Nigerian Gas Master Plan

1st Edition

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Introduction

Nigeria's potential as a major global gas supply and utilisation hub is high. The Nigerian Gas Master Plan was devised as a major interventionist concept to move the gas sector from its essentially dormant status in 2006 to a market-based system with willing sellers and willing buyers, realising the full potential of the sector for the benefit of all Nigerians.

The Nigerian Gas Master Plan is articulated in this document in three distinct chapters:

Part A: Context for the Gas Master Plan provides the structure and status of Nigeria's gas sector as it was historically, outlining the compelling rationale for a transitional period of government intervention;

Part B: The Policy Interventions describes the major government interventions aimed at jumpstarting the domestic market;

Part C: Current Status summarises the progress made to date (August 2013), and the growth achieved by the gas sector as a direct result of the interventions made.

The Nigerian Gas Master Plan represents an active and live plan that is periodically updated to effectively address changing market conditions and remain aligned with the ultimate growth vision for the gas industry. This document represents the 1st Edition.

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Table of Contents

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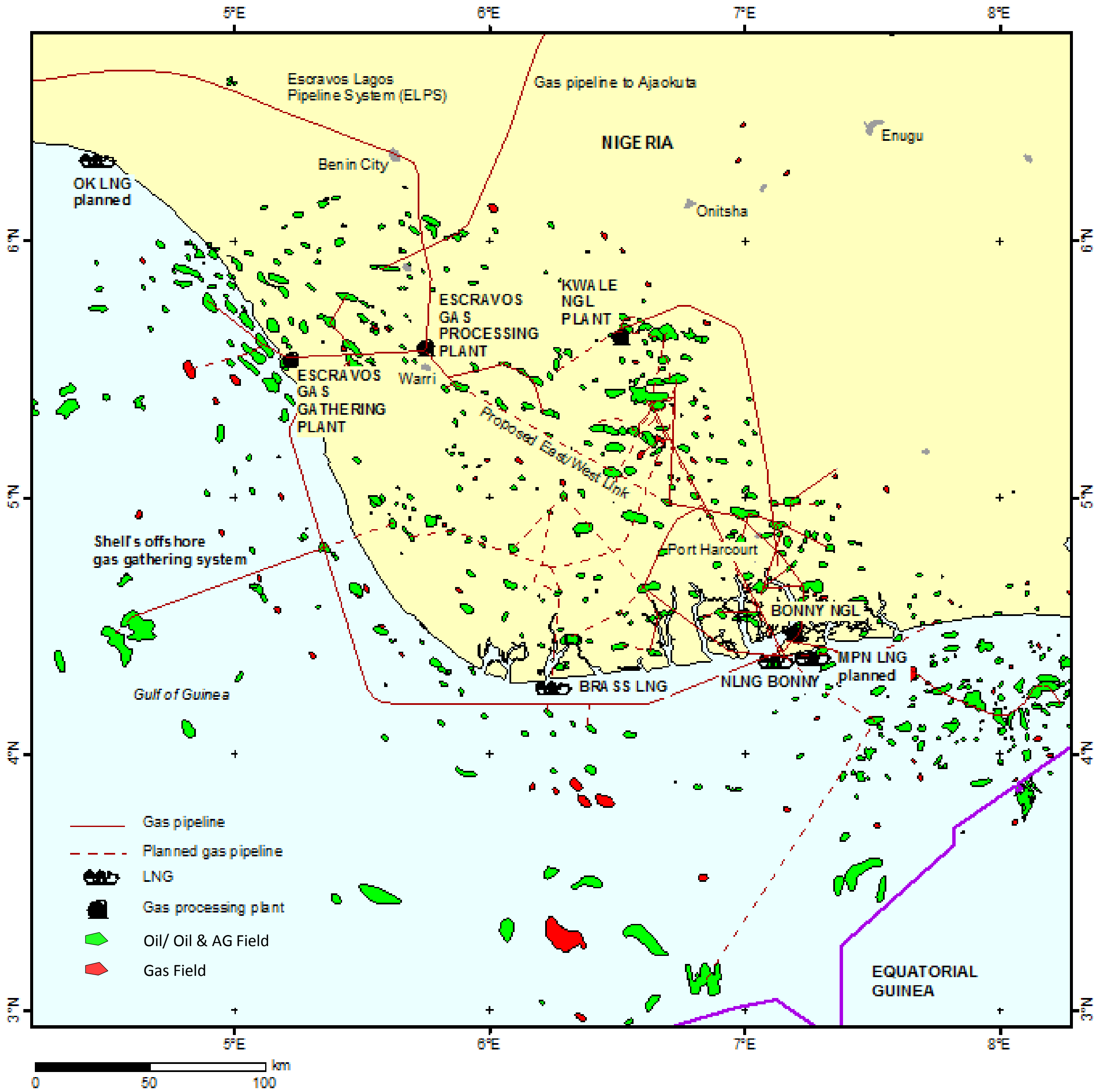
Part A: Context for the Gas Master Plan

1 Nigeria's Upstream Gas Sector

1.1 Substantial Gas Reserves

Nigeria's gas reserves are primarily located in the Niger Delta Basin which consists of 75,000 square kilometres of onshore swamp and extends offshore into shallow water and finally into deep-water frontier territory up to 150 kilometres offshore. Reservoirs are typically small, with hundreds of low volume deposits throughout the delta.

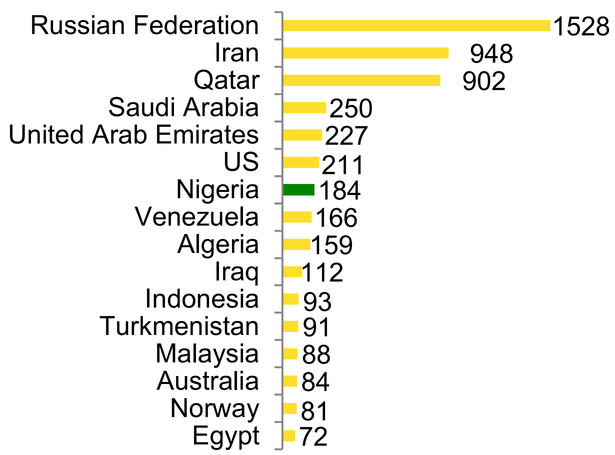
Figure 1.1: Nigeria Gas Fields and Infrastructure



Source: Wood Mackenzie and NNPC Gas Master Plan Team

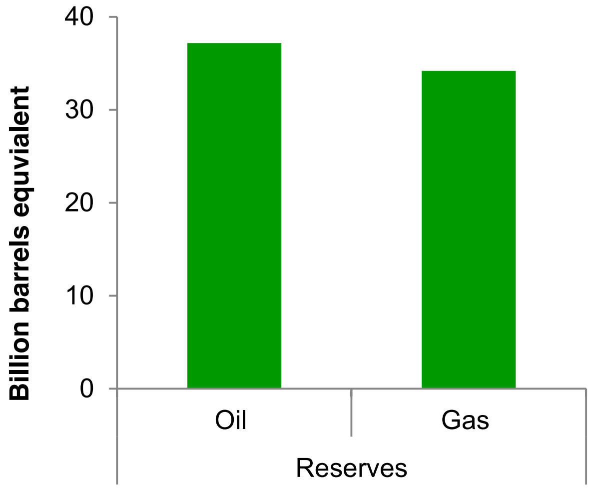
When considered on an aggregate basis, Nigeria's gas reserves are considerable. By the mid 2000s, Nigeria held the world's 7th largest proven reserves of natural gas. Furthermore, the volume of Nigeria's proven gas reserves is almost equivalent to the volume of Nigeria's oil reserves, which have consistently supported the development and growth of the nation since oil production began in 1958.

Figure 1.2: Global Proved Gas Reserves in 2006, tcf



Source: BP Statistical Review

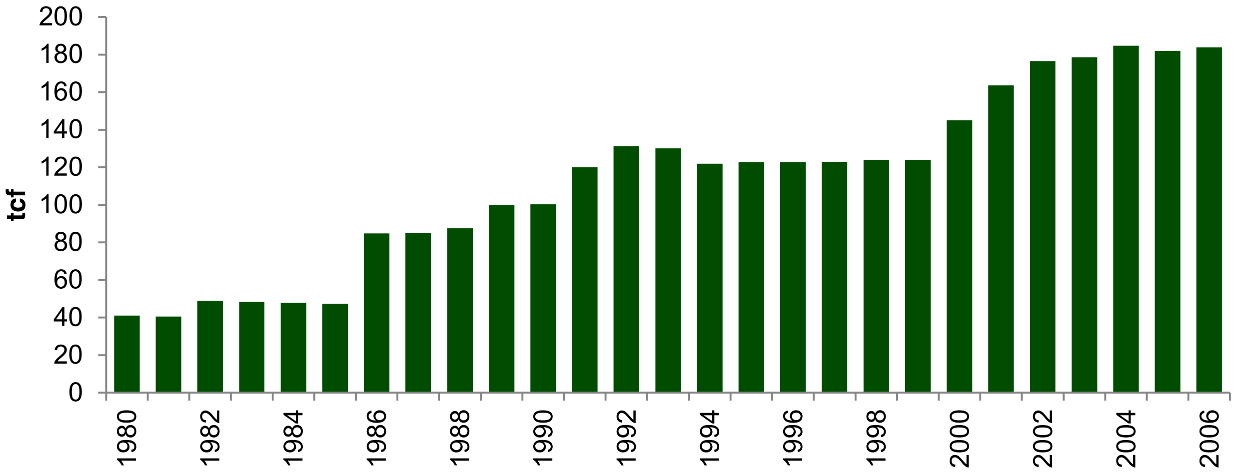
Figure 1.3: Nigerian Oil and Gas Reserves in 2006



Source: BP Statistical Review

Discoveries to date have largely resulted from exploration for oil, rather than from dedicated gas exploration. Despite this, gas reserves have grown from 123 tcf to more than 180 tcf in recent years (Figure 1.4). Indeed over 19 tcf of gas reserves were added from deep-water discoveries alone between 1999 and 2003. In addition to the considerable discovered resources of natural gas, there is widespread expectation of significant upside potential for Nigeria's proven gas reserves. A US Geological Survey estimates that the gas reserves potential in Nigeria could be as high as 600 trillion cubic feet.

Figure 1.4: Nigeria Gas Proven Reserves (P1+P2), 1995 – 2006



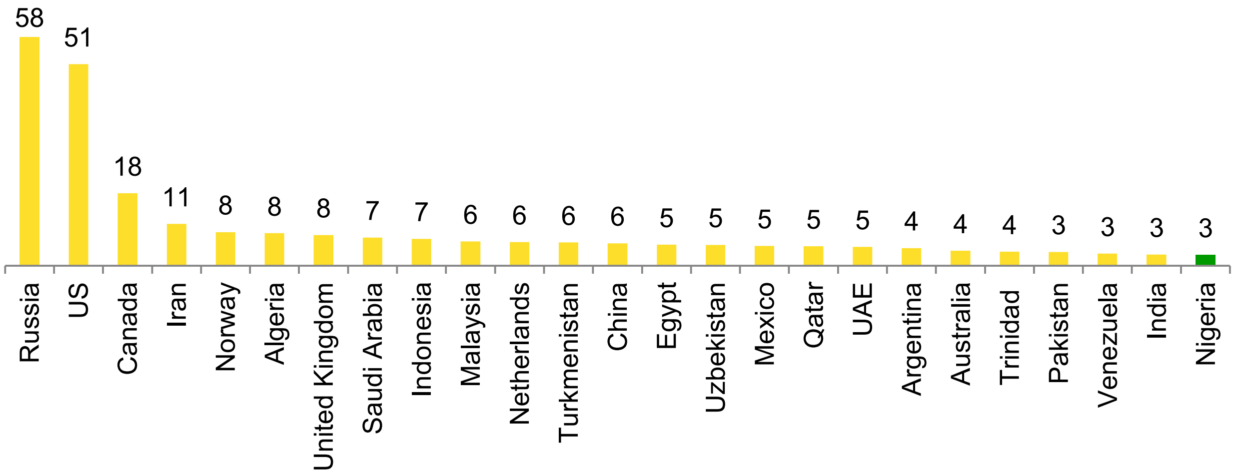
Source: BP Statistical Review

The level of undeveloped gas reserves coupled with limited commercial exploitation created limited incentive for companies to target gas in exploration ventures. The emergence of clear commercial pathways to monetise the country's large resource base of natural gas in both the domestic market and export markets of the future will undoubtedly drive future gas exploration within the Niger Delta Basin and in other basins.

1.2 Limited Exploitation of Gas Reserves

Despite this world-class resource base, Nigeria's gas reserves have historically remained largely untapped. Although Nigeria held the 7th largest gas reserves in the world, production levels of sales gas (i.e. excluding flaring and re-injection) in 2006 ranked only 25th globally.

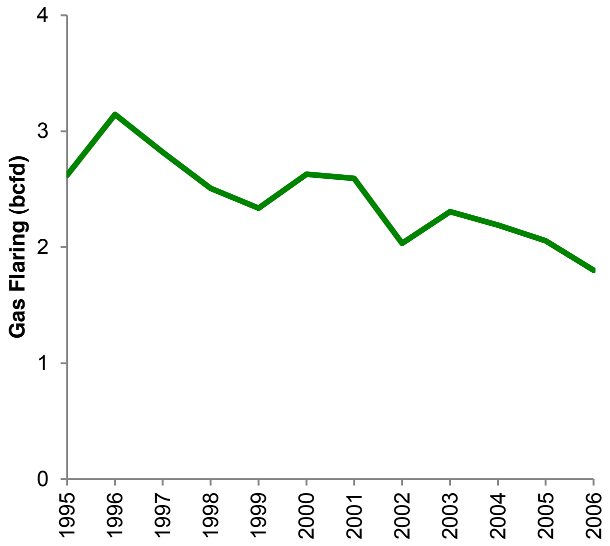
Figure 1.5: Global Gas Production in 2006, bcfd



Source: BP Statistical Review

Sales gas (i.e. gas sold for export or for domestic consumption) in Nigeria has historically been at considerably lower levels than actual gas production rates. The mismatch has primarily been caused by gas flaring. Most of the flared gas in Nigeria is associated gas produced from Nigeria's oil fields, as gas has historically been viewed as a nuisance by-product by the producers due to lack of access to monetisation routes. As such, flaring of considerable quantities of gas enabled producers to focus on the optimal development and production of the oil reserves without necessarily developing monetisation routes for the associated gas produced.

Figure 1.6: Nigeria Gas Flaring, 1995 – 2006



Source: BP Statistical Review

Environmental concerns led to increased focus on gas flaring and during the 1990s the Nigerian government made a number of commitments to reduce flaring and potentially end the practice by 2008.

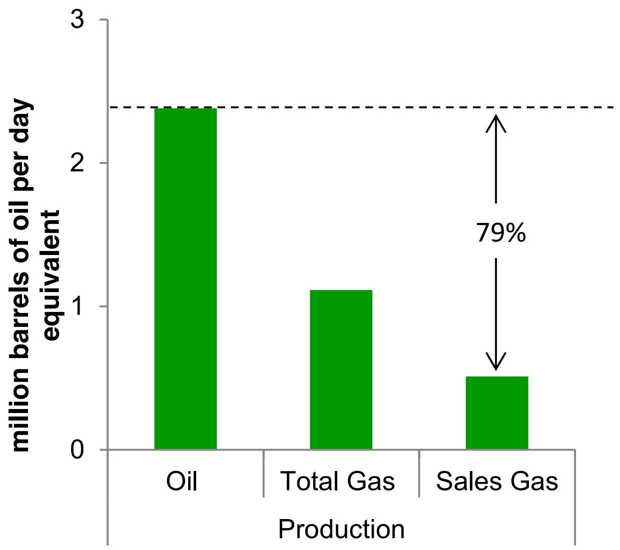
Gas flaring had been steadily reducing from peak levels in 1996 of more than 3 bcfd to around 2 bcfd in 2006.

This was achieved by providing monetisation routes for associated gas production. For example, the Cawthorne Channel project gathered 200 mmcfd of associated gas (which was previously being flared) from Cawthorne Channel, Awoba and Krakama oilfields located in the Niger Delta for use in power generation and as feedstock to NLNG.

Despite this encouraging progress, less than half of production was sales gas, with 37% being flared and a further 17% being used for re-injection and gas lift.

The net result is that Nigeria's natural gas resources have been considerably under-exploited. Despite similar reserves of oil and gas (on an energy equivalent basis), monetisation of Nigeria's rich hydrocarbon resources has been heavily skewed towards oil.

Figure 1.7: Oil and Gas Reserves and Production, 2006



Source: BP Statistical Review

The level of untapped natural gas resource in Nigeria was significant – the opportunity to grow the sector by both capturing gas not already flared and through the development of new fields was unparalleled on a global scale.

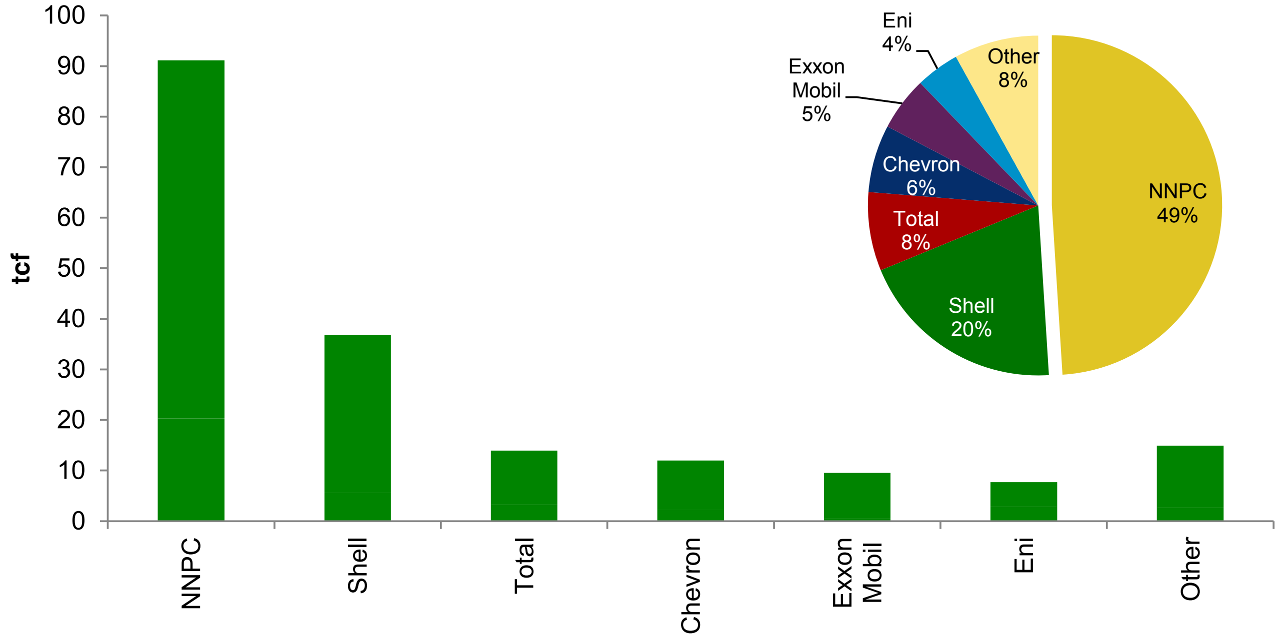
1.3 The Dominance of the Super Majors

The majority of Nigeria's gas reserves were held under long-established concessions of just six upstream JV operations:

- Chevron Nigeria Ltd. (CNL) – operator of the NNPC/CNL JV (NNPC – 60%, CNL – 40%);
- Mobil Producing Nigeria Unlimited (MPN) – operator of the NNPC/MPN JV (NNPC – 60%, MPN – 40%);
- Nigerian Agip Oil Company Limited (NAOC) – operator of the NNPC/NAOC JV (NNPC – 60%, NAOC – 20%, and ConocoPhillips - 20%);
- Shell Petroleum Development Company (SPDC) – operator of the NNPC/SPDC/TEPNG/NAOC JV (NNPC – 55%, SPDC – 30%, TEPNG – 10%, and NAOC – 5%);
- Total E&P Nigeria Limited (TEPNG) – operator of the NNPC/TEPNG JV (NNPC – 60%, TEPNG – 40%);
- Pan Ocean Oil Corporation (Nigeria) – operator of the NNPC/Pan Ocean JV (NNPC – 60%, Pan Ocean – 40%).

On a company basis, NNPC held the largest working interest in total proven gas reserves (due to its majority equity stake in JV operations), followed by Shell (20%), Total (8%), Chevron (6%) and Eni (4%).

Figure 1.8: Working Interest Remaining Gas Reserves in Nigeria in 2006



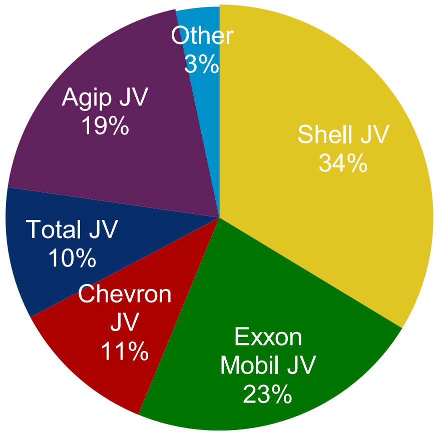
Source: Wood Mackenzie Corporate Service

Correspondingly around 97% of the gas produced in Nigeria was also from NNPC's Joint Ventures with the Super Majors (see Figure 1.9).

Only 3% of the total production came from the PSCs and other licences.

This market structure came both with positives and negatives. On the positive side, the Super Majors brought considerable experience in development and monetisation of gas resources. However, the presence of such formidable and capable participants was a key driver of the development of project-centric, segregated clusters of infrastructure, rather than a coordinated nation-wide approach to gas monetisation.

Figure 1.9: Gas Production in Nigeria in 2006



Source: NNPC Annual Statistical Review, 2006

1.4 Development of Project-Centric Gas Infrastructure

The evolution and development of gas infrastructure in Nigeria largely resulted from both the location in which the JVs were operating, in addition to the location of demand centres. In general, the Super Majors tended to operate their gas interests in isolation of each other. This resulted in the development of project centric (point to point) infrastructure, rather than an integrated system.

The Super Majors had highly diversified downstream interests, with a trend towards LNG as core. Essential infrastructure such as gas processing facilities and pipelines were owned, as follows:

IOC	Transmission Assets	Downstream Assets
Shell	OGGS, WAGP, Part owner of GTS1, Numerous tie-in lines	NLNG, OKLNG (future)
ChevronTexaco	WAGP	EGTL, LPG and LNG (future)
Exxon Mobil		NGL and NLNG (future)
Total	Part owner of GTS 1	NLNG
Agip	Part owner of GTS 1/2/4	NLNG, Brass LNG (future)

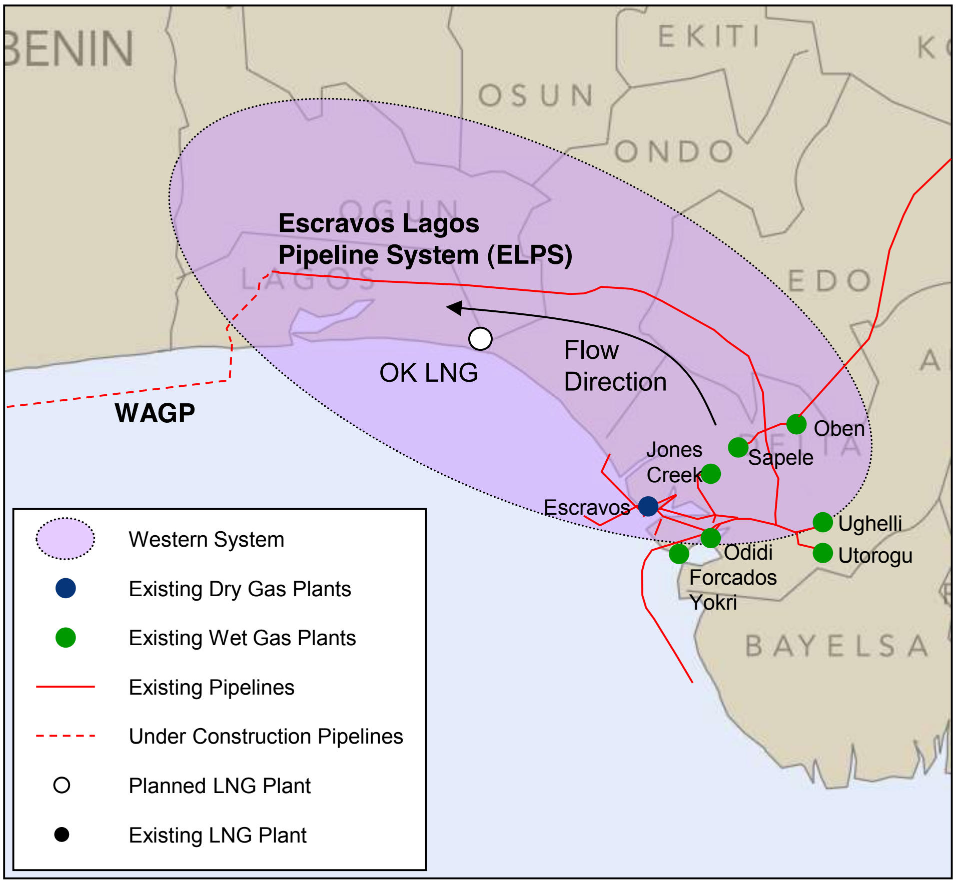
The resulting infrastructure grid was not entirely connected, and three separate discrete systems had been developed to serve the domestic market in the West, the East, and the LNG market:

- The Western System with gas flowing West towards Lagos, and North towards Ajaokuta, supplied gas for domestic use in the Western region of Nigeria and beyond Nigeria to Togo, Benin and Ghana;
- The Eastern Domestic System supplied gas to the domestic industrial and power users in Nigeria's Rivers, Akwa Ibom and Abia States;
- The Export System consisted of an Onshore Gas Transmission System (GTS) and an Offshore Gas Gathering System (OGGS) that gathered gas and transported it to NLNG for export.

Western Domestic System

The Western Domestic System comprised of the Escravos Lagos Pipeline System (ELPS), a 700km pipeline, which had a capacity of 1100 mmcfd. This pipeline system supplied the growing demand from the power and non-power sectors in Western Nigeria. The ELPS was supplied mainly by the Utorogu, Escravos, Sapele, Ughelli, Odidi and Oben gas plants, which were operated by Shell Petroleum Development Company (SPDC) and Chevron Nigeria Limited (CNL). As shown in Figure 1.10 below, the gas flowed west from Escravos to Lagos. The system also comprised of the Oben - Ajaokuta pipeline.

