Using natural gas to meet latent energy demand in Nigeria and deliver economic advantage.

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Abstract:

Nigeria was ranked second worst country in terms of gas flaring, its domestic energy demands keep increasing in the wake of inadequate alternative cleaner (compare to oil) energy sources like natural gas. This is why Nigerian gas master plan was proposed to develop the natural gas for domestic utilization. Consequently, this research studied the economics of different gas development projects that Nigeria can develop to meet latent energy demands and achieve the objectives of the gas plan. It also assessed the relationship between domestic gas consumption and real economic growth in the country.

The research used gas pipeline models that already exist in literature to analyse the investment cost, gas deliveries as well as costs and benefits of six possible gas pipeline routes options in the country. The BSRO pipelines route option was found to be more viable and estimated to have an annual gas delivery of 37.25 bcm, investment cost of $1.15 billion, NPV of $2.43 billion, IRR of 50.38%, payback period of 2.60 years for forty years of operation. However, in terms of coverage and ability to supply more gas to more locations, the all gas pipeline route option is more recommendable. The pipelines are more sensitive to discount rate, cost of gas transportation and capacity. Other gas pipeline routes options are also viable except the NRO gas pipelines, and it is recommended not to consider this option alone, even in the future, the best recommendation is to combine it with the BRO pipelines option.

Costs and benefits analysis of two other gas development projects (CCGT and GTL plants) were presented using net present value, internal rate of return and payback period accounting methods, and CCGT project was found to be viable and GTL project not viable in the country. Even though GTL project was found to be unviable at the market scenarios in the country, incentives are recommended to attract investment for this important gas development project. Both projects are more sensitive to their product prices. To analyse the effect of gas development on the country’s economy, an ARDL bound cointegration test, impulse response functions, variance decompositions and granger causality econometric methods were used in two different model specifications. The first model specification added real capital formation and real exports, and found no cointegration among the specified variables. However, it was found that among these variables, gas consumption has more influence to the movements in the real GDP than the other variables. Gas consumption is found to be highly and positively responsive to its own innovation, which means direct investment in the sector can result to significant improvement in the gas consumption in the country.

However, in the second model specification, where oil production, gas consumption and real GDP were used, cointegration was found, and positive and significant long run relationship was found between gas consumption and real economic growth, where a persistent 1% increase in domestic gas consumption in the long run causes 2.89% increase in real economic growth in the country. It was also found that the country is likely to be facing the economic problem of resource curse due to the potential adverse effect of crude oil production on real GDP, even though this is not statistically significantly justified.

The research also found that gas consumption cannot predict real economic growth in Nigeria and vice versa as both variables are independent of each other at the current trend. However, if gas flaring is stopped, and more investment as well as further infrastructures are provided in the gas sector in the country, the gas sector can then start to feed in more to the economic productivity, and thereby making the economy dependent on the gas sector eventually due to continues increase in gas consumption, and then the significant link between gas consumption and economic growth can be actualised. In addition, direct investment in gas development can lead to high positive impact on the gas consumption as discovered in this research. Natural gas should be supplied to residential and commercial sectors to stimulate more domestic gas demand through gas pipelines, CCGT and GTL. The country's economy should be diversified to tackle the likely problem of resource curse. The findings of this research further justified the Nigeria gas master plan's objective and serves as an academic guide toward actualizing and extending the objective of the plan in the country.

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List of Abbreviations

Akaike Information Criteria (AIC)
Annual Net Revenue (ANR)
Associated Gas (AG)
Augmented Dickey-Fuller (ADF)
Auto thermal Reforming (ATR)
Auto-Regressive Distributed Lag (ARDL)
Average Cost (AC)
Aviation Turbine Kerosene (ATK)
Base Route Option (BRO)
Billion (b)
Billion cubic feet (BCF)
Billion Cubic Metres (bcm)
British thermal unit (Btu)
BRO+NRO (BNRO)
BRO+SRO (BSRO)
Capital Formation (CF)
Centimetre (cm)
Chevron Nigeria Limited (CNL)
CO_2 capture and storage (CCS)
Combined Cycle Gas Turbine (CCGT)
Compressed Natural Gas (CNG)
Cost of electricity (COE)
Department of Energy (DOE)
Dickey-Fuller (DF)
Dimethylether (DME)
Domestic Supply Obligation (DSO)
Emission Performance Standard (EPS)
Energy Information Administration (EIA)
Energy Technology Systems Analysis Programme (ETSAP)
Equity Risk Premium (ERP)
Error Correction Model (ECM)
Error Correction Term (ECT)
Escravos gas plant (EGP)
Estimated Cost of Compressor Stations E (CCMS)
Expected Cost of Constructing Pipeline E (CCP)
Exports (xp)
Exports (XP)
First Alternative System (BWRO)
Fischer-Tropsch (FT)
Gas Consumption (GC),
Gas to Liquid (GTL)
Gas to Power (GTP)
Gas to Power (GTP)
Gas to Solid (GTS)
Gas to Wire (GTW)
Generalized Method of Moments/Dynamic Panel Data (GMM/DPD)
Gigawatts (GW)

Greenhouse Gas (GHG)
Gross domestic production (GDP)
Gross Fixed Capital Formation (CF),
Gross national expenditure (GNE)
Horsepower (HP)
Initial Investment costs (IIC)
Interest payment (IP)
Internal Rate of Return (IRR)
International Energy Agency (IEA)
Kilometre (km)
Kilowatt-hour (kWh)
Labour Cost (LC)
Levelised cost of electricity (LCOE)
Levelised Gas Transportation Cost (LTC)]
Liquefied Natural Gas (LNG)
Liquefied Petroleum Gas (LPG)
Log of Gas Consumption (LGC)
Log of GDP (LGDP)
Log of Export (LXP)
Log of Gross Capital Formation (LCF)
Low Pour Fuel Oil (LPFO)
Megawatt hour (MWh)
Megawatts (MW)
Methanol (MeOH)
Million (m)
Million British thermal units (mBtu)
Million cubic feet (MMCF)
Million cubic metres (mcm)
Million tons of oil equivalent (Mtoe)
Million tonnes per annum (Mtpa)
Multiyear Tariff Order (MYTO)
National Petroleum Corporation (NNPC)
Natural Gas (NG)
Natural Gas Hydrates (NGH)
Net Present Value (NPV)
Nigerian Bulk Electricity Trading Plc (NBET)
Nigerian electricity regulatory commission (NERC)
Nigerian Electricity Supply Industry (NESI)
Nigerian Electricity Supply Industry (NSEI)
Nigerian Gas Company (NGC)
Nigerian Liquefied Natural Gas (NLNG)
Nigerian Naira (N)
Northern Route Option (NRO)
Not recoverable (NR)
Oil Refinery Acquisition Price (RAC)
Operating and Maintenance Costs (O and M)
Partial Oxidation (POX)
Petroleum Motor Spirit (PMS)
Petroleum Products Pricing Regulatory Agency (PPRA)
Pipe Coating and Wrapping (PCW)

Pipe Material Costs (PMC)
Present Value (PV)
Purchasing Power Parity (PPP)
Reserve to Production (R/P)
Restricted Residual Sum of Square (RSSr)
Salvage Value (SV)
Schwarz's Information Criterion (SIC)
Second Alternative System (TRO)
South-western Route Option (SRO)
Straight Line Depreciation (SLD)
Terajoules (TJ)
Thousand Cubic Feet (MCF)
Thousand cubic feet (Mcf)
Thousand Cubic Metres (tcm)
Total primary energy demand (TPED)
Trillion Cubic Feet (tcf)
United Kingdom (UK)
United Nation Conference on Trade and Development (UNCTAD)
United States (US)
Unrestricted Sum of Square (RSSu)
Vector Auto Regression (VAR)
Vector Error Correction Model (VECM)
Weighted Average Cost of Capital (WACC)

Chapter 1. General Introduction:

1.1 Background

In recent times, the global energy industry has been full of fears, arguments and rising concerns over the world energy supply and security due to depletion of fossil fuels, especially oil. Prices of these primary energy sources (gas and coal as well as oil) have raised the concern of most countries in the world as large portions of oil and gas reserves continue to be concentrated in particular regions, while the demand is spread out over the globe.

In addition, despite the global demand for these resources, the world is now becoming worried over the harmful effect of these resources on the environment. The high energy consumers like China, India, Europe and America are left with the option of resorting to alternative energies. The recent discoveries of shale oil and gas reserves have surprised the market, which affected the price of oil and gas, also brought about disparity of gas prices. Most of the alternative energies developed in recent decades have not grown as fast as required, which means oil and gas may continue to dominate as major sources of primary energy for a long time to come. Nuclear energy also presents an opportunity for replacing oil and gas, but due to the health and security threat associated with the use of uranium, many countries are afraid of using it as an energy source.

It was reported that the domination of oil and gas resources in total energy mix will continue up to 2040 in Africa as reported in the IEA Africa Energy outlook, due to the slow growth of their potential replacements and/or alternatives [3]. However, the span of global proven conventional gas reserves was estimated to be around 54.1 years and that of oil around 52.53 years in 2014 by British Petroleum (BP) [4]. With the fear of oil production peaking, natural gas may take the lead in the future after it has long been dumped (or flared) due to the abundance and relative low cost of oil production. With the promising future for the natural gas especially in developing countries, where the demand for natural gas is very low, different sorts of natural gas uses can be developed to trigger its demand [5] [6].

As it has been reported in most of the International Energy Agency (IEA) reports, oil share in the global primary energy mix has been dropping and that of natural gas increasing steeply [7].

Natural gas was usually flared in countries like Nigeria due to absence of regulatory framework, developed infrastructures and limited investment in gas development as stated by

Giwa S. et al (2014) [8]. This is further evidenced by the low level of gas consumption and the continues gas flaring [9]. However, due to the emergence of the Liquefied Natural Gas (LNG), which is a very convenient way of transporting natural gas to longer distances, making it easy to supply gas to many of its potential markets in the world, this attracts huge investment in gas development and increase in natural gas production over the years [10].

However, almost 134 billion cubic metres (bcm) of natural gas associated in distant oil production fields were flared globally in 2010 [11]. This is partly due to lack of or low infrastructural development to help develop it as an economic resource. This made the natural gas to become more of a driving force to drill more of oil. For every 0.028317 cubic metres of natural gas flared at least three times more than that are re-injected for oil recovery enhancement [11] [12]. Tallying the directly flared natural gas with the ones being re-injected into oil wells, there could be a total of 566 bcm of natural gas that could be transformed to secondary energy globally every year on average, but it has been either flared or re-injected [13].

Even though, enhancing oil recovery through gas reinjection has its economic advantage of maximising the oil well productivity, but in a situation where the gas has lots of potential of meeting more energy demands, the gas reinjection can be considered a second priority since the contribution of gas reinjection to the overall oil well production is around 15% [14]. Primary oil recovery together with other forms of recoveries (without natural gas reinjection) through water and CO_2 flood, steam and chemical injections can achieve up to 45%-50% of oil recovery in an oil well [14].

World Bank global gas flaring reduction press revealed that there are more of untapped stranded gas than the conventional petroleum energy liquids been produced to date globally [11]. Stranded gas is the gas reserves that has been discovered, but has not been developed either due to economic or physical reasons. The economic reason being either due to the distance of the reserves area to the market, making it hugely expensive to transport it to the demand area, or the gas demand is saturated in the reserve area, making it very expensive to export to another country, or it is not lucrative to develop the gas at the prevailing gas market price. The physical reason is due to the exceptional depth of the gas reserves beneath the surface or beneath an obstruction, which requires additional expenses to drill. Stranded gas is found in pure gas field, and it is more expensive to develop due to the hazardous nature of the gas, which requires expensive and unique mode of transportation.

There are about 2,600 trillion cubic metres of natural gas globally in 2012 [15]. Stranded gas and flared gas present an opportunity for increasing global gas production. Stranded gas cannot be a waste since it can be developed anytime in the future, but flared associated gas is huge waste monetarily and harmful to the environment.

The top two highest gas flaring nations in the world are Russia and Nigeria [11]. Nigeria flared natural gas equivalent to a quantity of about 10% of the global gas flaring in 2011 [16], and in 2013, Nigeria flared 12 bcm of natural gas, [11] [17]. However, Nigeria is more in a challenging position since Russia has more of gas reserves and has higher energy per-capita access than Nigeria [18]. Nigerian proven gas reserves are larger than those of crude oil are, yet oil receives attention that is more favourable. This is despite its environmental effects (oil spillages and higher CO_2 emission compare to natural gas), price volatility and relatively early possible depletion.

Nigeria has the largest natural gas reserves in Africa, contributing 2.5% to the global share of proven gas reserves and 1.2% of the global gas production in 2014 [19] [20]. However, due to lack of domestic gas demand, inadequate or vandalism of gas infrastructure and the absence of incentives for gas development in the country, gas has not been fully utilized [21]. Natural gas was first discovered unintentionally in Nigeria while searching for crude oil. As at 2013, the reserves estimate of the country’s natural gas is around 5.1 trillion cubic metres [17], with about 50/50 distribution ratio between Associated Gas (AG) and Non Associated Gas [22].

Associated gas is the gas that is produced from oil producing wells; it is sometimes dissolved in the crude oil and sometimes separate from the oil. Non associated gas is produced in pure gas reservoirs [15]. Only a small fraction of the available gas reserves is currently being utilized, mostly for power generation and at levels that are insufficient to meet the rising electricity demand in the country. Similarly, zero level of gas consumption has been reported in transport, residential and commercial sectors of the economy [9].

