there will be no procurement or procurement-related disbursements under the proposed project. Should the IBRD PRG be called, IBRD would disburse to the beneficiary and the Government would then be obligated to repay IBRD in accordance with the terms of the Indemnity Agreement between the FGN and IBRD. The overall financial management of the transactions will be undertaken by a private entity according to commercial practices acceptable to the lenders. Within NBET, the organization includes a finance department, charged with accounting, financial management, and control, reporting, internal audit, and other financial management tasks.

6. ***Procurement***: The Bank has taken several steps to verify that costs for the proposed project are reflective of current market conditions, based on: (i) established best practices, (ii) study and evaluation of the respective analyses conducted by sponsors prior to their selection of preferred EPC contractors, (iii) assessment of the choice of EPC contractor as a sound and defensible one in terms of overall economy, efficiency, bankability and risk-mitigation. Since the IPP transactions did not undergo standard Bank procurement guidelines, the Bank carried out an independent assessment of the sponsor submitted proposals to ascertain adherence to principles of economy and efficiency under the proposal contracts (such as: EPC, LTSA, O&M). The analysis summary is presented below (with further details in Annex 6):

(a) *Azura Edo IPP* issued an international request for Expression of Interest (EoI) for implementation of the project on a 'turnkey' basis, and the scope of work included engineering, procurement, and construction and commissioning of all foundations, buildings, power generating equipment, auxiliaries, HV sub-station, local infra-structure, and connection to the existing HV substation and distribution facility adjacent to the planned Azura site. The project was to be implemented on a date-certain, guaranteed performance mandate with liquidated damages included for schedule, net output, and thermal efficiency. Following a rigorous process, Azura selected as the preferred EPC Contractor a consortium comprising Siemens AG, Siemens Nigeria Ltd. and Julius Berger PLC. Azura has been proactive in reducing its exposure to the numerous risks associated with implementation of a major power generating facility. Azura has acted to select proven equipment which is marginally more efficient than competitive offerings, and which will be installed and commissioned by the EPC Contractor with the best record of achievement in recent power projects in Nigeria. Combined cycle gas turbine technology could be considered for the Azura project. However, analysis shows that neither a plant of similar output to the proposed configuration (three gas turbines), or a plant with three gas turbines plus the heat recovery steam generators and steam turbine generator, would show economic advantage over the open cycle technology proposed. Given the relatively low cost of natural gas fuel in Nigeria, a combined cycle power plant is difficult to justify on economic grounds, and little experience with CCGT technology and operations has accumulated in Nigeria. Given that open cycle gas turbine technology is the most cost effective technology for major power generation in the Nigerian context and cost structure it is, therefore, reasonable to conclude that Azura has acted in a manner consistent with the World Bank guidelines for selection of the lowest overall cost alternative consistent with efficiency and technology appropriate for the location.

(b) *Qua Iboe IPP* issued an EoI for a turnkey contract for the construction of the power plant. The proposals were evaluated in terms of their estimated overall cost (including capital, estimated LTSA, fixed O&M, variable O&M, and fuel) and reduced to present worth at an annual discount rate of 15%. These costs were combined with the assigned project Internal Rate of Return (IRR) of 15% to determine the lowest PV price for power generation. Following a rigorous process, the preferred EPC Contractor was identified and the power plant configuration would be based on combined cycle (the identity of the preferred EPC Contractor is being kept confidential until NNPC Board issues approval). A separate EPC project has been identified for development of the 330 kV, 58 km transmission line required to connect the new power plant to the Nigerian power grid network at Ikot Abasi substation. The power plant EPC Contractor will however be responsible for construction of two additional 330 kV bays in the Ikot Abasi substation for connection of Qua Iboe to the Nigerian regional grid. Overall, the analysis concludes that Qua Iboe has acted in a manner consistent with the World Bank guidelines for selection of the lowest overall cost alternative consistent with efficiency and technology appropriate for the location.

Environmental and Social Safeguards

PRG Series

7. The PRG Series is classified as 'Category A' because of its geographical extent and the power sector investments it will support - a number of which have major environmental impacts. World Bank Performance Standards (PSs) for Projects Supported by the Private Sector (OP 4.03) are applied for the Azura IPP and subsequent transactions in this Series. For QIPP, the World Bank's Operational Policies apply (see Para. 10 below). Environmental and safeguards appraisal has been carried out by the joint WBG team. The safeguards preparation approach for PSGP is consistent with the overall project processing arrangement, in which two PRGs are presented for Board approval now, and subsequent investments for which PRGs are being sought will be presented to the Board as additional financing. A prerequisite for Board presentation of any investment will be completion and disclosure of the appropriate safeguards instruments satisfactory to the Bank. In Nigeria, ESIA drafts are disclosed in the project-affected area as part of the FMEnv review process that includes a public hearing and comment period. If the draft disclosed by FMEnv has already been cleared by the Bank, this disclosure will also satisfy the disclosure requirements of OP 4.01 and Performance Standard (PS) 1; otherwise, the proponent

will make a separate in-country disclosure after Bank clearance. Depending on investment type and setting, the main environmental impact management instrument to satisfy OP 4.01 and PS 1 requirements will be one of the following:

(iv)***For new IPPs – a full ESIA***: The IPPs nominated by FGN are all gas-fired generation plants of moderate size, many if not all of which would be classified in Category B if they were being supported as individual transactions. None of the power plants under consideration is expected to be located on or near critical natural habitats. However, FMEnv has been requiring full ESIAs for these plants, and the Bank will do the same. Ancillary facilities, the most significant of which are gas pipelines and power transmission lines, will be covered in the IPP ESIA when they are being constructed by the developer. When they are being constructed by NGC or TCN and thus have separate ESIAs in accordance with Nigerian regulations, those ESIAs will also have to be acceptable to the Bank, disclosed, and included in the documentation for Board presentation. Where a new IPP requires land acquisition, a RAP will also have to be acceptable to the Bank, disclosed and included in the Board presentation.

(v) ***For privatization of existing generating facilities:*** Depending on the characteristics of the individual transactions, GENCO privatizations (which may be gas fired or hydropower plants) will be treated as Category A or B under PSGP. An environmental audit acceptable to the Bank, including a remedial action plan to address deficiencies, risks, or legacy issues identified in the audit. The decision on disclosure of an audit will be made on a case-by-case basis with the client; some audits contain information that is sensitive from a security standpoint, and others do not. Clear responsibilities for implementation of the various elements of the action plan will have to be spelled out in the legal agreements for the privatization.

(vi)***For privatization of distribution companies:*** Privatization of distribution companies would be classified in Category B if it were being financed as a separate transaction. The investments the DISCOs will need to make in their respective systems may not be known with certainty at the time a PRG is issued. They are unlikely to require full ESIAs under World Bank or Government procedures, but new infrastructure investments by the DISCOs will need some level of environmental assessment culminating in formulation of environmental and social management plans (ESMP). For work at existing substations or other facilities that may be included in a DISCOs program, an environmental audit will be conducted as a first step in the implementation process to determine the physical state of the facilities, the viability of investing in their rehabilitation from an environmental management perspective, and the potential environmental and social impacts associated with the rehabilitation project. Under these circumstances, an Environmental and Social Management Framework (ESMF) has been prepared to guide DISCOs in carrying out the necessary environmental and social assessments or audits and preparing the appropriate safeguards instrument for each distribution system PRG. The level of detail and rigor in the assessment or audit should be consistent with Category B.

8. In addition to the safeguards instruments for individual investments, FGN will undertake a Sectoral Environmental and Social Impact Assessment (SESIA) for development of gas-fired generating plants in Nigeria. The terms of reference for the SESIA have been drafted by the Environment, Resettlement and Social Unit (ERSU) in PHCN, approved in draft by the Bank, and presented for stakeholder consultation at a workshop conducted by ERSU on 24 October, 2012. Comments and recommendations from the stakeholders have been taken into consideration in the final terms of reference. The SESIA will be conducted early in PSGP implementation, reviewed and approved by the Bank, disclosed, and made available to IPP developers to inform the ESIAs for their respective investments.

First Two IPP Transactions

9. *The Azura Edo site* disturbed areas that would not be considered natural habitat. Azura is acquiring land from two communities and have prepared a Resettlement Action Plan (RAP) approved by the Bank for this purpose. The Azura Edo plant will receive gas through short pipeline spurs from the Escravos-Lagos Pipeline System (ELPS) that has already been the subject of a Pipeline Integrity Study conducted for WAGP and updated for NEGIP. The plant will evacuate power to nearby TCN substations through short transmission lines - less than 1 km for Azura Edo. PS 8 applies to the project because the land being acquired for Azura Edo contains some shrines and sacred areas of local cultural importance. In addition, the excavation of the power plants' sites and ancillary activities relating to gas pipelines and mounting of the transmission lines may lead to chance finds of physical cultural properties. The Azura Edo ESIA and RAP provide for protection of known cultural resources, and the ESMPs for all plants will include measures to protect chance finds. PS 2, 3, and 4 also apply because of the industrial nature of the power plant workplaces, their emissions of air pollutants and greenhouse gases, and the risks, albeit minor, that gas-fired power plants and gas pipelines pose to nearby communities. The requirements of all triggered performance standards are met in the ESMPs included in the ESIAs with the exception of PS 5, for which RAPs are prepared. The ESRS was disclosed on September 5, 2013.

10. *QIPP Plant* will receive gas from the offshore platforms via a pipeline which will land at the Qua Iboe Terminal that abuts the plant site. Its power will be transmitted to TCN's Ikot Abasi Substation through a 58-km line that will be operated by TCN. The QIPP transmission line crosses small amounts of swamp forest and other wetland, and also affects crops and productive trees. The routing of the line was designed to minimize impact on populated areas. The QIPP plant site abuts the company's oil terminal and is on farmland, bush, and scrub forest. OPs 4.01, 4.04, 4.11, and 4.12 are triggered because of the project's overall environmental and social impacts; in addition, gas pipelines or transmission lines will pass through some natural habitats, the project may involve or affect physical cultural resources, and will also require acquisition of land used for agricultural production. ESIAs for the QIPP plant and QIPP transmission line were disclosed respectively on 19 June 2012 and 13 December 2012. The RAP for the QIPP transmission line was disclosed on 1 November 2013.

11. The ESMPs for the two plants and the QIPP transmission line indicate that nearly all potential adverse environmental, social, and health and safety impacts can be mitigated to low levels. None of the residual impacts are considered major, and the few that are predicted to be

moderate after mitigation are: short-term impacts on water quality caused by dredging, reduction in local biodiversity due to site clearing (Azura), and short-term noise impacts during construction. Loss of wetland associated with the NNPC/MPN QIPP transmission line is being minimized by modification of the originally-proposed alignment. Quantitative models were employed to analyze impacts on air quality and noise levels during plant operation - a process that involved consideration of cumulative impacts for the Azura Edo plant because of the proximity of another emission sources (the adjacent Ihovbor power plant). Modeling results predicted no violations of WBG or WHO guidelines.

12. The two plants would contribute to greenhouse gas emissions but to a much smaller extent than the most likely alternative power sources (fuel oil, coal, or individual diesel generators). Moderate positive impacts would occur in the form of short-term employment during construction, service contracts for local firms during construction and operation, and training for local people to prepare them for possible longer-term employment at the plants. NBET will rely on the Environment, Resettlement and Social Unit (ERSU) of the project implementation unit for NEGIP and NEDP for the management of safeguard policies. ERSU has demonstrated satisfactory capacity to address the impacts of power project and associated facilities; in fact, the ERSU prepared both the ESMF and the RPF for NEGIP. NEGIP, TDP and NEDP supervision missions have shown that the ERSU's capacity to implement the ESMF properly for those projects is fully adequate. ERSU has overseen audits of substations, prepared ESMPs, and supervised preparation of RAPs and implementation of ESMPs for substation and distribution line improvements and extensions.

Environmental and Social Performance Standards Triggered (for Azura)

Performance Standards	***Triggered***
PS 1. Assessment and Management of Environmental and Social Risks and Impacts	**YES**
PS 2. Labor and Working Conditions	**YES**
PS 3. Resource Efficiency and Pollution Prevention	**YES**
PS 4. Community Health, Safety and Security	**YES**
PS 5. Land Acquisition and Involuntary Resettlement	**YES**
PS 6. Biodiversity Conservation and Sustainable Management of Living Natural Resources	**NO**
PS 7. Indigenous People	**NO**
PS 8. Cultural Heritage	**YES**

Safeguard Policies Triggered (for QIPP)

Safeguard Policies	*Yes*	*No*
Environmental Assessment OP/BP 4.01	X	
Natural Habitats OP/BP 4.04	X	
Forests OP/BP 4.36		X
Pest Management OP 4.09		X
Physical Cultural Resources OP/BP 4.11	X	
Indigenous Peoples OP/BP 4.10		X
Involuntary Resettlement OP/BP 4.12	X	
Safety of Dams OP/BP 4.37		X
Projects on International Waterways OP/BP 7.50		X
Projects in Disputed Areas OP/BP 7.60		X

Annex 4: Operational Risk Assessment Framework (ORAF)

Nigeria: Power Sector Guarantees Project

<table>
<tr><th>Stakeholder Risks</th><th colspan="2">Rating</th><th colspan="2">Moderate</th></tr>
<tr><td rowspan="2">Description :
• Potential for adversely affecting consumer tariffs while consumers don’t perceive an immediate improvement in quality of service. The impact of the lifeline tariffs on the poor is not well understood and the subsidy may not be efficiently or effectively targeted.
• Generation output can be affected by disruptions in gas supplies by vandalism in the Niger Delta where much of the country’s gas reserves are.
• There are also existing labor union disputes arising out of the privatization process.
• Public perception that process delivering anything tangible.
• High level ownership may wane going into and after elections.</td><td colspan="4">Risk Management:
• Continuing the stakeholder communications and dialogue with FGN and civil society are already ongoing under other Bank operations. The consultation process could include stakeholder forums that can unite a wide network of CSOs under one umbrella. The project will support increased stakeholder consultation, transparency and participation in key regulatory reviews and future steps of the sector reform. Transparency will be provided through disclosing key documents at strategic locations in Nigeria and on Bank and the FGN websites, and consultation with local governments, traditional leaders, affected communities and NGOs. This participatory approach has proven successful under other Bank operations. To mitigate risks linked with the Niger Delta, the FGN has also established a high-level commission to address related issues and initiated several measures to begin reconciliation.
• The NEGIP AF project has allocated additional resources to enhance the communication and outreach efforts of the NERC and TCN to ensure transparency of the tariff setting mechanisms including safeguarding the interest of the poor and vulnerable groups.</td></tr>
<tr><td>Resp: FGN</td><td>Stage: Implementation</td><td>Due Date: Ongoing</td><td>Status: in progress</td></tr>
<tr><th colspan="5">Implementing Agency Risks (including FM and PR)</th></tr>
<tr><th>Capacity</th><th colspan="2">Rating:</th><th colspan="2">Substantial</th></tr>
<tr><td rowspan="2">Description :
• NBET is a new agency and there may be lack of adequate staff with technical knowledge which could hamper the preparation and implementation of the project activities.
• This project will be first of a kind IPP / PRG project in Nigeria and experience working with a private sector partners is limited.</td><td colspan="4">Risk Management :
• The Bank will provide technical assistance and capacity building under the proposed project to NBET to further improve the capacity to successfully plan and carry out the transactions under the project including working with the private sector partners.
• The project sponsors and bidders are experienced and professional agencies.</td></tr>
<tr><td>Resp: NBET and WB</td><td>Stage: Implementation</td><td>Due Date : Implementation</td><td>Status: N/A</td></tr>
<tr><th>Governance</th><th colspan="2">Rating:</th><th colspan="2">High</th></tr>
<tr><td>Description :
• Reform and privatization process is its initial stages and might be subject to teething pains. Integrity remains a source of risk for any investment in Nigeria. NBET is a new agency so; decision making process, accountability and oversight may be weak. The risk of NBET payment delays for power supply can make projects unsustainable.</td><td colspan="4">Risk Management :
• Currently, the Governance Reform Program is being supported by an IDA Credit- Economic Reform and Governance Project (ERGP). The project team has also been carrying out a close dialogue with the Government to ensure a transparent decision making process and governance structure for NBET. Specific provisions will be drafted under the project to mitigate the risk of payment delays or defaults. This risk will be mitigated through interagency collaboration between supervisory regulators, close partnerships among development partners and collaboration with other ongoing projects to strengthen governance. Further, execution of roles and responsibilities of sector institutions requires transparent execution of mandate and accountability.</td></tr>
</table>