Figure 1.10: Gas Infrastructure, Western System, 2006



Existing Pipelines	Capacity (mmcfd)
ELPS	1100
Oben – Ajaokuta	320

Export Infrastructure	Capacity (mmcfd)
WAGP (under construction)	500
OK LNG (Proposed)	3300* (22 mmtpa)

**Assumes 9% Liquefaction losses*

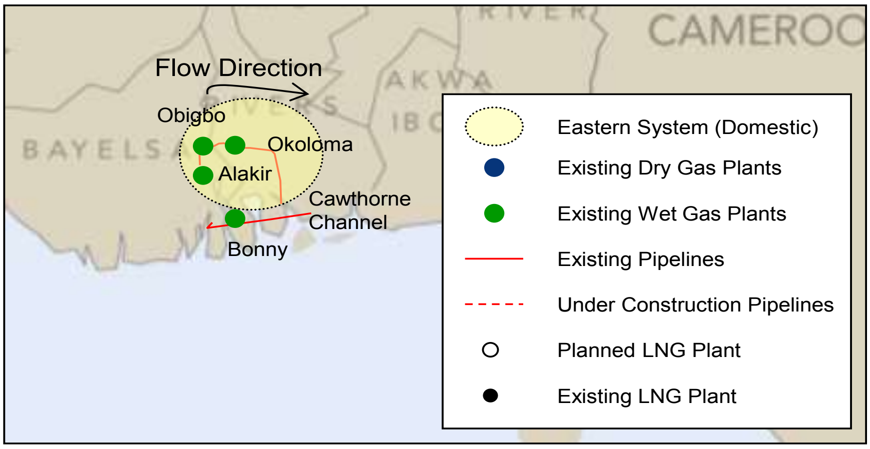
In addition to the existing system, there were a number of either proposed projects or projects under development in the Western System:

- The West Africa Gas Pipeline (WAGP);
- The four-train, 22 mmtpa capacity Olokola (OK) LNG project was planned to be developed in the Ogun State;
- The Trans-Saharan Gas Pipeline, which would extend further North, was planned to supply up to 2-3 bcfd of gas to Algeria and onwards to European markets;
- The Escravos Lagos Offshore Pipeline System (ELOPS), with a capacity of 1.25 bcfd was proposed to transport gas from Escravos to Lagos.

Eastern Domestic System

The Eastern Domestic System, in 2006, supplied gas to domestic industrial and power users. The Obigbo North – Ikot Abasi was considered the major trunk line in the eastern system and was supported by the main gas plants of Obigbo, Alakiri, and Okoloma, which were operated by SPDC. The pipeline system transported what was basically wet gas from these plants to the existing domestic market in the East. As shown in Figure 1.11 below, the flow direction was eastwards from Obigbo.

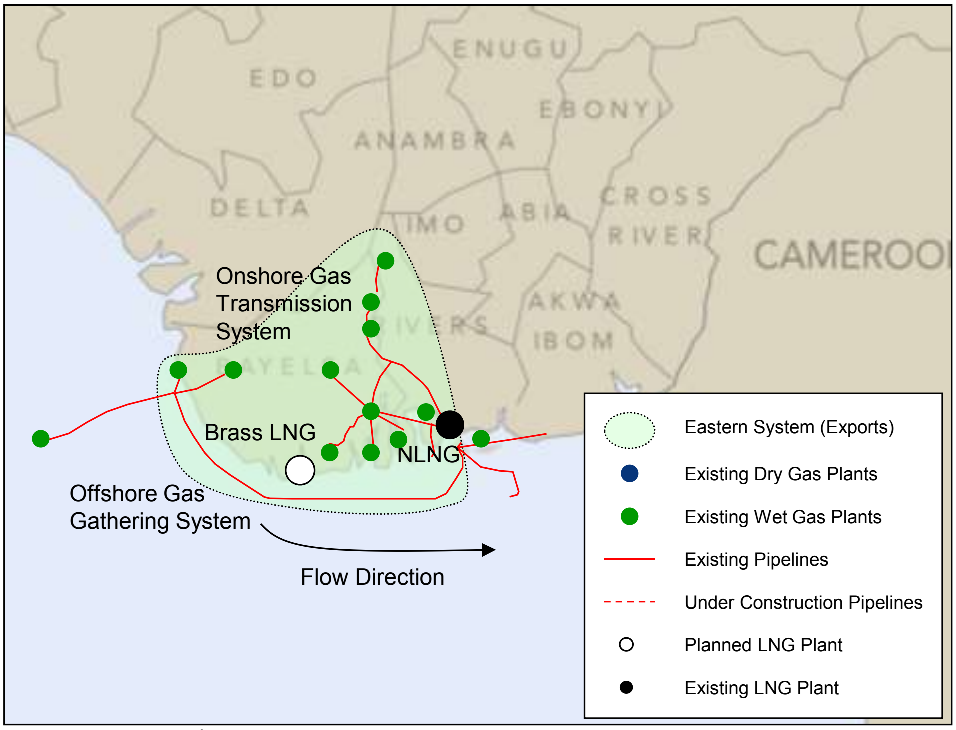
Figure 1.11: Gas Infrastructure, Eastern System in 2006



Export System

The Eastern system consisted of an onshore Gas Transmission System (GTS) and an Offshore Gas Gathering System (OGGS). The GTS gathered gas from Obiafu, Soku, Obite and Belema gas plants and transported it to NLNG for export. The OGGS gathered gas from dedicated fields offshore and transported it to NLNG for export.

Figure 1.12: Gas Infrastructure, Export System, 2006



Export Infrastructure	Capacity (mmcfd)
NLNG (operational)	3300* (22 mmtpa)
Brass LNG (Proposed))	1500* (10 mmtpa)

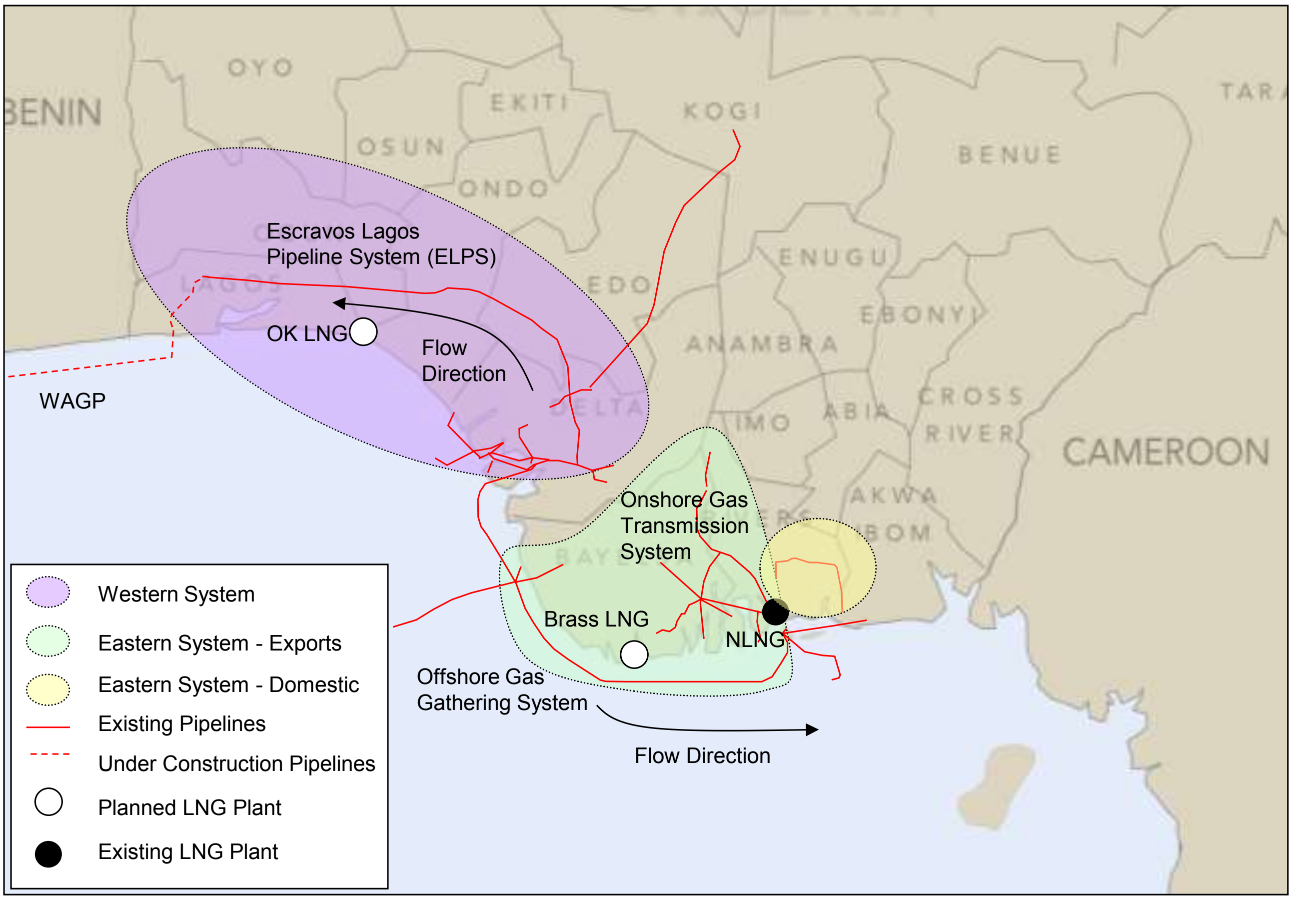
**Assumes 9% Liquefaction losses*

In addition to the existing system, the two-train 10 mmtpa capacity Brass LNG project was planned to be developed at Brass River.

The Fragmented Infrastructure Systems as a Platform for Growth

The graphic below provides a nationwide overview of the as-yet unconnected discrete infrastructure systems.

Figure 1.13: Gas Infrastructure in Nigeria, 2006



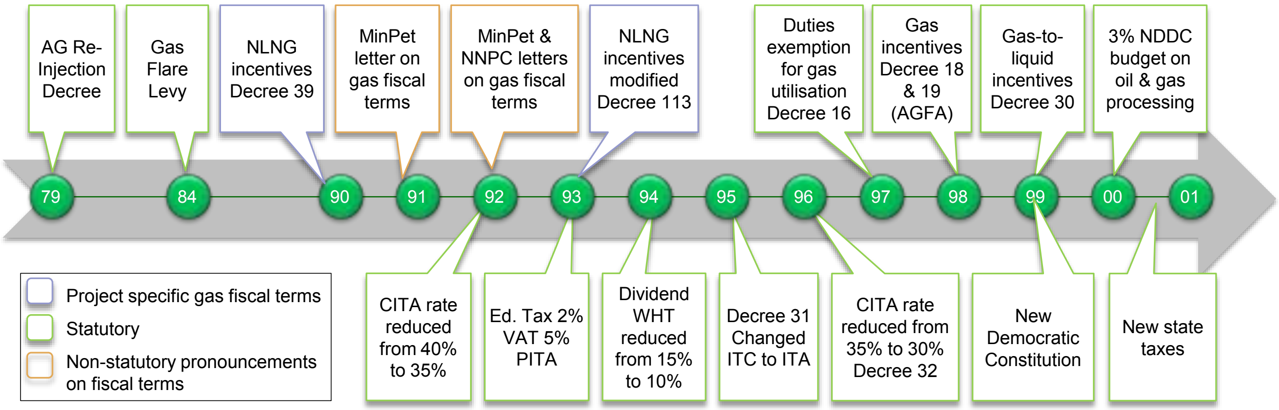
As is seen in other countries, the development of project-centric infrastructure can eventually allow interconnection providing a more robust and interconnected network to allow gas to move freely throughout the country.

The current pipeline system in Nigeria therefore provides a solid platform for a more robust interconnected system, and provides a solid base to expand to the North of the country, where there is currently no gas infrastructure.

1.5 Historical Fiscal Incentives to Kick-Start Nigeria's Gas Sector

Over the last 30 years, the Nigerian Government has made concerted efforts to ensure that there was a favourable climate for investment in the country's gas sector through its fiscal terms. These interventions have been focused on encouraging investment in both the upstream and downstream gas sectors and have targeted both associated gas and non-associated gas projects and were instrumental in the development of Nigeria's significant LNG export business. A summary of the key gas interventions is highlighted below.

Figure 1.14: Historical Fiscal Developments for Natural Gas in Nigeria



Source: NNPC Gas Master Plan Team

Upstream Fiscal Incentives

The fiscal incentives for upstream producers were introduced under section 10A of the Petroleum Profit Tax Act (PPTA), and included:

- **AGFA (Decree 18 and 19)**
  - Investments required to separate crude oil and gas from the reservoir into usable products could be considered as part of oil field development capex and thus deducted from PPT;
  - Capital investment on facilities & equipment used to deliver associated gas in a usable form to either the end-user or a designated custody transfer points could be treated, for tax purposes, as part of capital investment for oil development. The resulting capital allowances were deducted from PPT (at a marginal rate of 85%);
- **Gas-to-liquid incentives (Decree 30)**
  - The upstream producer was exempted from payment of royalty and PPT on any gas that was transferred to a GTL project.

Downstream Gas Fiscal Incentives

The applicable fiscal terms for downstream gas were included in Section 28G in CITA (Companies Income Tax Act). Company income tax rate was 30%, with a number of incentives to offset against taxes payable. To benefit from these incentives, companies were required to *"invest in natural gas liquid extraction facilities to supply gas in usable form"*. Gas supply in 'usable form' under CITA was defined as: "*the marketing and distribution of natural gas for commercial purpose and include power plant, liquefied natural gas, gas to liquid plant, fertilizer plant, gas transmission and distribution pipelines*".

The incentives (Decree 18, 1998) allowed for the following:

- Tax free period of up to 5 years, the minimum being 3 years (Decree 30, 1999):
  - The tax free period of a company shall start on the day the company commences production as certified by the Ministry of Petroleum resources;
- Tax free dividend during the tax free period where:
  - The investment for the business was in foreign currency, or
  - The introduction of imported plant and machinery during the period was not less than 30% of the equity share capital of the company;
- Accelerated capital allowance after the tax free period, as follows:

    - An annual allowance of 90% with 10% retention for investment in plant and machinery (Decree 19, 1998);
    - An additional investment allowance of 15% which shall not reduce the value of the asset; (Decree 30 1999);
- Interest payable on loan obtained with prior approval of the Minister for a gas project shall be deductible.

NLNG Fiscal Incentives

Nigerian Liquefied Natural Gas (NLNG) Act 1990 also provided additional incentives including:

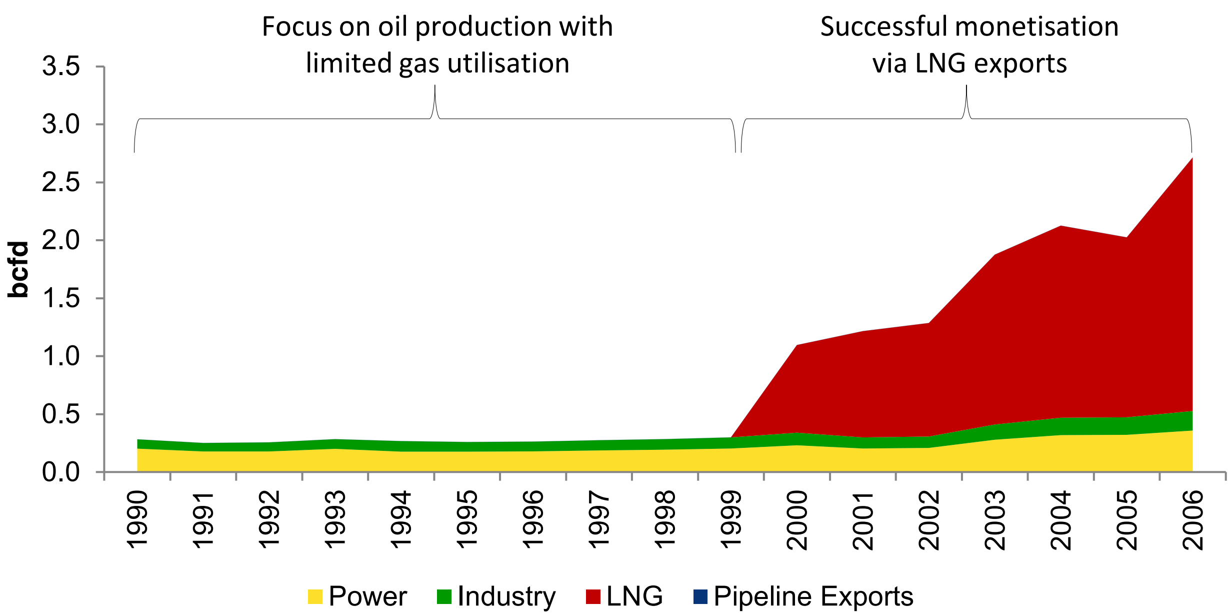
- NLNG received a 10 year tax holiday/break;
- NLNG was exempt from withholding tax on interest and dividend paid to non-residents and from income tax on work or services provided by non-residents.

These project specific fiscal incentives, when combined with AGFA and CITA incentives, provided sufficient commercial motivation to the IOCs in order to kick start the export market, and thus a marked increase in gas utilisation.

2 Evolution of Gas Utilisation

Despite relatively flat historic gas production, utilisation of natural gas had evolved through two distinct eras:

Figure 2.1: Historic Eras of Gas Utilisation



Source: IEA (power, industrial demand), Wood Mackenzie (LNG demand)

The first era of the Nigerian gas sector reflected the start of gas production in 1975 until the commencement of operations at NLNG in the late 1990's. This demand constrained era was marked by intense gas flaring, the introduction of a number of incentives to promote investment in gas utilisation with a focus on developing NLNG as this was considered the most promising route for gas monetisation. The first era, hence, resulted in the birth of an export-oriented gas sector.

The successful implementation of NLNG in 1999 heralded the start of the second era in the evolution of Nigeria's gas sector. This was characterised by a rapid growth in gas monetisation via exports of high value LNG, the beginning of steady decline in flaring, and initiation of new export orientated conversion projects (GTL). This era also saw a small increase in the utilisation of gas in both the domestic power and industrial sectors.

This second era highlighted the potential for the sector to respond to attractive market opportunities, and the positive impact that government interventions had on stimulating downstream export projects.

2.1 Modest Growth in Domestic Gas Consumption

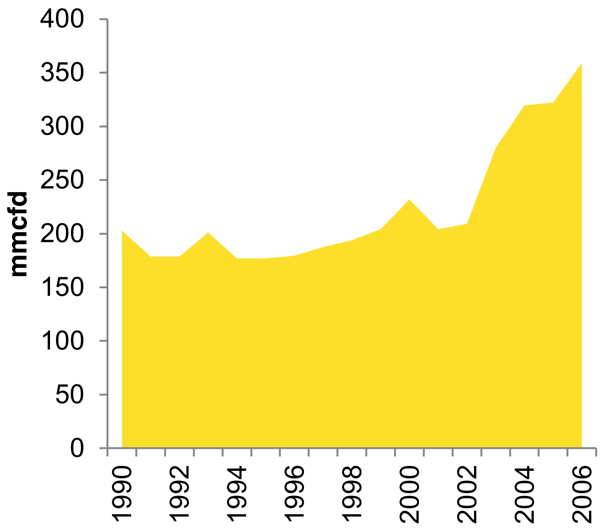
Gas consumption in the domestic market in Nigeria was relatively flat at approximately 0.3 bcfd throughout the 1990s. However, from 2002, Nigeria began to experience a general increase in domestic demand, and by 2006, gas consumption in the domestic market had reached just over 0.5 bcfd. This growth was mostly driven by the power sector, which comprised around 70% of total Nigerian domestic gas consumption.

Power Sector

The Nigerian power sector comprised of the Federal Government of Nigeria (FGN) owned Power Holding Company of Nigeria (PHCN), which was formed from the erstwhile National Electric Power Authority; another state-owned company called the Niger Delta Power Holding Company (NDPHC) tasked with developing new gas-fired generation and transmission projects (the National Integrated Power Projects – NIPP); and several Independent Power Producers (IPPs). As such, PHCN was the holding company for six generating companies, the transmission company and 11 distribution companies. Existing IPPs and the majority of future IPPs were intended to sell their power exclusively to PHCN.

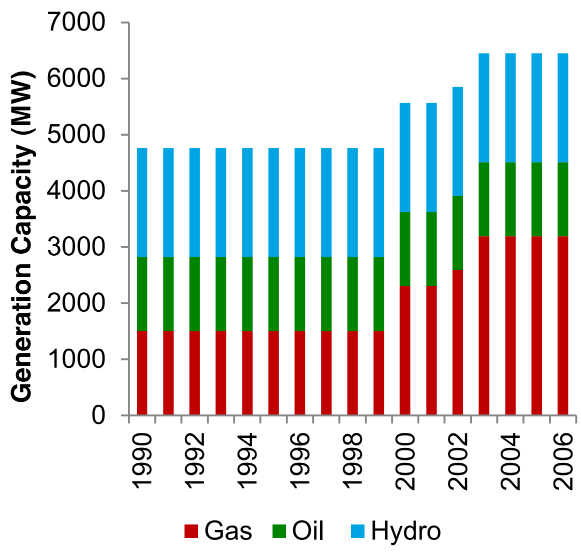
Starting in 2000, the power sector began making significant investments in gas-fired power capacity, and by the end of 2006, an additional 1689 MW had been commissioned (Figure 2.3). During the same period, gas consumption from power had increased by 55% (Figure 2.2).

Figure 2.2: Gas consumption by the power sector



Source: Historical Data Provided by IEA

Figure 2.3: Power generation, by fuel



Source: Wood Mackenzie Energy Market Service

Historic Gas Use in Industry

Industrial gas demand in Nigeria has historically come from a variety of small industrial uses, such as industrial heaters, boilers, ceramics, and kilns.

Initial attempts to kick start Nigeria's industrialization through the establishment of gas based industries saw limited success:

- Nigeria had one existing gas-based fertiliser production facility, Notore's 0.6 mmtpa Urea plant in Rivers State. This plant had been shut-down in 1999, and was not yet operational in 2006. Notore Chemical Industries Limited took over these assets from NAFCON (the FGN owned fertiliser entity) in 2005, and were in the process of rehabilitating the plant. In 2006, they had signed a 20 year Gas Supply Contract with the National Gas Company (NGC);

- Nigeria had two crude steel producers, Ajaokuta Steel's 1.35 mmtpa Blast Furnace and Delta Steel's 1 mmtpa Electric Arc Furnace at Aladja. Both these facilities were suffering a number of problems in 2006. Ajaokuta's Steel Blast Furnace had never been commissioned, but the plant's rolling mill had processed billets of steel. Delta Steel's facility was not able to operate at full capacity due to a number of problems, including the reliability of the power supply;
- The total installed capacity for cement production in Nigeria was about 11-12 mmtpa; however, production rates were estimated to be much lower due to power outages and insufficient natural gas supply. Gas-fired cement facilities included the Obajana Cement facility, and the WAPCO (West Africa Portland Cement Company) facilities at Ewekoro, and Shagamu;
- Nigeria had one existing aluminium production facility, the ALSCO smelter in Akwa – Ibom State which had a capacity of 197,000 tonnes per annum, and was expected to reach full production in 2011. At full production, this would require 140 mmcfd of gas; however, this facility was running well below capacity.

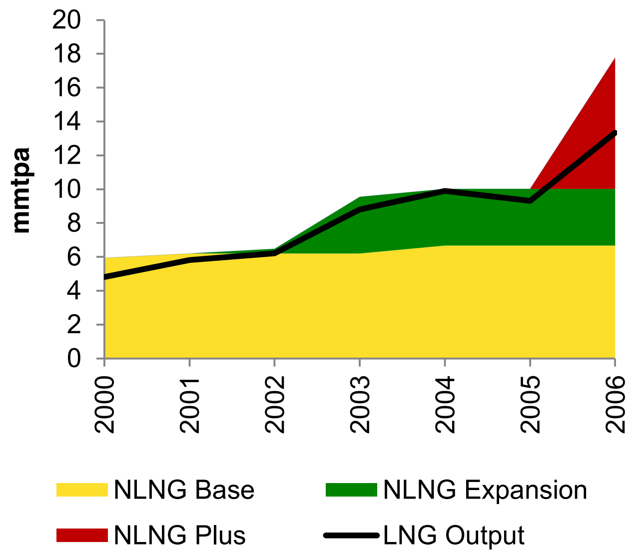
These stalled and failed developments can be characterised by poor management and limited funding from successive Governments, typically leading to their collapse and eventual privatization. The privatization of the steel and aluminium plants was inconclusive due to allegations of corruption in the process. The net result was that gas demand in the industrial and commercial sectors has historically remained well below its considerable potential. Important lessons have been learned about the nature and extent of Government participation in industrial gas sector. There is now broad acceptance that successful implementation of functioning gas-based industries will require private sector participation, and the Government's role should be limited to providing the appropriate commercial and regulatory frameworks to stimulate this.

2.2 Rapid Growth in Exports

LNG

The Nigeria LNG (NLNG) liquefaction facilities are located on Bonny Island in the Niger Delta. All of the project's trains are operated by the NLNG Company. They have the same participation – NNPC (49%), Shell (25.6%), Total (15%) and Eni (10.4%) - and are taxed within the same ring-fence.

Figure 2.4: NLNG Nominal Capacity and Output, 2000 - 2006



Source: Wood Mackenzie LNG Service

The plant had been producing since 1999, but can trace its roots as far back as the mid 1980s, when the concept of LNG from Nigeria was first considered. Improved fiscal terms for gas (AGFA, CITA, and project specific incentives), a desire to reduce flaring and monetise associated gas and increased demand for LNG in the Atlantic Basin markets enabled the plant to actually come to fruition. The NLNG plant had five operational trains with a sixth train (NLNG6) under construction and slated for completion in 2007. The historic output from NLNG and nominal capacity of each phase is shown in Figure 2.4.

Each phase was being supplied from a number of different supply areas (with differing equity participation). The initial NLNG Base project was supplied by the Shell/NNPC Joint Venture oil concession, the Total/NNPC Joint Venture oil concession and the AGIP/NNPC Joint Venture oil concession. As the additional LNG projects were developed, other fields operated by Shell (Bonga and EA) and Total (Amenam) started to supply the plant.

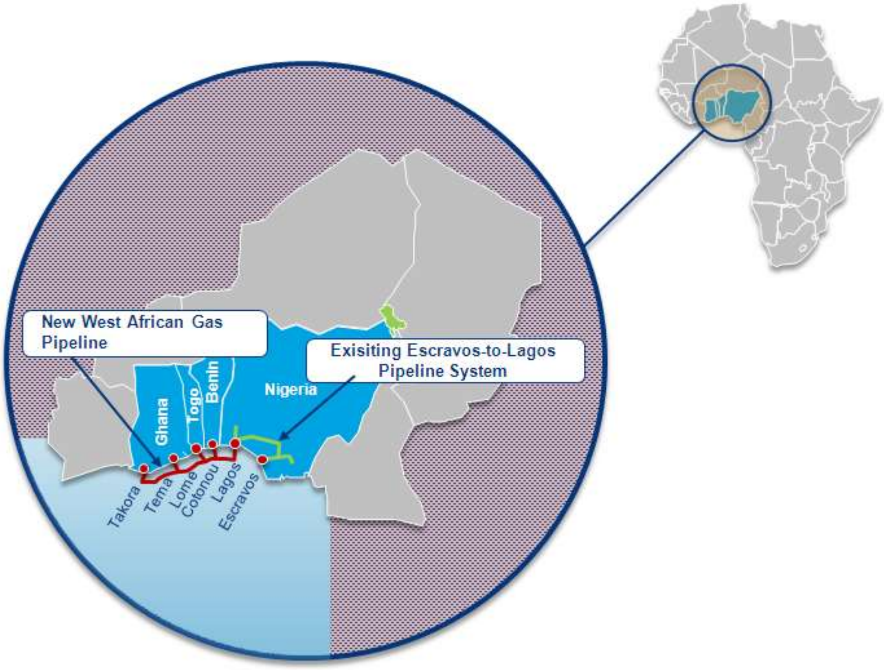
NLNG used approximately 2.2 bcfd of feedgas from these fields, and produced approximately 13.3 mmtpa of LNG. The LNG was sold under long term contract, which were signed on a project basis (i.e. NLNG Base, NLNG Expansion etc.). Most LNG sold from Nigeria was being sold into Europe.