Lack of development of gas reserves for primary consumption within the country makes the exports of the non-flared part of the produced gas as LNG to European countries the predominant option [23]. Nigeria imports petroleum products, especially petrol, which has been one of the major transport fuels in the country. However, the 2011 partial deregulation policy in the country has affected the nature of energy consumption in the country, where many people cannot afford to buy the petroleum products, especially petrol, due to its high price [24]. With the growing population indices and emergence of small and medium enterprises in the country, the in-country demand for energy continues to increase without a corresponding increase in the supply of energy, which restricts the economic growth of the country [24]. Therefore, in order to meet the latent energy demand, there is a case for developing natural gas for domestic consumption, so as to provide alternative energy products that people can substitute for petrol, enhance supply of electricity and provide sufficient industrial inputs.

Nigeria opted for gas export partly due to lack of visible demand for the gas within the country. Some portion of Nigerian population are not familiar with the potential of natural gas for meeting the country's energy demand. Few industrial and power companies utilize the gas, these being concentrated in the western part of the country. This is due in part to the fact that there is insufficient basic infrastructure (gas pipelines) to help move the gas to the areas of higher population or demand. Such infrastructures if provided may help stimulate private-sector investment in gas processing plants via Gas to Liquid (GTL) and Gas to Power (GTP) projects as a means of supplying transport fuels and electricity respectively, which will eventually stimulate high demand for natural gas in the country.

Subsequently, the Nigerian gas master plan proposed some set of infrastructures and some policy frameworks to help encourage investment and development of gas in the country. Therefore, this research used the gas master plan as one of its motivation to specifically identify and examine some of the key gas development projects that can be implemented to achieve the objectives identified in the plan, with a view to analyse their country specific economics, and compare between some of them for a well-informed assessment of their viabilities and cost requirement, so as to adequately inform investors of the costs and benefits of investing in the country's gas sector. This will guide the government and prospective private investors on the capital requirements of these projects, its economic returns and resulting effects on the economy.

The Nigerian gas master plan is designed to improve gas utilization within the Nigerian territory, eliminate gas flaring and make it affordable to industrial, residential and commercial sectors of the economy. The plan also mandates gas producers to supply certain portion of gas produced to domestic market. The petroleum ministry will predetermine this portion, and penalties shall be placed for any default. The plan also proposed construction of three gas processing plants in the oil and gas production region. These plants will be located in West Delta (Warri area), Obiafu (North of Port-Harcourt) and Akwaibom/Calabar area. Investment for these projects will be open for private investors [25].

Similarly, the plan proposed construction of the three transmitting gas pipelines within the country. One is the south-north gas pipeline, and then the interconnector, and then the western gas pipeline extensions as specifically explained in chapter two under gas pipelines in Nigeria. The western pipeline extension will reach Kwara, Ekiti and Ogun, and the South to North pipeline will supply up to Kano.

The gas pricing policy under the master plan has categorised the consumer sectors into domestic, industrial and other commercial sectors. Domestic sector includes power generation for residential use and lighting in the commercial sectors as well as domestic fertilizer industry [26]. The industrial sector includes GTL, fertilizer and Methanol exports industry. The other commercial sectors will include LNG, cement and Steel companies, CNG and Heavy industrial users.

The pricing regime for the strategic domestic sectors (e.g. Power) will be cost plus pricing, where a small-predetermined mark-up is set on top of the cost of production, that is the lowest cost of supply (+15% IRR). This is to ensure lower prices affordable to the residential and commercial sectors always. The strategic industrial sector (Methanol, GTL, Fertilizer) pricing will be based on the market price of the natural gas less the cost of supply, which means based on product netback basis but the gas floor price must be lower than the cost of supply of the gas (netback indexation), so that gas price increases proportionately with end product price. The other commercial sectors (cement, steel, CNG, and other domestic industries) will be priced according to opportunity cost, that is alternative fuel pricing regime, where LPFO, Diesel and/or PMS are used as alternative fuels [1] [27].

1.2. Motivation

The Nigerian gas master plan, which is aimed at improving the domestic gas utilization is used as a motive for the research. The research is framed to provide economic framework of the key gas development projects that can be implemented to achieve the objective of the plan. The research will also serves as an academic guide toward actualizing and extending the objective of the plan in the country. That is to say, it is motivated to support the deployment and extension of the Nigerian gas master plan. The research also aims to justify the objective for developing gas for domestic utilization, showcasing the resulting effect of the domestic gas utilization on the real economic growth in the country. The research is motivated to serve as an academic supporting document to the Nigerian gas master plan.

Similarly, the research is motivated by the need to improve the wellbeing of the people and to improve access to energy in the country. Considering the large gas reserves and the persistent gas flaring in the country, the research is motivated to identify the gas development projects that can be implemented to use gas as a means of improving access to energy and making the gas reserves useful for the economic growth in the country. The research is motivated by the need to have estimation of the viability of these gas development projects so that investors would understand the viability of these gas development projects, which could motivate them to invest in the country. The research is also motivated by the need to have recommendation on the optimal and viable projects, and the need to provide recommendations for incentives to encourage investment in other non-viable projects in the country (if any).

Having outlined the need for the domestic gas utilization, the research is also motivated by the need to identify an up to date economic consequences of the resulting gas consumption in the country, so as to understand the justification and implication of these investments on the economy. Therefore, the research is motivated by the need to have an up to date understanding of the dynamic relationships between the domestic gas consumption and real economic growth in the country. Therefore, the research is also motivated by the need to fill and respond to the academic gap in the economic analyses and comparison of gas development projects in the country as well as in the economic analysis of the relationship between gas consumption and economic growth in the country.

Therefore, this research will identify and study the economics of different gas development projects that the country can implement to achieve the objective of the plan. It will also analyse the relationship and effect of the domestic gas consumption on the economy, so as to identify the resulting effect of these interventions in gas development on the country's economy. As such it aimed to answer the following questions:

1.3 Research Questions

As the Nigerian gas master plan aimed toward domestic gas utilization, stoppage of gas flaring and supply of affordable gas to domestic sectors of the economy. This research identified some key gas development projects that can help achieve these objectives, and these are gas pipelines, GTL, and CCGT projects [6] [12]. The economics of these projects will be analysed, and the effects of domestic gas utilization on the economy will be assessed, so as to empirically justify the objective of the plan and provide clear investments' estimates and comparison toward achieving the objective of the plan. Therefore, the research is geared to answer the following questions:

1) In line with achieving the objective of the gas master plan in Nigeria of sufficient domestic gas supply, the research asks: What are the relevant gas development projects that can be developed to enhance more utilization of gas within the country? And one of them is the gas pipeline project as also outlined in the plan. The research then asks: What are the optimal combination of the proposed gas pipeline route options? And what are the costs and benefits of each of the gas pipelines route combinations? And how sensitive is each of the combination to market and project changes? This will help inform the government and prospective investors on the best combination of the gas pipeline route options, and the resulting costs and benefits of each of the gas pipelines routes so as to make informed and reliable investment decisions.
2) To achieve domestic gas utilization, gas development projects that create demand for gas need to be developed, and looking at the demand trend in the country, where electricity supply is inadequate and domination of oil products as transport fuels and industrial inputs continues [28] [29] , CCGT and GTL projects are identified as the projects that can be developed to meet some of the latent energy demand for both transport, residential, industrial and commercial sectors in the country, in line with the aim of this research and that of the master plan of creating more gas demand in these sectors. Therefore, this research asks: What are the costs and benefits of these two gas development projects? And which one is more viable in the country? This will provide empirical and analytical information about the prospects of each of these projects, and to recommend the most viable project among the two. The research will also ask, how sensitive are these projects to market and project changes? So as to identify the sensitive market parameters that significantly affect the viability of these projects. This will also enable discovery of any unviable project with a view to providing recommendation to improve its attractiveness.
3) As these gas development projects are cost intensive, and the objective of the gas master plan is to use the gas to foster the economic growth in the country, the research

asks: What is the cointegration, long-run and short-run relationship between domestic gas utilization and the real economic growth in the country? It also asks: What is the relative response of the domestic gas consumption as well as its contribution to the shock in real economic growth and vice versa? Due to the dominance of the crude oil production in the country, which is likely to have hindered the development of gas, the research hypothesized that, crude oil production may not have direct positive effect on the domestic industrial output i.e. real economic growth, but natural gas consumption does. These will provide empirical justification for the proposed gas investments for domestic utilization in the country, and for assessing the dynamic relationships between domestic gas consumption and real economic growth in the country. So that government and investors will understand the implication of their investment in domestic gas development.

4) Subsequently, in order to provide empirical justification for optimal policy frameworks, the research asks: What is the causality relationship between domestic gas consumption and real economic growth in the country? So as to further understand the policy and investment implications of domestic gas development, and to empirically prove if the domestic gas consumption can predict real economic growth in the country.

1.4 Aims and Objectives

The aim of this research is to discover how the gas can be utilised efficiently for domestic use to foster economic growth, improvement of wellbeing of the people and stoppage of the gas flaring in Nigeria. It aims to identify and analyse the economics and sensitivities of the relevant gas development projects that can help enhance domestic gas consumption. In other word, the aim of this research is to identify and analyse the relevant gas development projects that Nigeria can implement to stimulate latent demand for natural gas in the country in line with achieving the objective of the gas master plan of eliminating gas flaring and expanding domestic gas utilization in the country. The research also aim to find the dynamic linkage and relationships between domestic gas consumption and economic growth in Nigeria.

The objective of the research is to analyse the capital investment requirements for six different possible gas pipeline routes as well as their respective costs and benefits and value additions. An assessment will be carried out between these gas pipeline options in terms of its capital cost requirement, potential of gas delivery, returns on investments and sensitivities.

Based on these economics, it will identify which of the gas pipelines routes combinations are more economical and beneficial for consideration in the initial investment in the gas pipelines constructions in the country.

Another objective is to estimate the profitability of the identified relevant gas development projects in the country, in order to find out which of the gas transformation projects is more lucrative to investors and how intensive and sensitive are these investments in the country. It is also part of the objective of the research to analyse the cointegration between gas consumption and real economic growth as well as the dynamic long run and short run relationships between them in the country. It also aimed to analyse the dynamic relationship between these two variables in the event of shocks or innovation. It will also aim to study the causality between gas consumption and economic growth in the country. This will help give up to date information about the resulting effects of the gas development on the overall economic performance in the country as well as the dependency between the two variables.

The research will use the NPV, IRR, Payback period and investment cost models already established in the literature to analyse the costs and benefits of the gas pipeline projects. Gas pipeline investment cost models as identified in Shahi (2013) will be used to estimate the Nigerian-specific capital cost requirements and gas delivery of the proposed gas pipeline routes. The above three accounting methods are also used to analyse the economic costs and benefits of the relevant gas development projects i.e. GTL and CCGT projects. This will help provide information about the economic costs and benefits of the gas development projects aimed at expanding gas utilization and stoppage of gas flaring as outlined to be achieved in the gas master plan. Similarly, an econometric model called Auto-regressive Distributed Lag Model (ARDL) will be used to study the long run cointegration and multiplier effect of inland gas consumption on the real economic growth in the country. Impulse response and Variance decomposition will be used to analyse the dynamic response and contribution of gas consumption and economic growth to the unit shocks in the underlining variables and vice versa. Granger causality test using F-statistics from Vector Auto-regression will also be used to analyse the causality between domestic gas consumption and real economic growth in the country.

1.5 Significance of the research:

The research is significant for the following reasons:

1) The research is significant as it will identify the key gas development projects that Nigeria can develop to improve domestic gas utilization so as to reduce gas flaring, improve electricity generation, improve welfare of the people, facilitate more job opportunities, enhance productivity and efficiency in the productive sectors of the economy.
2) As the research will provide empirical and analytical analysis of these gas development projects, it will serve as viability indicative framework of these projects for government and prospective investors in the gas sector in the country.
3) The research will serve as the academic supporting document to the Nigerian gas master plan, as it aims to further provide economic assessment of gas development projects aimed at achieving domestic gas consumption as outlined in the plan. It serves as academic guide toward actualising the objective of the master plan
4) As the research is motivated to use natural gas to foster economic growth, it is significant as its finding will help in motivating and facilitating optimal gas development investments that are capable of improving the wellbeing of the people, creating gas consumption in residential, commercial and transport sectors of the economy, diversifying the economy and reducing the overall emission in the country.
5) The research is significant as it inform the government and prospective investors on the best combination of the gas pipeline route options, and the resulting costs and benefits of each of the gas pipelines routes so as to make informed and reliable investment decisions.
6) The research is useful as it provides academic and analytical evidence about the prospects of each of the two key gas transformation projects identified, and recommends the most viable project among them. The research also helps to identify the most sensitive market parameters that significantly affect the viability of these projects.
7) The research is significant as it provides academic justification for the proposed gas investments for domestic utilization in the country, by assessing the effect of these investments on the real economic growth in the country, so that government and

investors will understand the implication of their investment in domestic gas development.

8) The research is significant as it provides further understanding of the policy and investment implications of domestic gas development, and academically proves if the domestic gas consumption can predict real economic growth in the country, so that it will guide policy priorities.
9) This research is significant to Nigeria as it is in the process of transition to gas based and diversified economy, and its findings can be used as reference for such paradigm shift, hence the selection of this research among many applications submitted for sponsorship.