	The improved regulatory regime and accountability and governance mechanisms of sector institutions have assisted with greater transparency of financial transaction. Close monitoring by WBG and other stakeholders of the ongoing reform process will further assist with reducing the risk of fraud and corruption. WBG (IFC) has conducted an integrity due diligence of the Azura Edo IPP transaction supported under the PSGP.			
	Resp: FGN	**Stage: Implementation**	**Due Date : Ongoing**	**Status: Ongoing**
Project Risks				
Design	**Rating:** Low			
Description : • There are no major risks anticipated with the design of the project. The project includes standard applications typical and mainstream for PRG operations. There are some challenges related to uncertainties surrounding the brownfield GENCOs and DISCOs privatization process.	**Risk Management :** • PRG components follow the well-established frameworks under other Bank operations.			
	Resp: WB	**Stage: Implementation**	**Due Date : Ongoing**	**Status: Ongoing**
Social & Environmental	**Rating:** Moderate			
Description : • The risk that ESIAs/RAPs related to the selected sites are not adequately implemented by the private developers.	**Risk Management:** • Bank will provide capacity building support for NBET to increase their capacity to manage environmental and social impacts through regular environmental monitoring and periodic audits. WB/MIGA/IFC will also monitor through regular supervision.			
	Resp: FGN/WB/IPPs	**Stage: Implementation**	**Due Date : Ongoing**	**Status: Ongoing**
Program & Donor	**Rating:** Moderate			
Description : • The risk that delays in financial closure could delay the completion of the sub-projects.	**Risk Management:** • The sponsors will work to secure the agreed terms for the necessary financing from a diverse group of financial institutions comprising of IFC, MIGA, and IDA. The Bank will continue the close dialogue with the FGN to ensure alignment between Government's priorities with donor activities.			
	Resp: WB	**Stage: Implementation**	**Due Date : Ongoing**	**Status: Ongoing**
Delivery Monitoring & Sustainability	**Rating:** Moderate			
Description : • Delayed payments for power supply could undermine delivery and threaten sustainability.	**Risk Management :** • NBET is not yet a proven off-taker in the power market and does not have a track record of timely payments for delivered energy. However, the WBG risk mitigation framework will strengthen NBET's ability to stand by PPA obligations. The L/C structure provides security to the IPPs and their lenders about timely payments under the PPA.			
	Resp: WB	**Stage: Implementation**	**Due Date : Ongoing**	**Status: Ongoing**

<table>
<tr><td>Gas Supply</td><td>Rating:</td><td colspan="3">High</td></tr>
<tr><td rowspan="2">Description :
• The shortfall of gas supply remains a considerable risk for power generation in Nigeria. Investment in exploitation of the gas resources is not keeping up with demand. Furthermore, the risk to major gas pipelines due to vandalism and general unrest is also significant.</td><td colspan="4">Risk Management :
• Transactions supported under the PRG Series are in locations where gas resources are reliably available, either next to a major gas pipeline, or adjacent to a gas treatment plant. This will continue as selection criteria for future transactions supported under the PRG Series. Furthermore, IDA, under the ongoing NEGIP Project is supporting the increase of incentives and attractiveness of investment to gas suppliers by supporting the development of a commercial framework for gas supplies under FGNs revised pricing policy as well as a PRG for back the FGN’s obligations under a gas supply agreement (GSA).</td></tr>
<tr><td>Resp: FGN/IPPs</td><td>Stage: Implementation</td><td>Due Date : Ongoing</td><td>Status: Ongoing</td></tr>
<tr><td>Financial Viability</td><td>Rating:</td><td colspan="3">High</td></tr>
<tr><td rowspan="2">Description :
• Given the high uncertainty in predicting the technical and commercial losses of DISCOs, there is a high risk of sector facing financial viability challenges, given that the sector cash flows from current tariffs are not expected to be adequate to meet all sector obligations during the transitional period.</td><td colspan="4">Risk Management :
• The revised Multi Year Tariff Order (MYTO2) was implemented on June 1, 2012 and is based on a set of principles designed to reflect efficient and realistic cost levels for each of the generation, transmission, and distribution (including retail) sectors, taking into account (i) Cost recovery/financial viability; (ii) Signals for investment; (iii) Allocation of risk; (iv) Incentives for improving performance; (v) Transparency/fairness; (iv) Social and political objectives. Recognizing the weak base for distribution loss data in the current MYTO 2 model, NERC has agreed to launch a joint loss verification exercise with DISCO bidders post hand-over. The results will be used in determining revised loss baselines with corresponding adjustment in tariffs. The World Bank is also providing technical assistance to the NBET and FGN to analyze future sector cash flows and prepare corresponding mitigation measures to address short term revenue shortages including priority payment order, subsidy levels and management of remaining public assets.</td></tr>
<tr><td>Resp: NBET/WB</td><td>Stage: Implementation</td><td>Due Date : Ongoing</td><td>Status: Ongoing</td></tr>
<tr><td colspan="5">Overall Risk</td></tr>
<tr><td colspan="5">Implementation Risk Rating: High</td></tr>
<tr><td colspan="5">Comments: Overall, a high risk rating has been assigned due to the country context and exogenous factors that could impact the project performance.</td></tr>
</table>

Annex 5: Implementation Support Plan

Nigeria: Power Sector Guarantees Project

Strategy and Approach for Implementation Support

1. The Implementation Support Plan (ISP) described in the table below explains how the Bank and other development partners will support the implementation of the risk mitigation measures which has been identified in the ORAF (Annex 4). It is also linked to the results/outcomes identified in the result framework annex.

Implementation Support Plan

2. The level of technical support needed includes staff with energy sector knowledge and expertise; specialized commercial PRG expertise including commercial legal counsel and financial experts; safeguards specialists; power engineering as well as Monitoring and Evaluation (M&E) expertise. The primary responsibility for this support lies with the regional TTL with key inputs from specialized commercial PRG experts. The main focus in terms of support during implementation is summarized in the table below.

Post-Closing PRG Monitoring

3. Post-closing PRG Supervision: The level of technical support needed includes staff with energy sector knowledge and expertise; specialized commercial PRG expertise including commercial, legal counsel and financial experts. The primary responsibility for this monitoring lies with a specialized PRG expert. Regional team is key liaison on sectoral issues. The main focus in terms of support during implementation is summarized in the table below

Implementation Support Plan

Time	*Focus*	*Skills Needed*	*Resource Estimate (WB Only)*	*Partner Role*
First twelve months	Effectiveness, financial closure, selection of L/C banks, safeguards, construction progress, political developments.	Sector Safeguards Commercial Financial Legal Engineer Country team	$300,000	.

12th month-60th month (Including Mid -term review and Completion Report)	Review of progress in construction and generation by the IPPs; review of sector technical and financial performance; safeguards; overall reform process Review implementation progress of the reform process and the IPPs against indicators. Review status of Completion against indicators and PDO.	Sector Commercial Financial Legal Safeguards Environment Social M & E	$600,000	
61th month till end of guarantee effectiveness period	On-going supervision and monitoring of legal covenants and risks that could lead to a possible call on any of the signed Bank guarantees.	Sector Commercial Financial Legal	47,000 per year which include 27,000 of staff cost plus 20,000 of budget travel (one trip of two staff per year).	

Skills Mix Required

Skills Needed	*Number of Staff Weeks*	*Number of Trips*	*Comments*
Team Leader Energy Specialist PRG Specialist Financial Analyst Power Engineer Social Environmental Monitoring Procurement Financial Mgmt.	Estimated to be 7-10 weeks per person per year	Located in Nigeria 2-3 per year 2-3 per year 2-3 per year 1 per year Local staff Local staff 1-2 per year Local staff Local staff	To be adjusted annually depending on available supervision budget

Annex 6: Assessment of IPP Procurement Processes

Nigeria: Power Sector Guarantees Project

1. The Bank has taken several steps to verify that costs for the proposed project are reflective of current market conditions, based on: (i) established best practices, (ii) study and evaluation of the respective analyses conducted by sponsors prior to their selection of preferred EPC contractors, (iii) assessment of the choice of EPC contractor as a sound and defensible one in terms of overall economy, efficiency, bankability and risk-mitigation. Since the IPP transactions did not undergo standard Bank procurement guidelines, the Bank carried out an independent assessment of the sponsor submitted proposals to ascertain adherence to principles of economy and efficiency under the proposal contracts (such as: EPC, LTSA, O&M).

2. The objective of this independent review is to determine if the bidding and evaluation criteria and process used by the sponsors meet World Bank guidelines for openness, equal opportunity, and lowest equalized cost selection that would have been monitored if the World Bank had participated directly in the power plant tendering process. Further assessment details are available in PSGP files.

Azura Edo IPP

3. *Ownership and Operations*: The Azura power development is to be located near the city of Benin, Nigeria in an industrial area in the N-E sector of the city and adjacent to an existing NIPP power generating plant and HV substation. The project is to be implemented as part of the Federal Government of Nigeria's (FGN) power sector reform program, which has the stated goal of installing 40,000 MW of generating capacity by 2020. The Azura project will be based on open cycle gas turbine technology (OCGT) and will be configured for future conversion to gas turbine combined cycle (GTCC).

4. The project was formally proposed to the Nigerian Authorities by Azura Power West Africa Ltd. (Azura) in January 2011 when an application for a generation license was submitted to the Nigerian Electricity Regulatory Commission. As now configured, the project consists of three Siemens SGT5-2000 machines with a total installed capacity of 459 MW (site rating). The project will include an outdoor substation with high voltage link to the existing substation and distribution facilities. The project includes all necessary fuel handling, cooling, water supply, fire protection, control and protection.

5. The Power Purchase Agreement (PPA) was signed on 22 April 2013, and the project is scheduled for commercial operation in early 2017. The project development is being carried out by four project sponsors lead by Amaya Capital. The development team have engaged Parsons Brinckerhoff Engineering (PB Power) Manchester UK, to prepare the technical portions of the specifications, and carry out the performance assessments, and technical bid evaluations.

6. This project will be independently financed by a combination of equity raised by the sponsors with financing provided from international and local commercial banks, as well as Development Finance Institutions (DFIs). The loan repayment will essentially be made from payments received from the sale of available capacity and net electrical output, which will be dependent on the diligence with which the Nigerian authorities meet the payment obligations. The World Bank (WB) is providing Partial Risk Guarantees (PRG) to the project developers

in order that they are able to secure financing at more competitive rates than would be possible if such guarantees were not available.

7. *Plant Description and Identification of Potential Main Equipment Suppliers*: The Sponsors are: (a) Amaya Capital Ltd., a principal investment firm and investor in Azura Power Holdings Ltd. (APHL), its dedicated vehicle for investing in IPPs and the power distribution sector in Africa, jointly owned with the American Capital Energy and Infrastructure Fund, a fund managed by American Capital Ltd.; (b) Aldwych International Ltd. (Aldwych), an international power developer focusing on Sub-Saharan Africa; (c) African Infrastructure Investment Fund 2 (AIIF2), an Africa-focused fund managed by the Macquarie Group and Old Mutual which will invest through both its Rand-denominated and US$-denominated vehicles; and (d) Asset and Resource Management Ltd., a leading Nigerian asset manager. The Sponsors are investing in the Company through Azura Edo Ltd., an SPV incorporated in Mauritius. The Edo State Government, the local State authority, is also expected to have a 2.5 percent shareholding in the Company.

8. The Azura project is being developed by key personnel from (APHL) and Aldwych. Collectively, these individuals have a long history of successful development of power projects in sub-Saharan Africa including Nigeria, Tanzania, Uganda, Cameroon, and South Africa.

9. The day-to-day operation of the plant will be carried out by an experienced operating company utilizing local operating staff and maintenance personnel. This company will be directly responsible to Azura for all aspects of the power plant's routine operation and maintenance. Specific training will be provided for operation of the Siemens gas turbines and any other equipment considered unique to this project or which presents unusual requirements. PIC Group, a wholly-owned subsidiary of Marubeni, was selected as the Operation and Maintenance (O&M) contractor for the Azura Edo IPP.

10. Gas turbine based power plants require rigorous maintenance in order to operate continuously and high load factors. Such maintenance is normally carried out by specialized organizations providing such services internationally. Typically a long term contract (LTSA) will be signed between the plant owner and the maintenance provider. Azura Power West Africa expects to sign such an agreement for the Azura project (with Siemens) in May 2014 at the same time the contract for plant operation and routine maintenance is signed.

11. Azura Edo IPP issued an international request for Expression of Interest (EoI) for implementation of the project on a 'turnkey' basis, and the scope of work included engineering, procurement, and construction and commissioning of all foundations, buildings, power generating equipment, auxiliaries, HV sub-station, local infra-structure, and connection to the existing HV substation and distribution facility adjacent to the planned Azura site. The project was to be implemented on a date-certain, guaranteed performance mandate with liquidated damages included for schedule, net output, and thermal efficiency. Following a rigorous process, Azura selected a consortium comprising Siemens AG, Siemens Nigeria Ltd. and Julius Berger PLC as the preferred EPC Contractor. Azura has been proactive in reducing its exposure to the numerous risks associated with implementation of a major power generating facility. Azura has acted to select proven equipment which is marginally more efficient than competitive offerings, and which will be installed and commissioned by the EPC Contractor with the best record of achievement in recent power projects in Nigeria. Combined cycle gas turbine technology could be considered for the Azura project, however, analysis shows that neither a plant of similar output to the proposed configuration (three gas turbines), or a plant with three gas turbines plus the heat recovery

steam generators and steam turbine generator, would show economic advantage over the open cycle technology proposed. Given the relatively low cost of natural gas fuel in Nigeria, a combined cycle power plant is difficult to justify on economic grounds, and little experience with CCGT technology and operations has accumulated in Nigeria. Given that open cycle gas turbine technology is the most cost effective technology for major power generation in the Nigerian context and cost structure it is, therefore, reasonable to conclude that Azura has acted in a manner consistent with the WB guidelines for selection of the lowest overall cost alternative consistent with efficiency and appropriate technology.

Qua Iboe IPP

12. *Ownership and Operations*: The project is the Qua Iboe IPP (QIPP). Its owners are Mobil Producing Nigeria Unlimited (MPN) and the Nigerian National Petroleum Corporation (NNPC). MPN is the Operator of the NNPC/MPN Joint Venture. The Qua Iboe power plant will be located adjacent to the NNPC/MPN JV's Qua Iboe storage and processing terminal in Ibeno, Akwa Ibom State, approximately 20 kilometers south of Eket, Nigeria and which borders the Atlantic Ocean on the south coast east of the Niger Delta on the Bight of Benin.

13. During EPC tender stage the power plant was specified in two (2) configurations, either combined cycle or a simple cycle utilizing gas turbines only. In both cases the use of heavy duty, E class gas turbines was specified in recognition of the operating conditions in Nigeria. In either case the power plant was specified with a nominal generating capacity of 500 MW. A separate EPC project was identified for development of the 330 kV, 58 km transmission line required to connect the new power plant to the national grid. The power plant contractor will be responsible for completing associated interconnection works at the Ikot Abasi substation.

14. MPN plans to enter into an operating and maintenance contract with a qualified O&M contractor in the first 3 years to facilitate initial operation of the power plant and provide expertise during which MPN will gain plant specific experience. After the initial 3 years, the day-to-day operation of the plant will be carried out by experienced local operating staff and maintenance personnel employed by MPN. Specific training will be provided for operation of the gas turbines and any other equipment considered unique to this project or which presents unusual requirements. MPN will enter into a Long Term Service Agreement (LTSA) with the equipment manufacturer to service major plant equipment during the life of the project.

15. The project is scheduled for commercial operation in late 2018/early 2019. The recommended option is for a combined cycle configuration which requires approximately 48 months for construction and performance testing.

16. The project will be fully equity financed; 60 percent by Nigerian National Petroleum Corporation (NNPC) and 40 percent by Mobil Production Nigeria (MPN). No third party financing will be necessary.

17. The project will be fully equity financed; 60 percent by Nigerian National Petroleum Corporation (NNPC) and 40 percent by Mobil Production Nigeria (MPN). No third party financing will be necessary.

18. *Plant description and identification of potential main equipment suppliers*: The power plant was specified in two (2) configurations, either combined cycle (2-3 Gas turbines, 2-3 heat recovery steam generators, and 1 Steam Turbine generator), or a simple cycle utilizing

gas turbines only. In both cases the use of heavy duty E class gas turbines was specified in the EPC tender in recognition of the operating conditions in Nigeria and the level of operating and maintenance expertise available. In either case the power plant would be a nominal generating capacity of 500 MW at the site reference conditions of 30 degree C, 1012 mbar, 87 percent RH.

19. Potential major equipment suppliers include original equipment manufacturers (OEM) and others who are qualified to manufacture such equipment under license.