The successful implementation and operation of NLNG provided a reliable and commercially viable means for monetising Nigeria's gas reserves via high value exports. The level of success has incentivised investment in additional capacity resulting in sustained and rapid growth in exports.

West Africa Gas Pipeline

The West Africa Gas Pipeline (WAGP) represented the first international gas pipeline for Nigeria. This was initially conceived in the 1980s and took FID in 2004. The pipeline was expected to cut gas flaring significantly by providing an export route for associated gas production.

Figure 2.5: Location of the West African Gas Pipeline



Source: Wood Mackenzie

The West African Gas Pipeline (WAGP) is 678 kilometres in length and 20 inches in diameter. It extends from the Western coast of Nigeria to the neighbouring markets of Ghana, Benin and Togo and runs mostly offshore. The pipeline was designed to supply cheap gas from Nigeria to markets in Ghana, Benin and Togo, thus displacing expensive solid and liquid fuels which were widely used in the region whilst also providing a diversification of gas exports for Nigeria.

The WAGP was to be operated by the West African Gas Pipeline Co (WAPCo), owned by a consortium of public and private sector companies from Benin, Ghana, Nigeria and Togo. The equity owners of WAGP were Chevron (36.7%), NNPC (25%), Shell (18%), Volta River Authority (16.3%), Societe Beninoise de Gaz (2%) and Societe Togolaise de Gaz (2%).

The initial volume throughput was expected to be around 120 mmcfd, and was expected to increase as markets grew and other industries adopted imported natural gas as the feedstock/energy source of choice.

The gas transported in the WAGP was produced and processed by two existing joint ventures (JVs) with the Nigerian National Petroleum Corporation (NNPC). These were the NNPC/Chevron JV and the NNPC/Shell JV. Under 20-year contracts, each JV was due to supply 50% of the gas.

The successful implementation of the WAGP provided Nigeria with a diversification of export routes away from its sole dependence on LNG whilst at the same time strengthening commercial ties with Nigeria's near neighbours.

3 The Burgeoning Market Opportunity

The massive growth in export related gas developments of the 2nd era had been propagated largely by governmental interventions in the early 1990s and sent a clear message of what could be achieved in terms of exploiting Nigeria's natural gas resources. Given the expected growth in gas demand in international markets as well as the huge future requirement for power and industry in the domestic market, the platform was set for the next era of Nigerian gas monetisation.

3.1 Huge Investment in Gas Fired Power Generation

Nigeria had one of the lowest electricity consumption per capita in the world; of the 93 countries reported, Nigeria had the 9th lowest. Nigerian consumption of 111 kwh per capita fell way short of the world average of 2735 kwh.

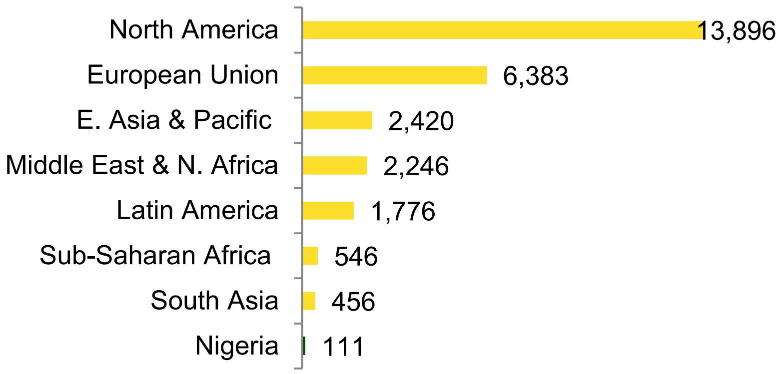
Rural electrification continued to be on the political and economic agenda and the FGN was planning on making significant investment in the power sector, rehabilitating PHCN generation units and investing in new capacity through the National Integrated Power Projects (NIPP).

From 3190 MW, gas fired generating capacity was planned to reach a minimum 11,300 MW within the decade, with incremental capacity of 5,500 MW from new generating capacity which was under construction and nearly 3,000 MW from rehabilitation of existing units at PHCN power stations.

Subject to possible development constraints, it was envisaged that additional IPPs could potentially bring the total to around 17,000 MW.

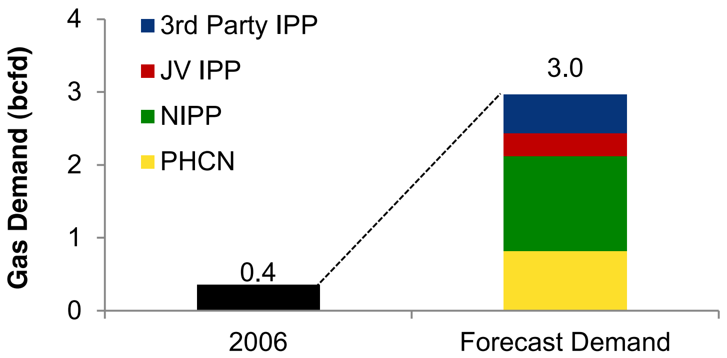
Following PHCN's rehabilitation programmes, the total gas to power demand was estimated at 3 bcfd.

Figure 3.1: Electricity per capita in 2006, kwh per capita



Source: World Bank Data

Figure 3.2: Total Planned Gas Demand for Power Generation



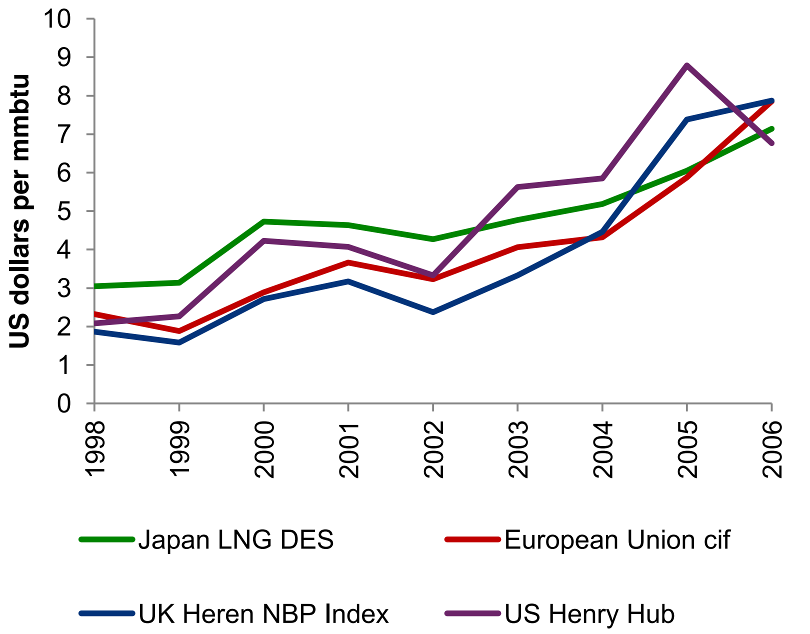
3.2 Relocating Gas Based Industries into Nigeria

Global gas demand from industrial end users grew at a respectable CAGR of 1.8% through the 1990s and mid 2000s as rising world GDP drove increasing demand for food, fuels and consumer goods. By 2006, industrial demand for natural gas had reached almost 65 bcfd.

By the 2000s, gas prices in traditional manufacturing centres were rising rapidly. At the same time, suppliers of gas in countries with limited historical domestic demand such as the Middle East and Trinidad and Tobago were holding gas prices at relatively low levels, thereby triggering a global restructuring of gas based industries with:

- Relocation of manufacturers away from demand centres into countries with abundant, reliable and low cost gas feedstocks;
- Idling (and in some cases mothballing) of Ammonia, Methanol and gas-based petrochemical plants in the US and Europe;
- An increasing reliance on imports into traditional demand centres in North America and Europe.

Figure 3.3: Historical Nominal Natural Gas Prices, 1995-2006



Source: BP Statistical Review

These established restructuring trends represented a timely opportunity to attract relocating industries away from their traditional locations in demand centres to Nigeria, thus transforming the nation into an exporter of gas-based chemicals to the world, and developing gas-based industries throughout the nation, diversifying gas availability to the north.

Fertilisers (Urea and Ammonia)

The global market size for Ammonia and Urea was just under 150 mmtpa and by 2025 was expected to grow to around 200 mmtpa. This was being driven by demand in Asia Pacific – which accounted for approximately 50% of total Ammonia consumption, and just under 70% of total Urea consumption.

By far the largest producers of Ammonia and Urea in 2006 were in Asia Pacific. China and India produced over 80% of the regions' Urea, with nearly 50 million mt and 20 million mt of production respectively. The major Ammonia and Urea producing countries tend to be those which have access to cheap and reliable sources of natural gas. In 2006, this was namely Trinidad and Tobago, Ukraine, Russia and the Middle East.

As shown in Figure 3.4 and Figure 3.5, the biggest importers of Ammonia and Urea in 2006 were Asia Pacific, Europe and North America. Virtually all of China's production went for domestic use, although China exported some fertiliser to SE Asia. India was also a large and growing importer of urea, 4.5 million mt in 2006. The USA imported nearly 5 million mt of Urea in 2006.

Figure 3.4: Ammonia Surplus/Deficit by region, 2006

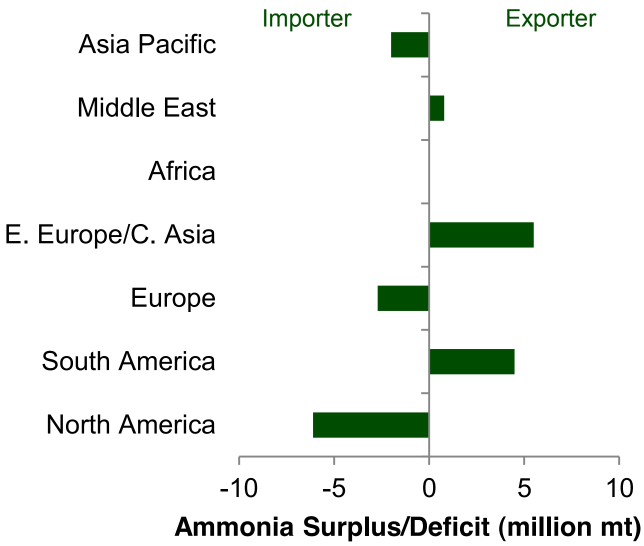
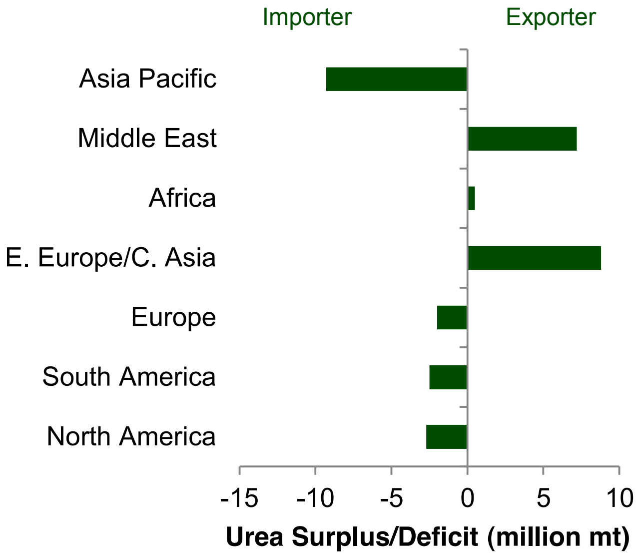


Figure 3.5: Urea Surplus/Deficit by region, 2006



In 2006, the United States' energy sector was undergoing a structural change. Prior to 2000, the Henry Hub prices in the US had been relatively stable. In late 2000 and early 2001, the Henry Hub price spiked, and the fertiliser industry was rocked. This spike in the gas price led to a series of Ammonia and Urea plant closures in between 2000 to 2005. US ammonia production declined and imports rose. From 2000 to 2006, the total number of ammonia plants dropped from 40 to 25. The largest decline was in small plants with annual production capacity of less than 500,000 tons.

Global Ammonia/Urea producers were seeking out alternative countries with cheap and reliable supplies of natural gas to feed the growing import demands from the US.

This therefore presented a significant opportunity for Nigeria to attract major world-scale gas-based Ammonia capacity additions.

The importance of agriculture in Nigeria's economy cannot be understated; agriculture was the main livelihood for over 70% of the labour force of 49.62 million people in 2006.[1] Agriculture contributed to ~40% of GDP, which was significantly higher than the contribution of oil and gas which was at ~15%.[2] However, Nigeria's agriculture potential was not being fully realised. Nigeria had one of the lowest fertiliser utilisations globally, utilising less than 10kg of fertiliser per hectare of arable land, as compared to the global average of 120 kg/hectare[3].

It was estimated that fertiliser production from Nigeria could meet around a sixth of global demand growth over the 2006-2025 period, amounting to 4% of global Ammonia demand by 2025. This is equivalent to about 7.6 mmtpa of Ammonia production, which would require incremental gas exploitation of around 0.67 bcfd.

The development of Ammonia and Urea businesses within Nigeria could be extremely valuable for the domestic economy both directly and indirectly:

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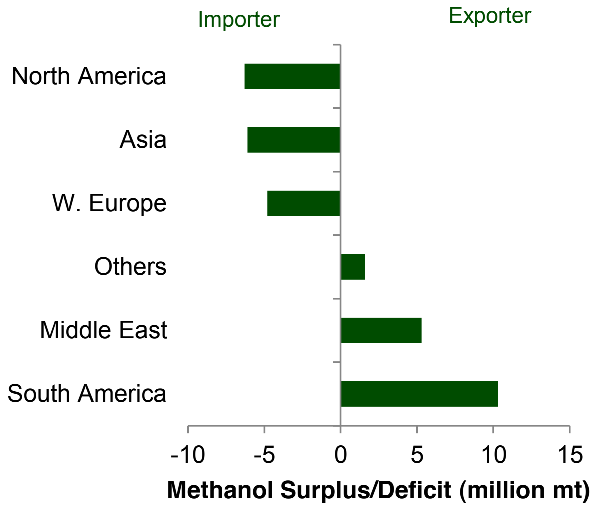
[1] CIA Factbook, 2007
[2] National Bureau of Statistics, Abuja, 2011
[3] World Bank Databank

- Displacement of imports. Nigeria consumed approximately 150,000 tonnes of Nitrogen fertiliser[7], almost all of which was imported. Domestic production would result in transportation savings, helping to displace imports;
- Fertiliser manufacturing can directly support permanent jobs to individuals who will work in the plants, and the construction workers for each new facility;
- Access to affordable nitrogen fertiliser impacts rural areas by increasing agricultural productivity, impacting rural incomes and increasing employment levels. The indirect economic benefits of a blossoming fertiliser industry would be felt across Nigeria.

Methanol

In 2006, global demand for methanol was approximately 37.5 million mt. Demand for methanol as a feedstock for production of other industrial chemicals was ~29 million mt (50% if which was for formaldehyde) and demand for MTBE was ~8.5 million mt. Global Methanol production was projected to grow to 68 mmtpa by 2025.

Figure 3.6: Methanol Surplus/Deficit by Region



As seen in Figure 3.6, North America, Asia and Western Europe were all substantial importers of Methanol. The Arabian Gulf exported to all three markets, with South America also exporting northwards to the USA.

Similar to the Ammonia business, the methanol market in the US was also rocked by the spike in natural gas prices in late 2000, early 2001.

This ongoing rise and volatility in Henry Hub prices resulted in many methanol plants in the US shutting down.

Global methanol producers had already started to move their operations to countries with large supplies of cheap gas. This led to a significant opportunity for Nigeria to attract major world-scale Methanol capacity additions.

Capacity additions of 5.8 mmtpa would correspond to Nigeria capturing a very reasonable 20% of the projected global demand growth to 2025, resulting in a ~9% market share.

Achieving this would require incremental gas exploitation of around 0.47 bcfd.

The development of a methanol businesses within Nigeria would create a large number of direct and indirect jobs and will provide a significant base load demand for natural gas:

- Methanol manufacturing will directly support permanent jobs to individuals who will work in the plants, and the construction workers for each new facility;
- Opportunities to use methanol in secondary businesses including formaldehyde, acetic acid and MTBE could be created throughout the country, with methanol being transported from the industrial park to other regions. This results in both a multiplier effect on economic growth, and a regional dispersion effect;
- "Swelling" domestic gasoline (PMS) by blending it with MTBE could result in reduced imports of high cost transportation fuels.

Petrochemicals

Ethylene is produced either in locations where there is a cheap and reliable source of feedstock or near to the secondary and tertiary manufacturing businesses that use ethylene as a feedstock to produce consumer goods. In 2006, the Middle East was the lowest cost producer of ethylene, as the region benefitted from a subsidised low cost and reliable source of ethane gas. For example, the government of Saudi Arabia was offering ethane at a rate of $0.75/mmbtu[4]. The only other region capable of producing large quantities of ethylene from ethane was North America, which was considered the marginal cost producer of ethylene in 2006 due to high Henry Hub prices (~$8/mmbtu) – see Figure 3.3. As a result of high Henry Hub prices, many gas-based petrochemical plants in North America were sitting idle.

The key demand market for ethylene and its derivatives was in Asia, and most notably China, due to the dominance in manufacturing of consumer products for the rest of the world. Import demand for ethylene in China was expected to remain strong despite expected capacity additions locally. Long term growth globally was expected at between 1 to 1.5 times global GDP.

Offering global petrochemicals producers ethane feedstock at lower prices than they can achieve in traditional markets such as the US represented a significant opportunity to develop an export hub in West Africa, serving both the starved markets in the US (due to uncompetitive domestic plants) and the high growth markets in the East.

Attracting petrochemicals manufacturers to Nigeria would also create secondary and tertiary derivative manufacturing opportunities. The location of these business opportunities can be dispersed throughout the nation, providing jobs not only in the state where the petrochemical plant exists but throughout the country. Secondary and tertiary business opportunities include:

- Manufacturing of plastics can be used across several businesses, a few examples are named below:
    - Agriculture & Water management (e.g. heavy duty films to cover food grain stored in open, drip irrigation systems, etc.);
    - Packaging (e.g. film for packaging of food items, etc.);
    - Automobiles (e.g. bumpers, dashboards, battery containers, etc.);
    - Electronics (e.g. radio components, etc.);
    - Consumer products (e.g. brushes, storage containers, footwear, etc.);
- Manufacturing of Synthetic Rubbers;
- Manufacturing of Synthetic Fibres;
- Manufacturing of Synthetic Detergents.

As such, a growing petrochemical industry in Nigeria would not only support the economic landscape of the state in which it is built, but would support the entire nation of Nigeria.

[4] *Shaikh, Sail A Al, NCB Article. The Kingdom's Comparative Advantages Propel its Global Position in Petrochemicals, September 2011*

3.3 Targeted Exports of Gas to Attractive Markets

Global Developments

Global natural gas demand had increased from 176 bcfd in 1990 to 255 bcfd in 2006. Although actual year–on-year growth in natural gas demand was much higher in Africa, South America, Middle East and Asia Pacific during this time period, Europe, North America, Russia and the Caspian regions continued to be the primary demand markets, together accounting for over 46% of the world's natural gas demand.

Figure 3.7: Global Natural Gas Demand by Region, 1990 - 2006

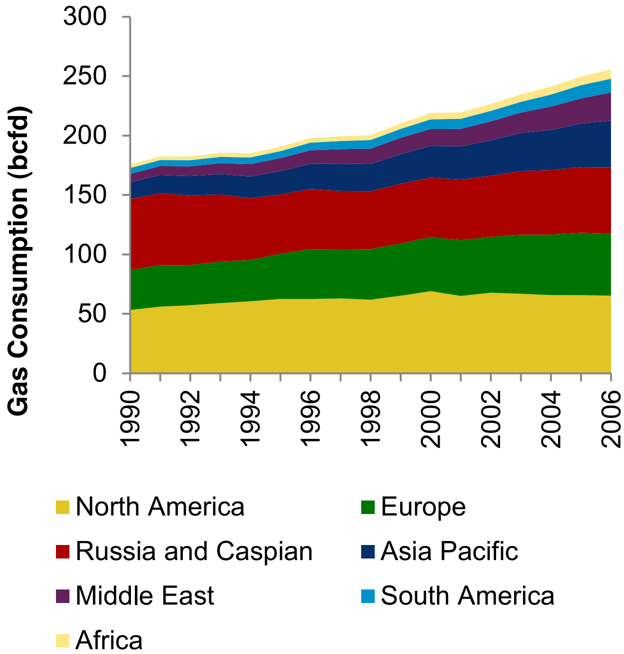
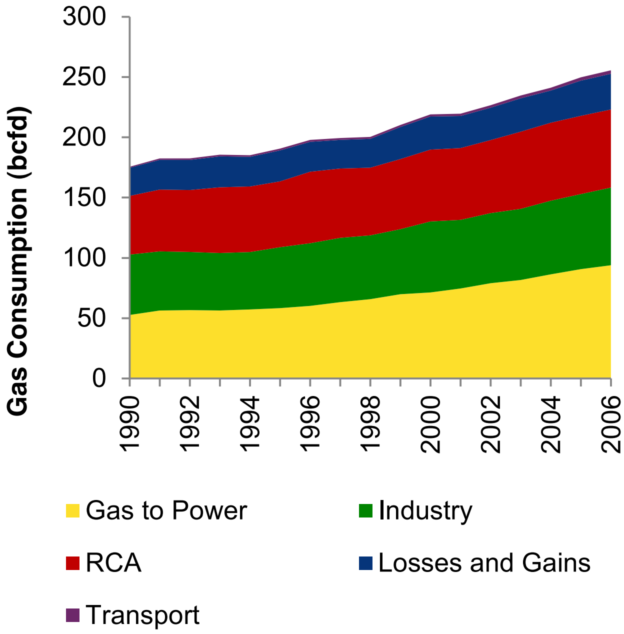


Figure 3.8: Global Natural Gas Demand by Sector, 1990 - 2006

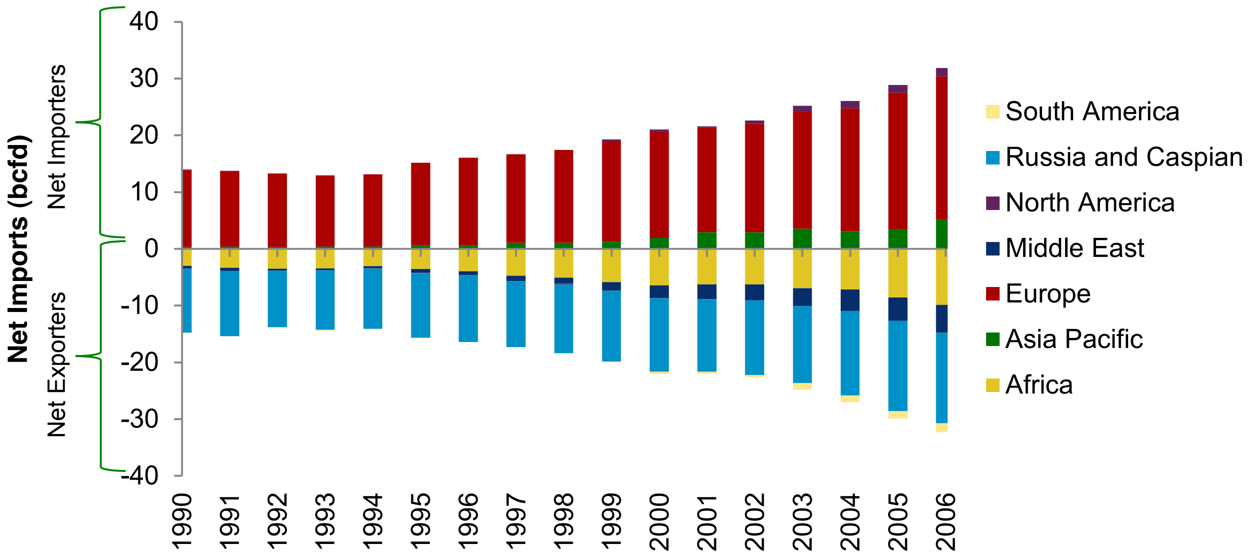


Source: Historical Data provided by IEA

Gas-fired power generation was the primary driver of worldwide incremental gas demand, growing from 53 bcfd in 1990 to 94 bcfd in 2006, a CAGR of 3.7%. This growth was driven by two key factors – firstly, increasing electricity demand fuelled by economic growth and secondly, replacement of an aging coal-fleet in Europe and North America. Gas was the fuel of choice in power for a number of reasons including costs, development time (much shorter than coal or nuclear) as well as increasing environmental concerns and pressure to reduce emissions.

In response to this growth in demand, global trade had also been steadily increasing from 1994 to 2006. Europe, Asia Pacific and North America were increasingly forced to depend upon gas imports (LNG or pipeline) from other regions to fill the developing gap between domestic gas supply and demand. Europe had access to pipeline gas from Russia and the Caspian region in addition to LNG imports. However, North America and Asia Pacific were mostly reliant on LNG imports to fill their domestic gas demand requirements. Figure 3.9 shows the historical net trade position for natural gas by region.

Figure 3.9: Net trade of natural gas by region, 1990 – 2006



Source: Historical data provided by IEA

One of the fundamental changes in gas was that North America, which had historically been seen as a self-sufficient market, was looking as though it would require a significant level of imports in order to offset declining domestic production.

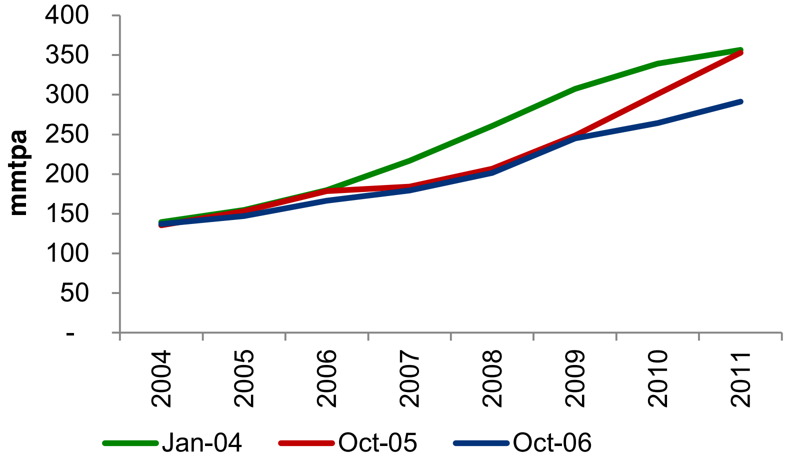
In order to meet the burgeoning demand, developing the next wave of exports projects was proving to be a big challenge.