1.6 Outline of the research

The research is categorised into six chapters, chapter two will discuss the conceptual frameworks of the research and review some of the related and relevant existing literature relating to the economics and comparison of the viabilities of the gas development projects as well as relationship between gas consumption and real economic growth. It will also highlight the overview of the Nigeria's energy industry. Chapter three will analyse the investment costs, potential gas deliveries, costs and benefits, value addition as well as sensitivities of the proposed gas pipeline route options. It will also analyse the viability and sensitivity of the relevant gas development projects using the three different accounting techniques. Chapter four will study the cointegration, long run and short run relationships between gas consumption and economic growth in Nigeria. The chapter will also analyse the impulse response and variance decomposition between these variables. Chapter five will analyse the causality between gas consumption and real economic growth in the country. Chapter six will be the general conclusion of the research.

Chapter 2. Literature review

2.1 Introduction

Many literature have reported on the economics of gas development projects, their possible economic returns and their impacts on the economies. This chapter reviews some studies on these areas, which constitute one of the major areas or objectives of this research. Firstly, in order to have broad understanding of the concepts, uses and economics of some key gas development projects, the chapter listed four gas development projects, which are categorised into two groups, first group are the gas transformation options, which include the Gas to Liquid (GTL) project and Gas to Power (GTP) project. The second group contains the gas transportation options, which include gas pipelines and Liquefied Natural Gas (LNG). Each of these gas development projects will be discussed looking at their relevant concepts, economics, challenges and their status in Nigeria. This is done with making reference to some developed countries like US and UK. This is followed by review on literature on the economic evaluation or viability and comparison between some of these gas development projects that are directly relevant to domestic gas utilizations. The chapter also reports about the existing literature on the relationship between gas consumption and economic growth. The chapter also reports on the relevant literature that analysed or reported on the Nigerian gas sector in general. This is to give a brief background and better understanding of the gas sector, which the research is reporting about.

2.2 Gas Transformation Options

These are gas development projects that can be used to transform gas into different useful energy products, these include GTL and GTP.

2.2.1 GTL Project

A GTL Concept

According to Panahi, et al (2012)[30], "A GTL (gas to liquids) plant consists of three main sections: synthesis gas production, Fischer-Tropsch (FT) reactor, and FT products upgrading". It is the process of utilizing natural gas, where the hydrocarbon feedstock (natural gas or any Gaseous feedstock) can be transformed into synthesis gas (contains mainly Hydrogen and Carbon Monoxide), and later the generated syngas pass through Fischer-Tropsch reactor to convert it into hydrocarbon liquids. These liquids can be used as transport fuels like gasoline or diesel, or any other desired liquid products, like kerosene for jet aircraft, naphtha for petrochemical use etc. The syngas process includes auto-thermal reforming, compact reforming, and catalytic and non-catalytic partial oxidation" [31]. GTL-FT process (referred to as GTL in the remaining parts of the research) is a special technological innovation that provides an alternative source of energy that can be used to tackle the global fear of possible oil depletion and to provide solution to the continuous raising concern of the huge stranded and associated natural gas reserves in the world.

Fischer and Tropsch invented the FT process in 1920, which made it possible to convert synthesis gas to different fuels. Fischer Tropsch (FT) GTL is the technological option for converting syngas to transport fuels and other petroleum liquids[30]. Recently, two oil companies SASOL and Royal Dutch Shell have improved such technology for commercial purposes. Royal Dutch Shell built the largest GTL plant in Qatar as at 2011, apart from the one it built in Malaysia. Similarly in 2008, a three hour test flight was flown within the borders of Britain and France with a fuel consisting of 60% ordinary jet kerosene and 40% GTL jet fuel supplied by Shell [32]. The GTL fuels are designed suitable to be mixed with any conventional fuel, as such there is no need for modification of combustion engine technologies. In 2009, Qatar Airline tested the GTL fuel mixture with Jet Kerosene on a commercial flight from London to Doha. There are lots of other technological test of GTL products and all proved excellent [33]. GTL plant can be of different sizes and efficiency level, the highest GTL capacity that was built was 140, 000 barrels of petroleum liquids per day (Pearl GTL plant in Qatar). The plant size can be reduced by decreasing the size of the hardware to produce up to a minimal capacity of 500 barrels per day [34].

Tonkovich, et al (2011) [13] in their paper titled "Micro-Channel Gas to Liquids for monetizing associated and stranded Natural Gas Reserves", looked at an innovative way of monetizing stranded natural gas reserves by way of processing the gas in a small scale GTL plants. They explored the possibility of applying "Micro-channel technology" to steam methane reforming and Fischer –Tropsch Synthesis (GTL) to reduce the economic costs involve in the two steps hydrocarbon process. Their research discussed extensively on the gas to liquids process that is enabled by Micro-Channel process technology "to improve the volumetric productivity and efficiency, reduce the capital cost and shrink the facility footprints, which is essential for economical small-scale on and offshore GTL facilities". They observed that conventional GTL technologies can only be used for large quantity of natural gas resource and requires huge amount of money to construct, which discourages investment, so the micro channel process of gas to liquids allows for low cost technological options for converting natural gas to liquids. According to them, “The challenge of monetizing smaller gas resources hinges on the ability to economically scale-down reaction hardware while maintaining sufficient capacity. By reducing the size and cost of chemical processing hardware, Microchannel process technology holds the potential of enabling cost effective production of synthetic fuels in smaller scale facilities, such as those needed for flare abatement”[13].

They also highlighted some few natural gas technological options like Compressed Natural Gas (CNG) and LNG, which they argued to be insufficient in developing the global stranded and associated natural gas unless complemented by GTL synthesis especially the Micro-Channel GTLs [11]. However, CNG and LNG can still process large volume of gas at a time, and micro channel process of GTL can complement by processing small amount of feed gas mainly for local use within the industry. Therefore, with gas pipelines, GTL, CNG and LNG plants operating at relative capacity can provide markets for huge portions of gas reserves in the country. This research will consider GTL plant as a project meant for utilizing the natural gas for domestic usage, which can spread around the country and turn large portions of gas reserves useful. However, Tonkovich, et al (2011) did not report on whether the small-scaled GTL plant is profitable or not. Details of GTL plants in the world as at 2002 is presented in Appendix A, as quoted directly from Fleisch T.H. et al (2002)[35].

B Economic Analysis of FT-GTL Plants

Shabbir, G. (2014) reckoned that GTL is a viable gas project that can be relied on as a means of developing the stranded and/or associated gas, he identified several other projects that he considered reliable, but failed to rank between them in terms of viability. However, Wilhelm et al (2001) compared all feedstock that can be transformed to synthesis gas, and found that the least cost feedstock for synthesis gas production that can be used for FT synthesis is natural gas. They considered different technological options for developing syngas from natural gas and found that among the five technological options for generating synthesis gas from natural gas only two of them were found more economically viable for the syngas production, which are “two-step reforming and Auto-thermal Reforming (ATR)” especially for large scale GTL plants. They mentioned that due to the possible improvement in FT catalyst and reactor design, GTL facilities will be less costly in the future [36]. They equally mentioned, “In the near-term, associated gas may offer the greatest potential, particularly where such gas is subject to flaring constraints and associated reinjection costs (for enhancing oil recovery).” However, before that improvement in the FT synthesis is achieved (which help in reducing the overall cost of GTL process) different economies of scale could be achieved to optimize the production of syngas and subsequent conversion to hydrocarbon products.

They identified that production of syngas cost lot more in the GTL value chain and tried to see how the syngas production cost can be reduced to the lowest economically possible level. According to them the predominant technology used in generating syngas is the “steam methane reforming (SMR)”, where methane and steam are converted to hydrogen and carbon monoxide. SMR acquired its dominance due to the high production of methane/hydrogen ratio over other available syngas producing technologies (two-step reforming, ATR, partial oxidation (POX), and heat exchange reforming) [36]. Finally, they made selective recommendations for Qatar and Nigeria, where they recommended application of only ATR for the two countries without stating reasons for that peculiarity. “ATR also known as catalytic partial oxidation, can closely control the final syngas composition by combining steam reforming with partial oxidation. The use of the process also results in higher operating pressures and improved thermal efficiencies” [37].

However, they have not considered the economic implication of combining two reforming technologies as they suggested. Additionally, a profit maximizing investor would have chosen the single reforming technology to minimize the cost if the syngas composition is sufficient for the FT synthesis.

Lee et al (2009) studied the economic evaluation of three different GTL products that are used as transportation fuels namely: F-T Diesel, Methanol (MeOH) and Dimethylether (DME). Since the profitability of a product in the process industry is dependent on the cost of its raw material and its product price, they varied the cost of natural gas (the raw material) two times, using high ($7.92/MMBtu) and low ($3/MMBtu) scenarios. Using payback period method to identifying the most profitable among the three GTL products, F-T Diesel was found to be more lucrative in the High Scenario, followed by DME and then MeOH, with the payback periods of 5.91, 9.76 and 13.24 years respectively.

In the low scenario, the order changed where DME was observed to be more profitable, then F-T Diesel, then MeOH. This is because the DME uses more raw materials (NG) than other products; as such any change in the price of the feedstock will immediately affect its manufacturing cost more than the remaining other two products. When the prices of each of the products were forecasted for the year 2012, the order of the viability as in the second scenario was maintained [38]. Their analysis was based on the assumption that the three GTL plants are based in the Middle East and the end products are to be transported to South Korea with 5000 km distance and they assumed that 200mscf/d of the feedstock is consumed by each of the plants. Their research is very important in making investment decisions among the three GTL products at a particular place and time. However, using Middle East as the case study makes their economic analysis not applicable to many gas producing countries that produce it more expensive. An average cost producing country would have been used as the case study. Similarly, using payback method alone in the assessment is not reliable as some investors are not interested on how early they can make profit but how big the profit is or the present value of future profits, as such they would have included the method of Net Present Value or Internal Rate of Return (IRR).

Another economic analysis of GTL plant was conducted by Wood et al (2012)[39] where they used IRR accounting method in examining the economic viability of the project. Their analysis was based on certain parameters such as cost of gas feedstock, price of petroleum products (GTL products prices are strongly influenced by the price of petroleum products, usually a bit above the petroleum products prices), capital cost, plant efficiency, operation and maintenance costs, cost of transporting the products, taxes and depreciations. Based on these factors, variation of the petroleum products prices and unit capital cost per barrel were made. Oil price per barrel was varied from $50 to $200, and production level between 50,000 and 200, 000 of barrels per day was varied. IRR percentage was calculated while varying the price of feed gas three different times at each combination of the oil price and production level. Their analysis concluded that the commerciality of a GTL plant is more sensitive to the price of oil and production capacity, and less sensitive to the cost of gas feeds. Their method of analysis particularly the assumptions are significant in making any economic analysis of GTL projects.

Another sensitivity analysis of GTL plant was made by Uzoh and Bretz (2012) [40] where they evaluated the economic sensitivity of a small-scale GTL plants. Their rational was based on the realization of the fact that most of economic evaluations consider large-scale GTL plants, with average capacity of 50, 000 barrels of GTL products per day. Uzoh and Bretz (2012) used similar economic method (IRR) like that of Wood et al (2012) in analysing the profitability of a small-scale GTL plant with the capacity of 1,000 barrels per day. Additionally, they complemented that with the use of Net Present Value (NPV) in confirming the commerciality of the project, which is a good practice. Almost similar parameters as used by Wood et al (2012) were adopted in their research. These parameters are capital cost, cost of feed gas, plant capacity, product price and cost of transportation. This is one of the strength of Uzoh's and Bretz's (2012) evaluation, because the price of the products and cost of transportation were additionally considered in the profit sensitivity analysis, unlike in that of Wood et al (2012), where only cost of feed gas, capital cost and oil price were used in the sensitivity analysis.

Uzoh and Bretz (2012) used spider diagram in detecting the level of sensitivity of each of the above parameters. Different scenarios were observed, where each of the parameters was at a time varied while holding the remaining parameters constant. According to their results, the most sensitive factor to profit is the product price, followed by capital cost and plant capacity (same level of sensitivity with capital cost though), and then the cost of feed gas. The least sensitive factor is the cost of transportation. However, they found that a small-scale GTL plant can be profitable. Their analysis did not consider different possible circumstances in locations, which might significantly affect GTL profit, and making it more sensitive to transportation cost, and this is why they should have consider a particular location and distance to markets. Cost of transportation can be the most sensitive factor in some countries where there is large disconnect (distance) between the plant and the market. Cost of transportation can be important also in countries where the transport fuel price is very high, which can affect the profitability of the project. Therefore, their results are not generic.

Patel B.(2005) found that the capital cost of LNG is 10-15% higher than that of GTL, but did not consider the operation and maintenance cost as well as profitability of the GTL project [41]. Buping B. et al (2010)[42] stated that it is difficult to arrive at the exact estimate of GTL capital cost, as it varies by countries, but mentioned that its fixed capital expenditure is around 85% of the total initial capital investment. They also estimated $2.5 billion as the total annual operation and maintenance cost for a plant with a capacity of 118,000 bbl/d, and $10.8 billion as the initial capital investment cost. The strength of their work is that, they went further to assess the profitability of the GTL using Return on Investment (ROI), Internal Rate of Return (IRR), and Payback method, which they found 10.7% as the ROI, 9% as the IRR and 8 years as the payback period. They found that cost of gas and price of GTL products are significant in determining the profitability of GTL plant. However, their analysis was generic, and may not be applicable in some countries. They should have selected a particular country to assess how viable the GTL plant will be in that country.

The above economic studies of the GTL project gives economic background on one of the gas development options that this study will consider. These studies serve as the conceptual description of one of the major gas development options, in line with this study, and it is apparent that very little has been written (from the survey conducted) on the profitability of GTL plant on country specific. This is why this research will consider the cost and profitability of the GTL project in Nigeria, so that investors can have an idea whether the project is viable in the country or not especially in comparison with other gas investment options. Similarly, some of the methodologies and approaches as used in the literature above will be applied for the purpose of this study.