20. The power plant scope of work includes several items which are necessary for this particular project but which are not 'normal' contract requirements for such a project. These include construction of temporary offloading facilities for transport of heavy components, hydraulic placement of up to 500,000 m3 of fill to facilitate site development, 'brown field' fuel gas piping to the power plant from a terminal point defined by MPN across MPN's QIT terminal, construction of two additional 330 kV bays in the Ikot Abasi substation, powerhouse building to house the gas turbine generators, three (3) years O&M costs as part of the EPC Contractor scope of work, and community assistance and human resource development.

21. A separate EPC project was identified for development of the 330 kV, 58 km transmission line required to connect the new power plant to the Nigerian power grid network at Ikot Abasi substation.

22. Qua Iboe IPP issued an EoI for a turnkey contract for the construction of the power plant. The proposals were evaluated in terms of their estimated overall cost (including capital, estimated LTSA, fixed O&M, variable O&M, and fuel) and discounted to present value at an annual discount rate of 15 percent. These costs were used with an assigned project Internal Rate of Return (IRR) of 15 percent to determine the lowest PV price for power generation. Following a rigorous process, the preferred EPC Contractor was identified and the power plant configuration would be based on combined cycle (the identity of the preferred EPC Contractor is being kept confidential until NNPC Board issues approval). A separate EPC project has been identified for development of the 330 kV, 58 km transmission line required to connect the new power plant to the Nigerian power grid network at Ikot Abasi substation. The power plant EPC Contractor will also be responsible for construction of two additional 330 kV bays in the Ikot Abasi substation for connection of Qua Iboe to the Nigerian regional grid. Overall, the analysis concludes that Qua Iboe has acted in a manner consistent with the World Bank guidelines for selection of the lowest overall cost alternative consistent with efficiency and technology appropriate for the location.

Annex 7: Economic Analysis of the PRG Series

Nigeria: Power Sector Guarantees Project

Executive Summary

1. ***Development impact***: A traditional cost-benefit analysis of the proposed PRG Series shows that the Series is economically viable. IPP investments supported by the PRG Series will significantly improve Nigeria's power supply capacity. In particular, 'incremental consumption', as result of the PRG Series was estimated. The analysis includes the impact of the current power shortages to the economy, electricity demand growth and cost of unserved electricity, the end-user tariff path (via the cost reflective MYTO 2), consumer's wiliness to pay (WTP), and the overall macro-economic impact of the reforms. Based on the methodology and assumption described in Annex 7, the estimated Economic Internal Rate of Return (EIRR) of the PRG Series is 33 percent and the Net Present Value (NPV) is US$3,628 million (at 10 percent discount rate). At 12 percent discount rate, the NPV is US$2,719 million. Sensitivity analysis was also conducted to test the robustness of the profitability of the project to changes in key parameters of project costs and benefits.

2. ***Appropriateness of public sector financing:*** The objective of the PRG Series is to increase the supply of energy to the Nigerian consumers. Given the scale of financing needed for the sector, this PRG Series will provide public sector financing to promote private sector investment and to support FGN's efforts by addressing the huge financing gaps. The WBG investment and risk mitigation framework for this Series is designed with complementary and efficient use of IBRD PRGs, IFC Loans, and MIGA Guarantees to support the FGN's agenda of increasing electricity generation and private sector participation in the sector. This Series assists the FGN in achieving its goals of investment promotion by private sector by an economically suitable mechanism - the PRG structure helps to conserve IBRD resources through the provision of minimal amounts of security to lenders and investors, while at the same time making projects bankable. PRGs have a significant leveraging impact - for the first two IPP transactions of the PRG Series, US$395 million in PRGs will mobilize US$1,942 million of investment.

3. ***World Bank's value added:*** Given the risk perception of investors towards Nigeria, and the weak credit profile of the new sector institutions, the anticipated scale-up in private investment would not be feasible without the intervention of credit enhancement and debt mobilization instruments (PRGs). WBG's support is critical for providing confidence to investors in the sector. Not only is the project helping crowd in much needed private capital, but it is also aligned and embedded in a strong sectoral dialogue with the authorities. In addition, WBG's technical assistance and overall support in bringing transactions to financial closure adds significant value to the sector and assists in the goal of increasing the supply of energy.

Detailed Analysis

4. The economic impact of the proposed PSGP Series is based on a traditional cost-benefit analysis, which identifies and compares economic costs and benefits in two cases, one 'with Series' and the other 'without Series'. IPP investments under the project will significantly improve Nigeria's power supply capacity. The primary beneficiaries of the PRG Series are the electricity customers in the Nigerian grid. Future customers will be able to obtain electricity access which would not otherwise be possible given the limited supply capacity. Just based on the two front-runner IPPs, the project is expected to increase the

supply by approximately **1,000 MW** capable of providing energy output of about **8,760 GWh**. At the time the plants are operational the ATC&C are conservatively estimated to be about 22 percent (down from the current 35 percent) over the life of the power plants. Consequently, approximately **6,800 GWh** of energy per year is assumed to be supplied to the consumers**.**

5. This additional energy can enable new connections as well as serve better the existing customers, including residential and commercial/industrial customers. The PRG Series will also enable organic growth of energy consumption rates and address the existing suppressed demand in the market. In addition to the increase in stably supply, it is likely that privatization of DISCOs will also lead to system upgrades that are expected to assist in reducing the system technical losses along the transmission and distribution lines in the coming years, leading to significant energy savings as well as increased consumption. However, for simplicity, the model only discusses the economic benefit of increased generation scenario.

I. Methodology and Assumptions:

6. The analysis focuses on direct quantifiable benefits resulting from the PRG Series. In particular, "*incremental consumption*", as result of the PRG Series is assessed and estimated.

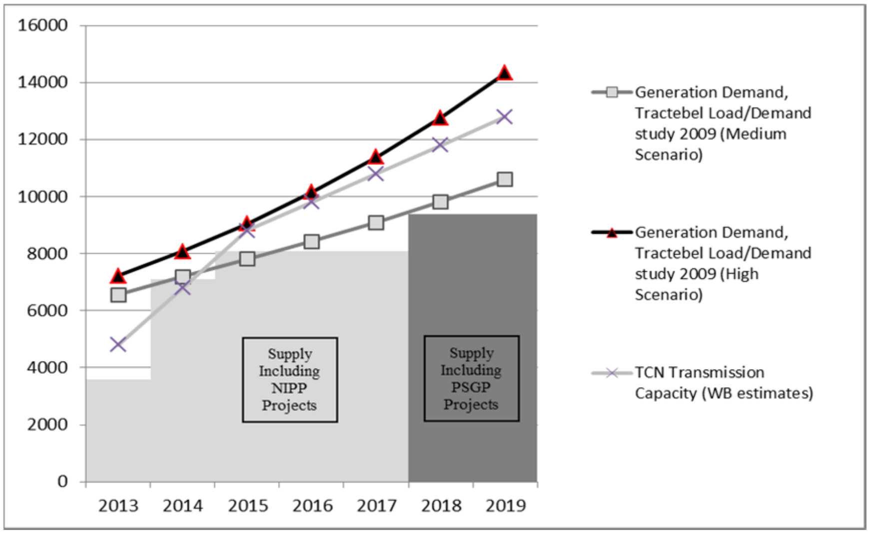
7. A range of less quantifiable benefits will also accrue from the PRG Series, including those from the socio-economic and environmental benefits of increased electricity access. Although not estimated, they should not be ignored in assessing the economic viability of the PRG Series. Increased access to electricity will ensure better education and income opportunities leading to improved living standards among the residents of the areas covered under the PRG Series. Children will be able to study at night; households will be enabled to start or expand home-based businesses, which are a main source of livelihoods especially among the poor. Reliable and expanded electricity supply will support commercial and industrial activities. Access to grid electricity will decrease reliance on polluting and expensive energy alternatives, reducing the threat to the environment and people's health. PRG Series costs comprise all costs associated with IPP setup and with serving the additional consumption in Nigeria. Both benefits and costs are estimated in economic terms at constant 2013 prices. The analysis is built over a period of thirty years and uses a discount rate of 10 percent. Benefits are assumed to become effective the year following completion of investments (2018).

II. Benefits of Incremental Consumption:

8. At present, load growth in Nigeria is extremely constrained by a number of factors including the limited supply as well as the transfer capacity of the transmission and distribution networks. The current available capacity is about 3,500 MW with overall electricity sales of about 30,000 GWh in 2012. The size of the electricity supply/demand gap in Nigeria is illustrated in the statistics recorded in the Government's Roadmap for Power Sector Reform which was published in August 2010. Investment supported by the PRG Series will assist in removing critical supply constraints and support planned expansion of electricity access and economic growth.

9. The ongoing NIPP projects will add 3,700 MW capacity in the coming three years, but it remains inadequate to bridge the supply deficit and more importantly to pave the way for the investment in new power supply capacity to meet the ever growing demand from a the Nigerian economy estimated to need approximately 1,000 MW of new power Generation capacity every year even after the current supply deficit has been met.

Figure 1: Demand and Supply Projections 2013-2019



III. Customer Willingness to Pay (WTP):

10. The analysis uses a traditional consumer surplus methodology to measure the net economic benefits of the incremental electricity demand that will be served as result of the project. In particular, the analysis assesses the change in consumer surplus (CS) experienced by new users once they gain access to electricity. The CS has two main components: first, the avoided cost of alternative fuels / self-generation for applications such as lighting and information/entertainment; and second the value attached to having access to utilities (refrigerators, air conditioners, etc.) that would not be available without electricity. Both are measured based on the willingness to pay for electricity (WTP). The change in consumer surplus of new electricity users is only part of the impact: this must be adjusted by the economic cost to the society in supplying the incremental consumption.

11. The average WTP for residential and commercial/industrial customers is estimated at around **US$0.30/kWh** based on the self-generation costs in Nigeria and for simplicity of calculations for the purpose of analysis. The WTP for residential customers is based on expenditures on non-electric forms of lighting such as kerosene and candles as well as on battery-powered appliances. For commercial and industrial customers, the WTP draws primarily on the costs associated with electricity supply from diesel generators incurred to meet their production needs. It is noted however, that for an accurate analysis of economic benefits associated to electricity access would require differentiating between the amount of energy that is currently used by non-connected customers and any additional energy consumption that might be induced as a result of having access to grid electricity. This is especially important for residential customers.

12. It is also noted that new users may take time to reach the average consumption levels observed among mature utility customers. More importantly, new users may be unable to pay for additional consumption or attach a lower value to it. Unfortunately, the absence of detailed socio-economic analyses carried out in the areas targeted under the project does not allow estimating variations in the energy consumption associated with having access to grid electricity, nor the utility attached to different levels of consumption.

Net benefits of incremental consumption:

13. The benefits assessed are adjusted to reflect the costs associated with serving the incremental consumption, including the economic costs of power generation, transmission and distribution. Distribution costs also reflect the new investments required for installing the additional connections. The analysis uses the MYTO 2 declaration for retail tariff as being cost reflective (at 2013 levels) that underlines the full costs of generating, transmitting, distributing and selling electricity to different categories of customers. A utility's cost of service includes its efficient operating costs plus an appropriate return on assets necessary to produce, deliver and sell electricity to customers and meet growing demand through investments. The full cost of service provides a basis for identifying the utility's revenue requirements and set appropriate, cost-recovering tariffs for different consumer classes. This analysis uses full costs for serving residential and commercial demand as estimated by the MYTO 2 under the base case scenario. Based on this scenario, the full cost of serving demand is equal to **US 14 cents/kWh**.

MYTO 2 - Average Tariff by Customer Group (Cost Reflective)

	2012	2013	2014	2015
Tariff Code	Energy Charge, N / kWh			
Residential R1	4.00	4.00	4.00	4.00
Residential R2	11.74	12.62	13.25	13.91
Residential R3	22.62	22.62	23.75	24.94
Residential R4	22.62	22.62	23.75	24.94
Commercial C1	16.56	16.56	17.39	18.26
Commercial C2	21.03	21.03	22.08	23.18
Commercial C3	21.03	21.03	22.08	23.18
Industrial 1	16.97	16.97	17.81	18.70
Industrial D2	22.04	22.04	23.14	24.30
Industrial D3	22.04	22.04	23.14	24.30
Special 1	16.24	16.24	17.05	17.90
Special 2	16.24	16.24	17.05	17.90
Special 3	16.24	16.24	17.05	17.90
Street Lighting S1	12.47	13.41	14.08	14.78

14. The use of full cost of service presents its limitations. Full cost of service may not be the perfect representation of the economic cost associated with the expanded electricity supply enabled under the project. In particular, there may be a double-counting problem related to distribution costs. Full cost of service may already capture at least in part distribution rehabilitation investments and O&M costs envisaged under the project, which are included in the cost side of the equation while computing net benefits from reduced technical losses.

Economic Returns:

15. Based on the methodology and assumption described above, the estimated Economic Internal Rate of Return (EIRR) of the project at 10 percent discount rate is 33 percent and the Net Present Value (NPV) is US$ 3,628 million. At 12 percent discount rate, the NPV is US$ 2,719 million.

Table 1: Estimated Economic Returns

	Discount Rate 10%	*Discount Rate 12%*
NPV (US$ million)	3,628	2,719
EIRR (%)	33.4	33.4

Sensitivity analysis:

16. Sensitivity analysis was conducted to test the robustness of the profitability of the project to changes in key parameters of project costs and benefits. The rates of return were examined under the following cases:

a. Total project costs: Increase of 5 percent and 10 percent in the overall project cost was considered which could be introduced as a result of delays or other unexpected variables such as externalities.

b. Decrease in benefits: Decrease in benefit of the project of 5 percent and 10 percent was considered which could be introduced as a result of slower consumption rates or lower than expected plant output – primarily due to slower than expected reduction in ATC&C losses.

c. Combined effect: The combined effect of 10 percent increase in project cost and 10 percent decrease in benefit was also considered as a worst case scenario for the project.

Table 2: Results of Sensitivity Analysis

Scenarios (at Discount Rate 10%)	*NPV (US$ million)*	*EIRR (%)*
Base Case	3,628	33.4
Costs Increase 5%	3,554	32.1
Costs Increase 10%	3,480	30.8
Benefits Decrease 5%	3,373	32.0
Benefits Decrease 10%	3,117	30.6
Costs Increase and Benefits Decrease 10%	2,970	28.2

17. In summary, the PRG Series is economically viable and variables such as '*incremental consumption of energy*' as well as '*capital costs*' have a strong impact on the economic viability of the PRG Series.

Figure 2: Economic Cost-Benefit Analysis (Sample Data Set)

Economic Impact		*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*2023*
Project Construction Completion Rate	*%*		*5%*	*20%*	*50%*	*80%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
Energy Supplied (GWh)	GWh/year						8,760	8,760	8,760	8,760	8,760	8,760
ATC&C Losses (Percent)	%						22%	22%	22%	22%	22%	22%
Project Related Incremental Energy Sales (GWh)	GWh/year						6,833	6,833	6,833	6,833	6,833	6,833
BENEFITS												
Average of residential and commercial	US$ ml./year						2,049.8	2,049.8	2,049.8	2,049.8	2,049.8	2,049.8
Totat Benefits	**US$ ml./year**						**2,049.8**	**2,049.8**	**2,049.8**	**2,049.8**	**2,049.8**	**2,049.8**
COSTS												
Capital Costs of Project	US$ ml./year		97.1	291.3	582.6	582.6	388.4					
O&M	US$ ml./year		1.9	5.8	11.7	11.7	7.8	7.8	7.8	7.8	7.8	7.8
Cost of service	US$ ml./year		-	-	-	-	1,226.4	1,226.4	1,226.4	1,226.4	1,226.4	1,226.4
Total costs	**US$ ml./year**		**99.0**	**297.1**	**594.3**	**594.3**	**1,622.6**	**1,234.2**	**1,234.2**	**1,234.2**	**1,234.2**	**1,234.2**
NET BENEFITS	**US$ ml./year**		(99.04)	(297.13)	(594.25)	(594.25)	427.27	815.67	815.67	815.67	815.67	815.67
NPV	**USD million**	**3,628**										
ERR	**%**	**33.4%**										

Annex 8: Financial Analysis and Viability of the Sector

Nigeria: Power Sector Guarantees Project

Note: It is to be noted that the new owners of the DISCOs were selected on the basis of their proposals on loss reduction in their respective DISCO zones. However, for the purposes of this analysis, the Bank has assumed a more conservative estimate of loss level reductions, which may not completely coincide with the targets set by the DISCO owners or the evolving transitional market situation. The analysis presented in this Annex are developed by the World Bank and does not, in any way attempt to exempt any DISCO owners from their obligations under the asset acquisition proposals made to the FGN.