Possible LNG developments were potentially adversely impacted by many factors, including:

- Moratoria on new LNG projects (Egypt, Qatar);
- Requirement for additional exploration to prove up gas (Libya, EG LNG);
- Technical challenges (Shtokman);
- Unclear Government position on exports (Indonesia, Venezuela);
- Overheated EPC markets – Costs for the construction of LNG liquefaction facilities had increased significantly over a few years leading up to 2006. This was partly because of the run-up in commodity costs but largely because the EPC market had overheated. There was only a handful of players that could credibly tackle LNG EPC and these players were becoming increasingly choosy and seeking to cover all costs. EPC was therefore becoming very sensitive to location and delays to EPC award decision were having a big impact on final costs. For example, Qatargas-2 EPC in Dec '04 was announce to cost $3 billion per train ($384m per integrated mmtpa). In December 2005, 12 months later, Qatargas-3 was announced to cost $4.2 billion ($538m per integrated mmtpa);
- Permitting and approval processes were taking longer than expected (Gorgon LNG);
- Partner selection / alignment issues were starting to have impacts on the ability for projects to take FID;
- Project development lead-times were increasing – in 2006, they were approximately 48 months for a Greenfield development.

As a result of these factors, a number of projects were being delayed, and short to medium-term supply forecasts for LNG were being significantly reduced to reflect this reality. Figure 3.10 below shows the LNG supply forecasts in January 2004, October 2005 and October 2006. The market forecast in 2011 had lost around 70 mmtpa (over 9 bcfd) of supply, as compared to forecasts in previous years.

Figure 3.10: LNG Supply Forecasts



Source: Wood Mackenzie

All of the above factors led to a perception that, although there were lots of *potential* supply projects, these projects were not being developed at a pace that could match the pace of growing demand. Both pipelines and LNG were taking longer to reach FID, and domestic long term security of supply was becoming an increasingly more important political issue. This was rapidly transforming the international natural gas market into a seller's, rather than a buyer's market.

The global LNG market was therefore expected to more than triple between 2006 and 2025. This growth expectation was driven by LNG demand in the three primary markets, the US, Europe and JKT(Japan, South Korea and Taiwan):

- The US was expected to account for ~40% of total growth in LNG demand between 2006 and 2020. There was the perception that gas production in the US had already peaked, and that domestic production would continue to decline. The US was seen as a "new player" in the LNG market, and it was forecast that its requirements for LNG imports would continue to grow in order to fill the increasing gap between domestic production and demand. The US was identified as a target market for many of the proposed LNG supply projects. Projects taking FID at this time were being underpinned, at least in part, by the significant amount of LNG that the US would require;
- The European LNG outlook remained healthy in 2006, and there was even potential upside from new importers. European buyers were increasingly concerned about limiting their reliance on Russian gas, and looking to LNG as an option for increasing their diversity and security of supply;
- Asian demand for LNG, particularly in the JKT markets was forecast to remain strong from 2006 to 2025.

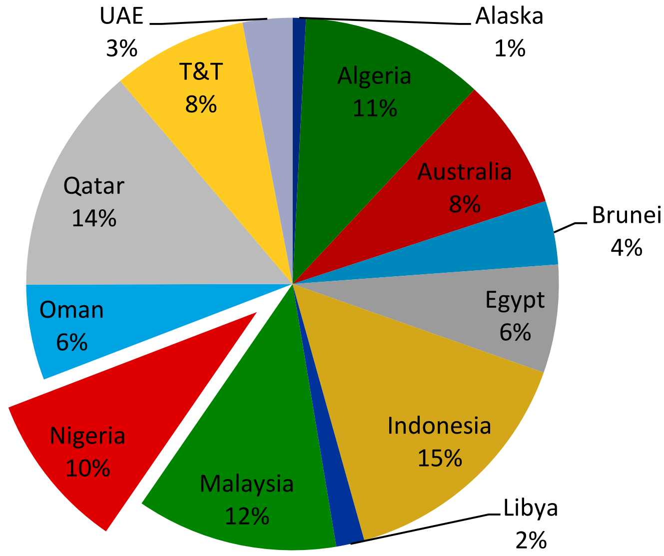
With rising international gas prices and an expectation for sustained strong demand growth for gas in international markets, Nigeria faced a significant opportunity to further develop export facilities in Nigeria.

Opportunities for Incremental LNG Exports from Nigeria

Figure 3.11 shows the nominal capacity of global LNG capacity in 2006 where Nigeria (5 trains) represents a 10% global market share. There was 186 mmtpa of nominal LNG liquefaction capacity that was commissioned worldwide. Nigeria, with NLNG, had 18 mmtpa of LNG capacity, with 3.5 mmtpa of additional capacity expected in 2007 with the commissioning of NLNG 6. The opportunity to maintain market share in the face of expected strong LNG sector growth was significant, and would translate into the construction of new parallel plants to NLNG, and implementation of further liquefaction trains within NLNG.

Nigeria was geographically very well located to serve the North American LNG market, and was already discussing expanding NLNG, and constructing two new greenfield projects, Brass LNG and OK LNG, predicated on supplying this market.

Figure 3.11: Nominal Capacity of LNG Liquefaction Facilities by Supply Country, 2006



These projects, primarily targeting the growing demand for LNG in the US, would have resulted in an additional 32 mmtpa of LNG export capacity in Nigeria. In addition, a further train of 8.4 mmtpa at NLNG (NLNG 7+) was being considered. The table below summarises the project specifications, as they were proposed in 2006.

Table 3.1: Proposed LNG Facilities in Nigeria in 2006

Proposed LNG Plant	Location	Number of Trains	Plant Capacity (mmtpa)	Feedgas Requirement* (bcfd)	Project Owners	Target Markets
Brass LNG	Brass River	2	10	~1.5	NNPC (49%) ConocoPhillips (16.25%) ENI (16.25%) Total (13.5%) Others (5%)	US
Olokola (OK) LNG	Ogun State	4	22	~3.3	NNPC Chevron (19.5%) Shell (19.5%) BG (14.25%) Others (6.75%)	US
NLNG 7+	Bonny Island	1	8.4	~1.3	Same as NLNG	US

**Assume 150 mmcfd of feedgas is required to produce 1 mmtpa of LNG*

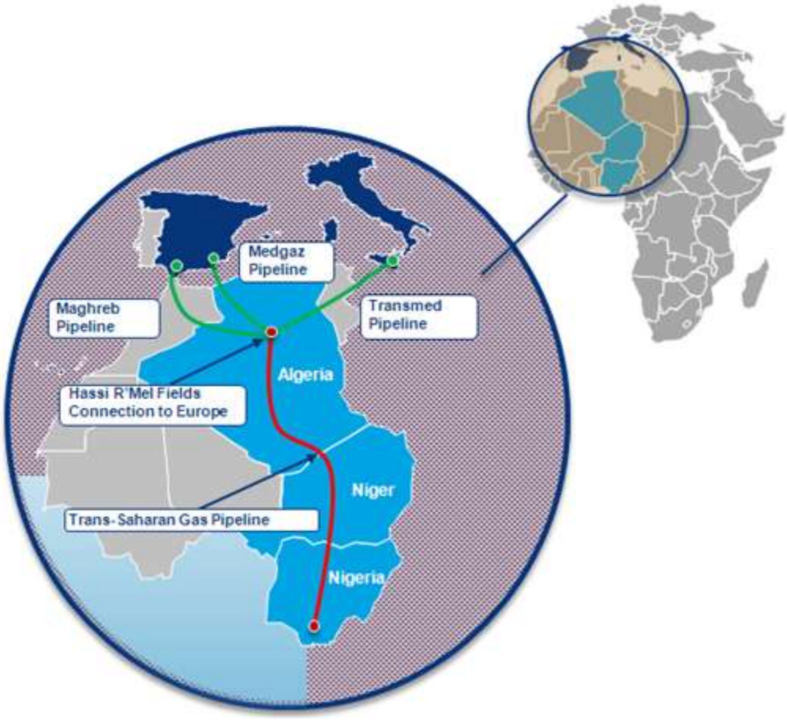
Opportunities for Incremental Pipeline Exports from Nigeria

The Trans-Saharan Gas Pipeline (TSGP) was a planned 4,300 kilometre pipeline, first proposed in the 1970s, to transport Nigerian gas through Niger and Algeria and onwards into Europe.

The TSGP was planned to run from the Akwa Ibom region of the Nigerian Delta to the Hassi R'Mel field in Algeria. With a planned capacity of 2,900 mmcfd, the pipeline was planned to further supply the existing Algerian pipelines, namely: Maghreb (GME), Medgaz and Transmed.

With Europe heavily reliant on gas imported from Russia, the TSGP was viewed as an opportunity to reduce reliance on Russian gas. By 2006, a feasibility study commissioned by NNPC and Sonatrach had been completed by Penspen, and the findings were that the project was technically and economically feasible. However, as a planned project, it was not clear who would be responsible for developing and owning the pipeline.

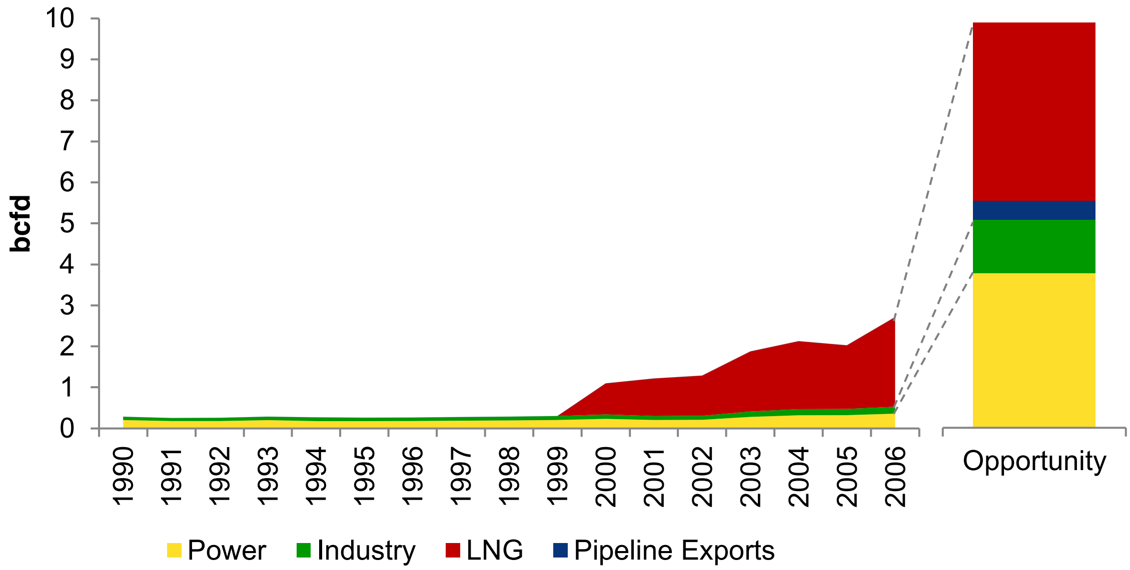
Figure 3.12: The proposed Trans-Saharan Gas Pipeline



3.4 The Size of the Prize

The opportunity to transform the sector by capturing the rapidly expanding and diversifying utilisation translated into a 2.5 times increase in monetisation of Nigeria's abundant, but largely untapped, gas reserves.

Figure 3.13: Nigeria's Opportunity for Gas Monetisation



The opportunity was such that it was deemed unacceptable for Nigeria to continue to accept the status quo and so work began on evaluating means to enable the sector to achieve its full potential.

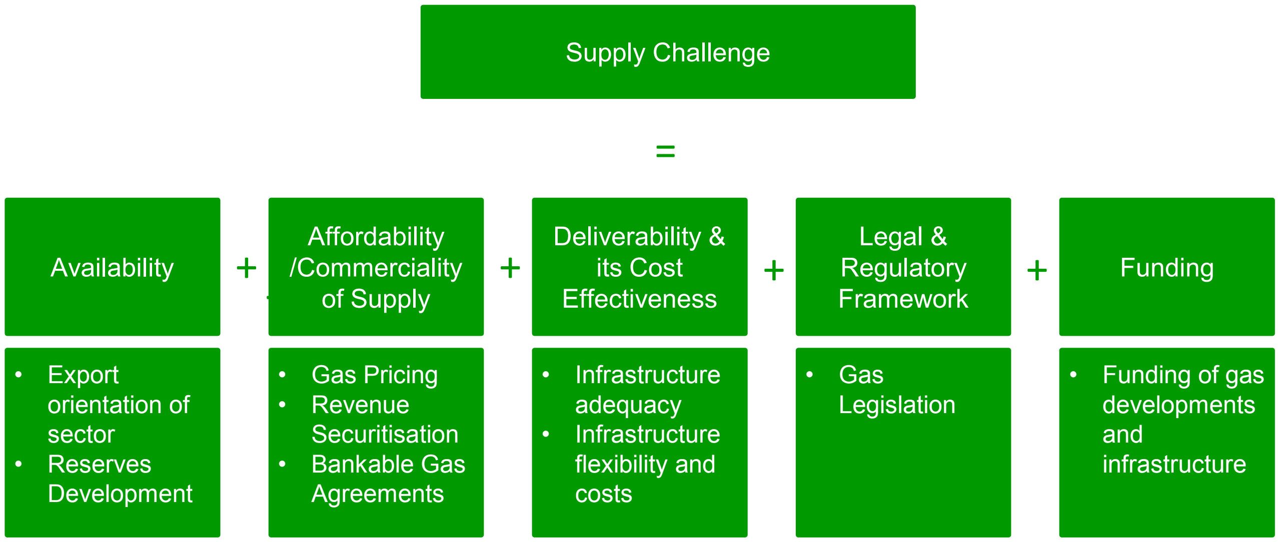
4 The Need for Government Intervention

4.1 Multiple Challenges Requiring a Coordinated Approach

There was a robust portfolio of gas opportunities (both domestic and international) that underpinned the growth potential for the Nigerian gas sector. The challenge was to create a stable and suitably attractive commercial environment to ensure that the full potential of the gas sector could be realised.

Five key factors underpinned the supply challenge in Nigeria, particularly in the domestic market. Sustainable supply growth to meet this burgeoning demand was only possible if all 5 challenges were addressed holistically, and this was the focus of the Gas Master Plan.

Figure 4.1: Supply challenge in Nigeria



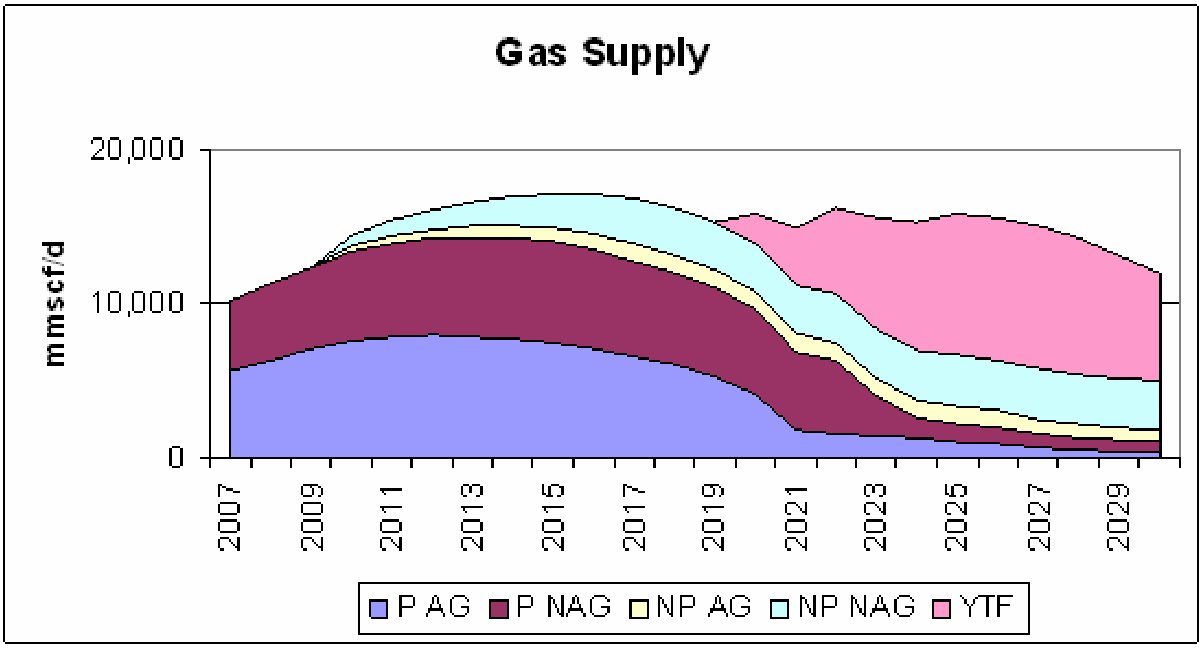
Availability of Gas Supply to the Domestic Market

There was a concentration of market power in a few dominant JVs, and these core IOC operators had typically focussed their gas activities on the export of LNG rather than on supply of the domestic market. This had been driven largely by the commercial returns associated with exports (compared to the domestic market), including high returns in the LNG plant, as well as the security of income associated with international LNG purchasers.

With limited confidence in the domestic market and significant fiscal incentives for the development of gas for exports, it is not surprising that the focus on gas monetisation had historically been on LNG. The full potential of the indigenous market could only be realised if the economic balance between the domestic market and exports could be redressed.

With current reserves, it was estimated that unconstrained gas production could reach a maximum level of 12-13 bcfd. This maximum production estimate was a theoretical number reflecting a notional environment where there are no financial, technical or geological constraints.

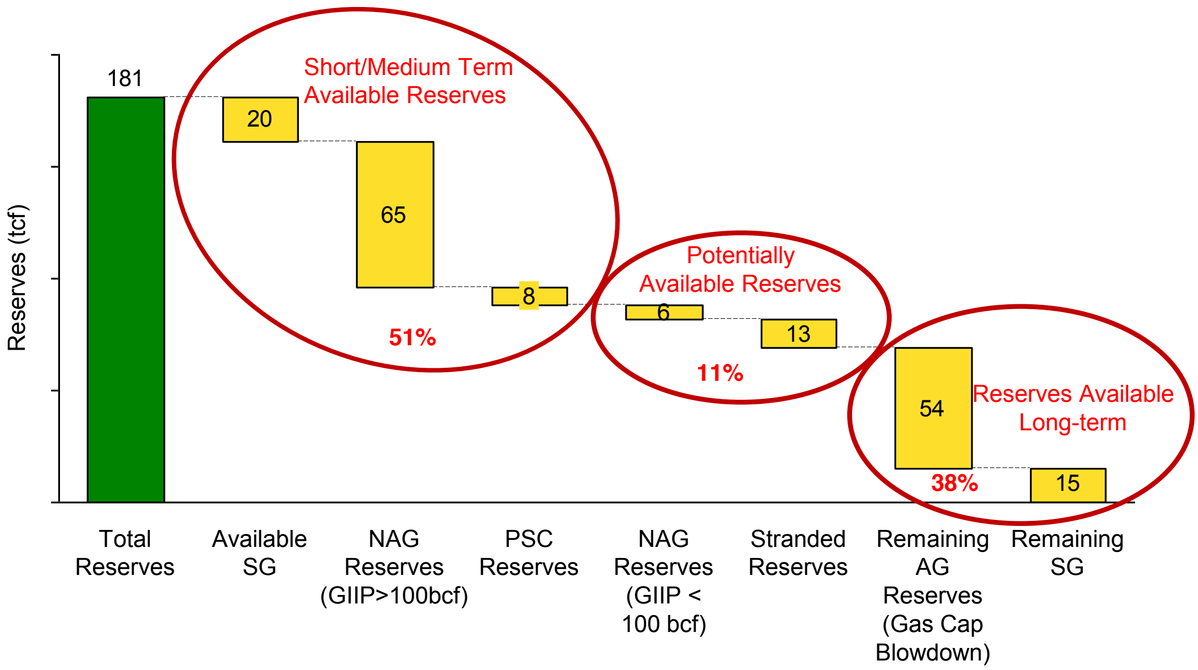
Figure 4.2: Unconstrained Gas Production Capacity



Source: GMP Team

In reality, not all of Nigeria's discovered gas reserves were readily accessible and exploitable. It was estimated that over 38% of Nigerian reserves were held within gas caps or as solution gas in oil reservoirs. The solution gas output is constrained by oil production, and the gas caps cannot be exploited until the oil reservoir is nearly depleted and no longer requires pressure support. Despite this it was still estimated that over 93 tcf of gas (or 50% of the country's current reserves) could be exploited in the near term (Figure 4.3).

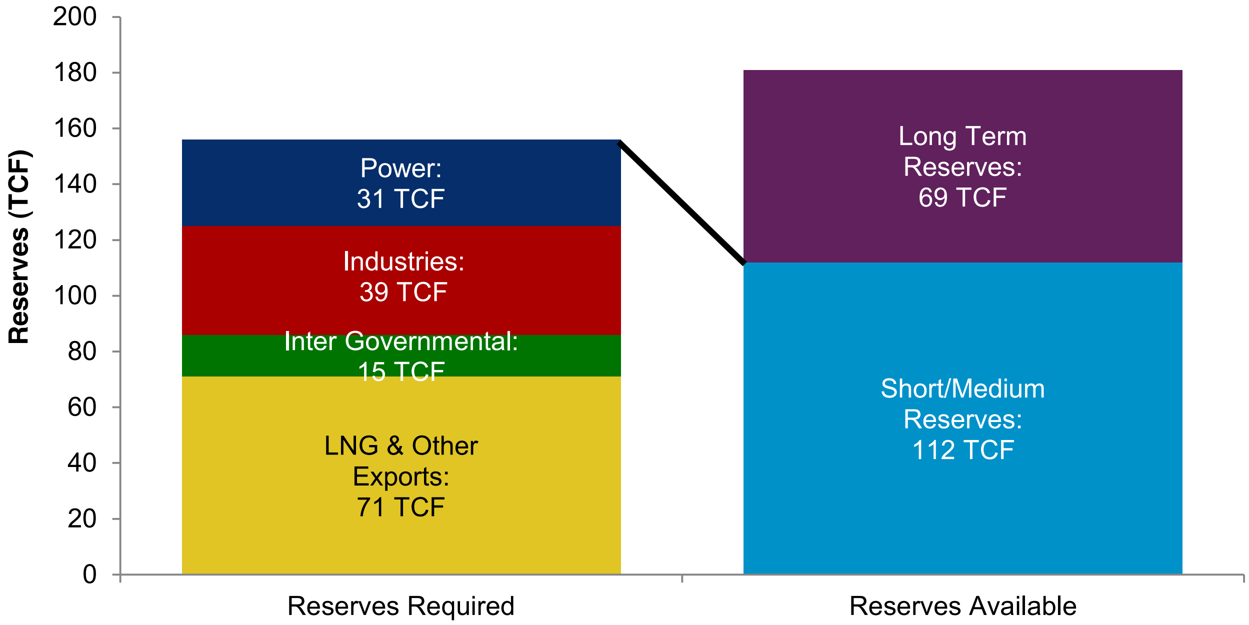
Figure 4.3: Break-down of Gas Reserves by type, 2006



Source: NNPC Gas Master Plan Team

Based on the foregoing, it was clear that with limited exploitable reserve levels and the significant volumes of gas already committed to exports (both LNG and pipeline), the effective management of the remaining reserves would be crucial in order to ensure domestic demand growth was not constrained.

Figure 4.4: Limited Proven Reserves Availability



Source: GMP Team

Affordability/ Commerciality of Supply

Other challenges mitigating against sustained supply growth for the domestic market included a lack of clear price setting arrangements for natural gas, a lack of confidence in the creditworthiness of gas buyers and the perceived weakness of GSPAs in terms of protection they offered the supplier.

Gas Pricing

The diversity of the downstream gas portfolio created opportunities and challenges alike. Perhaps the most critical challenge was the varying capacities of the various sectors to afford gas. In particular, the power sector, which was the single largest buyer, was least able to pay. As a result, end user prices varied from levels as low as $0.1/mcf (power) to as high as $2.0/mcf (private industry).

Companies with liquids production were more incentivised to deliver gas to the domestic market, as they could offset capital expenditures against oil profits. However, there were almost no commercial incentives for companies without oil assets to develop upstream gas fields for the domestic market.

Without clear and commercial gas price setting arrangements in place, gas fields and infrastructure investments were unlikely to be developed.

Revenue Securitisation

In 2006, IOCs/NNPC were owed over N10 billion by the domestic market for supplies provided in previous years. This history of non-payment for gas in the domestic market – mainly from government parastatals such as PHCN and ALSCON - created an unwillingness for IOCs to invest heavily in natural gas supply unless adequate interventions on revenue security were provided.

Bankable Gas Agreements

Historically a significant portion of gas supplied for the domestic was not backed by standard GSPAs. In view of the size of capital investments required to supply gas to the domestic market, these gas agreements are viewed as critical to enable investor confidence. A restructuring of the power sector was also creating a lack of clarity on who the counterparties were in the agreement.

Infrastructure

The project-centric approach to pipeline development suggested that scope existed for optimisation and subsequent cost reductions. The existing infrastructure situation; however, limited the flexibility of supply:

- Existing gas pipeline infrastructure was inadequate in capacity and reach for the current and projected demand growth;
- Lack of connectivity between East and West coupled with limited throughput capacity severely constrained supplies;
- Whilst gas reserves were concentrated in the East, there was limited connectivity with the West where demand was concentrated.

Likewise, scope existed to further leverage synergies in the development of gas processing plants, as well as to attract 3rd party investment. Domestic gas treatment facilities often had no provision for full liquids extraction, and rich gas was often being transported by the grid and sold to the end-users. As such, NGL value was not being fully utilised.

Given the legacy of Nigeria's gas industry as an adjunct to its oil business, the existing infrastructure was dominated by a few major incumbents with limited scope for third party access and participation. This further resulted in significant barriers to entry.

Legal & Regulatory Framework

While the execution of AGFA had an extremely positive effect on the development of the natural gas business in Nigeria, it did however favour existing upstream investors (JVs) and acted as a barrier to non-oil investors and new entrants into the sector. The key issues included:

- Offsetting capital costs at higher marginal rate (85%) than the rate at which gas profits were assessed did not give effective incentives for containment of costs;
- Giving tax relief as an uplift of capital expenditure encouraged upstream investors to 'gold plate' investments;
- The Government share of economic rent from gas development was low as this was essentially being funded from existing oil tax revenues (PPT);
- There was a need to have a proper commercial regulatory framework for the downstream gas sector, including the provision of third party access, pipeline ownership and tariff structure, gas transportation code, etc.

Funding

As a result of the aforementioned supply challenges, investors were not sufficiently incentivised to invest in downstream, midstream or upstream gas projects for the domestic market (other than GTL). These challenges needed to be overcome in order to meet the burgeoning demand and to provide a commercial basis for investment.

4.2 Lessons from Other Countries

While the development of Nigeria's domestic gas market will be challenging, there are many analogues from around the world where net exporting and/or self-sufficient gas producing countries have managed to kick-start their domestic markets, overcoming similar barriers and challenges, and achieve high market penetration. Table 4.1 highlights the historical growth rates of production and domestic demand of Egypt, Indonesia, Qatar, Trinidad & Tobago and Malaysia during an 11 year period of their greatest growth rates.

Table 4.1: Historical Production and Domestic Demand Growth Rates

Country	Egypt	Indonesia	Qatar	Trinidad & Tobago	Malaysia
Years	1990–2001	1990–2001	2001-2012	1993–2004	1994–2005
CAGR (domestic demand*)	11%	10%	12%	10%	10%
Market Size (bcfd)	0.7 – 2.3	0.7 – 2.0	1.0 – 2.8	0.4 – 1.2	0.7 – 2.0
Production CAGR	11%	3%	24%	17%	9%
Production (bcfd)	0.7 – 2.3	4.4 – 6.2	3.2 – 18.0	0.5 – 2.8	2.2 – 5.6

Source: IEA Historical Data (1980 – 2012
**Domestic demand = Total Final Consumption + Gas to Power)*

The lessons from this are two-fold:

- There are precedents for very strong growth rates in production (e.g. Qatar),suggesting that upstream companies are adept at increasing supply if demand (either domestic or export) is such that incremental production is commercially viable;
- Stimulating domestic demand growth appears more challenging, with only Qatar and Egypt able to exceed 10% CAGR.