C Challenges of GTL

Wood et al (2012) examined the major challenges that GTL technology is facing ranging from its complexity, expensiveness and low number of GTL process licensors, which hinders the development of stranded and associated gas in so many countries. Despite the opportunity that the GTL technology provides, yet it faces some investment uncertainty resulting from oil and gas market volatility. It was identified that traditional refineries may be exposed to only oil price volatility, GTL may be faced with the both oil and gas price volatility. They stated that “For F–T GTL to be commercial at oil prices of less than about $40/barrel, plant capital costs, operating costs and feed gas costs all have to be substantially lower on a unit basis than large-scale plants built in recent years have been able to deliver." This means that cost of hydrocarbon feedstock has to be low to enable the GTL hydrocarbon products to be as much competitive as oil products in the global market, so that investment will be attracted and further research and development can be sponsored to enhance the efficiency and the economy of the system. They recognised the fact that GTL technology is undergoing further research to reduce the capital and operating cost requirements [43]. With the recent oil price fall, other petroleum products may fall down, which affects the viability of the GTL projects.

Despite the abundant opportunity GTL provides, what hinders its progress is the huge cost associated with the syngas production, which constitutes large portion of the project's capital requirement. This is why some energy analysts recommend the use of other fuels to produce syngas instead of natural gas due to relative high price of gas in some locations. According to Spath and Dayton (2003)[44] "economic considerations dictate that the current production of liquid fuels from syngas translates into the use of natural gas as the hydrocarbon source. Nevertheless, the syngas production in a gas-to-liquids plant amounts to greater than half of the capital cost of the plant". As highlighted by Wood D. et al (2012), GTL's huge capital costs makes it monopolistic, and its low practical efficiency factor makes it even more costly. Volatility of crude oil and gas prices is another challenge that makes GTL investment uncertain [43].

D GTL in Nigeria

The Nigerian first ever GTL Plant is an investment collaboration (joint venture) between the country's National Petroleum Corporation (NNPC) and Chevron Nigeria Limited (CNL), which has the estimated capacity of 33, 000 b/d and has economic interest ratio of 75 to 25 for the CNL and NNPC respectively [45]. The plant site is located 100 kilometres away from Lagos, which is planned to receive its gas feeds from the Chevron-operated Escravos gas plant (EGP), while Sasol Chevron provides the marketing, technical and managerial services required for the project on behalf of the two shareholders. The plant is expected to mainly be producing petrol, diesel, kerosene and GTL naphtha products with Europe as the major market or place of export after domestic allocations [46]. The project has taken long time before it took off in September, 2014 [47] [45], it was initially expected to start operation in 2013, but it does not seem to see the light of the day at that projected time due to the continuous upward adjustment of the project cost, the last cost review was at $8.4bn. In 2011, the leading partner sent some Nigerians to South Africa to train on how to operate and manage the plant. The plant has the capacity to convert 350 million cubic feet of natural gas per day to produce Naphtha and Diesel [48].

As at early 2015, the Nigerian GTL plant produces only Naphtha and it is mainly for exports purpose. Only two trains are operational as at first quarter of 2015. GTL technology has enormous potentials of creating demand for the Nigerian stranded and associated natural gas that is concentrated in one region (Niger Delta),which constitutes 6% of the country's population[49], with larger population densities in far northern region, this indicates huge potential gas demand far from the gas reserves. This also underlines the need for gas transmission pipelines to the population concentrated regions. Therefore, establishment of GTL plants will help in producing various gas liquids that can be transported via conventional trucks to those regions or the plants can be spread around the country. Consequently, research (like this one) needs to be conducted to assess the investment as well as costs and benefits of GTL project in Nigeria with a view to utilize more of the gas within the country and provide energy fuels and inputs substitute to the presently available petroleum products which have become relatively unaffordable to Nigerians following the deregulation policy embarked by the Nigerian government.

2.2.2. Gas to Power using CCGT

A Concept, economics and challenges of CCGT

Gas to power technology usually called Combined Cycle Gas Turbine (CCGT) is a technological innovation that uses natural gas's hot exhaust to drive electric generators and generate electricity; it is an advancement of the ordinary heat engine (known as open cycle turbine), which helps improve energy conversion efficiency [50]. Most countries use CCGT in generating electricity including Nigeria, North America and Europe, it can be built within 2 years and can start generating electricity in one year, it's flexibility in terms of manipulating the energy output and its short payback periods attracts investors' confidence [51] .

Kehlhofer, R. (2009)[51] mentioned in his article that the economics of CCGT surpassed other steam power turbines, apart from it being the most environmentally favourable compare to other power turbines like Nuclear, Coal, and Biomass Power Turbines, CCGT appears to be most efficient with the recent improvement in its technology. Economic concern in comparing these power turbines is the energy efficiency, which is the ratio of the energy output (electricity) to the energy inputs (fuel feed) [51]. The thermal efficiency of the combined gas turbine is around 60% which is higher compare to the efficiency of coal power turbines which is around 32% to 42% [52].

Therefore, for economic selection of the type of fuel and power plant to be established, Kehlhofer, R. (2009), as the major point of considerations, has identified the following issues. "Long-term availability of the fuel at a competitive price, alternative for the primary fuel as backup, risk of supply shortages due to political interference, environmental considerations that favour a relatively clean fuel, such as natural gas, independence from a single fuel source, strategic reasons to use a domestic fuel, financing requirements (e.g., uninterruptible fuel supply)" [53]. One of his major findings is that, CCGT is found to be less expensive in terms of its construction and operation cost, but the gas feeds is more expensive than other hydrocarbon feedstock required in other turbines. He also suggested that long term agreement need to be considered to address the issue of fuel price volatility. They discovered that coal power station has more fuel flexibility (compatibility with other fuels), but CCGT plants have cheaper capital cost even though more expensive to run because of its high fuel cost.

He further mentioned that, eyes always have to be on the electricity price and compare with the prevailing or forecasted price of gas that is used in generating the electricity. Another observation is that, CCGT can achieve low cost of electricity when supplying for lower number of hours in a year, but other power plants acquire huge cost when supplying for shorter hours, that is to say CCGT is economical even when the demand is low. In terms of environmental friendliness, it was discovered that CCGT plant emits CO_2, which is only 40% of what coal power generating plant emits. [53] [51].

Even though Kehlhofer (2009) observed the environmental cleanness of the CCGT plants, he has not put more consideration on the cost of capturing the CO_2 emission in their cost analysis. However, Rubin et al (2012) have given a thorough concern on the cost of CO_2 capture and storage (CCS) for CCGT, where they found that CCS installation on CCGT plant will lead to increase on levelised cost of electricity (LCOE) by \$20-32/MWh (constant 2007\$) or \$22-40/MWh (2012 US dollar value). This is further confirmed by EIA in its 2014 energy outlook, which shows that an ordinary CCGT plant has an average LCOE of $66.3/MWh, while CCGT plant with CCS technology will have an LCOE of $91.3/MWh [54].

One of Rubin's et al (2012) major observations was that, new CCGT operators do not use CCS, because, they prefer to pay the emission tax than to apply the CCS technology. Based on this, they recommended for an increase in the emission tax to at least $125/t $CO_{2,}$ So that plants with CCS system can always be cheaper than plants without it [55]. However, they have not considered country specifications, as some countries like Nigeria do not enforce emission taxes on power plants [56] [57], so they would have suggested another incentives for using CCS in those countries, and they would have recommended some adaptation measures to reduce the emission going by [56]. Their analysis was not based on the retrofitting the CCS into the existing power plants, but on new ones to be built. This is because retrofitting could be costly due to limited space provision for its installations, which means countries like Nigeria that is in the process of building more CCGT plants have the opportunity of installing CCS at a lower cost than when the plants are in operation.

Another advantage of gas power plants is that, it can be used for base load, intermediate load and peak load. Rubin et al (2012) also highlighted the increasing use of the CCGT plants in America where they stated that in 2009 more than 20% of the electricity generated in America are generated from the gas turbines, which was just 10% in 1991 and which is also forecasted to be around 47% in 2035 [58]. In their article, they argued that natural gas could have a more favourable future due to the new environmental safety regulations that may discourage the use of coal power plants. Moreover, due to the forecasted increase in gas supply especially from the new shale gas reservoirs, they further realized that most of the CCS technologies and their retrofitting are mostly for the coal-fired power plant. This is because of its high Greenhouse Gas (GHG) emissions, but they highly recommended for the introduction of this technology also to the existing and new gas power turbines, which is why they analysed the cost effect of the carbon capture technology on the overall cost of the power plants[55, 59]. However, in some reports, it was observed that the introduction of the CCS into gas power plants reduces the net plant efficiency and net power output and at the same time increase the cost of electricity (COE) [60]. From their analysis, the increase in the levelised cost of electricity (LCOE) is 35% to 60% when compare with the plants without

CCS, but the major consideration is not cost increase, but the opportunity cost of installing the CCS which is the cost of CO_2 [59].

Lu, et al (2012), analysed the major causal of the 2009 US significant reduction in CO_2 emissions, which was about 6.59%. It was because of some significant shift from the use of coal-fired power plants to gas power plants, due to the steep decrease in the price of natural gas resulting from the gas supply increase from shale reservoirs. The cost of electricity using natural gas was reduced to around below 2-3 cents/kWh, this finding also corroborate with that of the Kehlhofer, R. et al (2009) as mentioned earlier, where they observed that cost of electricity using natural gas is influenced by the cost of the feed gas [61].

Therefore, from the two independent researches we can comprehend the significance of natural gas price on the cost of generating electricity using natural gas. What may puzzle the minds of people advocating for the use of natural gas in electricity generation is the inconsistency of the price of natural gas. Prices of natural gas differs from one country to another, in 2014, the price of natural gas averaged around $10 per MMBtu in Europe, $16 per MMBtu in Asia Pacific and $4 per MMBtu in US, which was similar to that of Nigeria. The disparity is attributable to the fact that there are no facilities for exporting the US shale gas or rather unwillingness to export it. According to energy analyst Kyle Cooper, natural gas prices used to be competitively cheaper, due to warmer weathers experienced, leading to fall in homeowners' demand for gas and low economic turn out, which made the investors to abandon the natural gas development for other more lucrative fossil fuel production like coal and oil. However, due to the growing structure of the global industrial economies and increase in energy demand from commercial and residential sectors, the overall demand surpassed the natural gas supply, shooting the price up [62].

The price of natural gas is usually related to crude oil price [63] as they are sometimes competitive commodities, a decrease in crude oil price resulting from its high supply causes natural gas prices to reduce resulting from its low demand especially in the long run [63]. With the recent fall in crude oil prices, which was $47.38 per barrel as at second week of January, 2015 [64], and which was caused by increase in crude oil supply (courtesy of shale oil and gas production), the natural gas price also falls down. So with this development, CCGT plants tend to be more cost effective for countries that do not produce gas given the low gas prices. However, for countries that will have to bear the cost of producing the gas may have to reduce production, which might reduce supply of the petroleum products and eventually push the price upward. Price of natural gas sometimes do not follow the oil price trend in circumstances like abrupt weather shocks and supply disruption. Improvement in technology and efficiency of the gas processing plants like the CCGT plant has led to increase in demand in natural gas, thereby shooting the price of natural gas up relative to fuel oil and hence to crude oil price [65].

As at 2012, almost 46% of the total electricity generated (34GW) in UK was from CCGT plants, this was due to its 55-60% efficiency (net calorific value basis), while open cycle turbines generated 1.6GW, which is 2.16% of the UK total electricity generation in that year [66]. Yet, the UK CCGT power generation is expected to increase in the future. However, the UK reliance on gas for power generation will not be sustainable in the long future due to its more reliance on gas import, which is almost 55% of the total gas supplied in the country in 2014 with the remaining percent being supplied from the UK North Sea [67] [68]. In Nigeria, more than 60% of electricity generation is from CCGT plants [69]. Countries like Japan being the second largest net importer of gas in 2012 also face sustainability challenge as it is exposed to the volatility of the price and supply of gas. Japan increased its dependency on imported gas following the Japan's suspension of nuclear plants in the country as a result of the Fukushima disaster in 2011 [70].

CCGT takes 3-4 years and longer than 30 years for its construction and operational period respectively [71]. Despite its long operational span, CCGT has high marginal cost (74% of its total levelised costs as fuel cost) and low capital cost (only 17% of the total levelised costs) compare to coal plant. It means that, CCGT plant is convenient for immediate construction due to its low capital requirement and short period of construction. Colpier (2002) argued that CCGT plant may not be economically viable for base load purpose but can be used to follow up load [72]. However, Starr (2007) mentioned that using it to follow up load will increase the maintenance costs due to the increasing thermal stress [73].

Additionally, the global natural gas reserves to production (R/P) ratio was 63 years as at 2012 and 54.1 years in 2014 [4], which raises the concern about future dependence on natural gas as a source of power, but if the unconventional gas fields are to be fully developed (e.g. Shale gas) the R/P ratio may increase to 250 years[74]. However, the RP ratio can increase due to possible future discoveries of gas. Another challenge of relying on natural gas as a source of power for countries that import gas via LNG is the level of emission, which is aggravated by the use of imported LNG. This is because using LNG increases the level of the emissions from the whole power generation chain, as it has to be regasified before sending it again to power stations, and through such a process, additional CO_2 emission is attracted[75]. This is why Nigeria has the potential of using CCGT technology to generate electricity and yet emit lesser CO_2 as it does not have to import natural gas. LNG constitutes 65% of the total natural gas supply in the UK, which increases the potential of higher emissions despite the Emission Performance Standard (EPS) limit of 450g $C0_2$/kWh [76].