1. To manage the transition and ensure adequate power supply to the ailing DISCOs, the FGN established the Nigerian Bulk Electricity Trading PLC (NBET) as a 'Central Buyer' to enter into power purchase agreements (PPAs) with Independent Power Producers (IPPs) and manage the contractual risks. NBET, a key agency in the power sector, was created to purchase power on behalf of the DISCOs until the industry develops adequate credit worthiness and the settlement, accounting, managerial, and governance systems required for successful direct bilateral contracting between IPPs and the DISCOs. While the sector focuses on building its credit worthiness, the counterparty of this PPA, whether private or public, will be relying on timely payments from NBET. That entails that NBET would need to demonstrate it has a sustainable business plan and is financially viable. The PPAs are back-to-back contracts to the vesting contracts which NBET will be signing with the DISCOs. The delivery point for power is the same under both agreements and the financial flows.

2. FGN has enhanced the capital reserves of NBET to increase its credit worthiness under the numerous PPAs it will be entering into and provide a buffer in the event of contingencies. US$350 million from the Eurobond sales[27], US$325 million from the sale proceeds of Egbin Power Plant, US$20 million from the sales proceeds of Olorunsogo and Omotosho power plants, US$145 million from budget appropriations as well as a security deposit of 3 months of revenues (irrevocable L/C) required from the DISCO owners. A securitization arrangement has been developed where market participants can tap into these accounts under an Escrow Account arrangement, in the event of shortfalls; these accounts are then replenished by the party responsible for the shortfall. This arrangement is contingent upon having a financially sustainable sector. It would require, as highlighted by the sector financial analysis, an achievement of the ATC&C loss reduction projections by the private sector, transmission loss reductions by the government-owned though privately managed TCN over the 5-year regulatory period as well an adjustment of tariffs by NERC prior to or at the initiation of the transitional electricity market.

Methodology

3. Financial analysis was developed by modeling the *sector-wide cash-flows* starting at the DISCO level – which is the entry point of the sector revenues. The distribution entities will incur capital and operating expenditures while seeking return on investment. These amounts are capped under MYTO 2 and the net revenues are then remitted to NBET which is responsible for payment to various GENCOs and IPPs that have been contracted to supply power.

[27] The bond proceeds would have to be repaid with a 5-year bullet repayment profile at 4.5% interest rate annually.

4. Following MYTO 2 implementation on June 1st 2012, the expectation was that there would be a significant improvement in remittances from DISCOs to the market operator which, unfortunately, did not take place. Data from the market performance showed only a slight improvement with vastly different performance of participating DISCOs. Some DISCOs, such as the Eko DISCO in Lagos State were repaying 100 percent of their invoices while others, such as the Yola DISCO, continued to default on all of their invoices.

Table 1: DISCO Performance

	Percentage of invoice paid (November 2012)	*Percentage of invoice paid (August 2013)*	*Percentage of invoice paid (January 2014)*
Abuja	51%	45%	41%
Benin	37%	25%	43%
Enugu	37%	37%	41%
Ibadan	66%	53%	48%
Jos	10%	7%	21%
Kaduna	31%	31%	38%
Kano	48%	37%	63%
Eko	100%	91%	98%
Ikeja	86%	80%	47%
Port Harcourt	37%	43%	51%
Yola	0%	0%	0%
Average	***54%***	***48%***	***47%***

5. This shortfall in remittances was the result of several factors:

(a) Higher transmission losses: MYTO 2 assumes 8 percent transmission loss, whereas in reality this could be as high as 13 percent;

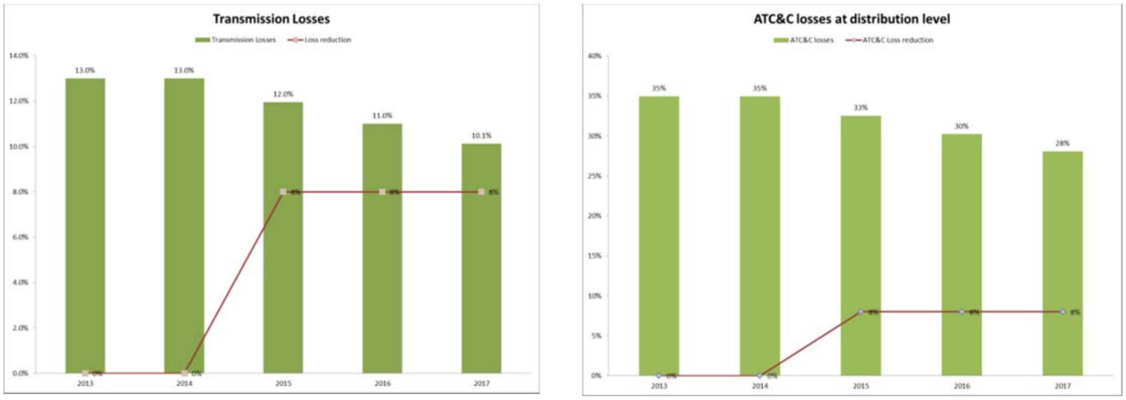
(b) Unreliable ATC&C loss data: MYTO 2 assumes 25 percent while in reality the loss could be over 35 percent;

(c) Lower injected energy in the grid, as a result of gas supply constraint, transmission bottlenecks and continued poor performance of existing generating assets, all resulting in less revenue collected by the DISCO required to recover their fixed costs;

(d) Increase in wage expense which followed MYTO 2 implementation as part of the government settlement with labor unions and which was not accounted for in the revenue allowance under MYTO 2. There has also been a reduction in the overall number of staff.

(e) The fall in invoice remittances that has occurred between November 2012 and January 2014 is the result of reduced generation output translating in less energy billed at the distribution level and thus an increased difficulty for the DISCO to recover fixed costs.

Figure 1: Scenario 1 loss reduction figures



6. In a context where a complex reform is moving at a high pace with multiple unknown variables and in an environment where reliable data is very difficult to collect, the World Bank team undertook this analysis using a scenario approach. Three scenarios were analyzed using a conservative view of what the supply will look like over the period 2014-2017:

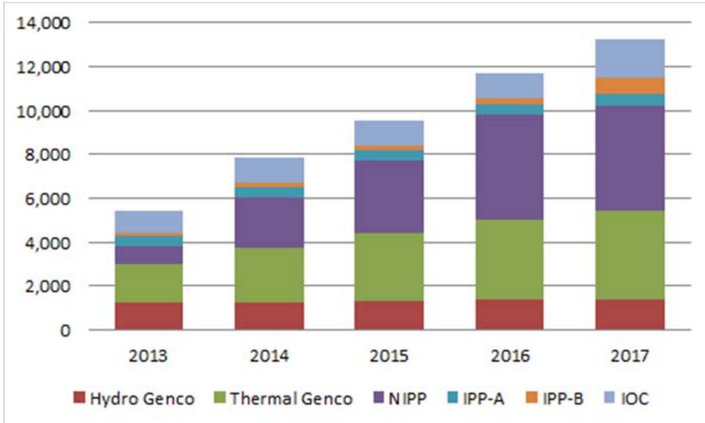
(a) Current scenario where transmission and distribution losses are reduced at an 8 percent annual rate under the current MYTO 2 tariff;

(b) Aggressive Loss Reduction Scenario where transmission losses are reduced at a 16 percent annual rate while ATC&C losses are reduced at an average 16 percent using a reduction strategy that was submitted by a preferred bidder for one of the DISCOs;

(c) Increased Tariff Scenario where NERC increases the tariff by 4 Naira/kWh (flat increase through 2014-2017).

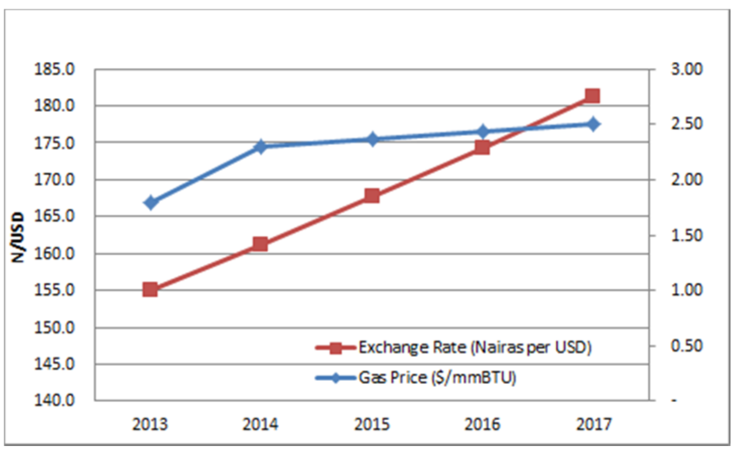
7. Supply assumptions: because of the numerous uncertainties, having an accurate forecast of supply over the next 5 years turned out to be a difficult exercise. Hence the Bank developed a conservative view of what the supply would look like tapping into different sources (NBET, NIPP, and NERC). In the figure below, the expected increase in installed capacity more than doubling is essentially driven by government-owned assets (the assets currently being privatized and expected to be rehabilitated by future owners and NIPP plants). New IPPs, including Azura and Qua Iboe IPPs, are expected to come online by 2017.

Figure 2: Forecast of supply in MWs over 2013-2017



8. Capacity and energy charges were provided by NBET for the base year 2013. Gas charges were indexed on gas price derived from MYTO 2 while O&M charges, indexed in Naira, were inflated at 6 percent per annum. Capital recovery component was assumed to be entirely indexed in US Dollars (conservative view) and was inflated using the foreign exchange rate forecast.

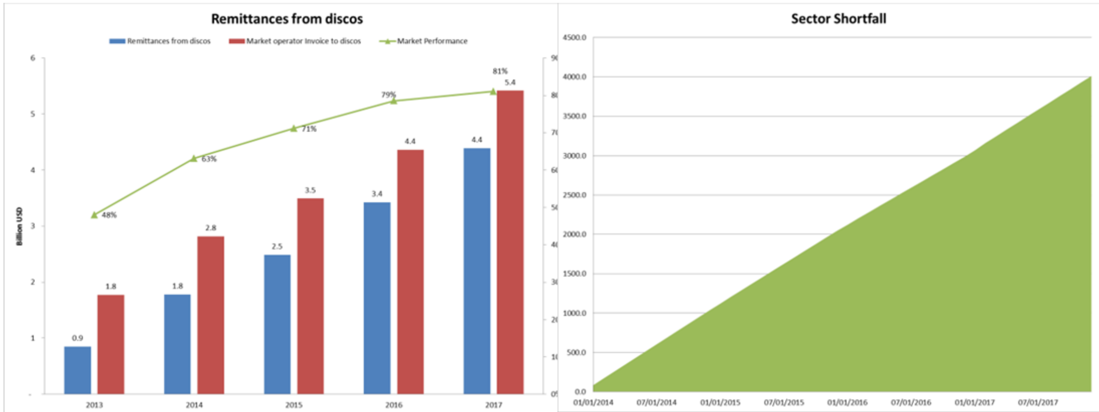
Figure 3: Foreign exchange rate (on left axis) and gas price (on right axis)



Scenario 1 - Assuming No Significant changes or Improvements in Sector

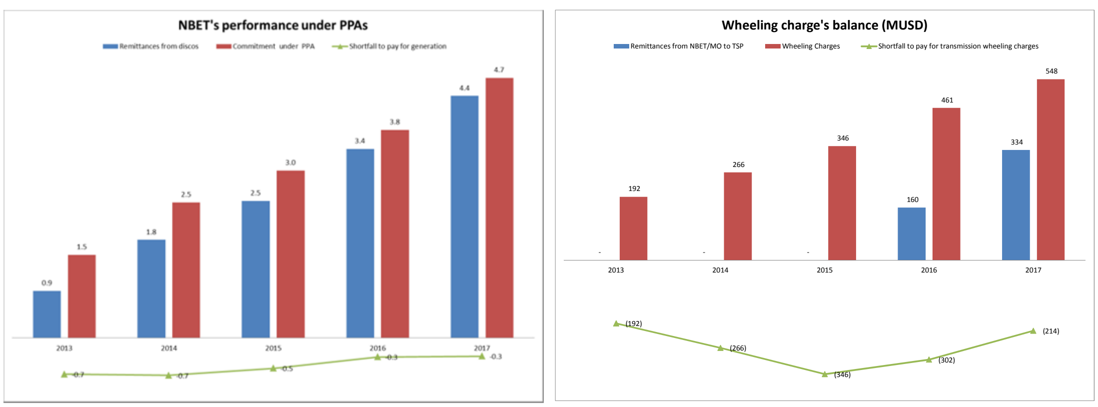
9. The level of remittances from the DISCOs to the market operator is expected to improve from 48 percent in 2013 up to 81 percent by 2017. The improvement in 2014 compared to 2013 is the result of higher expected energy injected into the grid which would enable new DISCO owners to recover more easily their fixed costs and thus perform better on the invoices sent by the market operator. As of 2015, loss reduction efforts start bearing fruit and level of remittances continues to progress. Despite this improvement, a 19 percent shortfall in the sector cash-flows would still be incurred by 2017. Over the period 2014-2017, a sector liability would aggregate to about US$4 billion, in average US$1 billion per year. This sector liability is essentially covering the shortfall to pay for generation, due to wheeling charges to transmission system provider and various administrative charges.

Figure 4: Sector Shortfall in Scenario 1



10. NBET's commitments under the PPAs are expected to ramp up in nominal value from US$1.5 billion in 2013 (assuming NBET has already contracted with all of the existing generation assets) to US$4.7 billion in 2017. Under this scenario, sector will have a structural deficit throughout the period 2014-2017; it amounts to about US$1.9 billion.

Figure 5: Sector Performance and Wheeling Charges under Scenario 1



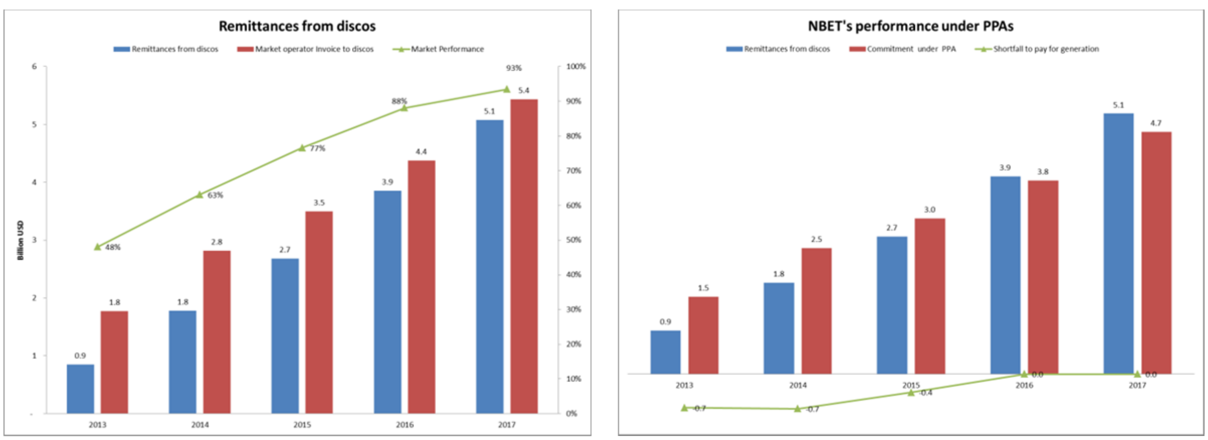
Scenario 2 - Aggressive Loss Reduction Scenario

11. The level of remittances from the DISCOs is a function of what the DISCOs can achieve in loss reduction following the takeover by private sector. In the Scenario 1, we have assumed an 8 percent annual reduction in ATC&C losses bringing the overall losses at 28 percent by 2017, a level that is higher than what MYTO 2 had predicted for this year. MYTO 2 had projected ATC&C losses would reach 13 percent in 2017. This alternative scenario is replicating the possibility of DISCOs achieving an aggressive loss reduction, especially if these losses turn out to be more commercial and billing losses hence requiring less capitalistic investments. ATC&C losses decrease from 35 percent down to 22 percent in 2017, a value that is closer to what MYTO2 has envisioned for this year. This scenario also assumed acceleration in the pace of transmission loss reduction up to 16 percent per annum.

Figure 6: Transmission and ATC&C Losses under Aggressive Loss Scenario

12. The level of remittances reaches about 93 percent by 2017 marking a significant improvement compared to the Scenario 1. This has a positive impact on sector's accounts that become balanced as of 2016. Remittances start flowing from NBET to the transmission system provider (TSP) in 2016. However, under this scenario, TSP will still incur a deficit in 2017 while other agencies are unable to receive any cash flow from the sector.

Figure 7: NBET Creditworthiness under Aggressive Loss Scenario



13. Sector liability originating from the sector is significantly reduced, falling from US$4 billion in the Scenario 1 down to US$2.8 billion.