Nigeria's situation shows strong parallels to these international benchmarks. The IOC JVs in Nigeria have already proven their ability to grow gas availability for LNG exports whilst the domestic market has remained largely dormant.

A number of case studies are presented below, focusing on the government interventions used by Indonesia, Egypt, and Western Australia to either stimulate domestic demand or to ensure that sufficient reserves remain available for the domestic market.

Case Study: Western Australia

Figure 4.5: Domestic Consumption in Western Australia

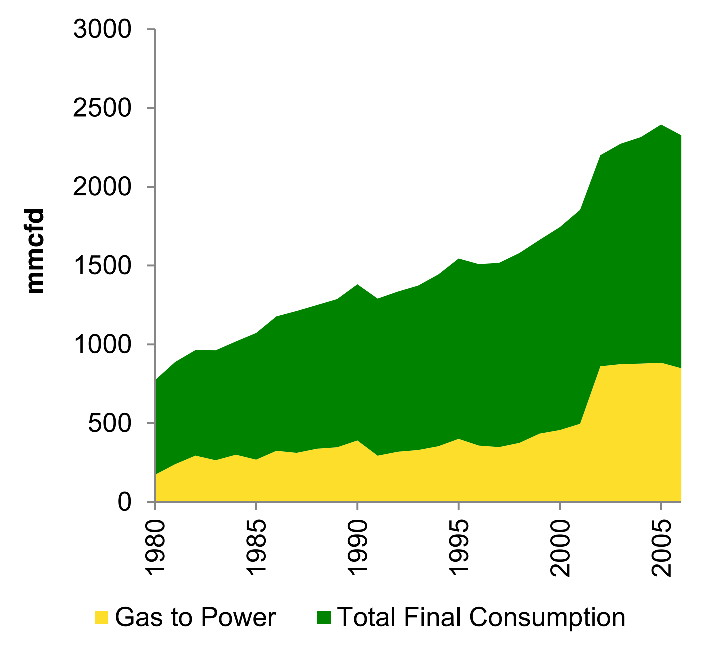
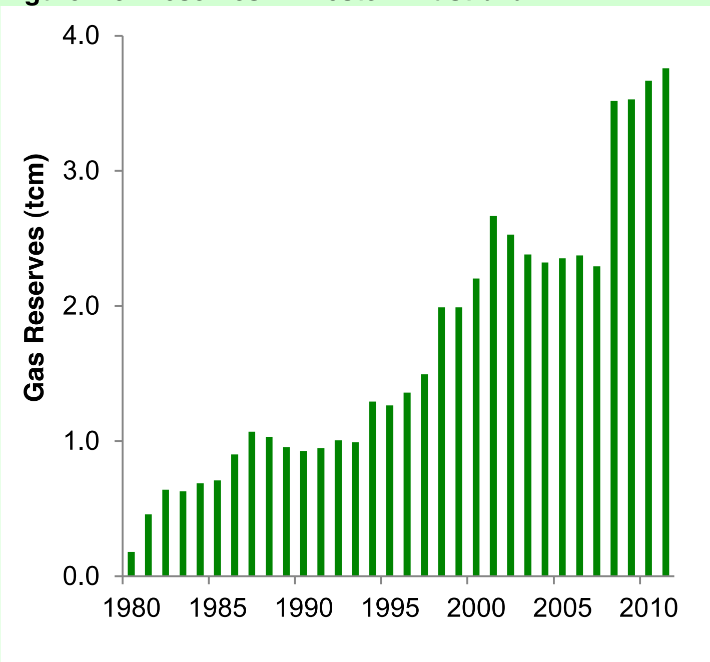


Figure 4.6: Reserves in Western Australia



Western Australia manages domestic demand while ensuring that exports provide the necessary incentives for further exploration.

Western Australia has a directive whereby a 15% reservation is made on all gas developments. Under the directive, up to 15% of the reserves associated with export gas projects is required to be reserved for domestic use as a condition of access to Western Australian land for the location of processing facilities.

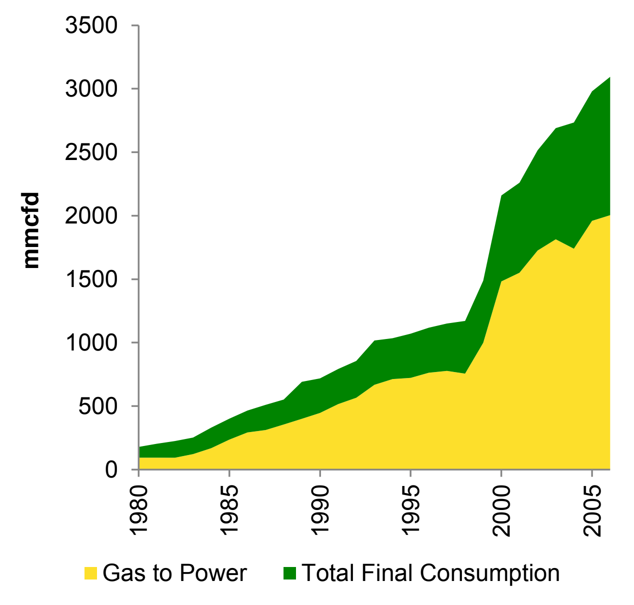
The Government also maintains a flexible approach on timing and volume and considers each project on case by case basis. Projects can also meet their Domestic Market Obligation (DMO) in “kind” by:

- Investing in new shale / tight gas developments
- Investing in domestic gas targeted exploration
- Investing in new domestic gas storage
- Providing third party access to gas gathering and processing infrastructure

The policy has resulted in an increased domestic gas supply (Figure 4.5), and incentivised operators to explore for sufficient reserves to satisfy domestic and export desires (Figure 4.6). Additionally, more expensive gas has increased the domestic gas price, which has promoted exploration of smaller prospect sizes.

Case Study: Egypt

Figure 4.7: Domestic Gas Consumption in Egypt



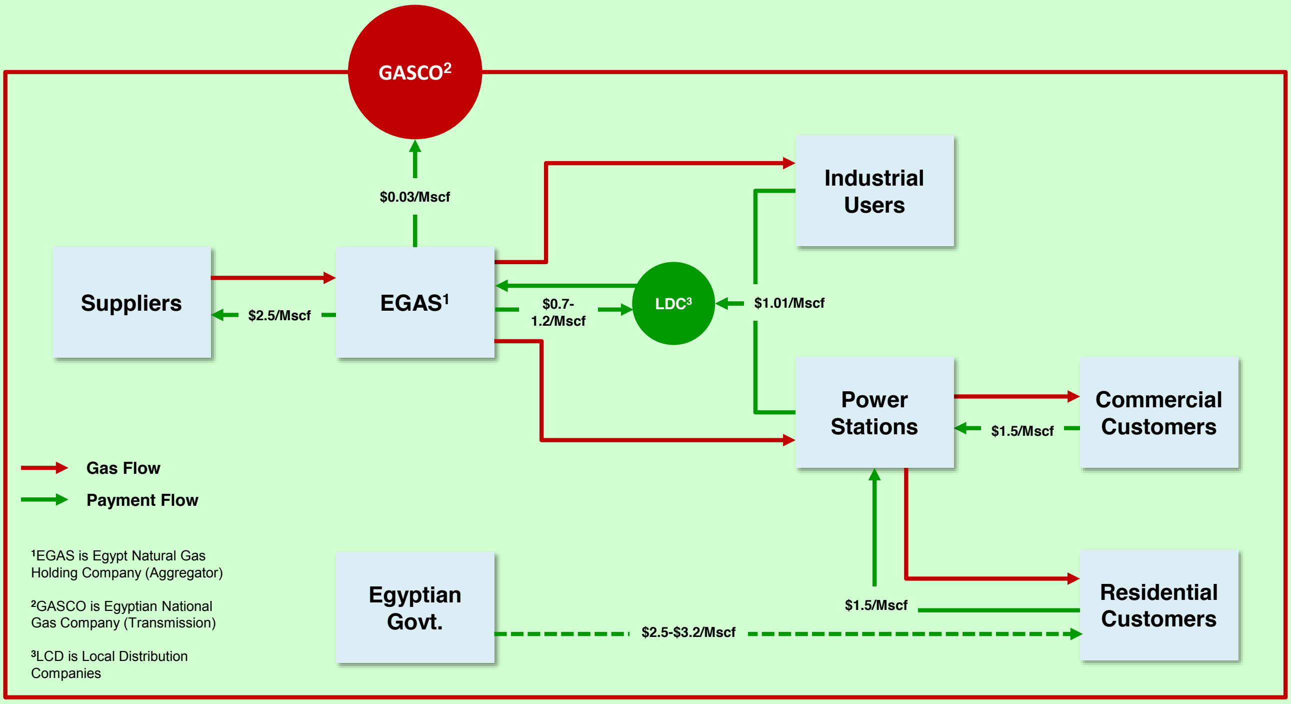
Gas demand accounted for 48% of total energy demand in Egypt, with gas having played an especially key part in the growth of the power sector. A number of interventions were introduced in Egypt to foster gas demand growth domestically:

Egypt heavily subsidised gas prices across all sectors, resulting in end-consumers paying less than the full economic price of the natural gas. This helped to stimulate demand in the industrial sector, and also resulted in a large scale substitution of liquid fuel in the power sector.

The Egyptian government introduced a policy, allocating one third of gas reserves for domestic market requirements, one third for future requirements, and the remaining third for exports.

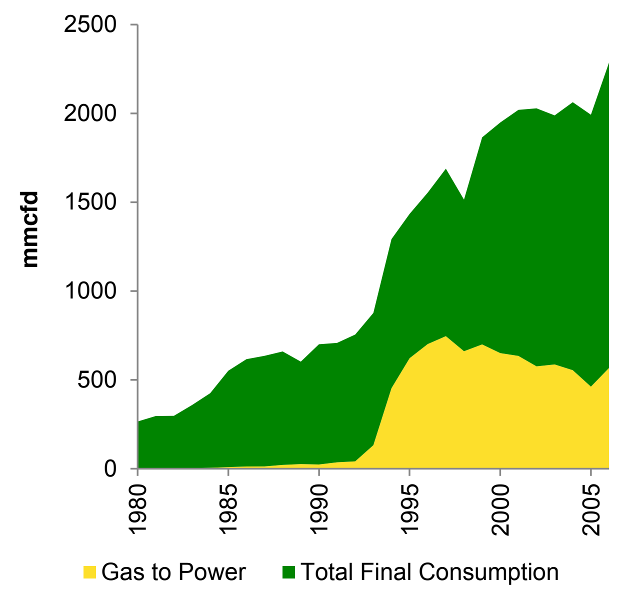
EGAS was introduced by the Federal Government of Egypt in order to manage these gas allocation requirements, in addition to acting as a single buyer of gas from suppliers. EGAS sets the end-user price, whilst enabling the balance between affordability of gas to customers and commerciality of supply for suppliers. The suppliers received a single aggregated price from EGAS, regardless of who the gas molecules are sold to.

Figure 4.8: EGAS Payments and Gas Flows



Case Study: Indonesia

Figure 4.9: Domestic Consumption in Indonesia



The domestic market in Indonesia was jumpstarted by the introduction of a domestic market obligation (DMO). Upstream contractors were committed to meet domestic market demand DMO allocating at least 25% of the gas produced from any development for domestic use.

- A rigorously enforced DMO resulted in significant gas-based industrial developments, which resulted in increased gas demand, notably by fertiliser plants, cement and steel;
- Agriculture was impacted by the availability of low cost fertiliser, and this had a direct impact on productivity of farm land.

In addition, the government applied a lower government take on gas developments thus making the returns suitably attractive to upstream developers.

Achieving strong growth in domestic markets has consistently required a number of government interventions, including provision of:

- Preferential fiscal terms for gas (e.g. Indonesia);
- Competitive gas pricing to attract and develop industry (e.g. Egypt);
- Domestic Supply Obligations;
- Gas Aggregators/Commercial Structure in order to administer pricing and domestic obligations.

There are three key considerations for the development of a country's natural gas strategy: realisation of country's resource potential, income and wealth generation and security of supply. The balance and relative weighting of these three considerations is specific to the needs and attitudes of the country. Governments find that there is a tension between incentivising exploration, and achieving maximum impact on both the overall economy and tax revenues.

In a number of case studies, the desired market response to government intervention has not been achieved, as the fine balance was tilted too heavily to one of the considerations. For example:

- In Egypt, the government was extremely successful in incentivising demand. Ambitious plans for petrochemicals and low subsidised domestic pricing led to a demand surge, and the market became increasingly hooked on cheap gas. However, the exploration for new reserves was not as successful as EGAS had forecast, and by late 2007, the government had placed a moratorium on new export projects. Exploration and development activity has stagnated post the imposition of the moratorium, and the domestic gas prices were not sufficiently high to stimulate new deep water exploration. Based on current reserves it is expected that a domestic supply/demand gap will open in around 2017/2018;
- The policy in Bangladesh was heavily weighted towards domestic supply security over exports. In 2000, after a number of significant gas discoveries, Bangladesh had proved gas reserves of 14.5 tcf and had an

R/P ratio of over 38 years (domestic consumption of around 1.1 bcfd). The IOCs (in particular Unocal and Shell) put significant pressure on the Government to consider allowing exports. However, the Government eventually decided in 2002 that it would not allow exports unless domestic proven reserves covered 50 years of domestic demand. Shell subsequently pulled out of the country in 2003 citing inability to export as one of the reasons. Exploration activity has declined and gas reserve additions have amounted to only 270bcf since 2001, and acreage is generally perceived as being under explored. Reserves have been declining steadily as demand has increased. Proposal for LNG imports are now being considered.

- In Oman, following the discovery of significant volumes of non-associated onshore gas in the early 1990s an LNG project was proposed to the Government of Oman by Shell. While this took several years before a final investment decision could be made, construction of a 7.2 mmtpa facility started in 1996 with first LNG loaded in 2000. Despite very limited additional exploration success in the mid and late 1990s, a second project of 3.7 mmtpa was proposed (backed by a Spanish utility buyer) even before the first was complete. The Qalhat project was subsequently developed alongside Oman LNG and first LNG was delivered to Spain in 2005. In the space of 5 years Oman had gone from no exports to around 1.5 bcfd. However the lack of exploration success was beginning to cause concerns even before Qalhat came onstream and from 2005 until 2010 supplies to the Oman LNG plant were gradually reduced due to the growing demand from the domestic sector – current LNG output is only around 78% of the installed capacity. Without significant new discoveries and with domestic demand expected to continue to grow, it is predicted that the market will start to run short by the end of the decade. Indeed there have been recent suggestions that Oman may need imports of LNG to cover peak requirements in the relatively near future.

4.3 The Conception of Nigeria’s Gas Master Plan

The parallel nature of the historic challenges in the sector and the lessons learned from other countries reinforced the need for government involvement if the sector is to achieve its full potential by capturing the burgeoning domestic and international market opportunities.

The Nigerian Gas Master Plan was therefore conceived as a major interventionist document to kick-start the sector whilst ensuring con-current presence in the domestic market, high value export markets and in industrial applications. The Nigerian Gas Master Plan has been developed taking into consideration the balance between incentivising exploration, security of supply, and wealth generation. By taking the lessons learnt from other countries, and customising for Nigerian peculiarities, the Gas Master Plan policies were developed.

Details of the various policy interventions and their intended impacts on the sector are provided in subsequent chapters of this document.

Part B: Policy Interventions

1 Gas Master Plan Intent

1.1 Strategic Intent

Nigeria aspires to leverage its abundant natural gas reserves to catalyse unprecedented domestic economic growth. Unlike oil, natural gas will be deployed to foster visible GDP growth by enabling geographically dispersed industrialization with the consequent impact on job creation.

To accomplish this, the strategic aspiration is anchored on 3 clearly articulated focus areas (Figure 1.1).

Figure 1.1: Strategic Intent of the Gas Master Plan

- **Gas to Power** – Natural gas will be deployed as Nigeria's dominant fuel for power generation, with an immediate objective of attaining at least a five-fold increase in generation capacity from about 3GW to 15GW by 2018;
- **Gas Based Industrialization** – Nigeria will be positioned as the African regional hub for gas based industries; i.e. industries that use natural gas as feedstock, such as Fertilizer, Petrochemicals, Methanol, CNG, etc. These primary industries, if properly delivered, will stimulate a wide range of small and medium scale secondary industries that will be geographically dispersed and drive GDP growth. Fertilizer production will boost agricultural yield, causing the growth of agro-processing and related industries. The petrochemicals industry will produce polyethylene and polypropylene which are the basic ingredients for a wide range of secondary industries such as packaging, plastics, carpets, etc. CNG for transportation, in addition to the environmental benefit, will displace PMS as the preferred fuel for transportation, reducing the nations spend on petroleum subsidy whilst improving the net disposable income of transport owners. The combined impact of the gas industrialization is widespread job creation and in-country value addition;
- **High Value Export** – Nigeria will selectively invest in high value export through LNG and regional gas pipelines. Specifically in LNG, Nigeria will aim to protect about 10% of global market share of traded LNG. It will also leverage its natural gas for regional economic influence by selective investment in cross-country pipelines within the sub-region, stimulating the economic growth of those nations and creating investment and sales outlet opportunities for Nigerian entrepreneurs and for Nigerian gas.

1.2 Gas Master Plan Policy Intent

The strategic aspirations above are aggressive. As highlighted in Part A, during the late 1990s and early 2000s the FGN attempted to accomplish similar objectives in the industrial sector as evidenced by the establishment of industrial companies such as NAFCON, ALSCON, Ajaokuta Steel Mill, Delta Steel Company, etc. However, these government owned ventures failed to operate on a commercial basis and thus were not sustainable. Most of these entities no longer operate or exist.

The GMP Policy intent is to enable the realization of these aggressive aspirations. Global analogues indicate that this can only be achieved and maintained through the creation of a fully competitive gas market – one which supports full private sector participation, operating within carefully crafted market and regulatory rules. The underlying policy thrust of the GMP is therefore to create, by the turn of the decade, a fully sustainable domestic gas market that is market led - competitive, characterized by 'willing buyer, willing seller' arrangements and structured in a manner that assures the FGN's objectives continue to be met.

Recognizing the current state of the Nigerian gas sector and the aspired end state envisioned in the policy, many tactical policy interventions are required to effectively transition the relatively young gas sector towards the end state of a fully competitive gas market. The GMP Policy is therefore an assembly of tactical policies aimed at transitioning the gas sector towards full competitiveness. It is a live document that will be updated to reflect the realities of the time and assure the long run policy objective is ultimately realized and sustained. In essence, this version of the GMP policy is a policy for Transition to a Fully Competitive Market. Once the market objectives are reasonably met, further policy interventions or revisions will be required.

The tactical policies span the areas highlighted in the Table below and full details are contained within the Appendices;

SN	Policy Intervention	Description	Instruments
1	Domestic Supply Obligation	Policy to jumpstart supply availability	DSO Regulation of 2008
2	Gas Pricing Policy	Transitional pricing policy review to move domestic gas prices from sub-commercial level towards export parity by end 2014	HM Pricing Letters, Supplementary Regulations
3	Gas Aggregation Company Established (GACN)	A One Stop shop for domestic gas buyers, licensed to manage the commercial aspect of the DSO by connecting the gas buyers with upstream producers (Sellers) through a tripartite Gas Sales and Aggregation Agreement. It aimed at developing the domestic gas market.	DSO Regulation of 2008
4	World Bank PRG, GSA Templates	Bankable commercial agreement between buyers and suppliers. World Bank revenue securitisation scheme to mitigate risk of payment failures for gas supplied to Government Entities.	Template Agreements
5	Network Code	Code to govern gas transmission network open access and entry protocol	Network Code
6	Gas Infrastructure Blueprint	Infrastructure blueprint for backbone gas pipeline and processing network	FEC Blueprint Approval
7	Gas Based Industrialisation	The Gas based industrialisation agenda aims to position Nigeria as the regional hub for gas based industries such as fertiliser, petrochemical and methanol	Mr. President's Gas Revolution Agenda

1.3 Roles and Responsibilities of Sector Participants

The roles and responsibilities of participants in the sector are summarised in the table below:

Entity	Role	Responsibilities
DPR	The current regulatory arm of the oil and gas industry.	• Supervise all petroleum industry operations being carried out under licences and leases in the country and for issuing these licences, as well as enforcing safety and environmental regulations.

MPR	The gas sector in Nigeria comes under the authority of the Ministry of Petroleum Resources.	• Initiate and formulate the broad policies and programmes for the development of the sector. The Ministry is responsible for the licensing of all petroleum, gas and power operations and activities.
NNPC	The state-owned corporation.	• Manage all state interests in the Nigerian petroleum industry.
GACN	The Strategic Gas Aggregator.	• Transitional institution to manage the price aggregation and the balancing of supply across the various sectors.
Gas Buyers	Gas buyers including the power sector, gas based industries, and wholesale Gas Marketers	• For secure supply, enter into Gas Sales Agreements with GACN and the "Gas Sellers" as gas purchaser/buyer.
IOCs	International Oil Companies who participate in both upstream and downstream gas sector in Nigeria.	• Dedicate a specific volume of gas supply to the domestic market based upon their gas reserves, their total production and their level of flaring. • Enter into a tri-partite agreement with GACN and "Gas Buyers" to sell its Domestic Supply Obligation (DSO).

2 Domestic Supply Obligation (DSO) Policy

2.1 Context for the DSO Policy

The gas sector has had to be in a position to respond to many time critical challenges including:

- Potential imminent explosive growth in demand from the power sector;
- A limited market window to entrench its position as a dominant player in global fertilizer, petrochemical and related industries. There is a need to rapidly attract and secure investors in these sectors;
- Urgent need to diversify the domestic gas market portfolio from the earlier scenario dominated by PHCN to one with a wider group of possible offtakers as a route towards market competition;
- Urgent need to develop the necessary gas infrastructure.

These near term challenges required a minimum gas supply flow that was significantly higher than the 300 mmcfd market that existed at the time. However, achieving a rapid growth in supply to drive the market was unlikely to happen on its own with the current structure of the sector which was dominated by oil-centric IOCs with little appetite for domestic gas market development. The DSO Policy was necessitated to jump start supply to the domestic market.

2.2 The DSO Policy Objective

The primary objective of the policy is to jumpstart gas supply availability to a level that will:

- Enable immediate response to the rapid growth in demand from NIPP and PHCN power plants;
- Create a base load of supply that could enable diversification of the market and jumpstart industrialization,
- Provide sufficient supply to underpin the commercial development of the extensive pipeline infrastructure required to support the market.

Based on the above, it was established that at a minimum, the domestic gas market be underpinned by about 5 bcfd of gas – enough to support at least 15GW of power, achieve about 4-5% global market share in fertilizer/petrochemical/methanol industries, and enable reasonable commerciality for investment in over 2000 km of gas pipeline infrastructure.

The thrust of the DSO is to create a base load of supply by intervention. However, beyond this threshold, it is expected that the basis for a fully competitive market would have been established and market forces will thereafter drive the growth of supply and demand in the market. In essence, the DSO Policy is a transitional policy intervention aimed in the short term at driving supply availability to a level that could sustainably support a fully competitive gas market.

2.3 The Key Elements of the DSO Policy

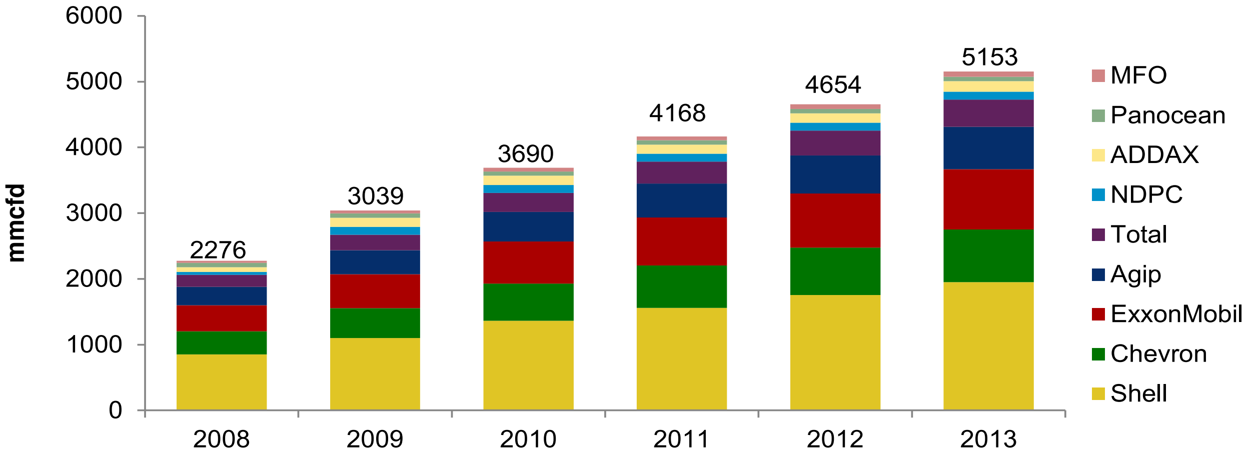
The DSO Policy stipulates that during the transition and subject to the Federal Ministry of Petroleum Resources (HMPR) subsequent assessment of the state of the nation's requirement:

- All oil and gas suppliers in the country will be mandated to set aside a certain amount of pre-allocated volume of gas for the domestic gas market;
- The mandatory obligation (called DSO) will be for a fixed volume of gas contributing to an overall base load determined by the HMPR for the purpose of transitioning the market only;

- It is intended that beyond this initial allocation, supply growth will be on a 'willing buyer, willing seller' basis, but the HMPR will retain the right to impose additional obligations, if considered necessary to do so in the interest of the nation;
- The DSO will be deployed for specific strategic purposes towards transitioning the market rapidly. This includes, but is not limited to, achieving a diversified offtake across sectors (power, industries, etc.), and stimulating the growth of backbone gas infrastructure across the country;
- The DSO will be administered centrally in order to ensure that FGN's strategic objectives for the transition are realized. The Gas Aggregator Company will be established to manage the DSO;
- Supporting commercial policies will be developed to assure commercial viability of the supply;
- Suppliers who meet their obligation will be able to supply excess gas above the DSO on a 'willing buyer, willing seller' basis;
- The obligation will be set based on a target 5 year realization frame.

The DSO legislation requires all associated and non-associated gas reserves holders to dedicate a specific volume of gas supply to the domestic market based upon their gas reserves, their total production and their level of flaring. Domestic supply obligations are broken down annually to a production obligation by year based on the reserve entitlements of each player. The sum of all obligations equals the planned domestic requirement for the stated period. Figure 2.1 summarises the domestic obligations, as issued by the DPR to all IOCs in 2009.

Figure 2.1 Estimated DSO Levels 2009



3 Gas Pricing Policy

3.1 Context for Gas Pricing Policy

End user prices in the Nigerian domestic gas market have typically been set at levels of around US$0.1/mcf into the power sector and up to US$2.0/mcf into private industry, significantly below international gas prices. These low prices have provided limited commercial incentive for the primary resource holders in Nigeria to develop and produce reserves for the domestic market – it simply has not been worth the effort. As a result, gas has either been flared or sent to the LNG plant since the commercial rewards (from LNG sales) have been sufficiently attractive.