In the case of oil production, cost of electricity generation is one of the major operating costs, as such gas to power technology can be installed at the oil production fields, so that it can serve dual purposes: first, to reduce the oil production cost and second to make the associated natural gas economically useful thereby saving the environment. This idea was appreciated in the final technical progress report by the United State Department of Energy (DOE), who reported on the Oilfield Flare Gas Electricity Systems (OFFGASES) project, which is a technology that uses micro natural gas turbines in generating electricity for oil fields located near Santa Barbara. The low emission micro-turbines are sited in four idle natural gas wells that were shut down due to the non-commercial quantity of the natural gas. According to the report, if the whole United States' (US) stranded or flared natural gas will be utilized for power generation, more than 16, 500 Megawatts could be generated, which will help reduce the cost of oil production and increase the supply of electricity in the country, and eventually reduce the price of electricity. The benefits will therefore be to the environment, the producers and the consumers [77].

Applying this sort of technology in Nigeria would have yielded more benefits than in the United States, because of the electricity shortage in the country, which led to additional cost for electricity generation in oil productions and manufacturing sectors. If the associated gas and the stranded gas will be fully utilized for electricity generation, per-capita energy access will be significantly improved, thereby boosting the economy and saving the environment. As mentioned earlier, natural gas is more environmentally friendly for generating electricity than other fossil fuels; this is technically supported by the IEA facts on the CO_2 emissions from different fuels per unit of energy output. The comparison is presented in table 2.1 [78] [79].

Fuel	CO_2 (pounds per mBtu)
Coal (anthracite)	228.6
Coal (bituminous)	205.7
Coal (lignite)	215.4
Coal (subbituminous)	214.3
Diesel fuel & heating oil	161.3
Gasoline	157.2
Propane	139.0
Natural gas	117.0

Table 2.1 CO_2 Emission by fuels: Pounds of CO_2 emitted per million Btu of energy for various fuels adopted from [78]

From table 2.1, natural gas emits carbon dioxide less than any of the fuels considered when burning the same value of heat. Despite the little emissions from the natural gas plants, technologies have been developed to ensure 100% emission abatement. A Science City Professor of Energy, Dermot Roddy who studied how the CCS technology can be retrofitted into existing natural gas power plants and other industrial facilities, looked at how the whole carbon emissions can be collected and transported in a single network; he also estimated the cost implications of these technologies. He mentioned that it will be difficult to have a consistent cost of transportation and storage as CO_2 compression and booster stations varies from systems [80]. However, Svensson et al (2004) attempted to estimate the cost of transporting the CO_2 to be around €1–2 per tonne of CO_2 for a pipeline length of 600km and a capacity of 40 Mte/year [81]. Using a smaller distance network (30km) with a capacity of 4.67 Mte/year, McCoy and Rubin estimated $0.34 per tonne of CO_2 as transportation cost, and a storage cost of $0.80 per tonne of CO_2 [82]. CO_2 emission capture, transportation and storage systems can be installed to the existing and new gas plants for electricity generation.

Dermot Roddy (2012) also developed a business idea for investors where they can develop long distant CO_2 networks that capture and transport emissions from different group of emitters not necessary from power generation plants but from the industrial sector. He then analysed the economy of the size and the length of these emission networks, adopting a cost model developed by McCoy and Rubin (2008). He cited different examples of Carbon Capture Storage (CCS) networks potential areas in the United Kingdom (UK), Europe, and America where clusters of CO_2 emitters were discovered. He described the oldest CO_2 pipeline (built over 40 years ago) in America with 3600 miles length, which indicates that CO_2 transportation and storage is not a new invention, but can be modified. The CO_2 emissions captured are usually transported to depleting oil field to enhance its recovery by increasing the pressure of the oil well[80] [83].

However, the question to ask is where do we store these emissions after it has been captured? Dermot Roddy in another article answered this question, where he explained that there is a developing option of "storing CO_2 in coal seam voids created during in-situ gasification of coal (or underground coal gasification) linked to CCS [84]. When carried out at depths of more than 800 metres, the void created in the coal seam is suitable for storing supercritical CO_2". He finally, concluded that the sizing, distance, accessibility and the economic returns of the CO_2 network will largely depend on the price of the CO_2 as well as the government policies, but a medium sized network is possibly more viable considering the estimated future CO_2 price[84]. List of Nigerian existing gas to power plant is presented in table 2.3.

2.3 Transportation options

The above ventures are different ways of transforming natural gas after it has already being supplied or made available. Most of the natural gas reserves are in remote or distant areas far from its demand and transformation units. Therefore, it must be transported in a safe and economically convenient way. This brings us to the two common routes of transporting natural gas to the consumption units or processing sites, which are liquefied natural gas and pipelines. Another option is compressed natural gas that is similar to LNG but not convenient for long distance and large quantity transportation. Gas pipelines were the pioneer means of natural gas transportation. It transports gas in its gaseous form, but it is not economically possible to transport it to far distant places (more than 3000km) [85]. Pipeline is limited for its restricted ability of meeting only a local or semi local markets (national or regional markets), and it is suitable for domestic gas utilization. Increasing demand for natural gas in many developed countries (like Japan) whose geographical locations are far from the gas reserves and whose economies rely mostly on the use of these resource, led to the emergence of LNG technology[86].

2.3.1 Gas Pipelines:

B Concept, economics and challenges of gas pipelines

The first metal natural gas pipeline was built in 1872 and with just a small distance of 5 miles in USA [87]. There were inefficiency of those pioneer pipelines, but due to the improvement of the pipeline technologies resulting from high demand of the natural gas, pipelines that are more efficient were constructed for wider distances and with large throughput capacity. Pipelines are of different categories namely: gathering, transmitting and distribution pipelines, but this research will be mainly concerned with the transmitting pipelines that supply natural gas from the production site to the consumption sites. These types of gas pipelines have high operating pressures, usually wide diameter pipelines, and can be built for long distances depending on the investment capacity. Some of these transmission pipelines connect to each other for storage and distribution purposes. Distribution lines can then supply to the end-users where large end users like steel mills or power stations can collect natural gas at a medium or low operating pressure from the transmission pipelines. Final consumers at residential and commercial sectors are supplied with natural gas through distribution companies. Distribution pipelines are the very low-pressured pipelines that connect to the final consumers. Gathering pipelines are the smaller production pipelines that collate the produced natural gas from the production wells [88].

Pipeline is one of the safest means of transporting natural gas, except for its construction, it has little or no environmental effect. With the recent technological improvement, corrosion and leakages can be detected long before it aggravates [89]. Gas pipelines for long have been a reliable and cheapest means of delivering natural gas to long distances. However, due to longer distance of the gas demanding countries, issues of territorial permissions and deep water crossing (of more than 2000 metres depth) have thrown a major challenge to the gas pipeline industry [90]. Additionally, some of the already developed gas production fields are depleting, therefore, the need for new offshore gas pipeline networks connected to new offshore production fields arises, which brings about huge capital investment requirement.

Moreover, offshore pipelines are observably more expensive than onshore pipelines, and most of the high quantity gas production fields are located offshore (including the Nigerian gas offshore reserves). Constructing a 32 inches (81.28cm) for just a mile offshore will cost around $2.5m, and $1.3m onshore [90]. Therefore, pipelines transportation favour resource rich countries, as it is economically convenient for domestic or neighbourhood supply (short distance), and for distant consumers, they have to pay for the long distance transportation cost.

According to the Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) report (2003)[85], gas pipeline transports are more economically viable except if the distance is more than 3000 km. Cross border issues and disruption have been so important issue of investment concern. It involves different countries with different ideologies and interest, which a transit country may be a source of conflict if it does not share common interest or mutual friendship with either the supplier or the consumer. This increases the business risk and uncertainty of cost estimation of the cross-border pipelines. It has been established in the same report that due to lack of international legal pipelines regimes, that articulates responsibilities and profit ratio of every party in the business, the propensity of conflict and disruption is likely to be common in the future. The report used 12 pipelines as a case study to examine the causes of conflict and the possible solutions. Among the suggested solution is that, a clear impartial legal system has to be established for pipeline transport and there shall be room for flexibility of the regulations to allow space for review of certain rules depending on the circumstances (which may not be expected). The Gas pipelines were also pointed as the most vulnerable compare to oil pipelines. Gas pipelines attract more economic rent than that of oil, as the transit nations assume monopolistic power and tend to bargain higher. This makes gas to have high supply security concern than oil, as more alternative suppliers or route can easily be sorted out in oil transport.

Smith (2013) mentioned that there would be a reduction in gas demand in the future, especially in developed countries that are far from the resource production sites. It was observed that despite the reduction in gas demand, there would still be a demand for imported gas. However, importing gas via pipelines could be more expensive in the future, as future gas pipeline viability is questionable due to the expected expansion of the distance between the gas producing countries and gas consuming countries [91]. Another challenge highlighted was the rapid approach to the export limits of some of the largest exporters (example Canada, Netherland) as a strategy to ensure domestic energy security. Some countries were identified as very difficult for international negotiations and the long period required to complete gas pipeline construction is another serious future threat to gas pipeline. This helps in making LNG as immediate possible substitute where gas pipelines proved economically and politically impossible [92]. Sylvie, et al (2003), mentioned "The key determinants of pipeline construction costs are diameter, operating pressures, distance and terrain. Other factors, including climate, labour costs, the degree of competition among contracting companies, safety regulations, population density and rights of way, may cause construction costs to vary significantly from one region to another."

Gas pipelines require quite a number of compressor stations, at a distance between 64km to 161km [93] [94] to maintain the desired pressure level, depending on the distance to the destination, this has great impact on the capital requirement for the construction and operation of the gas pipeline. The average cost of a unit throughput is determined by the "average rate of capacity utilization". Higher load factor and the utilization capacity lead to higher economic profitability of the project. Sylvie, et al (2003) also estimated that a pipeline construction with the diameter of 46 to 60 inches, and the throughput of 15 to 30 10^9 m^3 in a year will cost around $1 to $1.5 billion per 1000 kilometres[92], this is also refer to as the levelised cost of gas transportation. This sound threatening considering the market locations and the fact that new demand will emerge in the future. However, technological improvements give room for cost reduction as the project designs and constructions are efficiently improved to cut down the capital cost [92]. These improvements are recorded around the "inspection activities, laying and welding methods, steel quality and weight, thus reducing material costs and the period of construction." This will help also in reducing the long period needed for the gas pipeline construction, even at offshore gas production fields.

Francesco A. (2011) studied general approaches of analysing the economics of a new gas pipeline, where he highlighted that its cost is determined by the initial investment costs as well as operation and maintenance cost. While the benefit will be determined by the benefit derived from the savings resulted from substituting an existing fuel with natural gas as a result of the new pipeline, as well as improvement of the environmental conditions due to the relative cleanness of natural gas. His analysis used transmitting gas pipeline as a case study and does not include direct benefits derived from running the gas pipeline i.e. net cash flows. He estimated the investment cost of a new gas pipeline to be around $176EUR/km/cm^2$ and a levelised cost of gas transportation of around $8.46EUR/1000m^3$ [95]. His analysis could only be used as a guideline but not to be applied in a specific country. He did not also consider the debt financing, and depreciation factors in his analysis. His approach in estimating the initial investment cost and value addition of the pipelines is relevant to our referenced gas pipeline route options analysis.

Shahi, E. M (2005) accounted for depreciations, and specific input costs that constitute the initial investment cost including the cost of constructing the pipeline and compressor stations. He mentioned that the cost of constructing a gas pipeline is made up of pipeline material cost, which is determined by the diameter, thickness and length of the pipeline as well as the material cost, which is $800 per tonne of the pipe. It is also made up of pipeline coating and wrapping cost, which he said is 5% of the pipeline material cost. It also includes the labour cost which he recommended it to be $15, 000 multiply by diameter and length of the pipeline, but Rui Z. et al (2012) observed that the labour cost is averagely around 28% of the total cost of the gas pipeline based on the pipelines they observed [96]. Shahi, E. M. (2005) also estimated that the cost of compressor station is $2000 per horsepower capacity. His approach for the specific cost of constructing gas pipelines and compressor stations is useful for this research.

Kurz, et al (2012) highlighted one important factor in pipeline Economics. They mentioned that the diameter of the pipeline determines its profitability, if the diameter is increased, the throughput will also increase, which makes the average cost decreases. So adding more compressors will increase the pressure or the capacity and help in reducing the average cost. It is advisable in the course of designing or planning a pipeline project to consider large capacity if the reserve is in commercial quantity. However, space shall be provided for future expansion of the capacity as pipeline project has large economies of scale. Government regulation or control of the pipeline systems is emphasized due to the monopolistic nature of the market to avoid excessive profits from the suppliers or denial to the system or products [97].

C Gas pipelines in Nigeria

Gas pipeline industry has been in operation in Nigeria since the gas discovery in the country in late 1960s, but with a small supply of gas to few power stations. Recently, the Nigerian government is resolved to expand some of the existing gas pipelines in the country. Details of the proposed gas pipelines are contained in the Nigerian gas master plan[98] [99]. This is evidenced by the recent contract signed to build gas pipeline networks with a combined 30 billion cubic metres capacity per year with a diameter of 48 to 56 inches by Nigeria and Algeria [100] [23]. One of these pipelines is the Tran-Sahara gas pipeline initiated to provide route for the Nigerian stranded natural gas to Algeria, which will serve as a transit country to some European countries.