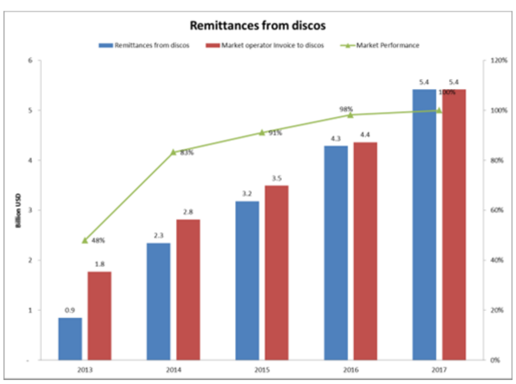
Figure 8: Sector Liability under Aggressive Loss Scenario

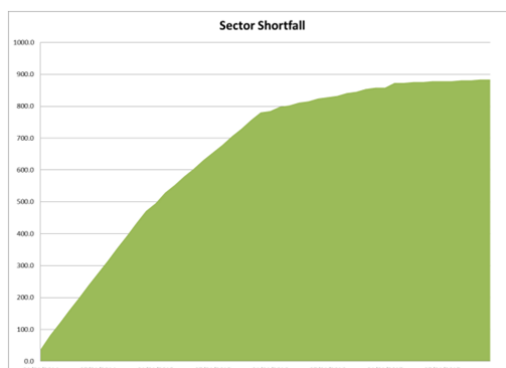
Scenario 3 - Increased Tariff Scenario

14. This alternative scenario aims to highlight the flexibility available within the sector to reach a sustainable regime. An increment of 4 Naira per kWh was added to the current MYTO 2 tariff as of 2014; the impact of these additional revenues were assessed at NBET, TSP and other agencies level as well as the required government support at a macro level. The level of losses, whether transmission or distribution losses, is kept at the same level as the Scenario 1.

15. The increase in tariff has an immediate impact on the remittances flowing to the market operator and the rest of the market stakeholders. As of 2015, default on market operator invoices by DISCOs is below 10 percent and is almost cured in 2016 (less than 2 percent default). This entails the sector is sustainable as of 2016. Sector liability accumulating over the period 2014-2017 is estimated at about US$ 900 million.

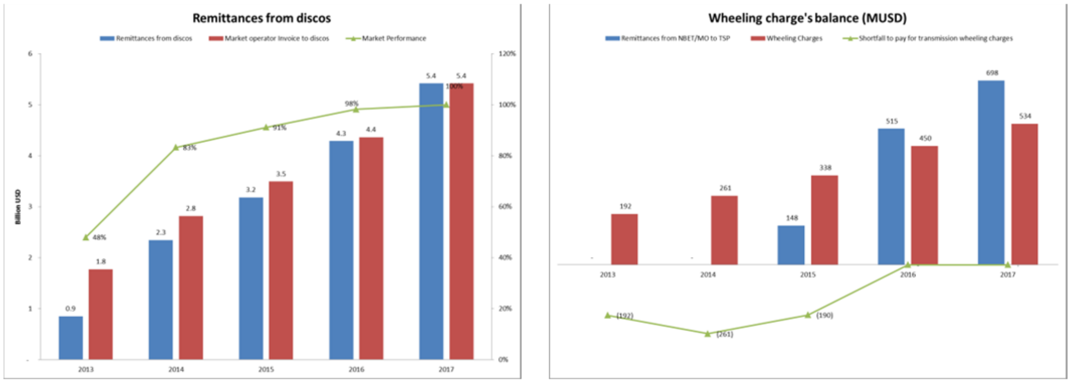
Figure 9: Sector Shortfall under Increased Tariff Scenario





16. The strong enhancement of remittances' level allows sector to be financially viable as of 2015. PPA payments are expected to be assumed by NBET relying on stronger cash inflows under the vesting contracts. TSP will have to wait until 2016 until it can be made whole.

Figure 10: Sector Performance under Increased Tariff Scenario



Annex 9: IPP Financial Analysis

Nigeria: Power Sector Guarantees Project

Azura Edo IPP

1. Azura Edo IPP is a Special Purpose Vehicle (SPV) established to design, finance, construct and operate, on a build-own-operate (BOO) basis a 459 MW gas-fuelled open cycle gas turbine (OCGT). The SPV's sustainability will depend upon the company's ability to design, finance, procure, construct, test, commission, operate and maintain the power plant. The project company will have one main source of revenue derived from the sale of electricity under a power purchase agreement (PPA) entered into with NBET.

Economic Assumptions

2. Currencies of projection are the US dollar and Naira depending on whether the indicator is quoted in US Dollars or Naira in project documents. Lenders' financial projections assume a Naira devaluation of 5 percent per annum relative to US Dollar. A US CPI of 2.2 percent is used for US-quoted indicators while a 12 percent Nigeria CPI is used for Naira-quoted indicators. The gas price is set at US$3.80 per mmbtu (which includes US$0.80 per mmbtu for transport) at beginning of operations, and increases at US CPI annually.

Project Capital Costs

3. The total estimated base project cost borne by Azura Edo IPP, including all development costs, construction costs and financing costs is expected to be about US$ 813 million. Of this total amount, direct EPC costs account for US$ 387 million, which is equivalent to US$ 843 per kW. Accounting for various financing, insurance and development costs, the total project cost per kW increases up to US$ 1,771/kW. Assuming financial close occurs by June 30th 2014, construction would start by Q3 2014 and is expected to last 30 months under the EPC contract. Budgeted contingencies in the financial plan amount to approximately US$58 million, equivalent to 7% of the total Project cost. The economic lifetime of the plant is estimated at 20 years.

Table 1: Project Cost and Financial Plan (in US$ millions)

4.

Uses of Funds			Sources of Funds		
Project Capital Expenditures	436.2	53.7%	**Equity**	**162.5**	**20.0%**
Of which, EPC Contract Cost	*386.7*	*47.6%*	**Mezzanine Debt**	**61.3**	**7.5%**
Budgeted Contingencies	57.5	7.1%	*Of which, IFC C loan*	*20.0*	2.5%
Development costs and fees	65.6	8.1%	**Total Senior Debt**	**589.1**	**72.5%**
Resettlement costs	10.3	1.3%	DFI Tranche	239.1	29.4%
Finance costs and fees	57.3	7.0%	*Of which, IFC A loan up to*	*95.0*	12.9%
Interest and fees during construction	42.8	5.3%	PRG-Covered Tranche	100.0	12.3%
Pre-funded DSRA	43.4	5.3%	MIGA-Covered Tranche	100.0	12.3%
Working Capital	25.0	3.1%	Local PAIF Tranche	150.0	18.5%
Project Securities	66.7	8.2%			
Security Registration	8.2	1.0%			
Total Uses	**813.0**	**100.0%**	**Total Sources**	**813.0**	**100.0%**

Financing

5. Based on the Lender's Financial Model dated March 21st 2014, the SPV is financed with 27.5 percent equity and 72.5 percent senior and mezzanine debt. The senior debt will be provided by a mix of international banks led by Standard Chartered Bank, with a total aggregate amount of US$200 million; they will be beneficiaries of IBRD's and MIGA's guarantees, each covering 50% of the exposure in this tranche. The local commercial tranche is expected to amount up to US$150 million, to be provided by First City Monument Bank PLC. (Nigeria) ("FCMB") who, in turn, is expected to receive (and pass on to the Project) concessional funding from Nigeria's Bank of Industry ("BOI") through the Power Aviation and Infrastructure Fund ("PAIF"). The DFI tranche is expected to represent close to US$240 million of the senior debt financing, of which IFC expects to commit US$50 million. The Project financial plan also includes up to US$61 million of mezzanine financing, of which up to US$30 million is expected to be provided by IFC.

Revenues and Tariff

6. The gas-fuelled plant is expected to operate as base load with an average availability factor of 87.9%.The plant will be generating 3.55 TWh in the first year. The power price aggregated it will receive from Bulk Trader and agreed by NERC on November 27th 2012 is estimated at US cents 9.142 per kWh in the first year (2017). Since then, the tariff has increased driven mainly by higher gas price which is envisioned to be a pass through. The tariff schedule for the first year of operation is as follows:

Table 2: Breakdown of PPA tariff expressed in US cents per kWh[28]

Component	NERC approved US cents /kWh	Lenders' Model US cents/kWh
Non-escalating Capacity charge - USD component	**3.933**	4.036
Non-escalating Capacity charge - NGN component	0.368	0.378
Escalating Fixed O&M Charge – USD component	**0.674**	0.610
Escalating Fixed O&M Charge – NGN component	0.180	0.031
Escalating Variable O&M charge – USD component	**0.428**	0.407
Escalating Variable O&M charge – NGN component	0.016	0.075
Fuel charge[29]	3.543	4.511
PPA tariff – 2017	**9.142**	**10.048**

7. Aggregate revenues to the project amount on first year of operation to US$ 356 million, of which US$ 200 million are pass-through costs broken into gas costs and variable and fixed O&M costs. These costs are indexed to gas price and inflation in US Dollar and Naira. The remaining US$156 million consist of capacity charges designed primarily to repay debt (senior and subordinated) and equity investors. Capacity charges are a function of the plant's availability and its capacity degradation through time; both availability and net capacity have been modeled with a conservative view.

Cash Flow Utilization

8. As with normal project finance operations, gross revenues arising out of the capacity, fuel and O&M payments by NBET will be applied to fund project expenses in the following order of priority: fuel payments, operating expenses, tax payments, various security fees, senior

[28] Naira components were translated into US$ at an exchange rate of 161 Naira/US Dollar.
[29] In reality, fuel will be paid as a pass-through at actual cost subject to a guaranteed heat rate to be agreed in PPA.

debt service payments, reserves required to be maintained by the SPV including debt service reserves, subordinated debt payments, shareholder loan payments; any remaining cash flow will be transferred to shareholders as dividends.

Debt Service of the Project

9. The Company's projected performance is contingent upon its ability to keep its operation and maintenance costs low while maximizing the plant's performance. The Project anticipates largely stable annual revenues, projected to remain above c.US$350 million until the end of the forecast period. Operating expenses and EBITDA are also expected to mirror the revenue profile and some upside may materialize if additional operational efficiency is achieved by the Company. Cash Available for Debt Service is forecasted to average at US$135 million annually to meet senior debt service obligations averaging at US$69 million per year, and US$18 million for mezzanine lenders.

Table 3: Base Case Summary Financial Projections (2017 – 2028) ***(all figures in US$ Mn)***

Calendar Year	2017*	2018	2019	2020	2022	2024	2026	2028
Revenues	**180.5**	**356.1**	**357.3**	**360.9**	**356.8**	**376.8**	**374.3**	**395.9**
Operating Expenses	-100.4	-200.7	-204.6	-209.1	-212.0	-227.9	-231.7	-248.9
EBITDA	**80.1**	**155.4**	**152.8**	**151.9**	**144.8**	**148.9**	**142.6**	**147.0**
Net Profit After Tax	54.0	63.0	63.2	65.8	64.5	53.8	73.7	69.6
Cash Available For Debt Service	81.4	155.6	152.5	151.7	140.4	146.3	122.5	104.5
Senior Debt Service	-42.1	-84.7	-83.8	-82.7	-80.4	-77.8	-38.1	-37.7
Mezzanine Debt Service	-8.8	-17.6	-17.6	-17.7	-17.7	-17.7	-17.6	-17.4
Senior DSCR - End of Year	1.93x	1.83x	1.81x	1.82x	1.73x	1.86x	2.45x	2.77x
Senior + Mezzanine DSCR - End of Year	1.60x	1.52x	1.50x	1.50x	1.42x	1.52x	1.81x	1.89x

* Lenders' base case conservatively assumes an additional construction period (and cost) of 6 months, resulting in a half year of operations in 2017

10. Debt service was amortized using a mortgage style repayment based on constant "payment + interest charge" over the project cycle while ensuring reasonable senior debt service cover ratios (DSCRs[30]). In the base case scenario, the minimum senior annual DSCR is 1.71x while the average annual DSCR is 2.07x. In contrast, the minimum junior DSCR is 1.40x, conveying the higher risk appetite by junior debt providers.

11. In light of the nascent nature of the markets and hence the high level of perceived risk by lenders, these levels of DSCR are considered appropriate for this transaction at this stage of the market reform. As the market gets more mature and tested, the DSCR is expected to drop in future transactions. In conformity with industry practice, a debt service reserve account of 6 months of Senior Debt Service worth is funded entirely upfront prior to commercial operations (about US$43 million).

Project Financial Analysis

12. Financial analysis of the project has been undertaken to assess the financial viability of the project from the perspective of the Special Purpose Vehicle (SPV). For the SPV, viability is assessed on the basis of the project's financial internal rate of return (FIRR) which

[30] DSCR is computed as the ratio of Cash Flow Available for Debt Service (CFADS) to Debt Service on a 12-month rolling basis (annual DSCR).

measures the overall return on capital generated by the project over the its economically useful life. Financial viability to shareholders is measured on the basis of the FIRR of equity invested in the project.

13. Based on these analyses, the project appears to be financially viable, both from the overall perspective of the project as a whole and to the equity holders. However, project viability, as well as equity returns to shareholders, is relatively sensitive to adverse changes in key variables. To assess the potential impact of changes in these variables, a sensitivity analysis has been undertaken under which the FIRRs are calculated under a range of adverse scenarios (see below for details).

14. In the base case scenario, the FIRR post-tax of the project is expected to be about 13.5. Payback period for firm is approximately eight years post financial close (end 2021).

Sensitivity Analysis

15. A number of sensitivity analyses were performed assuming that, for each projected year, the following scenarios occur: (i) non timely payment by the off-taker; (ii) reduced plant availability (due to either plant mechanical issues or gas-related outages) from 88 percent down to 78 percent; and (iii) 25 percent increase in operating and maintenance expenses. Starting from the base case assumptions, these factors were varied one at a time to determine how the corresponding DSCRs would be affected; a combination of reduced availability and increases in costs was also analyzed. The results, which are summarized in the table below, show that the Project can sustain significant downside scenarios.

Table 4: Sensitivity Analysis

	Year	Min Senior DSCR	Min Senior + Mezzanine DSCR
1	Base Case	1.71x	1.40x
2	Non-payment by NBET of 1 month of revenues p.a.	1.36x	1.11x
3	Plant availability of 78% (88% in Base Case)	1.48x	1.22x
4	25 % increase in O&M costs + US$20 million increase in Major Maintenance costs	1.58x	1.30x
5	Combined scenarios (3) + (4)	1.36x	1.11x

Qua Iboe IPP

16. A joint venture between Nigerian National Petroleum Corporation (NNPC) and Mobil Producing Nigeria Unlimited (MPN) is leading the development and financing of a 533 MW combined cycle gas turbine (CCGT) power station to be located at the Qua Iboe Terminal in Ibeno, Akwa Ibom State. The Joint Venture will have one source of the revenue from the sale of electricity under a power purchase agreement (PPA) to be entered into between MPN (on behalf of itself and NNPC) and (NBET).

Economic Assumptions

17. Currencies of projection are US dollar and Naira depending on whether the indicator is quoted in US Dollar or Naira in project documents. Projections table on a Naira inflation rate of 15 percent and a US Dolalr inflation rate of 3 percent. In 2019, gas price is set at US$2.32 per mmBTU and increases at US CPI assumed to be 3 percent annually, which is consistent with Nigeria’s Gas Master Plan price of US$2.00 per mmBTU in 2014 escalated at US CPI.

Project Capital Costs

18. The total estimated base project cost, including all development costs, construction costs and financing costs for the power plant and the transmission line is expected to be about US$1,136 million. Of this total amount, direct capital costs for the power plant account for US$1000 million. This is consistent with capital costs for CCGT power plants within the region which are typically around US$1,800 per kW. For the 58km 330kV double circuit transmission line, the capital cost is US$136 million which is about US$2.3 million per km.

Table 5: Project financing plan (Sources and Uses of funds)

Sources of Funds	US$ '000	Uses of Funds	US$ '000
Equity	**1,136,290**	**Power plant**	**1,000,173**
Equity capital - power plant	1,000,173	**Transmission line**	**136,117**
Equity capital - transmission line	136,117		
Total Sources	**1,136,290**	**Total Uses**	**1,136,290**

19. Subject to the satisfactory completion of all required commercial agreements, construction is expected to start in Q1-2015 and last about 48 months. Projected commercial operation date is Q1-2019 but the gas turbine units will be able to start up earlier. Economic lifetime of the plant is assumed to be 20 years from commercial operation date. Project stakeholders are working towards an accelerated schedule to enable EPC award by year-end 2014 which, in turn, would result in commercial operations in 2018.