3.2 Gas Pricing Policy Objectives

The long run pricing policy objective is predicated on the development of a fully liberalized market i.e. 'willing buyer and willing seller' market arrangements. Currently the conditions for a fully liberalized market do not exist as existing domestic gas prices are sub-commercial and inadequate to support significant natural gas development and production on a commercial basis. It is therefore the primary objective of this policy to increase gas prices for all potential suppliers to a level which will provide adequate commercial returns and stimulate development and growth in gas supply.

3.3 The Key Elements of the Gas Pricing Policy

The transitional pricing policy aims to transition from the existing sub-commercial pricing to a region of fully market led pricing over a period of time (estimated between 3-4 years) but dependent on the development of a fully open market environment. It is planned that the transitional pricing policy for natural gas will gradually move from the current low prices towards the export parity price, i.e. the price currently being achieved by suppliers to the LNG facility. Under these conditions it is assumed that suppliers will be indifferent as to where the gas is supplied since the price will effectively be the same. The transitional pricing policy also aims to assure competitiveness of natural gas pricing within the domestic market. Consequently, it recognizes the liquid rich content of natural gas in Nigeria and is therefore predicated on an assumption that the liquids will, in many instances, provide significant income to the gas producers and as such will help provide economic support to any gas developments. In addition, the transitional pricing policy aims to support the concurrent objective of catalyzing gas based industrialization and accelerated gas availability.

Consequently, the transitional pricing policy is a sector based gas pricing arrangement which breaks the domestic market into three (3) distinct sectors during the transition. The sectors are:

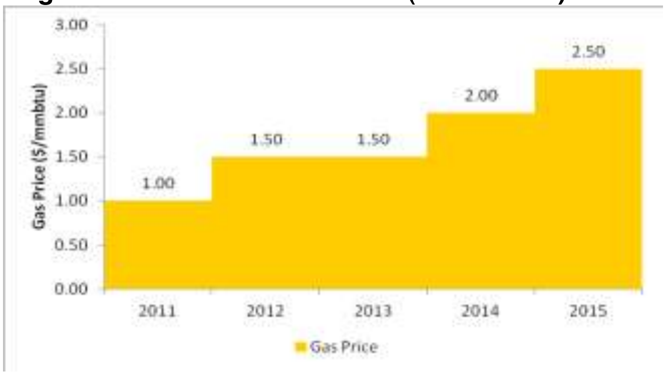
- Power;
- Gas Based Industries;
- Wholesale/Local Distribution Companies.

Pricing for each sector during the transition is developed to meet the specific objective for that sector and recognizes the specific challenges of each.

Gas Price for Power Sector

Gas prices to the power sector are being transitioned to reflect a cost-plus pricing arrangement. As reflected in Figure 3.1 below, a stepwise approach is followed to progressively move gas from sub-commercial levels to a $2.50/mmbtu by 2015.

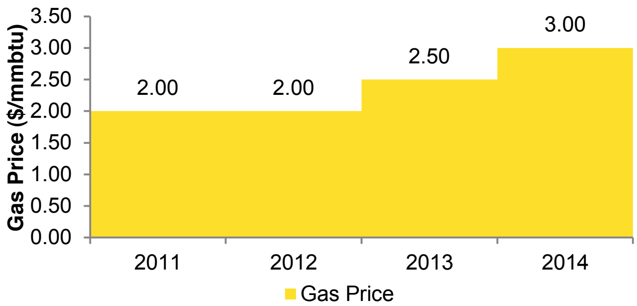
Figure 3.1: Gas Price to Power (2011 - 2015)



Gas Price to Wholesale/LDC

For gas sales to local distribution companies, prices are set to reflect the cost of alternative fuels. Below is the transition price to wholesale/LDC.

Figure 3.2: Gas Price to Wholesale (2011 - 2014)



Gas Price to Gas Based Industries

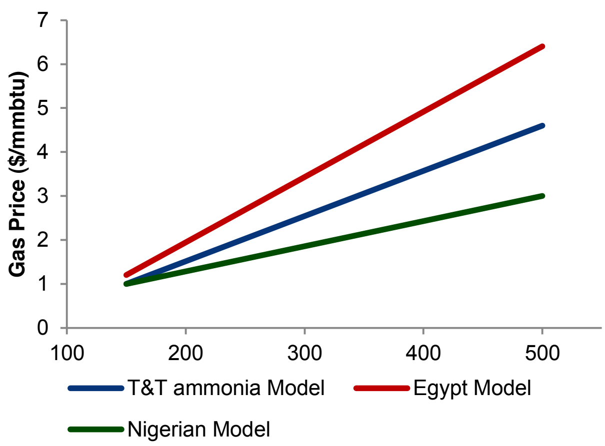
For gas sales to industry, prices are determined based on a netback pricing principle. The approach recognises the different international market conditions for exports from different industries and is therefore adapted to ensure competitiveness relative to competing countries like Trinidad & Tobago, Saudi Arabia, Egypt, etc. The gas price formula used in Nigeria together with a comparison of resultant Nigerian gas prices with other competing countries is shown below.

Figure 3.3: Gas Price Formula

Gas CP = NRP * (1 + EPF)

- EPF = (CMPP – PRP)/PRP
- CP is the applicable gas price in $/mmbtu
- NRP is the National Reference Price
- NRP = $0.9/mmbtu (RT2011) @ Product Reference Price
- PRP = Product Reference Price,($325/MT)
- EPF is the End Product Factor
- CMPP is the three Months Average End Product Price
- Floor price - $0.9/mmbtu, Capped Price - $3.0/mmbtu

Figure 3.4: Gas Price to Gas Based Industries



Whilst the pricing for buyers is sector based, gas suppliers will receive an aggregate of all three prices. This aggregate price is designed to trend towards the export parity price.

At the end of transition, it is intended that future incremental gas additions will be predicated on market principles determined by 'willing buyers' and 'willing sellers'. It is intended that the target of export parity for the transition phase will bring the average domestic gas price to within the range of market determined prices.

The pricing policy assumes that NGLs produced (extracted from the rich gas) will be priced at market rates and consequently the combination of aggregate price for dry gas at export parity levels plus revenues based on market determined NGL price will provide adequate returns on investment for upstream development. In essence, the pricing policy is a mixture of fully liberalized market determined prices for NGLs plus the regulated pricing regime for dry gas.

The transitional pricing policy applies to the DSO volume only and for the transition period only. Suppliers who have met their obligation are able to progress into 'willing buyer, willing seller' arrangements for the incremental volume above their DSO.

Gas Transmission Tariff

The gas network transportation infrastructure that exists today was built with government funding. However, the infrastructure blueprint approved by the Federal Executive Council (FEC) has a huge investment requirement which government alone may not be able to carry. To this end, it is expected that a Public Private Partnership (PPP) arrangement will be deployed to have this actualised. In order to support the investment required, the gas transmission tariff on the backbone gas transmission infrastructure has been set at $0.80/mcf on a postage stamp use of transmission network basis.

4 Market Structure & Credibility Policies

4.1 The Context to the Market Structure & Credibility Policies

Historically, in the Nigerian natural gas market there has been considerable uncertainty for private entities as to whether a commercially viable business can be established and maintained in the sector. With limited clear and transparent regulation in the gas business, it has been extremely difficult for companies to overcome the apparent risks for the necessary investment to be made.

It is deemed unlikely that the desired growth in the market can be achieved without independent entities to ensure that supply and demand are proactively managed, to act as intermediaries in agreements between suppliers and buyers, and to oversee the overall operation of the market and its infrastructure. While GSAs currently provide some degree of commercial security, the issue of non-payment risk with some offtakers is a significant issue for suppliers. Creditworthiness of some Nigerian end consumers would undoubtedly continue to be a challenge unless this risk can be addressed.

4.2 The Market Structure & Credibility Policy Objectives

The overall requirement to reinforce the credibility and creditworthiness of the domestic gas market consists of a number of key objectives:

- To create an independent government entity for the transition period which assists in managing the balance of supply and demand, facilitates gas transactions and oversees the effective operation of the country's gas infrastructure;
- To mitigate some of the risks of non-payment for gas suppliers through appropriate guarantees;
- To provide robust legal and commercial frameworks for gas related transactions including gas sales, processing and transportation which encourage the growth of the domestic gas sector;
- To develop a network code for the growing pipeline network to ensure open access and clear articulation of general operating principles.

The intent is to prepare the market for full liberalisation by addressing these key market issues through the transitional period.

4.3 The Key Elements of the Strategic Gas Aggregator Policy

The Strategic Gas Aggregator is intended to manage the price aggregation and the balancing of supply across the various sectors.

The Strategic Gas Aggregator is based on some of the key positive elements from the EGAS experience (see Part A). The Strategic Aggregator is a non-profit entity to be regulated by the Department of Gas in the Ministry of Petroleum Resources. The Department of Gas in collaboration with DPR will also determine the Domestic Supply Obligation for each Producer and ensure its implementation. Post PIB, the Strategic Aggregator will be regulated by the Downstream Petroleum Regulatory Agency. The Downstream Petroleum Regulatory Agency will regulate both the technical and commercial activities of the Midstream and Downstream sectors of the Nigerian Petroleum Industry. Hence, the aggregator itself will not be a regulator, it will not determine the DSO, nor will the Strategic Aggregator enforce the DSO.

The Aggregator is established as a transitional institution that will in principle perform the following functions:

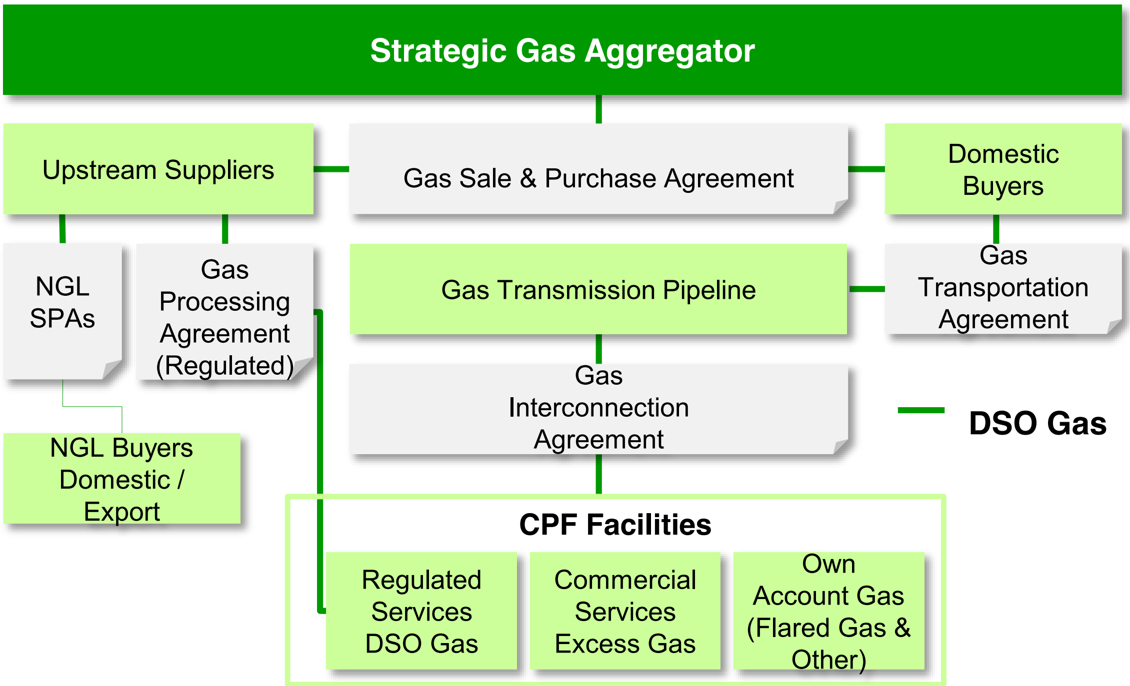
Function	Tasks
Manage the implementation of the DSO regulation. This includes the disbursement of the DSO gas to the various sectors ensuring a minimum aggregate domestic gas price that tracks the transition to export parity. This function will continue until the end of the FGN's intervention through the DSO and the Strategic Aggregator.	▪ Interface with the regulator on DSOs and availability ▪ Manage allocations of suppliers to buyers ▪ Constantly simulate aggregate price based on actual allocation ▪ Notify the regulator when allocation arrangements threaten aggregate price
Manage demand and act as an intermediary between domestic buyers and upstream suppliers.	▪ Act as the first point of contact for gas buyers and process their demand requests ▪ Conduct due diligence on buyers and suppliers and determine accordingly if demand is credible ▪ Periodically update the regulator on domestic demand growth ▪ Conduct due diligence on infrastructure availability for gas delivery
Manage the implementation of all revenue securitization instruments as required (**this will run until the expiry of foundation GSPAs**)	▪ Manage the receipt of revenues from the domestic buyers through an escrow account and effect the payment of the aggregate domestic gas price to the upstream suppliers ▪ Calculate periodic aggregate price ▪ Process securitization through the escrow account for suppliers in the case of default on payment by buyers, and track the impact of such default on the aggregate price
Oversee the overall network/system administration throughout its existence.	▪ Monitor and capture, on an ongoing basis, the total system flows through a network of meters ▪ Routinely facilitate real time gas swaps in the event of short term gas shortages ▪ Lead a daily operational interface between the gas transporter, buyer, and suppliers ▪ Coordinate the deployment of swing capacity or swaps leveraging its real time knowledge of available supply capacity in the system ▪ Advise the transporter on supply sources in the event of shortfalls, and in extreme shortfall cases liaising with the regulator on global rationing of supplies across sectors
Operate as a trading platform, which will commence in the future when the market is commercially mature.	

4.4 The Key Elements of the Bankable Commercial Arrangements Policy

A number of standardised agreement templates exist to underpin the various contractual relationships required to make the proposed investments in both blueprint infrastructure and upstream supplies commercially viable. These template agreements are intended to provide support for an orderly transition from a non-bankable to bankable environment, where all investments are backed by robust commercial arrangements. The agreements, each holding a common set of elements, are intended to form the starting point for all negotiations:

- **A Gas Supply and Purchase Agreement (GSPA)** between an Upstream Supplier and a Domestic Buyer. This is the primary contracting document that underpins the operation of the DSO. It is a tripartite agreement between an Upstream Supplier, a Domestic Buyer, and the Strategic Aggregator. It is an agreement to supply Pipeline Sales Gas to the designated Domestic Buyer. The level of supply will be mandated by the DSO. From the revenues paid by the Domestic Buyer, the Upstream Supplier will pay fees for gas processing and transportation;
- **A Gas Processing Agreement (Regulated):** The gas processor will be remunerated for its investment in CPF capacity to process DSO Feed Gas by selling such capacity to Upstream Suppliers through a Gas Processing Agreement, which is a bilateral agreement between an Upstream Supplier and the Gas Processor. It is an agreement to receive DSO Feed Gas and process it to produce DSO Pipeline Sales Gas under a Regulated Tariff. Execution of this agreement will be crucial to the Upstream Supplier's ability to meet its DSO to the Minister of Petroleum Resources;
- **A Gas Transportation Agreement (GTA)** is a bilateral agreement between a Domestic Buyer and a Gas Transmission Pipeline Company for the shipment of Pipeline Sales Gas from the Title Transfer Point of the CPF to the Domestic Buyer's facilities. Title to DSO gas transfers from the Upstream Supplier to the Domestic Buyer occurs at the Title Transfer Point of the CPF. The Domestic Buyer will contract with the Gas Transmission Pipeline Company to ship gas from this Title Transfer Point through the GTA;
- **A Gas Interconnectivity Agreement** is a bilateral agreement between a gas processor and a Gas Transmission Pipeline Company aimed at ensuring that gas processed and contracted for is adequately transferred from the CPF into the appropriate Gas Transmission Pipeline.

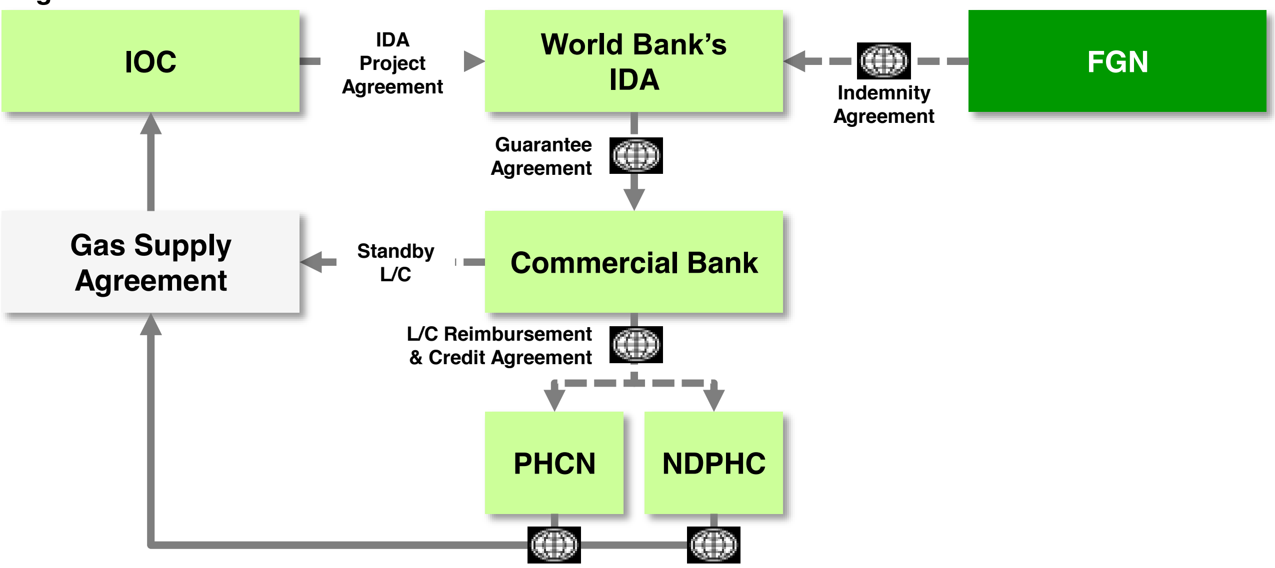
Figure 4.2: Contractual Arrangements



4.5 The Key Elements of the Partial Risk Guarantee Policy

World Bank Partial Risk Guarantees (PRG) will be issued to address the issues of non-payment. The World Bank Partial Risk Guarantee is a revenue securitization scheme in case of default on payments. The PRG also supports the implementation of the DSO by ensuring payments are made to suppliers, thus guaranteeing their returns and further incentivizing them to comply.

Figure 4.3: World Bank PRG for Revenue Securitization



4.6 The Key Elements of the Network Code Policy

The National Gas Transportation Network Code is intended to manage open access to the network, and is predicated on aspects of the UK network code. Essentially, the Code is intended to be a contractual framework between transporters and network users that provides open competitive access to existing and future gas transportation infrastructure. To support the successful transportation of gas for power generation and other domestic use, the following key elements are included in the code:

- Gas Entry Requirements – this is particularly relevant to issues such as gas quality and the measurement and allocations of gas in order to ensure an appropriately consistent and equitable treatment;
- Transportation Charges – this comprises Capacity Charges, Commodity Charges and Overrun Charges under the code. The applicable rates are set through publication of a statement published by the operator from time to time in accordance with a process overseen by the Department of Petroleum Resources;
- Metering and Measurement - The provision and technical specification of measurement and metering stations;
- Nominations - The provision of nominations by Shippers is designed to assist the Operator in managing the System.

5 Gas Infrastructure Blueprint

5.1 Context for the Gas Infrastructure Blueprint

To date the development of gas infrastructure in Nigeria has largely been driven by field to plant connections with little or no consideration of the potential for an interconnected system. Despite this there have been some major segments of gas infrastructure developed over the years (particularly in the South) and as such a relatively robust interconnected pipeline network could be achieved with some key infrastructure additions connecting existing systems as well as extending supplies to the North.

However, so far there have been few commercial incentives for private companies to become actively involved in the development and operation of gas infrastructure. A clear investment opportunity must be presented to potential developers for the desired gas grid to be established.

5.2 Gas Infrastructure Blueprint Objectives

The key objective of the gas infrastructure policy is to establish a clear opportunity for potential investors that will:

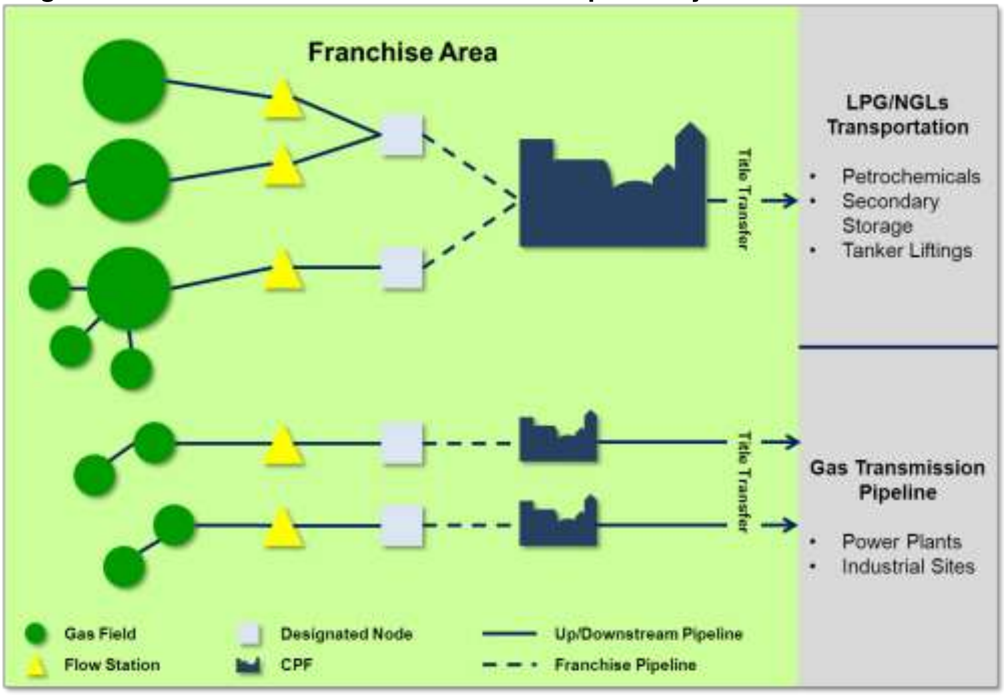
- Maximize the penetration and reach of natural gas across the country;
- Facilitate efficient connection of as many suppliers to as many demand centres in an integrated 'hub and dispatch' structure;
- Where possible, leverage connectivity between domestic and export infrastructure for flexibility of supply;
- Provide for an efficient system to maximize the extraction of NGLs and other valuable by-products from the rich gas through the use of central processing facilities (CPFs).

5.3 The Key Elements of the Gas Infrastructure Blueprint

The Gas Infrastructure policy is predicated on long run commerciality to support PPP and ultimately private sector investment. However, initially it is skewed towards FGN funding. The infrastructure policy framework therefore focuses on backbone gas pipeline infrastructure and CPFs strategically located at designated hubs in the network. The pipelines are based on commercial principles of operation and access is governed by the national network code.

The philosophy behind the blueprint is that feed gas from the flow stations and designated nodes of the Upstream Suppliers within a Franchise Area will be transported to a Central Processing Facility (CPF), where gas will be treated and NGLs extracted. The Pipeline Sales Gas will then be evacuated via the nearest Gas Transmission Pipeline system, whilst the extracted NGLs will be stored in NGL storage and handling facilities pending export into the domestic market or external markets. An illustration of the philosophy is shown is Figure 5.1 below:

Figure 5.1: Illustration of the Transmission Pipeline System



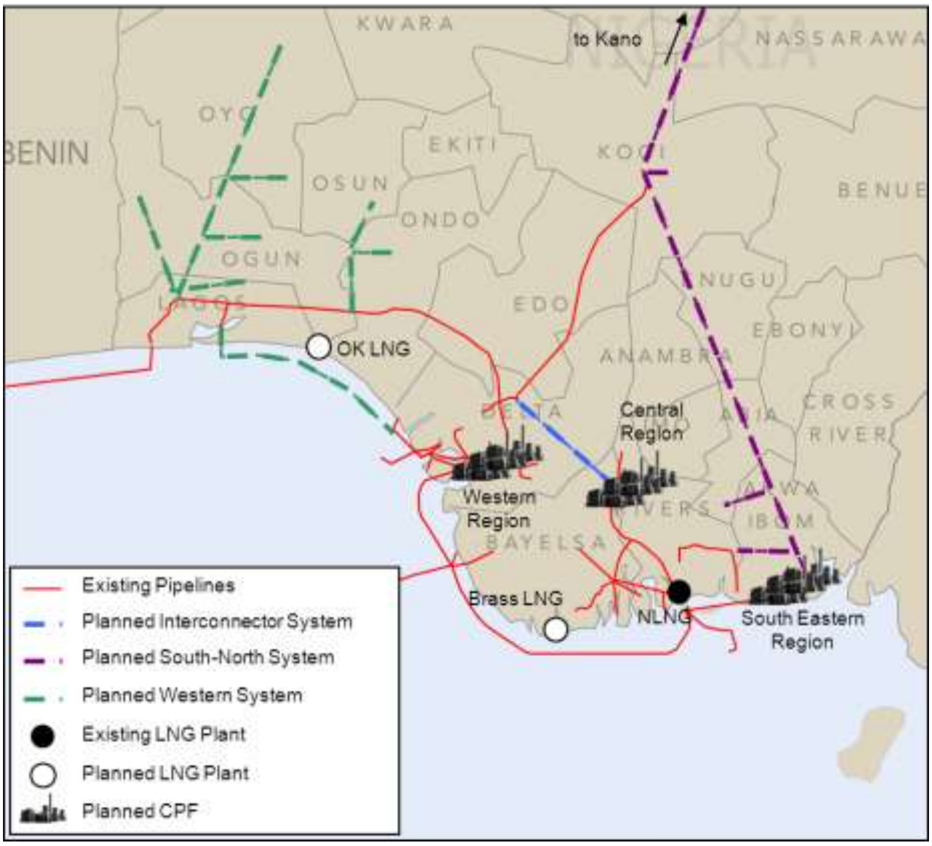
The Blueprint is designed around this hub and dispatch model, and characterised by a network of gas transportation and Central Processing Facilities (CPFs).

The proposed CPFs are situated in three regions – the Western Region, the Central Region and the South Eastern Region.

There is a proposed network of three Gas Transmission pipeline systems:

- **South-North Gas Transmission Pipeline System** – This planned pipeline will originate from the South Eastern Region CPF, crossing through the Eastern states of Abia, Ebonyi, and Enugu to Kano and Kaduna via Ajaokuta and Abuja. This will be the main backbone system transmitting gas to the Eastern, Middle, and Northern parts of Nigeria. It will also transit gas for the proposed Trans-Saharan Gas Project;
- **Western Gas Transmission System** – This pipeline comprises the existing Escravos-Lagos Pipeline System (ELPS), a planned offshore bypass originating from the Western Region CPF linking up with the ELPS in Sagamu and with provisions for a spur extension to the Olokola LNG plant. The system also includes further a western extension to Jebba, Kwara State and Osun State. It will serve the entire western region of Nigeria and enhance the capacity of ELPS;
- **Interconnector Gas Transmission System** – This pipeline will originate from the Central Region CPF and comprise of a new pipeline to Oben as well as the existing Oben-Ajaokuta link. It will serve as an interconnector between the reserves rich eastern area and the major Western and North-South Transmission Systems. It will provide access to additional gas supplies from the eastern area to serve the market intensive west and north axis. In essence, this system will bridge the East, West, and Northern parts of Nigeria with respect to gas access.