The pipeline will be connected to the "Trans-Mediterranean, Maghreb–
Europe, Medgaz and Galsi pipelines" which will supply the Gas to the European countries. "The length of the pipeline would be 4,128 kilometres: 1,037 kilometres in Nigeria, 841 kilometres in Niger, and 2,310 kilometres in Algeria"[100], the pipeline is presented in figure 2.1 below. The trans-Sahara gas pipeline is an extension of the proposed south to north (trans-Nigeria) gas pipeline, which extended the Ajaokuta gas pipeline to Kano. The south to north gas pipeline is 56 inches and 48 inches diameter pipelines, from Calabar to Ajaokuta (of 490 kilometres) and from Ajaokuta to Kaduna (of 495 kilometres) respectively [1] [23]. Adding the distance from the Niger Delta gas-producing region to Ajaokuta, the trans-Nigeria gas pipeline (south-north pipeline only) will have a distance of 985 kilometres. This is also part of the Nigerian gas master plan[46], in addition, the other connecting pipelines like the Escravos gas pipeline extension made up of different inches will cover around 686 kilometres [27], and the interconnector gas pipeline, which is 100 kilometres long and 42 inches in diameter. The eastern and north gas pipeline extensions are potential future plan [26].

The business interest of the trans-Sahara pipeline will be 45% for Nigeria, 45% for Algeria and 10% for Niger republic. It was estimated to cost around $13 billion [101], and the trans-Nigerian was estimated to cost more than $2 billion with debt and equity ratio of 60:40[23]. Recently, there were lots of interest from some European countries to contribute in the gas pipeline construction, but the major players are mainly looking for who will add to the technical efficiency and improvement that will help reduce the cost without compromising the capacity. The trans-Nigerian pipeline is the immediate big gas development project that will be implemented soon and the engineering design is billed to start in early 2015. Figure 2.1 illustrates the general overview of the trans-Nigeria and trans-Sahara gas pipeline.

Figure 2:1: Tran-Sahara Gas Pipeline System[26]

The red line is the extended trans-Sahara gas pipeline up to Algeria, with other extension to European countries. The proposed networks of trans-Nigeria gas pipeline expansions are shown in figure 2.2 below [1] [101].

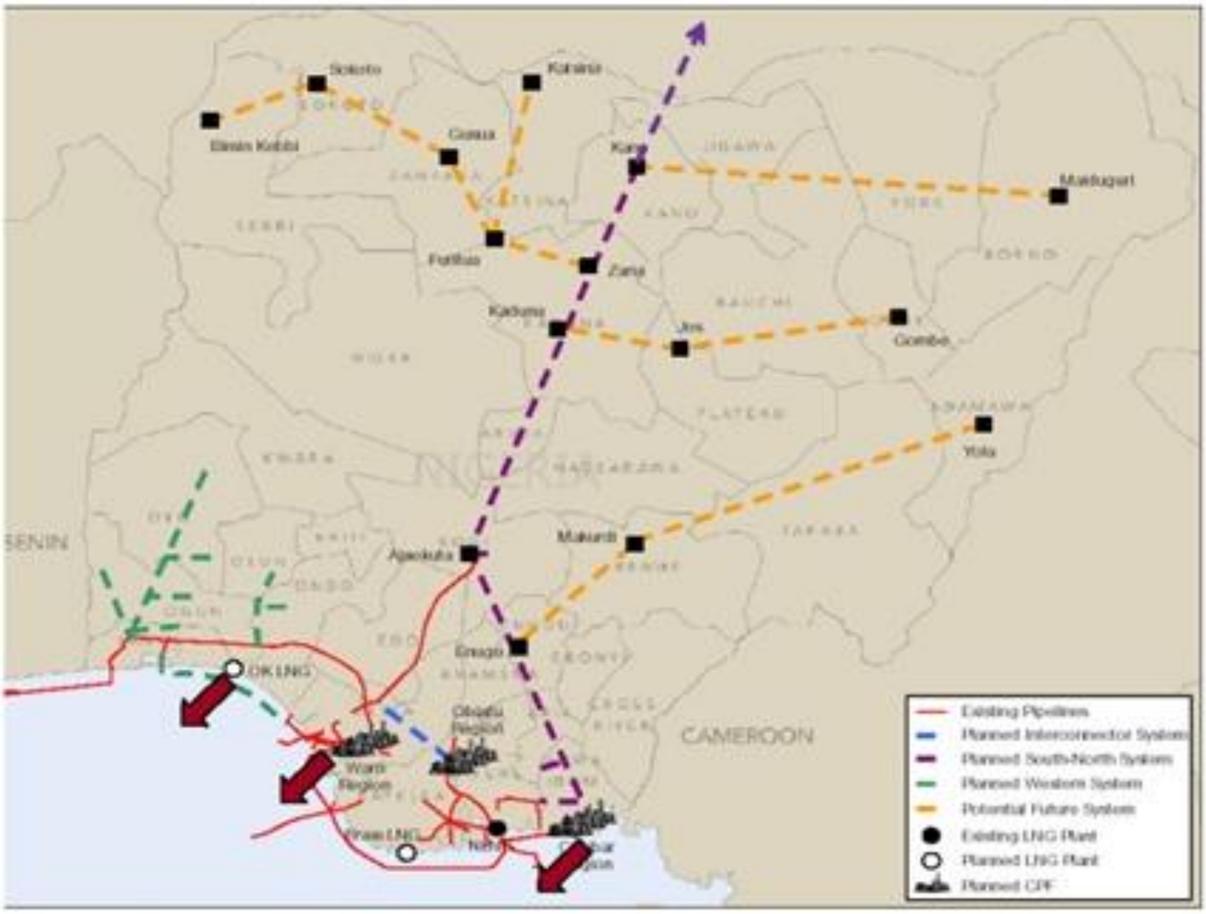


Figure 2:2 Proposed and existing gas pipelines in Nigeria [1]

From figure 2.2, the purple line is the proposed Trans-Nigerian, the yellow lines are the future extensions, the blue line is the proposed interconnector and the green lines are the proposed south-western extensions. The red lines are the existing lines. The only operating cross-border gas pipeline from Nigeria is the West African gas pipeline, which runs across some of the West African countries (Nigeria, Benin, Togo, and Ghana). The aim of the gas pipeline is to deliver purified natural gas to Ghana, which will be mainly be used for power generation and for industrial use. The pipeline links to the Nigerian Escravos-Lagos pipeline then pass through the coastal region (offshore). According to the West African Gas Pipeline Company (WAPco) the main pipeline is 20 inches in diameter, while Benin (Cotonou) and Togo (Lome) pipelines are 8 inches each, and the Ghana (Takoradi) pipeline is 18 inches in diameter. “The Escravos-Lagos pipeline system has a capacity of 800 mscfd, and the WAPCo system will initially carry a volume of 170mscfd and peak over time at a capacity of 460mscfd”[102] [103]. According to the company, the benefit is enormous, as it will reduce the cost of acquiring the natural gas for the West African Countries and ensure efficient supply of the cleanest fossil fuel. The project will serve as a foundation for further international investment; it will help in improving power supply and industrial growth in the region. It was estimated to cost $974 million [46]. The West African gas pipeline is illustrated in figure 2.3.

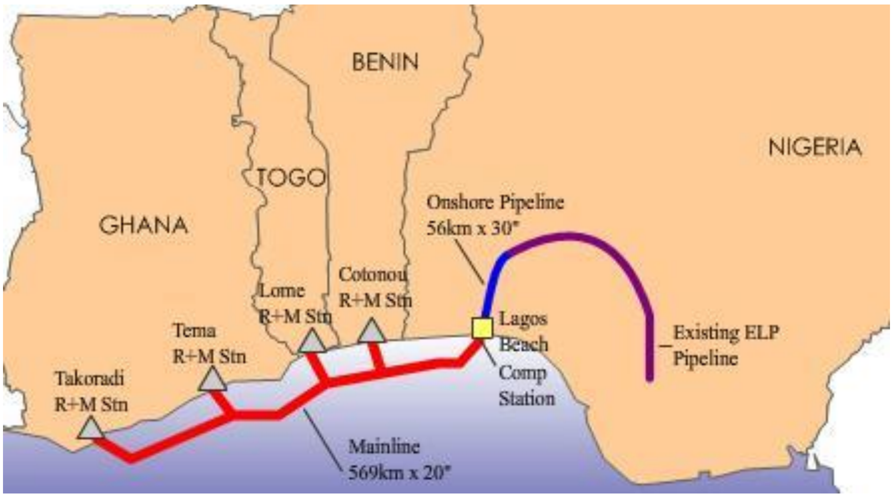


Figure 2:3 West African Gas Pipeline. Sourced: West African Gas Pipeline Company [103]

As at May 2008, there are more than 1000 kilometres connected gas pipelines within the Nigerian territory, which are concentrated in the Niger Delta region. Other pipelines beyond the gas-producing region are the Ajaokuta gas pipeline and the main Nigerian Escravos-Lagos Pipeline system that links the pipelines to the Lagos beach, which links to the West African gas pipeline and for further transportation via LNG or extended pipeline. The following table represents a summary of the existing major gas pipeline networks in the country. The map of the major gas networks is presented in figure 2.4 [104].

Project Name	Start Point	End Point	Diameter (inches)	Length (Kilometres)
Transmitting System	Banga Field	Bonny Terminal	32	268
Escarvos-Lagos Pipeline System (ELPS)	Escravos	Lagos	36	340
Aladja System Pipeline	Oben	Ajaokuta	24	294
Greater Ughelli System	Ughelli	Warri	-	90.3

Table 2.2 Major Gas Pipeline Networks within Nigerian Border

Figure 2:4: Map of major gas pipelines in Nigeria: gas pipelines indicated by the bold red lines. [105]

The four major gas transmitting pipelines in Nigeria covering slightly more than 1000 kilometres of land, supply gas to few power, cements and fertilizer plants. Nigerian Gas Company further expanded the chart of the Nigerian gas pipeline systems by considering other small distant pipelines and by looking at their destinations to various industrial companies and power stations as follows [106]:

1. The Aladja Gas Pipeline System which supplies the Delta Steel Company, Aladja.
2. The Oben-Ajaokuta-Geregu Gas Pipeline System, supplies Gas to Ajaokuta Steel Company, Dangote’s Obajana Cement Company and PHCN Geregu Power Plant.
3. The Sapele Gas Supply Systems which supplies gas to PHCN Power Station at Ogorode, Sapele.
4. The Imo-River-Aba System for gas supply to the International Glass Industry Limited PZ, Aba Textile Mills and Aba Equitable Industry.
5. The Obigbo North -Afam system caters for PHCN Power Station at Afam,
6. The Alakiri to Onne Gas pipeline system supplies gas to the National Fertiliser Company

(NAFCON) now Notore Chemicals for fertilizer production;

7. The Alakiri -Obigbo North -lkot Abasi system for gas supply to the former Aluminum Smelting Company of Nigeria (ALSCON) Plant now Rusal Industries in Ikot Abasi.

8. The Escravos-Lagos Pipeline (ELP), which supplies gas to NEPA's Egbin Power Plant near Lagos. Subsequent spur lines from the ELP supply the West African Portland Cement (WAPCO) Plants at Shagamu and Ewekoro, PZ Industries at Ikorodu, City Gate in lkeja Lagos, PHCN Delta IV at Ughelli, and Warri Refining and Petrochemical Company at Warri.

9. Ibafo – Ikeja Gas Supply Pipeline System supplies gas to Ikeja City Gate from where Gaslink distributes to the Lagos Industrial Area (LIA).

10. Ikeja – Ilupeju – Apapa Gas Pipeline System currently operated by Gaslink for Gas Supplies to Greater Lagos Industrial Area.

11. Ajaokuta – Geregu Gas Pipeline System, which supplies gas to the Geregu PHCN Power Plant.

12. Ajaokuta – Obajana Gas Pipeline System, which supplies gas to Dangote's Obajana Cement Plant (OCP).

"All these facilities comprise of over 1,250 kilometres of pipelines ranging from 4" to 36" in diameters with an overall design capacity of more than 2.5 billion standard cubic feet of gas per day (bscf/d), 16 compressor stations and 18 metering stations. The facilities represent a current asset base of more than N21 Billion business contact" Nigerian Gas Company Limited (2012) [106]. There are other pipeline projects going on, and some are being proposed. The on-going projects include the expansion of the existing pipelines and extension of pipelines to new areas, especially the Northern part of the country, where there is no single pipeline network despite the largeness of the region and huge human population, which comprises almost 56% of the nation total population of more than 160million people [107].

2.3.2 Liquefied Natural Gas

A Concept of LNG

The LNG process involves the elimination of some components in natural gas like dust, helium, water and heavy hydrocarbons that may hinder its mobility downstream. It is then condensed in to a liquid form by cooling it to almost -160^{0}C [108]. LNG constitutes of methane up to 95% and few percent of ethane and insignificant percent of Propane, Butane and Nitrogen. The LNG process makes it possible to transport large quantity of energy density and volume in a small quantity comfortable for long distance delivery offshore. LNG achieves more reduction in volume than Compressed Natural Gas (CNG), because the more the natural gas is condensed the more it can convey high energy density [109]. This makes the LNG more economically viable than CNG.