Financing

20. The Sponsors' equity covers 100 percent of the cost of the project.

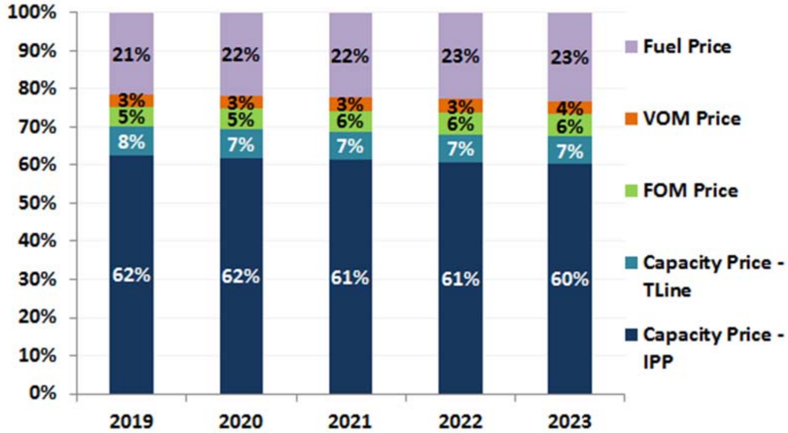
Revenues and Tariff

21. Given the significant shortage of capacity in the country, the gas-fuelled plant is expected to operate as base load with an 85 percent load factor. This number excludes interruptions to the power grid. The plant will be generating 3.92 TWh in the first full year of operations. The breakdown of the tariff schedule for the first years of operation should be as follows:

Table 6: Breakdown of Tariff Expressed in Percentage Share

Component	Share
Capacity price – IPP	62.5 %
Capacity price – Transmission line	7.5 %
Fixed O&M	5.3 %
Variable O&M	3.2 %
Fuel charge[31]	21.4 %
Tariff – 2019	100 %

[31] In reality, fuel will be paid as a pass-through at actual cost subject to a guaranteed heat rate to be agreed in PPA.



22. Aggregate revenues to the project amount on first year of operation to US$ 339 million, of which US$ 120 million are pass-through costs for gas costs and variable and fixed O&M costs. These costs are indexed to inflation in US Dollar and Naira. The remaining US$ 219 million consist of capacity payments designed to repay equity investors. Capacity payments are a function of the plant's availability and its capacity degradation through time.

Cash flows and Financial Internal Rate of Return (FIRR)

23. The projected cash flows (for the power plant and transmission line) are shown in the table below. The project FIRR, which measures the overall return on capital generated by the project over its economically useful life, is currently estimated at 13.8 percent at year 20. Given that the project is fully funded via equity, the project and equity FIRR are the same. The FIRR is higher than the weighted average cost of capital (WACC) established by MYTO 2 or than the WACC of another comparable Central African OCGT project. Conversely, it is much lower than the return on equity (RoE) of comparable West and Central African gas power plants. As the project is fully funded by equity, the fact that QIPP's FIRR is significantly lower than the other projects' RoE while higher than the WACC of comparable projects appears reasonable.

Table 7: Cash Flows over the period 2015-2038

		2015	2016	2017	2018	2019	2020	2021	2022	2023	2028	2033	2038
Cash Flows		-4	-3	-2	-1	1	2	3	4	5	10	15	20
Total revenue	$ MM	0.0	0.0	0.0	83.1	338.5	335.4	336.3	345.1	344.9	365.7	381.1	407.6
Costs													
Capex (Equity Portion)	$ MM	402.1	243.1	265.4	206.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Plant Fixed O&M	$ MM	0.0	0.0	0.0	0.0	14.4	25.1	27.9	18.3	18.8	21.8	25.3	29.3
Plant Variable O&M	$ MM	0.0	0.0	0.0	0.0	28.1	13.9	13.9	5.2	22.4	7.0	3.8	19.6
Fuel cost	$ MM	0.0	0.0	0.0	31.0	72.5	73.3	75.1	78.6	80.1	93.6	107.0	124.9
Taxation	$ MM	0.0	0.0	0.0	16.7	0.0	0.0	0.0	0.0	0.0	2.4	77.6	74.8
PRG/LC, MIGA	$ MM	5.3	4.3	4.8	4.8	5.3	5.1	4.9	4.7	4.5	3.4	2.4	1.5
Total costs	$ MM	407.5	247.4	270.2	258.9	120.3	117.4	121.8	106.7	125.9	128.3	216.1	250.1
Dividend withholding tax	$ MM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	16.5	15.9
After Tax Cash Flow	**$ MM**	-407.5	-247.4	-270.2	-175.8	218.2	218.0	214.5	238.4	219.1	236.9	148.5	141.6
Total Cash Flow	2,647												
IRR	**13.8%**												

Sensitivity Analysis

24. Assuming the Sponsors and the Bulk Trader agree that the level of returns is adequate, the project as shown is financially viable. However, viability may be sensitive to adverse changes in key variables. To assess the potential impact of changes in these variables, a sensitivity

analysis has been undertaken under which the FIRRs are calculated under a range of adverse scenarios.

25. Gas price does not have much impact on project's returns as it is a pass through for the project. However an (i) increase in capital costs, (ii) delay in COD, and (iii) decrease in plant's availability would have a large impact on the IRR. A combination of two or three of these negative scenarios would seriously impact the project's financial viability with a FIRR decreasing to 6.2 percent. However this is highly unlikely and the project appears financially robust.

Table 8: Sensitivity Analysis Results

Scenario	***Project/Sponsors FIRR (%)***
1. Base case	13.8 %
2. Increase in capital costs by 20%	11.5 %
3. Availability decreases from 85% to 70%	11.2 %
4. COD delayed by one year	11.1 %
5. Combination of scenarios 2, 3, and 4.	6.2 %

Annex 10: IBRD PRG Term Sheets

Nigeria: Power Sector Guarantees Project

AZURA EDO POWER PROJECT

SUMMARY OF INDICATIVE TERMS AND CONDITIONS OF THE PROPOSED IBRD PARTIAL RISK GUARANTEE IN SUPPORT OF DEBT MOBILIZATION

This term sheet contains a summary of indicative terms and conditions of the proposed Partial Risk Guarantee ("Guarantee") by the International Bank for Reconstruction and Development ("IBRD") for discussion purposes only and does not constitute an offer to provide an IBRD Guarantee. The provision of the IBRD Guarantee is subject, inter alia, to satisfactory appraisal of the Project by the IBRD, compliance with all applicable policies of the World Bank, including those related to environmental and social safeguards under the World Bank Performance Standards, review and acceptance of the ownership, management, financing structure, and project/transaction documentation by the World Bank, and the approval of Nigerian Bulk Electricity Trading PLC ("NBET")/Federal Republic of Nigeria ("FGN") as well as the management and Executive Directors of the IBRD in their sole discretion.

IBRD-Guaranteed Loan Agreement	
Borrower:	Azura Power West Africa Limited ("Borrower")
Shareholder:	Azura Edo Limited
Guaranteed Lenders:	Standard Chartered Bank, in its capacity as lender and acting as Agent for other commercial lenders.
Loan Amount:	Up to US$125 million
Term:	The term of the loans provided by the Commercial Lenders is expected to be 12 years door to door from closing to last repayment date.
Repayment Terms:	Annual, semi-annual or quarterly (to match payment periods under the IBRD-Guaranteed Loan Agreement).
Loan Interest Rate:	Spread acceptable to IBRD and payable by the Borrower, expected to be 5.25% p.a.
Currency:	US Dollars.
Use of proceeds:	Proceeds to be used for the design, engineering, procurement, construction, and financing costs of the project, but excluding development fees and other costs typically included on the World Bank negative list (e.g., acquisition costs for nuclear, military, land or luxury items, or for goods or services from territories that are not a member of the World Bank, etc.)
Drawdown:	Pro rata with the other loans of the project or in such other proportion acceptable to the IBRD.
IBRD Guarantee Agreement	
Guarantor:	IBRD.
Beneficiaries:	Commercial lenders, or the facility agent or trustee on their behalf, as provided in the *IBRD-Guaranteed Loan Agreement*.

Guarantee:	IBRD will guarantee to the Beneficiaries amounts up to the Maximum Guaranteed Principal, plus scheduled interest thereon[28],they would have otherwise received from the Borrower, but for:
	(a) any default by NBET to make a payment of the Capacity Payment, Energy Payment, Gas Payment, Start Up Payment, or Supplemental Payment (each as defined under the power purchase agreement ("PPA") between NBET and the Borrower); provided that the IBRD Guarantee is not callable unless and until the buyer payment security provided by NBET under the PPA is fully drawn (and has not been replenished in whole or in part); or (b) any default by the FGN to pay in accordance with the terms of the Put/Call Option Agreement to be entered into between the Borrower and FGN (the "PCOA") an amount at least equal to[29]: (1) the Share Purchase Price – Expropriation, calculated using the DO Adjusted Amount as the Applicable Purchase Price multiplied by the number of Shares that are required to be acquired pursuant to Clause 3.1.1 of the PCOA following the occurrence of an Expropriation of Shares; or (2) the DO Adjusted Amount[30] following an Early Termination triggered for any of the following events: (i) Buyer Default (Clauses 18.3 and 18.5 of the PPA); (ii) Expropriation (Clause 18.6 of the PPA); (iii) Prolonged Force Majeure Event that is a Local Political Force Majeure Event (Clause 21.8 of the PPA); (iv) Local Political Force Majeure Event without Restoration (Clause 21.9 of the PPA); (v) Change in Law without Restoration (Clause 21.9 of the PPA); (vi) Local Political Force Majeure following Restoration (Clauses 21.1.2, 21.10.5.3, 21.10.6.2 and 18.8 and of the PPA); (vii) Change in Law following Restoration (Clauses

[1] Means scheduled interest due and payable on any advances made pursuant to the IBRD-Guaranteed Loan. For the avoidance of doubt, IBRD does not cover penalty interest, default interest or charges of a similar nature.

[2] Note that this formulation may be subject to change in order to reflect the terms of the PCOA, which has not been executed.

[30] Note that the "DO Adjusted Amount" provides that insurance proceeds and cash available would be subtracted from the "Debt Outstanding".

	21.10.5.3, 21.10.6.2 and 18.8 of the PPA); The following events may also be covered, subject to confirmation by NBET and Borrower and further IBRD due diligence on the matter: (i) Prolonged NGC Gas Transportation Constraint (Clause 18.7.2 of the PPA); (ii) Prolonged Gas Supply Constraint (Clause 18.7.1); (iii) Prolonged Force Majeure Event which is a Foreign Political Force Majeure Event (Clause 21.8 of the PPA); (iv) Prolonged Force Majeure Event that is a Natural Force Majeure Event (Clause 21.1.4 of the PPA); and (v) Any other event agreed by NBET and Borrower under the terms of the PCOA and determined to be acceptable by IBRD.
Maximum Guaranteed Principal:	The aggregate of the principal amount of the IBRD-Guaranteed Loan committed (or, at the end of the availability period of the IBRD-Guaranteed Loan ("Availability Period"), disbursed), not to exceed US$125 million (or such lesser amount agreed among the Commercial Lenders, the Borrower and NBET and acceptable to IBRD).
Guarantee Fee (recurring)[31]:	50[32] bps per annum, payable semi-annually in advance by the Borrower, on the disbursed and outstanding amount of the IBRD-Guaranteed Loan (and scheduled interest thereon), which is callable under the IBRD Guarantee.
Up-front Fees[33]:	(a) A Front-End Fee of 25bps of the Maximum Guaranteed Principal payable by the Borrower.
	(b) An Initiation Fee of 15bps of the Maximum Guaranteed Principal (but not less than US$100,000) payable by the Borrower.
	(c) Processing Fee of 50bps[34] of the Maximum Guaranteed Principal payable by the Borrower. (d) Reimbursement of IBRD outside legal counsel expenses

[3] FY14 pricing.
[4] For IBRD guarantees, the guarantee fee includes an annual maturity premium of 0.00% for maturities up to 12 years, 0.10% for maturities greater than 12 and up to 15 years, and 0.20% for maturities greater than 15 and up to 18 years (FY14 pricing).
[5] FY14 pricing.
[34] IBRD may charge higher than usual Processing Fee if internal costs are incurred over and above the expected costs of preparing and making the IBRD guarantees effective.

	by the Borrower.
Conditions precedent to the IBRD Guarantee:	Usual and customary conditions (to be satisfied in form and substance acceptable to the IBRD) for financing of this type including but not limited to the following:
	(a) firm commitment for sufficient financing to complete construction of the project, including satisfactory contribution of equity by the project sponsor(s);
	(b) execution, delivery and effectiveness of all project and financing agreements, satisfactory to IBRD, including execution and delivery of (i) a Guarantee Agreement between the Guaranteed Lenders and IBRD; (ii) a Project Agreement between the Borrower and IBRD; (iii) a Cooperation Agreement between NBET and IBRD; (iv) an Indemnity Agreement between IBRD and FGN; (v) the PPA between the Beneficiary and NBET; and (vi) the PCOA among the Borrower (and its shareholders), NBET and FGN;
	(c) Delivery of all relevant host country environmental approvals required for the operation of the project, and compliance with all applicable World Bank requirements relating to environmental and social safeguards under the World Bank Performance Standards and sanctionable practices[35];
	(d) provision of satisfactory legal opinions; and
	(e) payment in full of the Upfront Fees, and the first instalment of the Guarantee Fee (if Guarantee Fee is not paid up front).
Suspension of coverage:	If any of the following types of events, *inter alia*, occurs and is continuing prior to the end of Availability Period, IBRD may by written notice to Lenders deny guarantee coverage to any subsequent drawdowns:
	(a) any event (potential event of default) which, with the passing of time or giving of notice or both, may lead to a claim on the *IBRD Guarantee*;
	(b) material default by the Borrower under its Project Agreement with IBRD, including without limitation, in respect of any obligations relating to environmental and social safeguards under the World Bank Performance Standards;

[6] "Sanctionable practices" include corrupt, fraudulent, collusive, coercive, or obstructive practices.

	(c) suspension by IBRD or the International Development Association (”IDA”) of loans to or guaranteed by Nigeria or breach by Nigeria of its obligations under the *Indemnity Agreement*;
	(d) suspension or lapse of Nigeria from membership in IBRD, IDA, or the International Monetary Fund; or
	(e) a Sanctionable Practice (coercion, collusion or corrupt, fraudulent or obstructive practices) is found to have been engaged in, in connection with the Project.
Exclusions:	IBRD is not liable for losses directly resulting from (i) acts or omissions of the Borrower (including its direct and indirect shareholders and any of its contractors), or the Beneficiaries, (ii) non-compliance with Nigerian laws in effect on, or events occurring before, the date of the *Guarantee Agreement*, or (iii) Sanctionable Practices in connection with the project attributable to relevant parties, as determined by IBRD.
Termination by IBRD:	Except in respect of demand notices already delivered to IBRD, any default in payment of Guarantee Fees will automatically terminate the *IBRD Guarantee*. IBRD may also terminate the *IBRD Guarantee* if any of the following types of events occurs, *inter alia*:
	(a) any changes are made without IBRD’s consent in those provisions of the transaction documents (including any financing agreements) in respect of which IBRD’s consent is required; or
	(b) any of the transaction documents becomes invalid, illegal, or unenforceable and such materially affect the rights or obligations of IBRD under the IBRD Guarantee Agreement, the Project Agreement with the Borrower or any other transaction document; or
	(e) if there is substantial evidence that the Borrower (including its direct and indirect shareholders and other relevant parties, as determined by IBRD) or the Beneficiaries have engaged or engage in Sanctionable Practices (coercion, collusion, corrupt, obstructive or fraudulent practices) in connection with the Project; or (f) if the Borrower is in violation of the World Bank guidelines, environmental and social safeguard policies under the World Bank Performance Standards applicable to it.
Subrogation:	If and to the extent IBRD makes any payment under the *IBRD Guarantee* and Nigeria has failed to reimburse IBRD for the

	amount so paid in accordance with the terms of the *Indemnity Agreement* and such failure has continued for at least 60 days after notice from IBRD, IBRD will be subrogated immediately to the extent of such unreimbursed payment to the Lenders' rights.
Claims and disputes:	Claims by Guaranteed Lenders must be made within 90 days of the occurrence of a Guaranteed Event with IBRD paying within 60 days thereafter. If there is a dispute between FGN and the Borrower under the PCOA, or NBET and the Borrower under the PPA, as to FGN's or NBET's (as applicable) obligation to pay or the amount of its liability, the *IBRD Guarantee* would be callable only in respect of amounts that FGN or NBET (as applicable) is obligated to pay, and fails to pay, in accordance with the procedures contained in the PCOA or PPA (as applicable). For the avoidance of doubt, IBRD will pay once FGN's or NBET's liability has been determined, whether through expert determination, settlement agreement between the parties, arbitral award, or otherwise, so long as such determination is final and binding (i.e., an arbitral award is not necessarily required).
Provisional Payments:	IBRD will make Provisional Payments for scheduled payments, if: (i) the Borrower or the Guaranteed Lenders are unable (within an agreed time period) to commence or proceed with dispute resolution in accordance with the relevant provisions of the PCOA or PPA (as applicable) by reason of court decision, judgment or order in Nigeria (whether temporary or permanent, and whether commenced by FGN, NBET or emanated from third party legal action) to (i) prevent or impede the dispute resolution process, (ii) have the dispute transferred to or determined by the courts in Nigeria, or (iii) otherwise pursue the dispute in a manner not consistent with the agreed dispute resolution mechanism and not agreed by the Borrower; and (ii) the Guaranteed Lenders and/or the Borrower have agreed with IBRD that they will use their best efforts to resolve the dispute and the Guaranteed Lenders have provided IBRD with acceptable collateral (e.g., irrevocable stand-by letters of credit) to repay IBRD on call the amount of the provisional payment and interest thereon in the event that the it is subsequently determined that the liability of the FGN or NBET (as the case may be) is less than the full amount of the provisional payment. The Guaranteed Lenders' obligation to repay the Provisional Payments expires after five (5) years (or such other period acceptable to IBRD to be agreed) if dispute resolution continues to be interrupted.