Figure 5.2: Illustration of the Infrastructure Blueprint



The roadmap for implementing the Blueprint is divided over three phases of development.

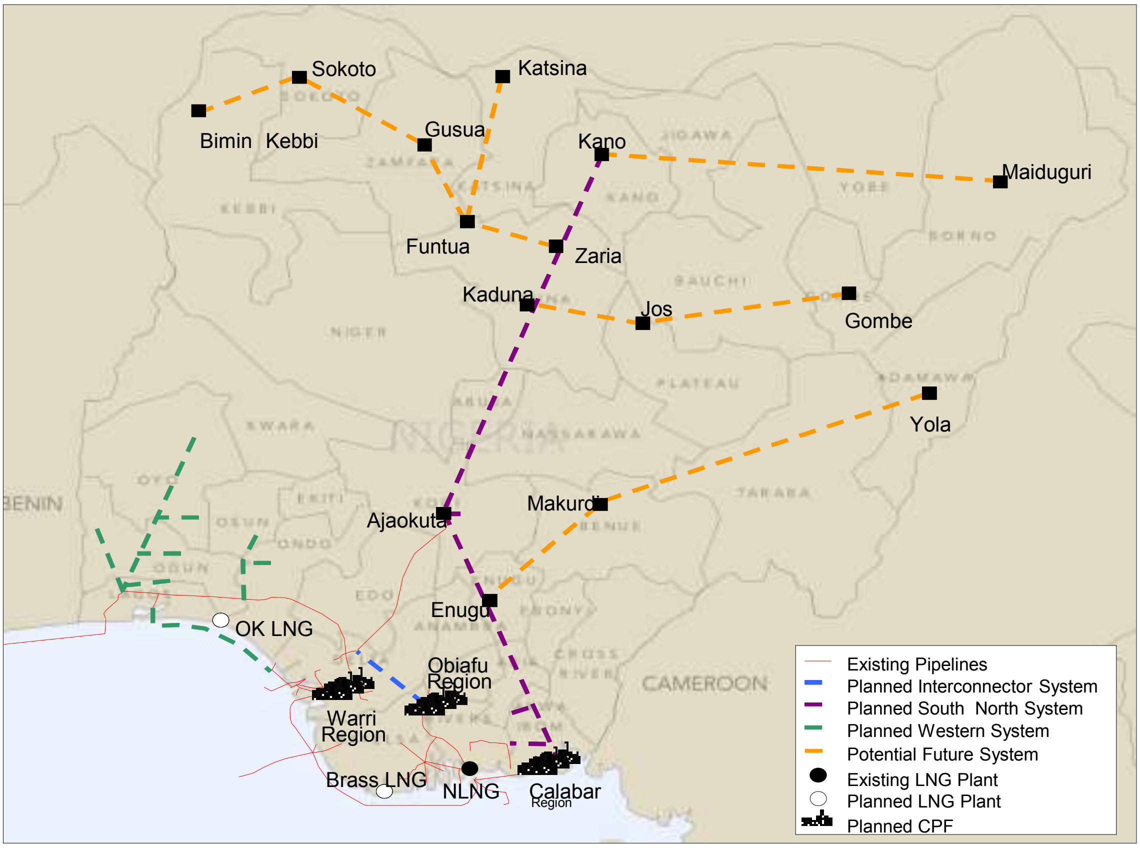
Phase 1 of the policy blueprint comprises:

- The expansion of the existing ELPS system;
- Interconnection of the East West network systems through Ob3 pipeline;
- Debottlenecking and expansion of the eastern network system through QIT, Obigbo, Calabar, Ajaokuta;
- Development of the northern network system, Ajaokuta-Kaduna-Kano pipeline;
- Three central processing facilities to be suitably located to support the gas based industrialization agenda.

Phase 2 will see expansion of the laterals to the North East and North West from the Ajaokuta-Kaduna-Kano pipeline. Phase 3 will include extension to the North West from the ELPS. Itoki-Ibadan-Jebba pipeline. Exact trajectories of Phase 2 & 3 will be optimized over time

The infrastructure as proposed in the Gas Master Plan is an initial phase and will provide a backbone around which future expansions will be anchored, the development of which may mirror that shown in Figure 5.3.

Figure 5.3: Potential Future Nigerian Gas Infrastructure System



6 Gas Industrialisation

6.1 Context for the Gas Industrialisation

The global restructuring trends of gas-based industries away from the existing demand centres represents a timely opportunity for Nigeria to attract international investors and to develop new industries within Nigeria which will provide considerable benefits throughout the domestic economy. To reinvigorate and accelerate this agenda, the Gas Revolution Master Plan was launched in 2011.

6.2 Gas Industrialisation Policy Objective

Nigeria's strategic intent is to add value to its natural gas resource by engaging in gas based industries like Fertilizer, Methanol and Petrochemical. This will be achieved by redirecting gas that might otherwise have been flared towards the development of these gas based industries.

A key objective of the Gas Industrialisation policy is to stimulate GDP growth through employment creation in associated secondary industries which are dispersed throughout the nation. The benefits to the nation will be maximised via the multiplier effects of the primary gas based industries rather than via a maximisation of direct tax revenue.

6.3 The Key Elements of the Gas Industrialisation Policy

The following elements are included in the overall industrialisation policy in order to achieve the desired impact on the overall economic productivity of the country:

- Leverage natural gas for use in primary industries/ anchor facilities that will stimulate economic growth, but that can also be geographically dispersed and have a higher impact throughout the country;
- Leverage the synergies which can be gained by co-locating plants in purpose-built gas based industrial clusters with world scale production of fertilizer, petrochemicals, methanol and related products;
- Drive gas based industrialisation through using the supply of wet gas predicated primarily on the DSO and the CPFs (Infrastructure Blueprint) to supply dry gas and natural gas liquids for gas based industrialisation (see figure below);
- Capture the full NGL value;
- Progress fertilizer projects in order to boost domestic fertilizer utilisation in the domestic agriculture sector thereby increasing productivity and enhancing its contribution to GDP. This will be achieved both through improving crop yields and through stimulating the growth of agro processing industries which will be geographically dispersed around the agricultural belts of the country;
- Strategically support development of petrochemical industries in the primary production of Polypropylene and Polyethylene and other primary products which can then be sent to various part of the country to stimulate geographically dispersed secondary industries e.g. Manufacturing;
- Incentivise anchor investors in these sectors thus attracting a critical mass of such investments to jumpstart the industrialization agenda;
- Use the gas based industrialization policy to target domestic consumption as well as also encouraging export of these industrial products;
- Use the gas based industrial program to support creation of over 5 million jobs in the medium term across the value chain and across the country.

The operating model reflects the targeted use of wet gas predicated primarily on the DSO and the CPFs (Infrastructure Blueprint) to supply dry gas and natural gas liquids for use in gas based industries.

Figure 6.1: Operating Model of Nigeria's Gas Revolution

1

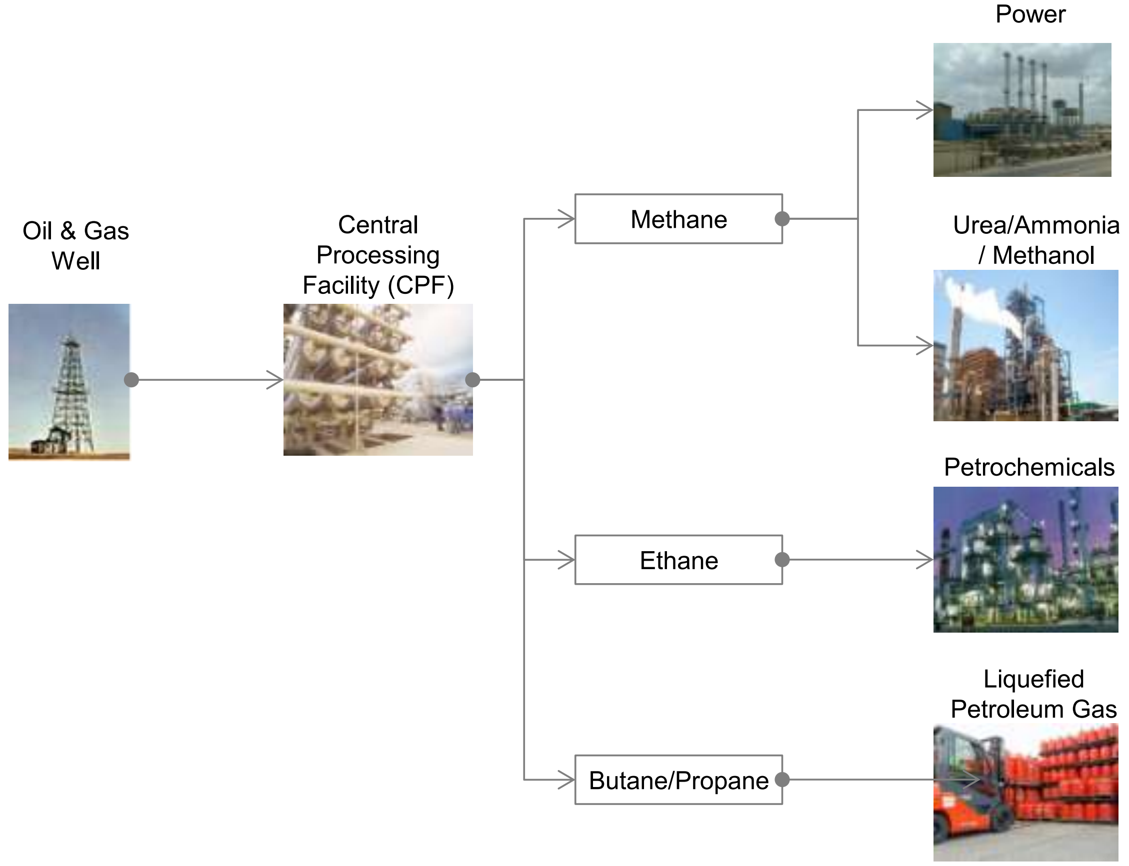
Supply of wet gas predicated primarily on the Domestic Supply Obligation.

2

Deployment of Private Sector led Central Processing Facilities (CPFs) that extract the full range of constituents from gas that will underpin industrial diversification.

3

A diversified portfolio of credible downstream gas based industry investors (fertiliser, petrochemicals, etc.) that will anchor the industrialisation agenda.



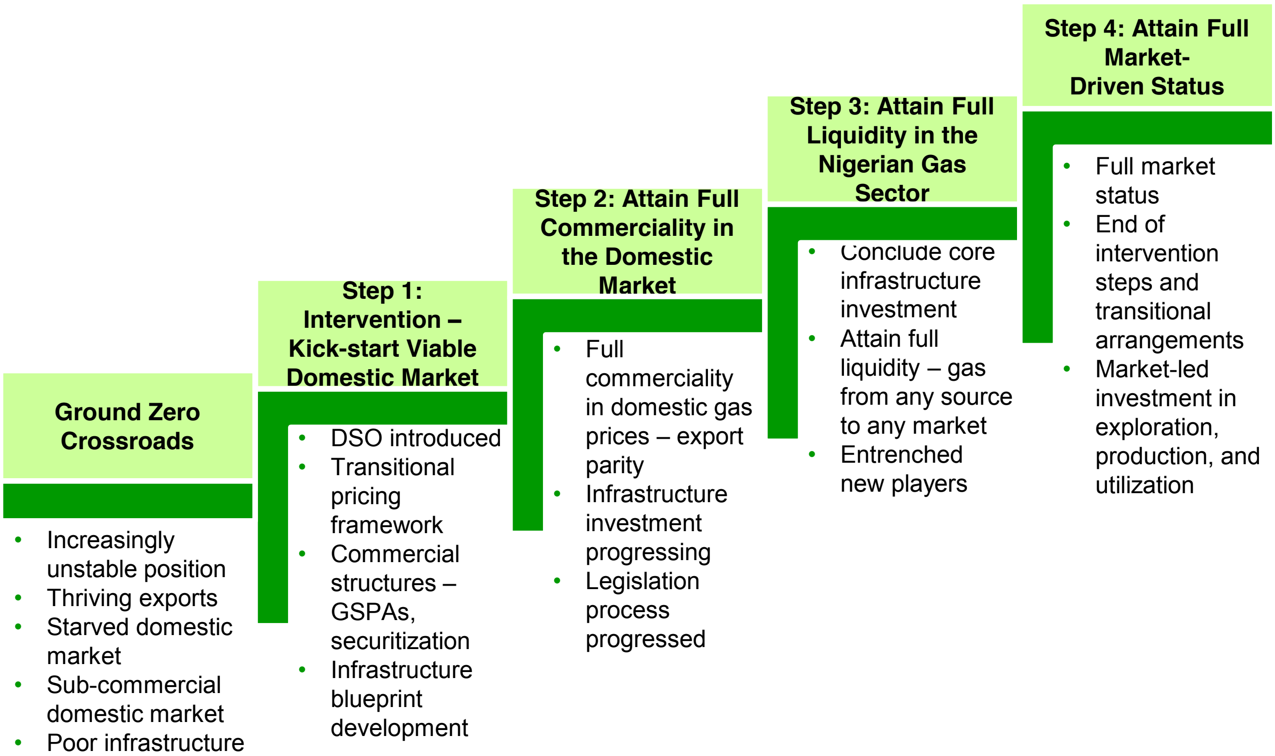
7 Overall Implementation Framework

7.1 The Planned Phased Approach

The various policies described above are being implemented in concert in order to reposition Nigeria's gas market from "ground zero" to a fully liberalised market with "willing buyers" and "willing sellers". The approach has four distinct steps that are designed to achieve this transition in an orderly manner:

- Step 1 consists of the major interventions required to kick-start the domestic market through the introduction of the following policies: DSO, Transitional Pricing Framework and Infrastructure Blueprint;
- Step 2 drives the domestic market towards full commerciality by executing the steady but managed rise in domestic gas prices towards export parity. This step also includes further progressing investment in infrastructure as per the Infrastructure Blueprint;
- Step 3 focuses on the delivery of the Infrastructure Blueprint in order to attain full liquidity in the gas sector and ensuring gas mobility between all sources and all markets either directly or through swap arrangements;
- By Step 4 the market will be fully liberalized and all segments will be operating on a fully commercial basis. This step will see an increase in the number of players, and full establishment of infrastructure as well as regulatory and legislative frameworks.

Figure 7.1: Transitional Approach to Interventions



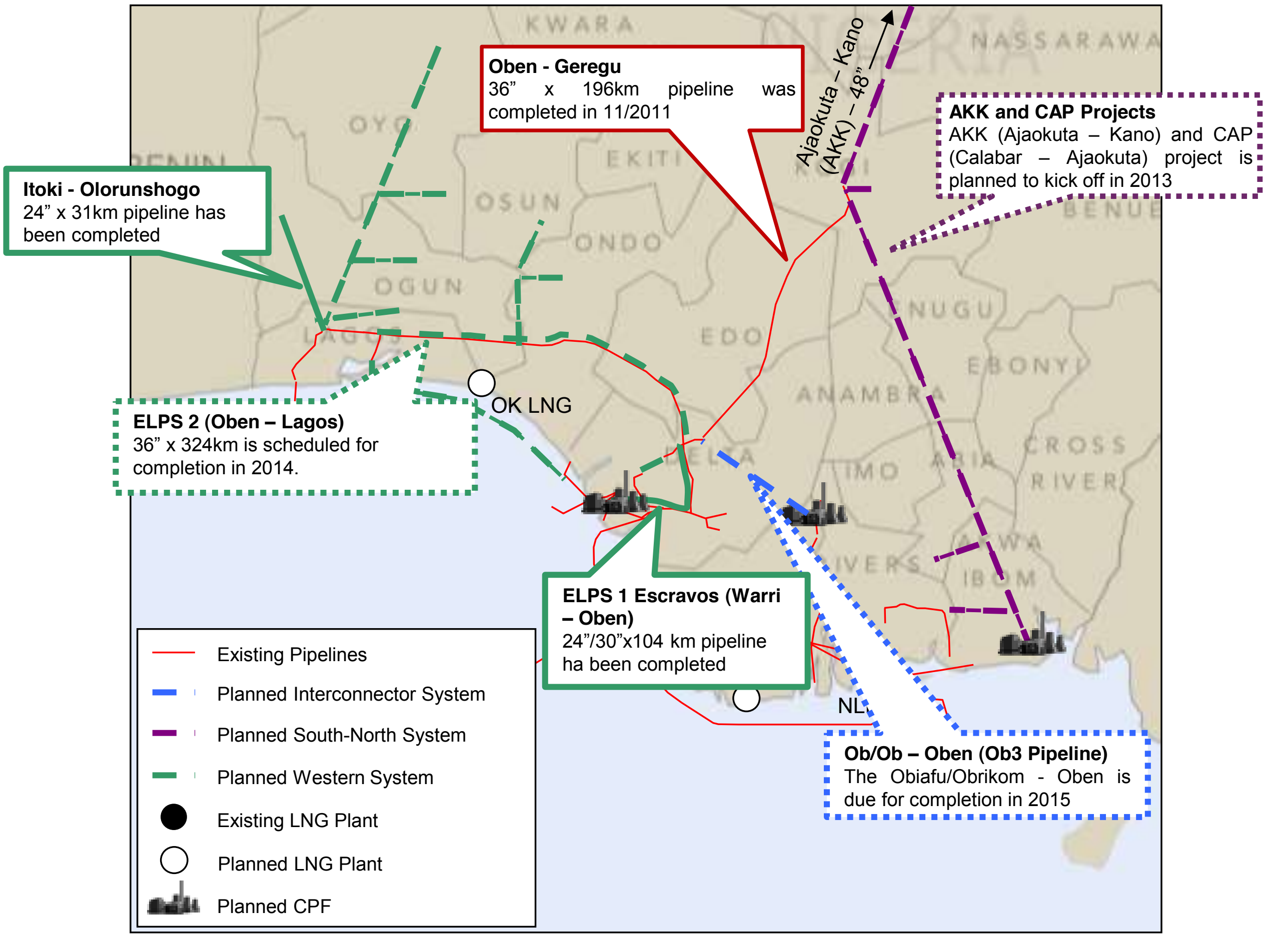
Part C: Current Status

1 Gas Infrastructure and Supply

1.1 Contracts Awarded for Major Transmission Pipeline Additions

The Gas Infrastructure Blueprint defines an integrated network of required gas pipeline additions to maximize the penetration and reach of natural gas across the country. In response to this, a major investment program is underway with over 355km of pipelines having already been added to the system by NGC (Nigerian Gas Company) since 2006. Progress achieved in terms of completed pipelines and projects which have been launched is summarised in Figure 1.1 below:

Figure 1.1: Progress Update - Gas Infrastructure Blueprint



Completed Pipelines

- Itoki-Olorunshogo 24" x 31km pipeline has been completed and is currently supplying gas to Olorunshogo power plant, which permanently addresses the challenge of supply delivery to Olorunshogo PHCN/NIPP Plants;

- ELPS 1 Escravos – Warri-Oben 24"/30" x 104km project has been completed, addressing stranded gas in Escravos. Additional 80mmcf/d (300MW) is currently supplied to the domestic market and a further 70mmcf/d (250MW) by Q3 2013.

- Oben-Geregu 36” x 196km pipeline was completed in November 2011, addressing supply deliverability to Geregu power plant and providing flexibility for future expansions.

Pipeline Investments in Progress

To date progress has been made in the expansion of the ELPS pipeline network with an expectation that capacity will have doubled to 2.2bcf/d by the end of Q2/3 2014. ELPS 2 – Oben-Lagos 36” x 324km is an ongoing project that will enable expanded supply to support all future power and industry expansion.

In addition to the ELPS expansion, progress has been made on the following Gas Infrastructure Blueprint pipelines:

- Work commenced on the OB3 interconnector pipeline, which bridges the East with the West and North, and this is expected to be completed by end Q2 2015;
- The other pipelines (QIT-Ajaokuta-Kano) are at technical development stage with a view to delivery by end 2018.

The Ministry of Finance has indicated that $450m of Eurobonds is now available to support the delivery of gas infrastructure, with emphasis on completion of the OB3. Based on this steer, the project implementation strategy of the Gas Infrastructure Blueprint has been updated to reflect this objective.

The balance of the infrastructure blueprint will be delivered in 2 parts:

- Part 1: Referred henceforth as ‘Early Gas Priority 1 Project’ comprises the following elements;
    - Completion of the OB3 pipeline;
    - Construction of the 20” x 41km pipeline from Cawthorne Channel-Alakiri-Obigbo-NOPL intersection.

  Estimated costs of this project are $240 million, and completion is expected in Q2 2015, with an incremental gas supply on completion of 375 mmcfd. This Early Gas phase will be funded exclusively from the Eurobonds, leaving a balance of $210m out of the Eurobonds for deployment to Part 2.

- Part 2: Comprises of 2 elements including:
    - ‘Early Gas Priority 2 Project’ targeted at the ExxonMobil incremental gas at QIT. It is a 230km pipeline from QIT-Obigbo-NOPL intersection-OB3 entry point at Obiafu
        i. The project will commence concurrently as Early Gas Priority 1, but is timed to be completed by Q2 2016 when the Exxon Mobil Oso-QIT pipeline will be completed, delivering additional 300mmcf/d at QIT
        ii. The project will add 300mmcf/d to the grid, part of which will be consumed at QIT by the ExxonMobil JV IPP.

    b. ‘Expanded Phase 1 East-North Network Project’ targeted at incremental gas (about 700mmcf/d) from the Assa North/Ohaji South (ANOS) gas development. The project will comprise
        i. The Obigbo-Umuahia-Enugu-Ajaokuta pipeline
        ii. Ajaokuta-Abuja-Kaduna-Kano pipeline completion

Part 2 will be delivered through a PPP funding scheme. The funding for the PPP arrangement will include:

- the balance of the Eurobonds;
- an assumed $250m annual contribution from the FGN (compared with historical annual FGN gas infrastructure appropriation at level of $490m);
- 3rd party private sector debt and equity.

1.2 Two Central Processing Facilities Currently in Pre-FEED

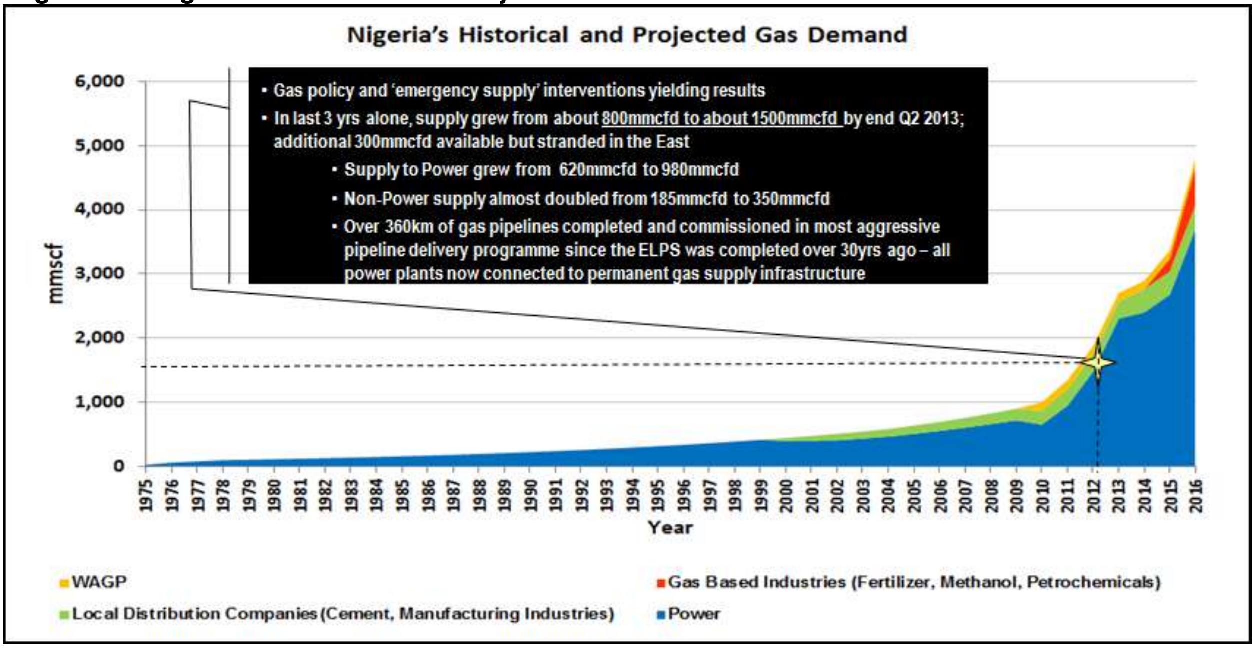
The Gas Infrastructure Blueprint also defines the requirements for a number of Central Processing Facilities (CPFs) as an integral part of the policy to implement an efficient hub and despatch model for Nigerian gas production. In response to this, major progress has been made in selecting investors who will develop and run gas processing facilities and gas conversion industries. The current progress of developments in these first two CPFs is summarised in the table below.

	Central CPF	Western CPF
Location	Obiafu/Obrikom	Ogidigben
Sponsors	Oando, NAOC (Agip) and NNPC	CNL, SPDC, Sahara Energy Resources and NNPC
Capacity	Phase 1: 0.6 bcfd	Phase 1: 1 train of 0.8 bcfd Subsequent phases: 2 trains x 0.8 bcfd
Process	To be determined by the Pre-FEED contractor	The Western CPF is being planned to be developed in 3 trains of 800mmcfd each: the first two trains to process rich gas and extract the NGL while the last train will process the lean gas currently flowing in the pipelines for the purpose of ethane extraction for the petrochemical plant. Also, a de-ethanizer will be added to the first two trains to extract ethane in time for the commissioning of the petrochemical plant.
Stage	Commencing Pre-FEED	Commencing Pre-FEED
Contractors	For the Central CPF, NAOC being the technical partner in the consortium will handle the Pre-FEED through one of its subsidiaries in Italy. KBR and NETCO will jointly work as the Project Management Consultants for the Central CPF Pre-FEED stage. No EPC contractor has been selected since the project is still at the pre-FEED stage.	Granherne, a subsidiary of KBR will handle the Pre-FEED for the Western CPF with ILF Engineers Nigeria Limited handling the Pre-FEED for the associated pipelines. KBR is the selected Project Management Consultant for the Western CPF Pre-FEED Stage. No EPC contractor has been selected since the project is still at the pre-FEED stage.
Contractual Agreements	Gas processing agreements will be negotiated during the FEED stage	Gas processing agreements will be negotiated during the FEED stage
Financial Close	Expected 2015	Expected 2015
Start of Operations	Expected 2018	Expected 2018

1.3 Robust Plans for Supply Increases Supported by Infrastructure Developments

Progress with both the Infrastructure Blueprint and the implementation of the DSO has supported a three-fold increase in gas supplies to the domestic market, rising from around 500 mmcfd in 2006 to 1500 mmcfd by April 2013.

Figure 1.2: Nigeria's Historical and Projected Gas Production



Further rapid growth in supply is expected in the short term and will be supported by the pipeline and CPF projects which are currently being implemented.