The first liquefaction experiment in the world was undertaken by a British Chemist Michael Faraday where he liquefied different sort of gases including natural gas [108]. The first liquefaction plant was constructed in U.S. in 1941 where the liquefied natural gas was stored not for commercial deliveries. For so many years since the discovery of natural gas, the only available option for transporting natural gas was pipeline until 1959 when the first liquefied natural gas was produced on an industrial scale. In 1959 the first LNG tanker was built when a "World War II liberty freighter" was converted into LNG tanker where it carried an LNG cargo from Louisiana to Canvey Island in the United Kingdom [110]. Having successfully transported natural gas in a liquefied form, other LNG plants started coming on board especially in the U.S. Similarly, in early 1960s, the British Gas Council planned to import LNG from Venezuela, but before the contract was signed, proximate reserves were found in Algeria. In 1964, United Kingdom was the first importer of LNG and Algeria was the first exporter of LNG. As a result more terminals were built in Atlantic and Pacific regions and this led to continuous growth of the LNG all over the world [39].

Over the years, natural gas becomes an important fuel in the world and its demand increases globally. However, the natural gas reserves were not spreading in the same way like its demand, as the resource is concentrated in few regions or countries. Subsequently, the need to transport the natural gas to the consuming countries becomes necessary to optimize the use of the natural gas for economic gains. The pattern of gas reserves do not conform with the trend of its increasing demand as there are more increasing demands spread all over the world with narrow concentration of the resource in few territories. For example, Qatar, Russia and Iran hold 58.4% of the global gas reserves in 2012 and consume only 19.4% of the world natural gas produced. This means they can turn their surplus reserves into revenue by transporting the natural gas to greater distance market through LNG [111]. Due to the increasing demand and emergence of new gas uses, the need to transport it to farer distances became necessary, which pipeline networks may not be economically feasible for such distance deliveries. Similarly, the terrain and political concerns in the transit or crossing countries that these pipelines pass makes pipeline a difficult option. All these, couple with the expensiveness and long-time construction span of the gas pipeline networks necessitate for alternative way to delivering natural gas to long distance markets, hence the preference of LNG mode of gas transport. LNG is about 1/600th of its initial gaseous state [108]. The process of LNG is Shown in figure 2.5 [112] [109].

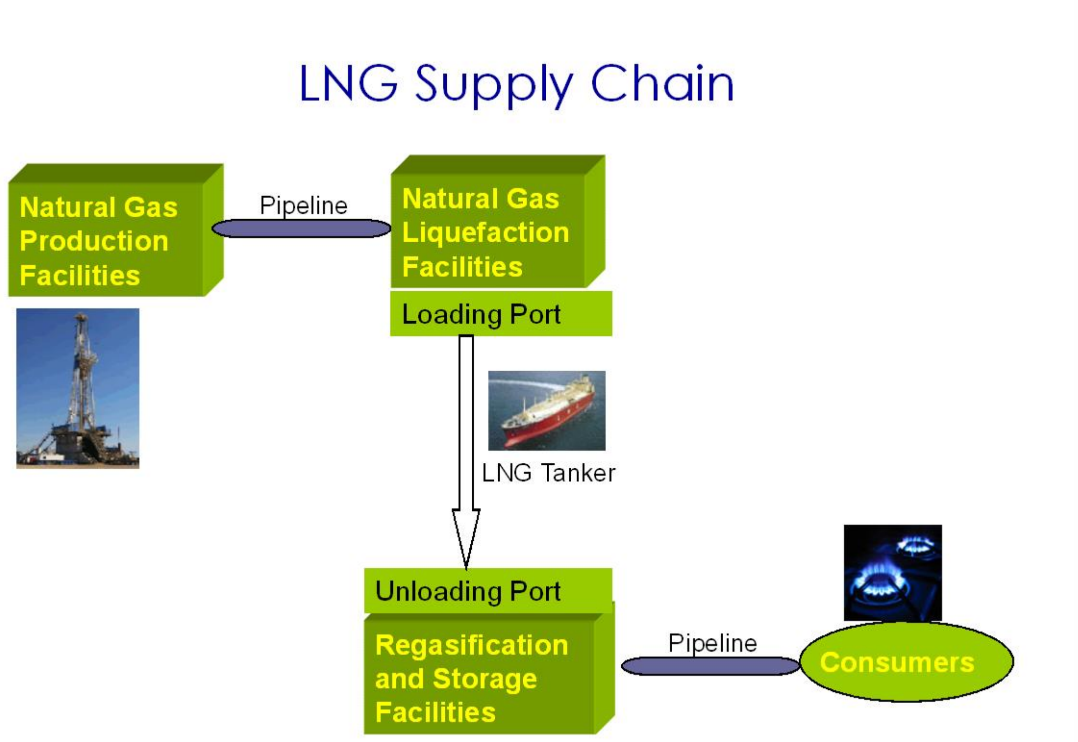


Figure 2:5: LNG supply chain: Source: [112]

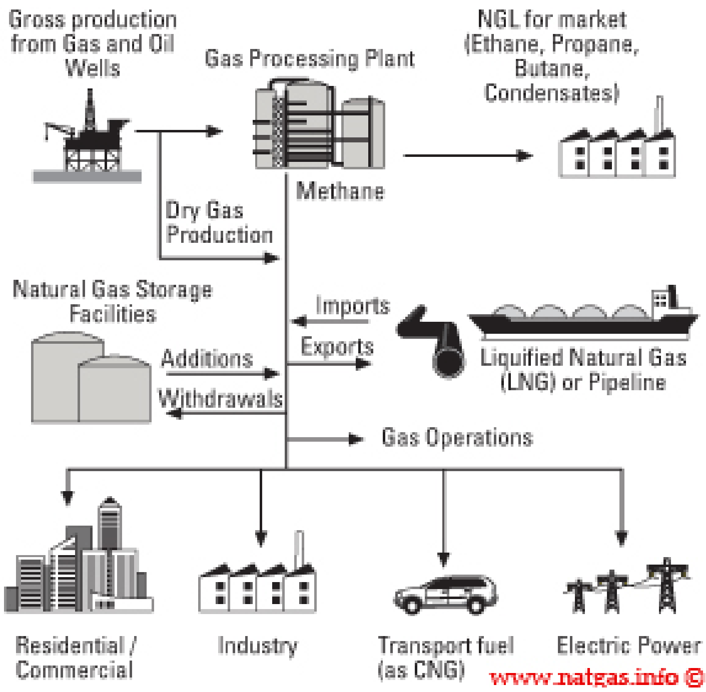


Figure 2:6: Expanded LNG supply chain [94]

From figure 2.5 and 2.6, the chain of LNG starts with the gas production from either the pure gas reserve or oil and gas associated reserve, the gas will then be transported via a gas pipeline to the liquefaction plant. This means that gas pipeline is an integral part of LNG process. After been liquefied, it will then be loaded into the LNG tanker for offshore transportation to the targeted market place. On arrival at the destination, the LNG will then be regasified, meaning that, it will be reconverted to its natural gaseous state. From there it will be transmitted via pipeline to the consumer sites, which means, even none gas producing countries may need gas pipelines. The chain of gas supply ends at consumer sector, which includes residential/commercial, industry, transport and power generation.

B Economics of LNG

LNG is very expensive to produce and requires very expensive cryogenic tanks and sea vessels for storage and transport. The cost of LNG treatment and transportation is one of the discouraging factors for using LNG as a means of conveying natural gas. The cost of an LNG plant has an estimated value of $1.5 billion per 1 million tonnes per annum (Mtpa) capacity. An average receiving LNG terminal will cost $1 billion and LNG vessel will cost between $200-300 Million as at 2012 [113]. Even though, in recent times there were improvements in LNG technology, which makes it more competitive, but due to the increase in the material cost and a relative monopolistic power of the LNG contractors, the cost of LNG has increased again [114]. However, an LNG plant tends to enjoy the benefit of economies of scale, where the average cost reduces despite the increasing production in the long run. The LNG chain is divided into liquefaction and regasification, which investors may invest based on their interest [115].

The value chain of LNG as mentioned earlier consists of the exploration, production, liquefaction, shipping, storage and regasification. To make LNG competitive, investments need to be made on each of these linked chains. A situation where, we have lots of exploration or production of natural gas without a corresponding increase in the LNG plants or facilities, the LNG market may not be economically viable as the limited number of plants will assume a monopolistic power and the market will be distorted. Therefore, LNG market is dependent on the relatively proportionate investments in all of the value chains. As at June 2011, there are "25 LNG export terminals (liquefaction), 89 import terminals (regasification) and 360 LNG ships in the world, with the United State having the highest number of LNG facilities" (IGU 2011) [116]. LNG has been one of the favourable means of transporting natural gas due its safety records so far, which is evident by the increasing number of its facilities as indicated above [113]. The required LNG investment in the future will rise to $20 billion per year up to 2025 due to the increase in the demand for the product as projected to be around 420 Mt/year [115]. One of the things that determine its profitability is the distance of the delivery, which affects the price of the LNG. The shipping cost of LNG per million Btu is $2.5-$3.5 or $4.5-$5.5 depending on the distance, which may affect the landing cost of the product [117]. Elaboration of these value chains cost was provided by Jensen (2006), which is presented in figure 2.7:

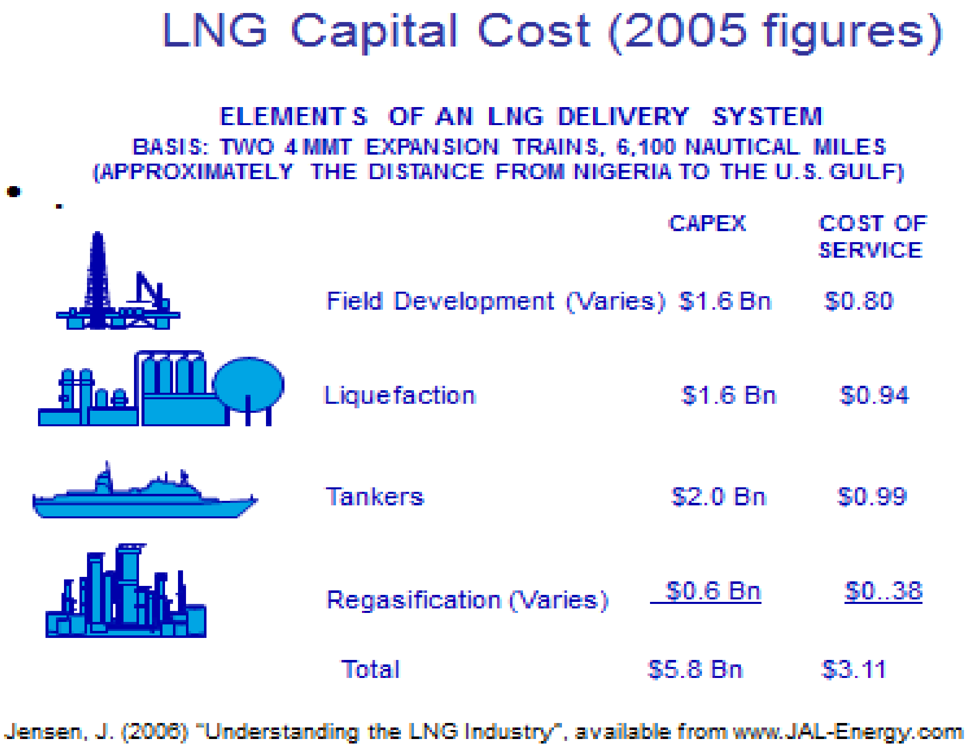


Figure 2:7: 2005 LNG Capital cost

Figure 2.7 shows the capital costs and associated costs of servicing the fixed assets as well as the terminals (maintenance costs) involved within the four LNG value chains irrespective of the volume of the production. The value chains are developing the gas production field, liquefaction terminal, LNG transport (LNG tankers) and the receiving Terminal (regasification). An investor can have a clue on which part of the value chain he/she wants to invest. The main liquefaction cost takes only 28% of the total capital expenditure, the remaining 72% of the capital cost was shared between field development, cost of tankers and regasification at 28%, 34% and 10% of the total capital cost respectively. The overall cost of the value chain is $8.91 billion for 6,100 nautical miles (9817 km), which is equivalent to a distance from Nigeria to U.S. gulf [118].

LNG can be a direct consumer commodity and can facilitate other consumptions. It can be used for cooking and heating in residential and commercial sectors. It is also an essential commodity for the industrial sector and power generation as it provides opportunity of storing natural gas for future use. For example, during winter when there is high demand of natural gas for warming houses, the LNG that has been stored for long time can be regasified to supply more gas to meet up with the demand. Likewise for the power generation plants, natural gas can be stored through LNG to serve as a fuel reserve for peak consumption periods [117].

The economics of LNG shows that the longer the market distance the more LNG becomes economically viable. Figure 2.8 shows the transportation cost of the two natural gas transportation options (gas pipeline and LNG) to identify the most cost effective mode for shorter and longer distance gas deliveries as at 2012 [117].