Non-Accelerability of Guarantee for Ongoing Payments:	The IBRD Guarantee is non-accelerable if the underlying payment obligations of the IBRD-Guaranteed Loan are accelerated as a result of a Guaranteed Event related to a NBET payment obligation under the PPA. In such instances, the IBRD Guarantee will cover payment of principal up to the Maximum Guaranteed Principal and scheduled interest thereon payable in accordance with the original payment schedule applicable to the IBRD-Guaranteed Loan.
Accelerability of Guarantee for Termination Payments:	The IBRD Guarantee may be accelerated if the underlying payment obligations of the IBRD-Guaranteed Loan are accelerated due to a Guaranteed Event related to a FGN termination payment obligation under the PCOA. In such instances, the IBRD Guarantee will pay off the principal outstanding up to Maximum Guaranteed Principal (and interest accrued thereon).
<u>Indemnity Agreement</u>	
Parties:	IBRD and FGN.
Indemnity:	FGN will reimburse and indemnify IBRD on demand, or as IBRD may otherwise direct, for all payments under the *IBRD Guarantee* and all losses, damages, costs, and expenses incurred by IBRD relating to or arising from the *IBRD Guarantee*; provided, that, IBRD will not make any such demand with respect to any provisional payment made to the Guaranteed Lenders until the liability of the FGN or NBET (as the case may be) has been finally determined or the dispute resolution continues to be interrupted for five (5) years.
Covenants:	FGN will covenant, *inter alia,* that it: (a) will comply with all its obligations under the transaction documents; (b) will obtain IBRD's consent prior to agreeing to any change to any transaction document which would materially affect the rights or obligations of IBRD under the IBRD Guarantee Agreement or any other transaction document, including prior to exercising any call option under the PCOA; (c) will provide certain notices to IBRD; (d) will take all action necessary on its part to enable the Borrower to obtain any required approval or environmental authorization for the Project and to perform all of the Borrower's obligations under the Project Agreement and other relevant transaction document; and

	(e) will not create or permit to exist or occur any circumstances or change in Nigerian law which would render obligations under the Project Agreement, the Cooperation Agreement and any other relevant transaction document illegal, invalid, unenforceable, ineffective or void in whole or part.
Remedies:	If FGN breaches any of its obligations under the *Indemnity Agreement* or if NBET breaches any of its obligations under the *Cooperation Agreement*, IBRD may suspend or cancel, in whole or in part, the rights of FGN to make withdrawals under any other loan or credit agreement with IBRD or IDA, or any IBRD loan or IDA credit to a third party guaranteed by FGN, and may declare the outstanding principal and interest of any such loan or credit to be due and payable immediately. A breach by FGN under the *Indemnity Agreement* will not, however, cause prejudice to any existing guarantee obligation of the IBRD under the IBRD Guarantee.
Governing law:	The *Indemnity Agreement* will follow the usual legal regime and include dispute settlement provisions customary for agreements between member countries and IBRD.
Project Agreement	
Parties:	IBRD and the Borrower.
Representations and warranties:	The Borrower will represent, among other standard and project-specific provisions, as of the effective date, that it (i) is in compliance with applicable environmental laws and the applicable World Bank guidelines, environmental and social safeguard policies under the World Bank Performance Standards, and other applicable requirements and (ii) neither it (including, its direct and indirect shareholders and other relevant parties, as determined by IBRD), nor any of its affiliates has engaged in any sanctionable practice (i.e. corrupt, coercive, obstructive, fraudulent or collusive practices as defined by IBRD) activity in connection with the project.
Covenants:	The Borrower will covenant, among other things, that it will (i) use the proceeds of the disbursements under the IBRD-Guaranteed Loan exclusively for the project and in accordance with the terms and conditions of the *IBRD-Guaranteed Loan Agreement*, (ii) comply with applicable laws, including environmental laws, and the applicable World Bank environmental and social safeguard policies under the World Bank Performance Standards; (iii) provide annual audited financial statements and other reports, (iv) provide access to the project site and documentation, (v) not engage in any sanctionable practice in connection with the Project, (vi) comply with World Bank sanctions procedures and guidelines regarding individuals or firms included in the World Bank Group

	list of firms debarred from World Bank Group-financed contracts; and (vii) will obtain IBRD's consent prior to agreeing to any change to any transaction document to which it is a party which would materially affect the rights or obligations of IBRD under the IBRD Guarantee Agreement and other relevant transaction document.
Costs and expenses:	The Borrower will indemnify and reimburse the World Bank for reasonable out-of-pocket expenses incurred in connection with the consideration of any requests for IBRD's consent, any amendments to documentation, or the preparation for and actual enforcement or protection of rights under the *IBRD Guarantee* and other documentation.
Governing law:	English law.
<u>Cooperation Agreement</u>	
Parties:	IBRD and NBET.
Covenants:	NBET will covenant, *inter alia,* that it: (a) will comply with all its obligations under the transaction documents; (b) will obtain IBRD's consent prior to agreeing to any change to any transaction document which would materially affect the rights or obligations of IBRD under the IBRD Guarantee Agreement or any other transaction document, including prior to exercising any termination rights under the PPA; (c) will provide certain notices to IBRD; (d) will take all action necessary on its part, in accordance with and as required by the terms of the project-related agreements to which it is a party, to enable the Borrower to perform all of the Borrower's obligations under the Project Agreement, and other relevant transaction document; (e) will cooperate with IBRD and furnish to IBRD all such information related to such matters as IBRD shall reasonably request; and promptly inform IBRD of any condition which interferes with, or threatens to interfere with, such matters; and (f) will comply with certain account management obligations in connection with the Project revenues.

SUMMARY OF INDICATIVE TERMS AND CONDITIONS OF THE PROPOSED IBRD PARTIAL RISK GUARANTEE IN SUPPORT OF PAYMENTS UNDER THE POWER PURCHASE AGREEMENT

AZURA EDO POWER PROJECT

This term sheet contains a summary of indicative terms and conditions of the proposed Partial Risk Guarantee ("Guarantee") by the International Bank for Reconstruction and Development ("IBRD") for discussion purposes only and does not constitute an offer to provide an IBRD Guarantee. The provision of the IBRD Guarantee is subject, inter alia, to satisfactory appraisal of the Project by the IBRD, compliance with all applicable policies of the World Bank, including those related to environmental and social safeguards under the World Bank Performance Standards, review and acceptance of the ownership, management, financing structure, and project/transaction documentation by the World Bank, and the approval of Nigerian Bulk Electricity Trading PLC ("NBET")/Federal Republic of Nigeria ("FGN") as well as the management and Executive Directors of the IBRD in their sole discretion.

Applicant:	Nigerian Bulk Electricity Trading Co. ("Bulk Trader"), as "Buyer" under a Power Purchase Agreement ("PPA") with the Seller.
Purpose:	The IBRD PRG would backstop the failure by Bulk Trader to repay the Issuing Bank for the amounts drawn by the Seller under the Buyer Payment Security on account of payments due to the Seller from the Bulk Trader under the PPA following the occurrence of a Guaranteed Event (as defined below).
IBRD Guaranteed Security:	The security posted by the Bulk Trader to secure certain of its payment obligations under the PPA (the "Buyer Payment Security"), which may take the form of a revolving standby irrevocable letter of credit or a demand guarantee, and which, in either case, will be issued in favor of the Seller by the Issuing Bank at the request of Bulk Trader. The Bulk Trader's obligations to repay the Issuing Bank for the amounts drawn under the Buyer Payment Security will be guaranteed by IBRD. Any amounts drawn by the Seller under the Buyer Payment Security that are repaid by Bulk Trader to the Issuing Bank within the Reimbursement Period would be reinstated as described below.
Buyer Payment Security Beneficiary:	Azura Power West Africa Limited ("Seller").
Issuing Bank:	A commercial bank acceptable to IBRD, the Bulk Trader and the Seller (choice of Issuing Bank may be subject to a minimum credit rating).
Form of Buyer Payment Security:	The Buyer Payment Security will be issued in a form satisfactory to the Seller, Bulk Trader and IBRD.

Guaranteed Events:	Bulk Trader's failure to make a payment of the Capacity Payment, Energy Payment, Gas Payment, Start Up Payment, or Supplemental Payment (each as defined under the PPA) (as such will be detailed in the PRG Support Agreement).
Maximum Stated Amount:	The maximum amount available for draw under the Buyer Payment Security (the "**Stated Amount**") shall be an amount to be agreed between Seller and Bulk Trader (and acceptable to IBRD) and in no event shall exceed US$120 million. The actual amount made available for drawing under the Buyer Payment Security in any given year shall be in accordance with the schedule of payments agreed between Bulk Trader and Seller (and acceptable to IBRD), which may be amended from time to time by the parties, but at no time shall exceed the Stated Amount.
Security Validity Period:	Up to 20 years from the date of the occurrence of the Commercial Operation Date under the PPA, <u>provided</u> <u>that</u> provisions, to be agreed, allowing for the winding down of security and IBRD Guarantee support if NBET satisfies certain criteria (such as NBET's (i) creditworthiness; (ii) track record; (iii) ability to procure a letter of credit) will be included.
Reimbursement **Period:**	Following a drawing under the Buyer Payment Security by the Seller, Bulk Trader would be obligated to repay the Issuing Bank the amount drawn under the Buyer Payment Security together with accrued interest thereon within a period twelve (12) months from the date of each drawing ("Reimbursement Period") pursuant to a Reimbursement and Credit Agreement to be concluded between Bulk Trader and the Issuing Bank. In the event of a timely repayment by Bulk Trader, the Buyer Payment Security will be reinstated by the amount of such repayment. In the event of a non-payment on the due date, the Issuing Bank would have the right to call on the IBRD Guarantee for principal amounts plus accrued interest due from Bulk Trader under the Reimbursement and Credit Agreement. Any amount paid by IBRD to the Issuing Bank under the Guarantee would be deducted from the Maximum IBRD PRG Guaranteed Amount and even if Bulk Trader's payment default is remedied, following a payment under the Guarantee, those amounts would not be reinstated.
Bulk Trader's obligation to Replenish the Buyer Payment Security under the PRG Support Agreement:	The Bulk Trader will undertake under the PRG Support Agreement to maintain at all times the Stated Amount to be available for drawing under the Buyer Payment Security; provided that a failure to maintain such balance will not constitute a Bulk Trader's default under the PPA so long as (i) Bulk Trader is current on its payment

	obligations under the PPA, and (ii) Bulk Trader repays the Issuing Bank and replenishes any amount drawn under the Buyer Payment Security within 12 months after the date of the drawing (see also Reimbursement Period above).
Interest Rate on Drawings During the Reimbursement, Period Charged by the Issuing Bank:	A spread acceptable to the Bulk Trader and IBRD, and payable by the Bulk Trader.
Maximum IBRD Guaranteed Amount:	The IBRD PRG shall be capped at the Stated Amount (which is an amount to be agreed between Seller and Bulk Trader not to exceed US$120 million), plus accrued interest. The Buyer Payment Security shall be available for drawings by the Beneficiary upon filing of a claim on the basis of drawdown mechanisms and the presentation of supporting documentation to be agreed between the parties in the PRG Support Agreement and the Buyer Payment Security instrument, and satisfactory to the IBRD.
Maximum IBRD PRG Period:	The Security Validity Period plus 14 months.
IBRD PRG Fees (recurring)[36]:	50[37]bps per annum on the Maximum IBRD PRG Guaranteed Amount (and interest thereon) which is callable under the IBRD Guarantee, payable six monthly in advance by the Seller.
IBRD Upfront Fees[38]:	(a) A Front-End Fee of 25bps of the Maximum IBRD PRG Guaranteed Amount payable by the Seller. (b) An Initiation Fee of 0.15% of the Maximum IBRD PRG Guaranteed Amount (but not less than US$100,000) payable by the Seller. (c) Processing Fee of up to 0.50[39]% of the Maximum IBRD PRG Guaranteed Amount payable by the Seller. (d) Reimbursement of IBRD outside legal counsel expenses by the Seller.
Fees of the Issuing Bank:	To be negotiated between Bulk Trader, the Issuing Bank, and the Seller, and payable by the Seller.

[36]FY14 pricing.
[37]For IBRD guarantees, the guarantee fee includes an annual maturity premium of 0.00% for maturities up to 12 years, 0.10% for maturities greater than 12 and up to 15 years, and 0.20% for maturities greater than 15 and up to 18 years (FY14 pricing).
[38]FY14 pricing.
[39]IBRD may charge higher than usual Processing Fee if internal costs are incurred over and above the expected costs of preparing and making the IBRD guarantees effective.

Conditions Precedent to the Effectiveness of the IBRD Guarantee:	Usual and customary conditions (to be satisfied in form and substance acceptable to the IBRD) for operations of this type including but not limited to the following: (a) firm commitment for sufficient financing to complete construction of the project, including satisfactory contribution of equity by the project sponsor(s); (b) execution, delivery and effectiveness of all project and financing agreements, satisfactory to IBRD, including execution and delivery of: (i) a Guarantee Agreement between the Issuing Bank and IBRD; (ii) a Reimbursement and Credit Agreement between Issuing Bank and Bulk Trader; (iii) a PRG Support Agreement between Bulk Trader and the Seller; (iv) a Project Agreement between the Seller and IBRD; (v) a Cooperation Agreement between the Bulk Trader and IBRD; (vi) an Indemnity Agreement between IBRD and FGN; and (vii) the PPA between the Seller and NBET. (c) Delivery of all relevant host country environmental approvals required for the operation of the project, and compliance with all applicable World Bank requirements relating to environmental and social safeguards under the World Bank Performance Standards and sanctionable practices[40]. (d) provision of satisfactory legal opinions; and (e) Payment in full of the Upfront Fees, and the first installment of the IBRD Guarantee Fee.
Guarantee Agreement:	The terms and conditions of the IBRD PRG would be embodied in a Guarantee Agreement between the Issuing Bank and IBRD.
Project Agreement:	The Seller would enter into a Project Agreement with IBRD in respect of the IBRD Guarantee. Under such agreement, the Seller will provide reports (including audit reports) and other relevant Project information, and make warranties, representations and covenanted undertakings, including in respect of compliance with applicable environmental laws and relevant World Bank environmental and social safeguards under the World Bank Performance Standards and World Bank anti-corruption policies and procedures, including relating to sanctionable practices. **IBRD may suspend or terminate the Guarantee if the Seller breaches the warranties, representations or undertakings under the Project Agreement.**

[40] "Sanctionable practices" include corrupt, fraudulent, collusive, coercive, or obstructive practices.