Investments in gas supply are planned to come on stream between 2013 and 2015 to ensure gas availability grows in line with the rapid growth in infrastructure capabilities and to ensure that the DSO targets are met. These will bring an additional 1 bcfd of gas on stream to supply the domestic market.

This will achieved through a combination of expanding or constructing new gas processing plants, and the completion of several new pipeline connections. The Mid-term gas supply additions that are planned between 2013 and 2015 are shown in Figure 1.3 below.

Figure 1.3: Mid-term Gas Supply and Infrastructure Additions (2013 - 2015)

2014 (605mmcfd)

- Additional gas from NPDC Oredo – 22km pipeline between Oredo and PanOcean Ovade gas processing plant and hook up new gas wells (100mmcfd)
- Expansion of Seplat Oben Gas Plant (30mmcfd)
- Obite Gas Supply (225mmcfd)
- Shell Forcados Yorki Upgrade (80mmcfd)
- Release of 170mmcfd stranded gas in the East to supply NIPPs Power Plants (Alaoji, Gbarain and Omoku)

Q1-Q2 2015 (400mmcfd)

- Utorogu New Plant (80mmcfd)
- NPDC Odidi Re-entry (40mmcfd)
- Shell Alakiri (100mmcfd)
- Shell Agbada (80mmcfd)
- Shell Southern Swamp (100mmcfd)

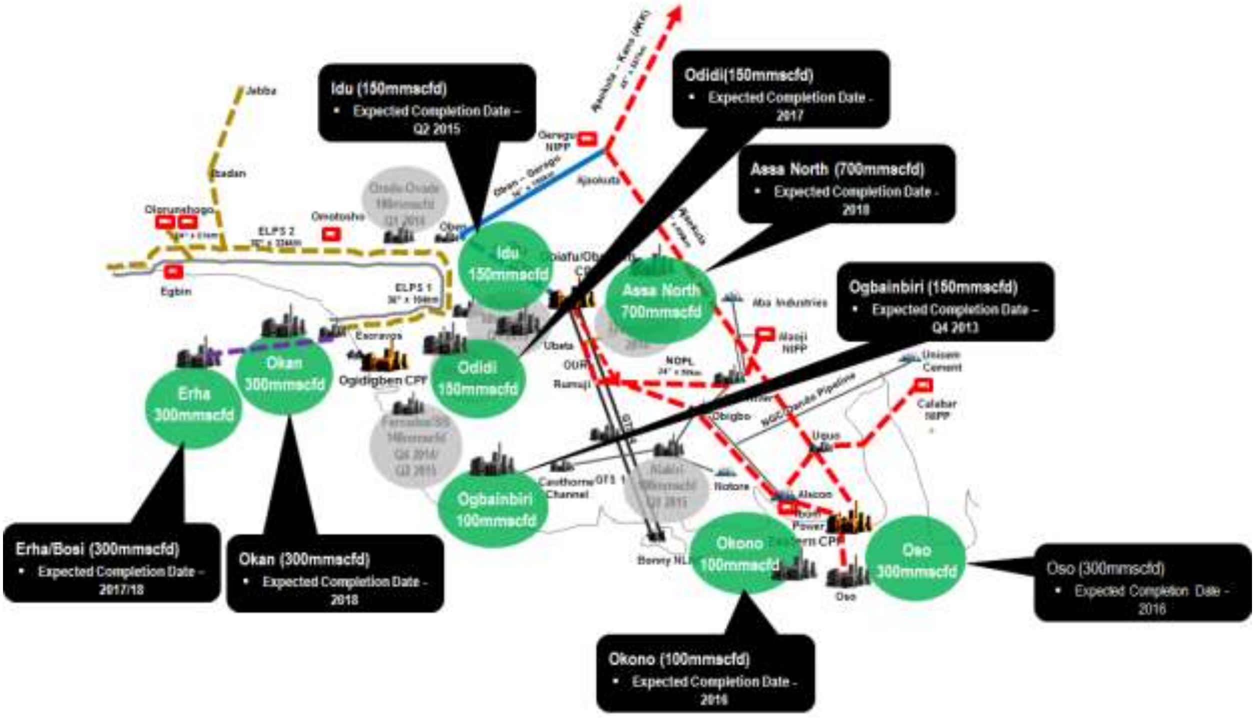
Q3-Q4 2015 (340mmcfd)

- Completion of the East-West Interconnector pipeline (OB3) – Move stranded 340mmcfd to the West

Total medium term gas supply – 1345mmcfd

A second wave of supply projects between 2015 and 2019 will bring an additional 2100 mmcfd of supply to the domestic market. These long-term supply additions are centred on additional gas processing facilities, and a total of eight projects are being progressed at various stages of development, as illustrated below.

Figure 1.4 Long-term Gas Supply Additions (2015-2019)



2 Gas Utilisation in the Power Sector

2.1 Gas Supply to Power is Responding to Demand Growth

One of the fundamental objectives of the Gas Master Plan interventions is to support a five-fold increase in power generation capacity via the deployment of natural gas as the dominant fuel in the sector.

Gas supply to power is currently constrained primarily as a result of outages caused by vandalism to key infrastructure:

- ELPS A pipeline was vandalized in June, 2013, resulting in 190mmcf/d gas supply loss comprising:
    - Outage of 120mmcf/d of existing supplies;
    - Addition of 70mmcf/d of new supplies from Escravos.
- In addition, 45mmcf/d of gas is also lost due to supply challenges at the Oben Gas plant;
- As a result, many power plants have been in restricted mode of operation – with a total estimated loss of 1991MW. New generating capacity will also add to the widening gap between demand and supply.
- At the end of Q3, 2013, the total gas supplied to power will generate about 4,000MW versus available generating capacity of 5,600MW.

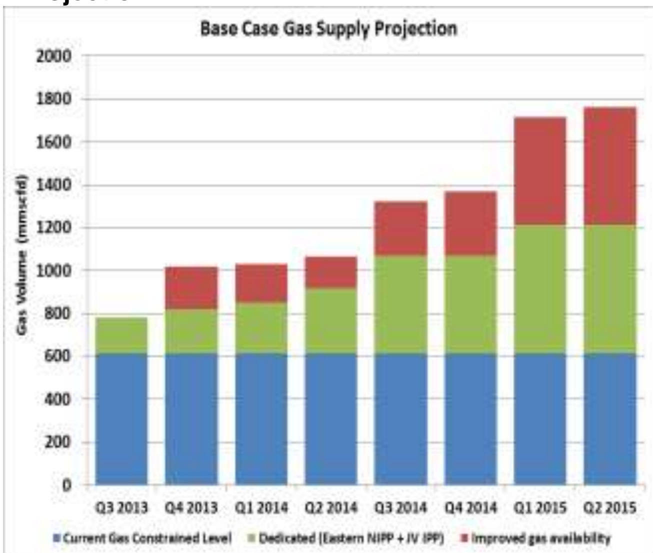
Repair works are in hand to restore capacity by November 2013:

- NGC has commenced repair of ELPS A pipeline with an estimated completion time of end October, 2013
- In addition, SEPLAT has commenced repair efforts at the Oben Plant - production is increasing steadily and is expected to be fully reinstated by October, 2013
- NNPC is also fast tracking the expansion of ELPS 2, particularly the 40km stretch PS4/PS5 between Itoki and Emuren. This will boost pressure downstream of Itoki with some impact on pressure of supply at Olorunshogo with an estimated completion time of Mid-November, 2013
- Before the end of Q4, 2013, major repairs would have been effected restoring 700MW of power.

The restoration of pipelines and new gas additions will enable gas supply to power to reach 1.78bcf/d by Q2 2015:

- NPDC Oredo-Pan Ocean 22km bypass will add 100mmcf/d.
    - This project is progressing steadily for delivery in Q1 2014;
- SPDC JV Southern Swamp / Forcados Development will add a further 140mmcf/d – the project is ongoing;
- SPDC JV Alakiri Plant upgrade will add 100mmcf/d – the project is ongoing and is due for delivery in Q1 2015

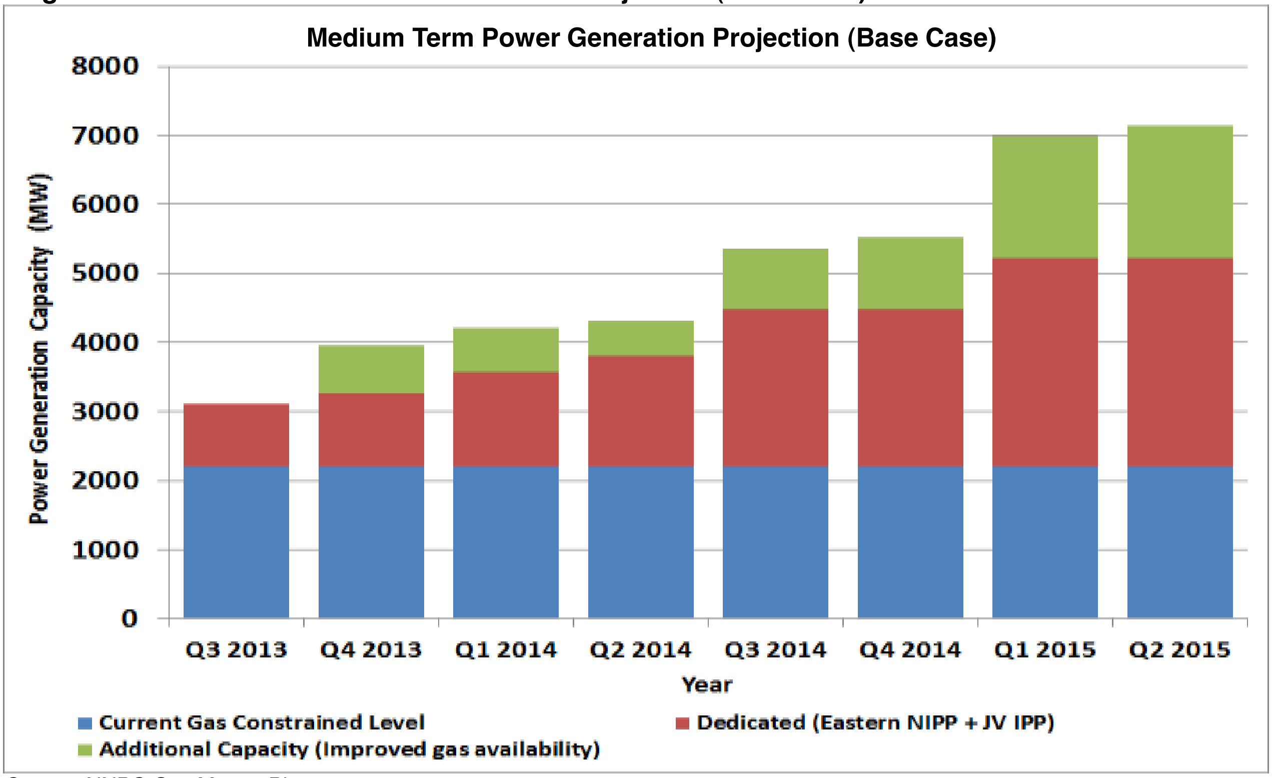
Figure 2.1: Base Case Gas Supply to Power Projection



Source: NNPC Gas Master Plan team

The restoration works will together result in sufficient gas supply to support 7150MW of generating capacity by Q2 2015:

Figure 2.2: Medium Term Power Generation Projection (Base Case)



Source: NNPC Gas Master Plan team

2.2 Gas Prices to Power Transitioned to Support Long Term Supply Growth

The transitional Gas Pricing policy is intended to support the development of a fully liberalized market which is characterised by 'willing buyer and willing seller' arrangements.

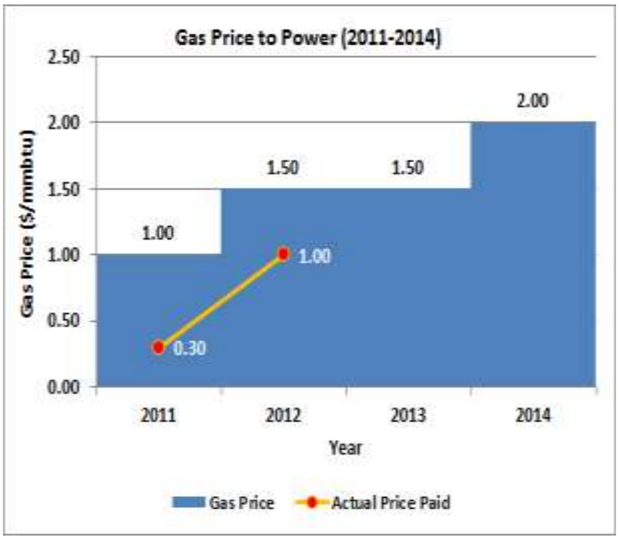
In a growing and fully liberalised market, it is therefore essential that gas prices are sufficiently high to incentivise the supply increases required to keep pace with demand growth.

To ensure sustainability of future gas supply to the power sector and meet the aggressive growth targets presented in Figure 2.3, Mr President approved a revised set of future gas prices in 2010.

As such, the power sector has seen prices rise from $0.12/mmbtu in 2006 (price paid by PHCN for natural gas) to approximately $1/mmbtu in April 2013, with a target of $2/mmbtu by 2014.

By 2014, gas suppliers will hence be realizing an aggregate gas price from the domestic market that is considered sufficient to support the required upstream supply increases.

Figure 2.3 Revised Gas Price to the Power Sector and Actual Gas Price Paid



**Reflects actual gas priced paid in April 2013*

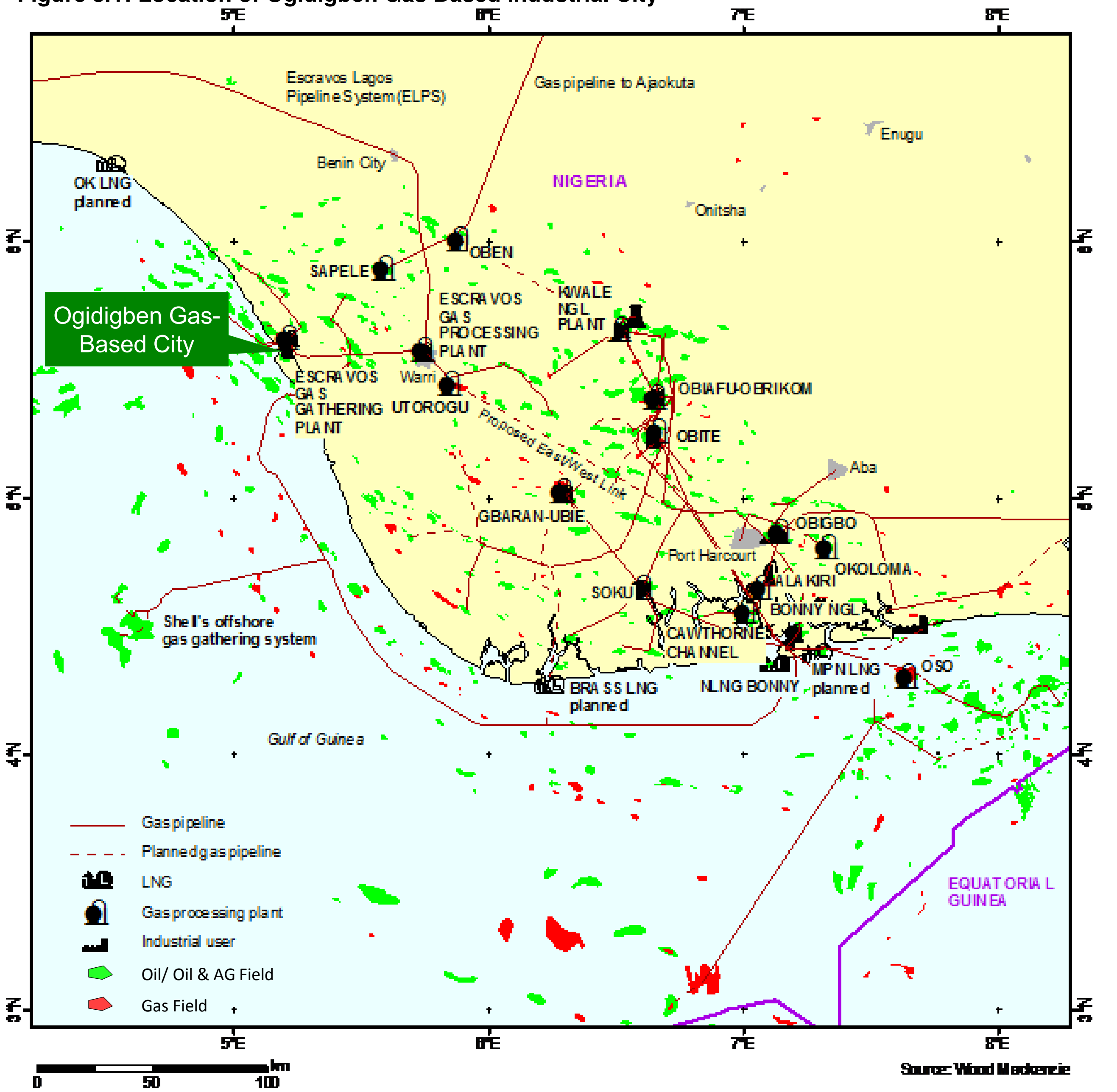
3 Development of Gas Based Industries

3.1 Implementation of Nigeria's First Industrial City

The Gas Industrialisation policy is now being implemented, and Presidential approval was gained in 2012 for development of Nigeria's first gas-based industrial city at Ogidigben, Delta State.

Ogidigben is set across the Escravos River from Chevron's Escravos GTL location and aims to be the largest gas based industrial park in Sub-Saharan Africa with world-class projects in Fertilizers, Petrochemicals, Methanol and Power.

Figure 3.1: Location of Ogidigben Gas Based Industrial City



Source: Wood Mackenzie

Figure 3.2: Schematic of Ogidigben Gas Based City

Source: Worley Parsons and NNPC Gas Master Plan Team

Ogidigben is a highly desirable location since:

- The planned gas based industrial city is located by the ocean, and has a better draught compare to the initial location (needs to be dredged) to enable easy access for exports of any surplus production;
- The location can be served by an existing Breakwater at Escravos (with any required upgrades to be undertaken by NPA);
- It is near the Escravos River, for easy inland access of products to domestic consumers;
- Ogidigben's proximity to existing gas infrastructure ELPS is also advantageous, enabling relatively easy gas access with low pipeline infrastructure development cost;
- The location is on unencumbered land, Certificate of Occupancy (CofO) has been issued for 2700 Hectares;
- The location has been granted Presidential approval for FTZ status.

Figure 3.3: View from Chevron's Escravos GTL Location (Left) and the Current View of the Ogidigben Location (Right)

Source: NNPC Gas Master Plan Team

The development will include all required infrastructure to provide an integrated platform for development of further gas based industries in future.

Figure 3.4: Ogidigben Gas Based Industrial Park – Anchor Investors and Support Investors

The Ogidigben project will include gas transmission pipelines, upstream gas development, LPG Plants, port infrastructure and real estate development, pipe milling and fabrication yards and financial services.

Figure 3.5: Investment Requirements

Source: NNPC Gas Master Plan Team

Development of the Industrial City is progressing rapidly:

- The policy approach is attracting significant investors interest. In the fertilizer sector, over 8MTPA (million Tonnes Per annum) fertilizer capacity is now proposed by various investors, with the first 1.3MTPA capacity by Indorama now going into construction phase. Several others are in advanced stage of attaining financial closure and award of EPC contract. Many of these are targeted for start of operations between 2017-19;

- With the above capacity outlay, Nigeria is now well positioned to supply over 10% of the world's global tradable fertilizer by 2017, making it the undisputed regional hub;
- The certificate of Occupancy for 2750 Hectares of land for the Ogidigben Industrial Park has been issued and the administrative process of declaring the location a FTZ has begun;
- Work has commenced on the geotechnical soil sampling, EIA assessments and other related marine assessment;
- Full site clearing of Phase 1 (about 750 Hectares) will commence shortly. Phase 1 will house;
  - A gas Central processing facility with initial processing capacity of 800mmcf/d;
  - 150MW power plant;
  - 2.6MTPA fertilizer plant by Nagarjuna;
  - 1.3MTPA petrochemical Plant by Xenel;
  - Port and residential estates
- Site clearing will be followed by site preparation and base infrastructure preparation through 2013/14, with full blown construction activity commencing in late 2014 for the various plants. It is expected that between $100-$200m will be expended by the FGN on the site infrastructure development in 2013 alone.
- The various investors are progressing through varying stages towards financial closure and contract award e.g. the CPF is going through the pre-Front End Engineering Design phase, the Fertilizer investors are almost concluding EPC contract award and Petrochemical investors in pre-Front End Engineering assessment.
- The industrial park is expected to commence production in 2017 with the CPF and Fertilizer plants

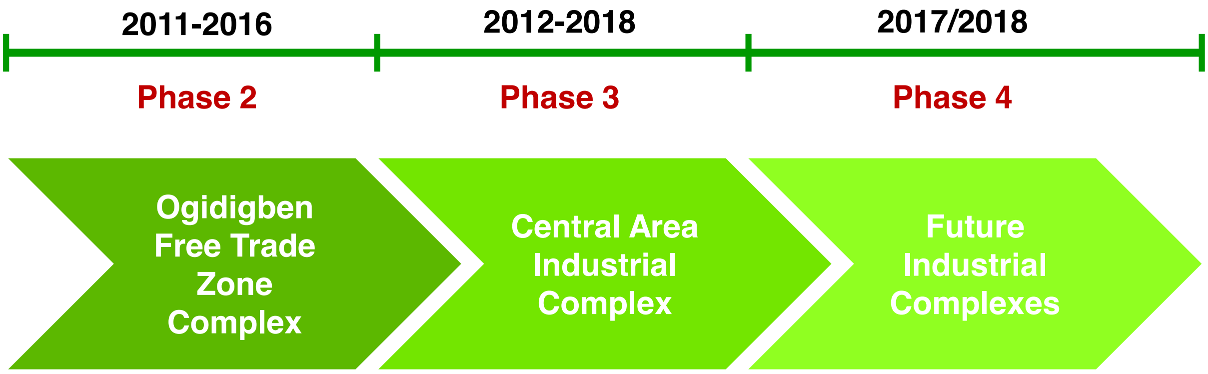
Over 2000 jobs will be created in 2013 alone from this initiative. In the medium term, it is estimated that over 150,000 jobs will be created during the peak of the construction phase of these gas based industries at Ogidigben.

3.2 A Platform for Nationwide Gas Based Industrialisation is Established

The ultimate aim of Gas Industrialisation policy is to create over 5 million direct and indirect jobs from the spin-off secondary industries that will arise from this initiative. The aggressive growth aspirations necessarily require adoption of a phased approach.

The current efforts at the Ogidigben complex are therefore being pursued as part of a scalable model for ultimate replication at other strategic sites throughout the nation. Once the Ogidigben complex is established as the Western area Industrial City, the same concept will then be employed in the Central area before supporting the development of future industrial complexes.

Figure 3.6: Phased Implementation of Nigeria's Gas Revolution Agenda



As such, the current developments at Ogidigben can be considered to provide a springboard for subsequent sister developments throughout the nation.

4 Gas Exports

The West African Gas Pipeline (WAGP) was conceived as a major component of the strategic intent to leverage Nigeria's natural gas to provide regional economic influence and sales opportunities for Nigerian entrepreneurs. The WAGP is now contributing that strategic aim. Gas began flowing in March 2010, with WAPCo delivering 30 mmcfd of gas through WAGP to the Takoradi power plant in Ghana. In April 2011 first flows were delivered to Togo. Throughput averaged 78 mmcfd in 2011 and has been growing steadily. It is currently supplying over 100 mmcfd to neighbouring countries.

Development of the Brass LNG project is a major component of the strategic aim to protect market share in global LNG markets. Commitment to the Brass LNG project has been maintained to enable early FID as soon as conditions are favourable. As such, preparations for implementation of the 10mmtpa project have been sustained since completion of the FEED by Bechtel in 2006: FID is planned for 2014.

Acronyms

AG	Associated Gas	**MMBTU**	Million British Thermal Units
AKK	Ajaokuta – Kaduna - Kano	**mmcfd**	Million Cubic Feet per Day
AN	Ammonium Nitrate	**Mcf**	Thousand Cubic Feet
BCFD	Billion Cubic Feet per Day	**MTBE**	Methyl tert-butyl ether
BOE	Barrels of Oil Equivalent	**mmtpa**	Million Tonnes Per Annum
CAGR	Compound Annual Growth Rate	**MW**	Megawatt
CAP	Calabar – Ajaokuta Pipeline	**MYTO**	Multi-Year Tariff Order
Commercial Demand	Defined a demand from small industries including cement	**NAG**	Non-Associated Gas
CNG	Compressed Natural Gas		
CNL	Chevron Nigeria Limited	**NDPHC**	Niger Delta Power Holding Company
CPF	Central Processing Facility	**NGC**	Nigerian Gas Company
DAP	Di-Ammonium Phosphate	**NGL**	Natural Gas Liquids
DPR	Department of Petroleum Resources	**NGMP**	Nigerian Gas Master Plan
DSO	Domestic Supply Obligation	**NIPP**	National Integrated Power Projects
ELPS	Escravos Lagos Pipeline System	**NLNG**	Nigerian Liquefied Natural Gas Plant
EPC	Engineering Procurement and Construction	**NNPC**	Nigerian National Petroleum Company
FEED	Front End Engineering & Design	**NGDC**	National Geophysical Data Center
FGN	Federal Government of Nigeria	**OB3**	Obiafu/Obrikom - Oben
FID	Final Investment Decision	**OGGS**	Offshore Gas Gathering System
GACN	Gas Aggregation Company Nigeria Limited	**OK LNG**	Olokola Liquefied Natural Gas Plant
		OML	Oil Mining Leases
GDP	Gross Domestic Product	**OTC**	Offshore Technology Conference
GIIP	Gas Initially In Place	**P1**	The sum of proved hydrocarbon reserves
GME	Gazoduc Maghreb-Europe	**P2**	The sum of proved and probable hydrocarbon reserves
GMP	Gas Master Plan	**PHCN**	Power Holding Company of Nigeria
GSPA	Gas Sales and Purchase Agreement	**PIB**	Petroleum Industry Bill
GTA	Gas Transportation Agreement	**PMS**	Premium Motor Spirit
GTS	Gas Transmission System	**PRG**	Partial Risk Guarantee
GW	Gigawatt	**PSC**	Production Sharing Contract
Industrial Demand	Defined as gas demand from CNG, Fertiliser and Methanol Plants, Petrochemicals	**PVC**	Polyvinyl chloride
IEA	International Energy Association	**SE Asia**	South East Asia
IOC	International Oil Company	**SNG**	Shell Nigeria Gas
IPP	Independent Power Plant	**SPDC**	Shell Petroleum Development Company
JKT	Japan, South Korea and Taiwan	**T&T**	Trinidad and Tobago
JV	Joint Venture	**TCF**	Trillion Cubic Feet
kt/pa	Kilotonne Per Annum	**TSGP**	Trans-Saharan Gas Pipeline
kWh	Kilowatt Hour	**US**	United States
LNG	Liquefied Natural Gas	**WAGP**	West African Gas Pipeline
LPG	Liquefied Petroleum Gas	**WAPCO**	West Africa Portland Cement Company
mmboe/d	Million Barrels of Oil Equivalent per Day	**WAPCo**	West African Gas Pipeline Company