PRG Support Agreement:	Bulk Trader will enter into a PRG Support Agreement with the Seller under which Bulk Trader would undertake to indemnify the Seller for the loss of revenues resulting from the occurrence of a Guaranteed Event on the basis of drawdown and dispute resolution mechanisms and supporting documentation to be agreed between the parties and satisfactory to IBRD and to be consistent with the provisions under the PPA.
Reimbursement and Credit Agreement:	Bulk Trader will enter into a Reimbursement and Credit Agreement with the Issuing Bank in which it will undertake to repay the Issuing Bank the amounts drawn under the Buyer Payment Security, together with accrued interest, within the Reimbursement Period.
Indemnity Agreement:	FGN would enter into an Indemnity Agreement with IBRD. Under this agreement, FGN would undertake to indemnify IBRD on demand, or as IBRD may otherwise determine, for any payment made by IBRD in connection with the IBRD PRG. If FGN breaches any of its obligations under the *Indemnity Agreement* or if NBET breaches any of its obligations under the Cooperation Agreement, IBRD may suspend or cancel, in whole or in part, the rights of FGN to make withdrawals under any other loan or credit agreement with IBRD or IDA, or any IBRD loan or IDA credit to a third party guaranteed by FGN, and may declare the outstanding principal and interest of any such loan or credit to be due and payable immediately. A breach by FGN under the *Indemnity Agreement* will not, however, cause prejudice to any existing guarantee obligation of the IBRD under the IBRD Guarantee. The Indemnity Agreement will follow the legal regime, and include dispute settlement provisions, which are customary in agreements between member countries and IBRD.
Cooperation Agreement:	NBET would enter into a Cooperation agreement with IBRD pursuant to which it will undertake to (i) comply with all its obligations under the transaction documents to which it is a party, including promptly replenish the Buyer Payment Security if it is ever drawn; (ii) will obtain IBRD's consent prior to agreeing to any change to any transaction document which would materially affect the rights or obligations of IBRD under the IBRD Guarantee or any other transaction document (including prior to exercising any termination rights under the PPA); (iii) will provide certain notices to IBRD; (iv) will take all action necessary on its part to enable the Seller to perform all of the Seller's obligations under its Project Agreement with IBRD, and other relevant transaction document; (v) will cooperate with IBRD and furnish to IBRD all such information related to such matters as IBRD shall reasonably request; and promptly inform IBRD of any condition which interferes with, or threatens to interfere with, such matters; and (vi) will comply with certain account management obligations in connection with the Project revenues.
Choice of Law:	English law.

<u>SUMMARY OF INDICATIVE TERMS AND CONDITIONS OF THE PROPOSED IBRD PARTIAL RISK GUARANTEE IN SUPPORT OF PAYMENTS UNDER THE POWER PURCHASE AGREEMENT</u>

QUA IBOE POWER PROJECT

This term sheet contains a summary of indicative terms and conditions of the proposed Partial Risk Guarantee ("Guarantee") by the International Bank for Reconstruction and Development ("IBRD") for discussion purposes only and does not constitute an offer to provide an IBRD Guarantee. The provision of the IBRD Guarantee is subject, inter alia, to satisfactory appraisal of the Project by the IBRD, compliance with all applicable policies of the World Bank, including those related to environmental and social safeguards, review and acceptance of the ownership, management, financing structure, and project/transaction documentation by the World Bank, and the approval of Nigerian Bulk Electricity Trading PLC ("NBET")/Federal Republic of Nigeria ("FGN") *as well as the management and Executive Directors of the IBRD in their sole discretion.*

Applicant:	Nigerian Bulk Electricity Trading Co. ("Bulk Trader"), as "Buyer" under a Power Purchase Agreement ("PPA") with the Seller.
Purpose:	The IBRD PRG would backstop the failure by Bulk Trader to repay the Issuing Bank for the amounts drawn by the Seller under the Buyer Payment Security on account of payments due to the Seller from the Bulk Trader under the PPA following the occurrence of a Guaranteed Event (as defined below).
IBRD Guaranteed Security:	The security posted by the Bulk Trader to secure certain of its payment obligations under the PPA (the "Buyer Payment Security"), which may take the form of a revolving standby irrevocable letter of credit or a demand guarantee, and which, in either case, will be issued in favor of the Seller by the Issuing Bank at the request of Bulk Trader. The Bulk Trader's obligations to repay the Issuing Bank for the amounts drawn under the Buyer Payment Security will be guaranteed by IBRD. Any amounts drawn by the Seller under the Buyer Payment Security that are repaid by Bulk Trader to the Issuing Bank within the Reimbursement Period would be reinstated as described below.
Buyer Payment Security Beneficiary:	Mobil Producing Nigeria Unlimited, on its own behalf and as representative of the joint venture ("Seller").
Issuing Bank:	A commercial bank acceptable to IBRD, the Bulk Trader and the Seller (choice of Issuing Bank may be subject to a minimum credit rating).
Form of Buyer Payment Security:	The Buyer Payment Security will be issued in a form satisfactory to the Seller, Bulk Trader and IBRD.

Guaranteed Events:	Bulk Trader's failure to make a payment of the Capacity Payment, Energy Payment, Gas Payment, Start Up Payment, or Supplemental Payment (each as defined under the PPA) (as such will be detailed in the PRG Support Agreement).
Maximum Stated Amount:	The maximum amount available for draw under the Buyer Payment Security (the "**Stated Amount**") shall be an amount to be agreed between Seller and Bulk Trader (and acceptable to IBRD) and in no event shall exceed US$150 million. The actual amount made available for drawing under the Buyer Payment Security in any given year shall be in accordance with the schedule of payments agreed between Bulk Trader and Seller (and acceptable to IBRD), which may be amended from time to time by the parties, but at no time shall exceed the Stated Amount.
Security Validity Period:	Up to 20 years from the date of the occurrence of the Commercial Operation Date under the PPA, <u>provided</u> <u>that</u> provisions, to be agreed, allowing for the winding down of security and IBRD Guarantee support if NBET satisfies certain criteria (such as NBET's (i) creditworthiness; (ii) track record; (iii) ability to procure a letter of credit) will be included.
Reimbursement **Period:**	Following a drawing under the Buyer Payment Security by the Seller, Bulk Trader would be obligated to repay the Issuing Bank the amount drawn under the Buyer Payment Security together with accrued interest thereon within a period twelve (12) months from the date of each drawing ("Reimbursement Period") pursuant to a Reimbursement and Credit Agreement to be concluded between Bulk Trader and the Issuing Bank. In the event of a timely repayment by Bulk Trader, the Buyer Payment Security will be reinstated by the amount of such repayment. In the event of a non-payment on the due date, the Issuing Bank would have the right to call on the IBRD Guarantee for principal amounts plus accrued interest due from Bulk Trader under the Reimbursement and Credit Agreement. Any amount paid by IBRD to the Issuing Bank under the Guarantee would be deducted from the Maximum IBRD PRG Guaranteed Amount and even if Bulk Trader's payment default is remedied, following a payment under the Guarantee, those amounts would not be reinstated.
Bulk Trader's obligation to Replenish the Buyer Payment Security under the PRG Support Agreement:	The Bulk Trader will undertake under the PRG Support Agreement to maintain at all times the Stated Amount to be available for drawing under the Buyer Payment Security; provided that a failure to maintain such balance will not constitute a Bulk Trader's default under the PPA so long as (i) Bulk Trader is current on its payment obligations under the PPA, and (ii) Bulk Trader repays the Issuing Bank and replenishes any amount drawn under the Buyer Payment Security within 12 months after the date of the drawing (see also

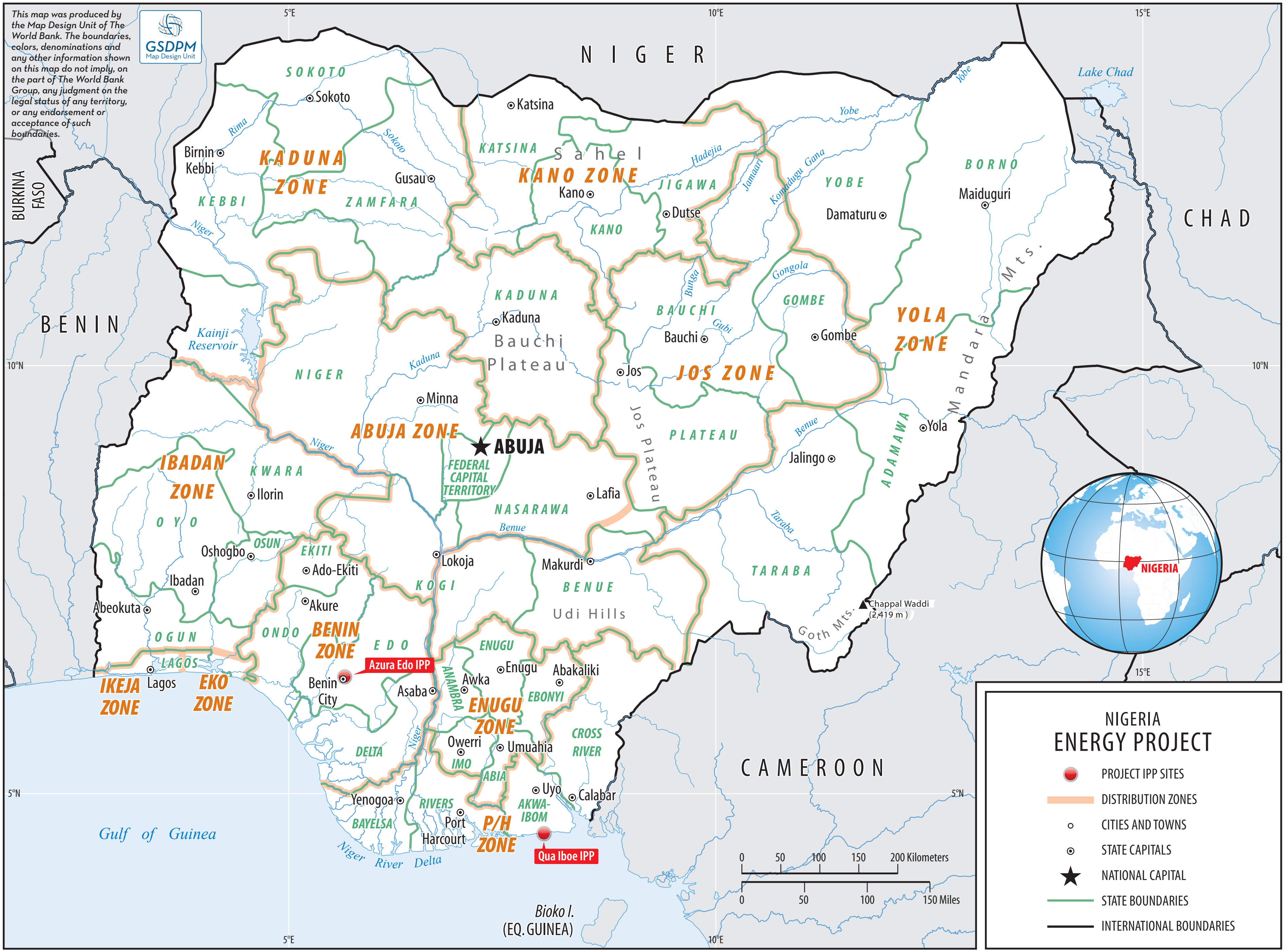
	Reimbursement Period above).
Interest Rate on Drawings During the Reimbursement, Period Charged by the Issuing Bank:	A spread acceptable to the Bulk Trader and IBRD, and payable by the Bulk Trader.
Maximum IBRD Guaranteed Amount:	The IBRD PRG shall be capped at the Stated Amount (which is an amount to be agreed between Seller and Bulk Trader not to exceed US$150 million), plus accrued interest. The Buyer Payment Security shall be available for drawings by the Beneficiary upon filing of a claim on the basis of drawdown mechanisms and the presentation of supporting documentation to be agreed between the parties in the PRG Support Agreement and the Buyer Payment Security instrument, and satisfactory to the IBRD.
Maximum IBRD PRG Period:	The Security Validity Period plus 14 months.
IBRD PRG Fees (recurring)[41]:	50[42]bps per annum on the Maximum IBRD PRG Guaranteed Amount (and interest thereon) which is callable under the IBRD Guarantee, payable six monthly in advance by the Seller.
IBRD Upfront Fees[43]:	(e) A Front-End Fee of 25bps of the Maximum IBRD PRG Guaranteed Amount payable by the Seller. (f) An Initiation Fee of 0.15% of the Maximum IBRD PRG Guaranteed Amount (but not less than US$100,000) payable by the Seller. (g) Processing Fee of up to 0.50[44]% of the Maximum IBRD PRG Guaranteed Amount payable by the Seller. (h) Reimbursement of IBRD outside legal counsel expenses by the Seller.
Fees of the Issuing Bank:	To be negotiated between Bulk Trader, the Issuing Bank, and the Seller, and payable by the Seller.

[41]FY14 pricing.
[42]For IBRD guarantees, the guarantee fee includes an annual maturity premium of 0.00% for maturities up to 12 years, 0.10% for maturities greater than 12 and up to 15 years, and 0.20% for maturities greater than 15 and up to 18 years (FY14 pricing).
[43]FY14 pricing.
[44] IBRD may charge higher than usual Processing Fee if internal costs are incurred over and above the expected costs of preparing and making the IBRD guarantees effective.

Conditions Precedent to the Effectiveness of the IBRD Guarantee:	Usual and customary conditions (to be satisfied in form and substance acceptable to the IBRD) for operations of this type including but not limited to the following: (f) firm commitment for sufficient financing to complete construction of the project, including satisfactory contribution of equity by the project sponsor(s); (g) execution, delivery and effectiveness of all project and financing agreements, satisfactory to IBRD, including execution and delivery of: (i) a Guarantee Agreement between the Issuing Bank and IBRD; (ii) a Reimbursement and Credit Agreement between Issuing Bank and Bulk Trader; (iii) a PRG Support Agreement between Bulk Trader and the Seller; (iv) a Project Agreement between the Seller and IBRD; (v) a Cooperation Agreement between the Bulk Trader and IBRD; (vi) an Indemnity Agreement between IBRD and FGN; and (vii) the PPA between the Seller and NBET. (h) Delivery of all relevant host country environmental approvals required for the operation of the project, and compliance with all applicable World Bank requirements relating to environmental and social safeguards and sanctionable practices[45]. (i) provision of satisfactory legal opinions; and (j) Payment in full of the Upfront Fees, and the first installment of the IBRD Guarantee Fee.
Guarantee Agreement:	The terms and conditions of the IBRD PRG would be embodied in a Guarantee Agreement between the Issuing Bank and IBRD.
Project Agreement:	The Seller would enter into a Project Agreement with IBRD in respect of the IBRD Guarantee. Under such agreement, the Seller will provide reports (including audit reports) and other relevant Project information, and make warranties, representations and covenanted undertakings, including in respect of compliance with applicable environmental laws and relevant World Bank environmental and social safeguards and World Bank anti-corruption policies and procedures, including relating to sanctionable practices. **IBRD may suspend or terminate the Guarantee if the Seller breaches the warranties, representations or undertakings under the Project Agreement.**
PRG Support Agreement:	Bulk Trader will enter into a PRG Support Agreement with the

[45] "Sanctionable practices" include corrupt, fraudulent, collusive, coercive, or obstructive practices.

	Seller under which Bulk Trader would undertake to indemnify the Seller for the loss of revenues resulting from the occurrence of a Guaranteed Event on the basis of drawdown and dispute resolution mechanisms and supporting documentation to be agreed between the parties and satisfactory to IBRD and to be consistent with the provisions under the PPA.
Reimbursement and Credit Agreement:	Bulk Trader will enter into a Reimbursement and Credit Agreement with the Issuing Bank in which it will undertake to repay the Issuing Bank the amounts drawn under the Buyer Payment Security, together with accrued interest, within the Reimbursement Period.
Indemnity Agreement:	FGN would enter into an Indemnity Agreement with IBRD. Under this agreement, FGN would undertake to indemnify IBRD on demand, or as IBRD may otherwise determine, for any payment made by IBRD in connection with the IBRD PRG. If FGN breaches any of its obligations under the *Indemnity Agreement* or if NBET breaches any of its obligations under the Cooperation Agreement, IBRD may suspend or cancel, in whole or in part, the rights of FGN to make withdrawals under any other loan or credit agreement with IBRD or IDA, or any IBRD loan or IDA credit to a third party guaranteed by FGN, and may declare the outstanding principal and interest of any such loan or credit to be due and payable immediately. A breach by FGN under the *Indemnity Agreement* will not, however, cause prejudice to any existing guarantee obligation of the IBRD under the IBRD Guarantee. The Indemnity Agreement will follow the legal regime, and include dispute settlement provisions, which are customary in agreements between member countries and IBRD.
Cooperation Agreement:	NBET would enter into a Cooperation agreement with IBRD pursuant to which it will undertake to (i) comply with all its obligations under the transaction documents to which it is a party, including promptly replenish the Buyer Payment Security if it is ever drawn; (ii) will obtain IBRD's consent prior to agreeing to any change to any transaction document which would materially affect the rights or obligations of IBRD under the IBRD Guarantee or any other transaction document (including prior to exercising any termination rights under the PPA); (iii) will provide certain notices to IBRD; (iv) will take all action necessary on its part to enable the Seller to perform all of the Seller's obligations under its Project Agreement with IBRD, and other relevant transaction document; (v) will cooperate with IBRD and furnish to IBRD all such information related to such matters as IBRD shall reasonably request; and promptly inform IBRD of any condition which interferes with, or threatens to interfere with, such matters; and (vi) will comply with certain account management obligations in connection with the Project revenues.
Choice of Law:	English law.



NOVEMBER 2013

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