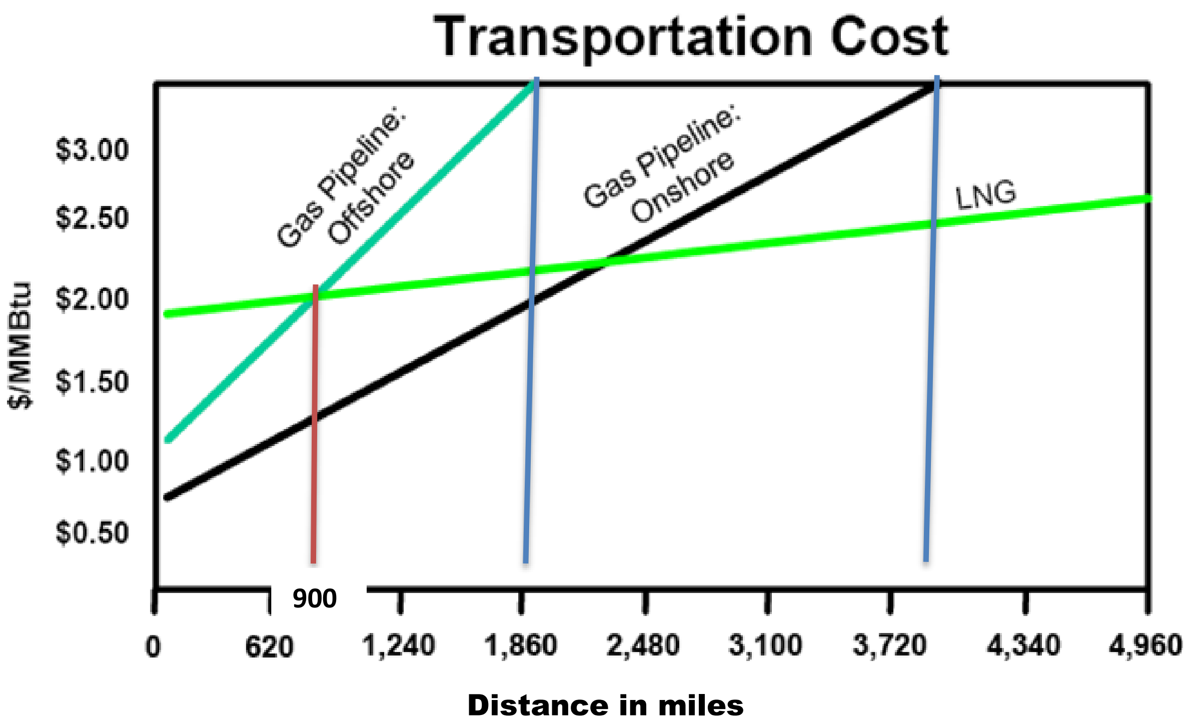


Figure 2:8: Comparison of gas transportation cost via gas pipeline and LNG [117]

From figure 2.8, for a distance of 1860 miles (2993.38 km), offshore gas pipeline will be the most expensive option as $3.50 will be spent to transport one million Btu of natural gas, but if LNG is used for that the same destination only $2.20/MMBtu will be spent. However, if the gas reserve is onshore, then around $1.90/MMBtu will be spent to transport the gas for the same distance through pipeline (cheaper than LNG). But most of the commercially viable gas reserves are offshore, which means LNG is more economical than offshore gas pipelines if the distance is above 900 miles (1448.41 km) for offshore gas reserves [117]. If the reserves are onshore, gas pipeline is more economical if the distance is not more than 1900 miles (3057.75 km). Any distance beyond around 2000 miles, LNG is the most viable option.

According to Michelle (2012), "LNG development is especially important for countries like Nigeria and Angola. In these countries, most of the natural gas that is produced with crude oil is flared because there are few alternatives for usage or disposal of the excess gas" [117].

C LNG in Nigeria

LNG is the prioritized mode of transporting gas outside Nigeria since the Nigerian Liquefied Natural Gas (NLNG) plant came on stream in 1999. Even though it was incorporated since 1989, with NNPC, Shell, Total and Eni as shareholders with 49%, 25.6%, 15% and 10.4% share interest respectively [46]. The NLNG plant started operation in 1999 and delivers LNG to many countries in the world. It has the existing production capacity of 22 million metric tonnes of LNG per annum from its 6 LNG trains, which represents 10% of LNG consumption globally [119]. It also has the capacity of producing 4 million tonnes of LPG per year. It requires 3.5 bcf/d volume of natural gas to operate at the maximum capacity. The Nigerian LNG plant produced 140 billion cubic metres of LNG in 2013 [120].

The only Gas transmitting pipeline connected to the NLNG plant is the 20 miles long and 36 inches (91.44cm) diameter gas pipeline from the Niger Delta area [121]. LNG is the fastest growing and reliable natural gas processing facility in Nigeria with the successful completion of the sixth LNG train in 2007 (in 8 years). This has contributed immensely to the total gas utilization in the country through the years [9]. Both CNG and LNG are not been used for domestic utilization. LPG production in the country has been zero [7], but yet the country imports LPG from outside [26]. The gas domestic utilizations are mainly (70%) by power sector, the remaining 30% of domestic gas utilization been used by cement and fertilizer industries as well as iron and steel plants [26].

Additional LNG plants are proposed which are Olokola ($7 billion worth) and Brass River LNG ($3.5 billion worth), which are yet to take off, but so far close to $1.5 billion has been spent on the projects as at the second half of 2014 [122] [26].

2.4 Literature on comparison between Gas Development Projects

As the research is aimed at comparing some of the above gas development projects that are directly relevant for domestic consumption, a look at the existing literature was made to understand the past comparative analyses made between these projects, so that this research will be informed of the contributions made and the existing gap, which would necessitate the unique comparison to be implemented in this research. The literature will also show how the approaches to be used for this comparison was used in other countries' case studies with a view to identifying the optimal use of these approaches for the purpose of this research, as such the following few relevant literature are reported.

Khalilpour and Karimi (2012) identified six options for developing natural gas, these options are: gas pipelines, LNG, CNG, GTL, GTS (gas to solid) and GTW (gas to wire). They analysed these projects and observed their sensitivities to some factors that can affect its investment security. These factors are market fluctuations, market embargos, political changes and technical advances. Their rational was that, in most of the literature, profit assessments were made, but not deliberate evaluation of these projects under possibility of uncertainties were made. They used net present value (NPV) in identifying the profitability of each of these projects under the above-mentioned disturbing conditions, and they found that LNG, CNG, and GTL are less sensitive to these disturbing factors. They used Decision Analysis (DA) in examining uncertainties and investment risks in making investment decisions. Their analysis is significant in making long-term investment decision, so that investment would not be at risk at the event of uncertainties. The three identified projects above would then be the favourable investment projects under such uncertainties [53]. However, they should have included CCGT plant in their analysis, as it is one of the mostly used gas development project. Similarly, in addition to the NPV method, additional accounting methods should have been included, and their research should have been country specific. Their research was based on exporting the natural gas abroad, rather than based on in-country consumption purposes. They should have included environmental footprints among their parameters like in the work of Lars et al (2011).

Lars et al (2011) [123], also analysed three natural gas utilization prospects namely LNG, CNG and GTL with a view to identifying their potentials and possible risks associated in terms of their application and finally evaluated the less economically risk prospect among the three. They mentioned that both offshore pipelines and LNG are built to transport natural gas to market, which are later complemented by CNG and GTL. Since these technologies are competing to convey natural gas to a market place, then there is need for an assessment to determine the more efficient and economically profitable technology, which they tried to find in their paper, they based their judgement on the premium prices of the products of each of the evaluated technology. They first discussed the three natural gas utilization projects and assessed them based on six (6) parameters namely: offshore applicability, transportation, infrastructure, schedule, permitting and safety, and environmental footprint. Other comparisons were made on qualitative and commercial value chain concepts. They used Monte Carlo-based simulation tool in assessing these projects by looking at the revenue, expenditure and possible risks associated with them, and they observed that LNG to be favourable among the three projects due to its long-term span for contractual agreement and guarantee of supply. They both left out an important parameter in sensitivity analysis, which is the price of the products of these technologies, which would have significantly affect their analysis and conclusions. They should have included gas pipeline in their analysis as it is the traditional way of transporting the gas, and they should have presented it in country specific like in the work of Thomas and Dawe (2003).

Thomas and Dawe (2003) have compared some gas utilization projects, but they refused to apply any of the accounting techniques, rather they analysed them qualitatively analysing their advantages and disadvantages only, without showing their quantitative analysis [124]. Deshpande and Economides [125] also did not use a particular accounting method, but rather looked at the cost of transporting gas using CNG and LNG at a particular distance, and they did not use country specification as well, and they found CNG to be very easy and more viable to transport gas than LNG at distance below 2,500 miles and gas price range of $0.93-$2.23/MMBtu. Najibi et al (2009), looked at the country-specific comparison in Iran, but only compared the production cost of four gas transportation options namely gas pipelines, LNG, CNG and NGH, where they found gas pipelines to have lower cost of production at distance up to 7,600 km, and LNG having the lowest gas production cost at a distance above that [126]. However, they should have included GTL and CCGT projects in the analysis.

Chyong et al (2010) analysed the unit cost of transporting natural gas from Russia using a new gas pipeline called Nord Stream, and compared it with the unit cost of transporting the gas to Europe using the existing line for transporting natural gas from Russia to Europe. They used the levelised cost of transporting natural gas from the Gazprom's gas production fields. They also analysed the economic benefit to Gazprom with and without the Nord Stream using three scenarios of normal, low and high gas demand in Europe. They found that the Nord stream will have an investment cost requirement between $19.9 billion and $23 billion. They found that, if the Nord stream is to operate at 75% of its capacity, the Ukraine route would be cheaper but only for the period until 2021. This is because by this time the Nadym-Pur-Taz gas reserves must have been depleted, and with a shift of production to far north of Russia, the Nord stream will be cheaper even at 75% operation capacity, as the north production fields are more proximate to the European markets than the Nadym-Pur-Taz fields [127]. However, at 100% operation capacity, the Nord stream is cheaper at all times.

The four segments of the Nord stream (Gryazovets-Vyborg, Nord-Stream offshore, Opal, and Nel) we estimated to have an average levelised cost of gas transportation of $28.7/thousand cubic metres (tcm), $21.2/tcm, $5/tcm, $2.7/tcm, and $12.8/tcm respectively. Everything being equal, the Nord stream has positive NPV in the three demand scenarios, with the average NPV being $4 billion for low demand scenario, $6.9 billion in the normal scenario, and $20 billion in the high demand scenario. The Nord stream has an offer hand than the existing pipelines because; it has lower transportation cost, it avoids Ukraine's high transit fees, and it has low possibility of disruption risks. This type of analysis is related to this type of research as comparison of different proposed gas pipelines routes will be compared, but within the country.

However, Chyong's et al (2010) conclusion that the Nord stream is more economical until 2039 on the assumption of the lowest (-0.2%) possible gas demand fall from Europe may not be possible. This is because, Europe's reliance on Russian gas may rapidly drop at a higher rate than expected as Robertson H. (2014) highlighted [128], and the percentage of this decline was proposed to be over 33% by Andreas, G. and H. Wade (2012) [129]. Strict energy efficiency savings, LNG capacity expansion and discovery of the shale gas, which has implication on the demand and price of the Russian gas may eventually affect the overall profitability of the gas networks analysis in the future [129]. Therefore, this may affect the profitability of the Russian gas pipelines.

Country specific literature is recommended to account for the country peculiarity. Charles 2010 reviewed different gas utilization projects in Nigeria including LNG, GTL, GTP, CNG and pipelines, but he only narrated background and description of these projects in the country, without applying any accounting techniques for profit analysis [130]. His work is relevant to this research as it provides description of some of the referenced gas development projects to be analysed in the country. Nwaoha and David (2014) also reviewed five gas development projects in Nigeria namely GTL, CCGT, CNG, LNG, GTF, and pipelines, but they refused to present specific costs and benefits analysis of these projects, and only presented the industry status and description of these projects in the country, and recommended their advantages. These description is relevant to this research as it covers the key projects to be compared in this research and will help frame subsequent discussions [23].

Stanley (2009) also itemized the above gas utilization projects in Nigeria and qualitatively discussed them with emphasis on GTL, but also did not apply the costs and benefits analysis specific to the country [131]. Sonibare and Akeredolu (2006), projected the level of gas consumptions that can be achieved within Nigeria through two gas development projects for cooking and electricity generation purposes, but refused to estimate the viability or compare between the economics of the gas development projects [132]. Alimi (2014) applied investment of return and payback period for a GTL project in Nigeria and estimated 20% as the project's return on investment in the country. He mentioned using the payback period method, but refused to clearly state the period of investment return, but he stated that the viability of the GTL project in the country is highly sensitive to capacity [133]. Nwanko (2008) also applied IRR and added NPV, and profitability index in his work comparing the viability of GTL and LNG projects in Nigeria, where he found GTL to be more viable than LNG. His research is relevant, but he should have compared GTL with CCGT as both are aimed at meeting domestic demand of energy in the country as out rightly identified in his work [134].

Usman (2006) [135] analysed a gas project in Nigeria, i.e GTL, and used NPV and sensitivity analysis to evaluate its viability in the country, he found GTL to be viable, but his assumptions are not reliable as he used personal assumptions about the prices of the GTL products instead basing it on the crude oil price like in the work of Al-Shalchi (2008). Alawode and Omasikin (2011) reviewed some gas development projects in Nigeria including

LNG, GTL, CCGT, CNG and Gas to Solid, even though the combination included both GTL and CCGT plants which are of primary interest to this research, but they refused to apply any accounting technique to quantitatively analyse these projects [136]. Further survey was made on the Nigerian specific viability comparison between GTL and CCGT projects, and we could not trace any existing literature that studied the economics of these two projects in the country, and no literature has compared the viability of the proposed gas pipeline route options in the country. This why this research will economically assess the viability of the CCGT and GTL projects in line with evaluating the economics of the domestic gas development projects that will stimulate inland gas demand as stipulated to be achieved in the Nigerian gas master plan. The combinations of the gas pipeline route options as contained in the plan would also be assessed quantitatively and recommendation will be provided on the optimal gas pipeline route combination. The above reported literature are directly relevant and provide basic information and approaches that can be considered in the research.

2.5 Gas Consumption and Economic Development

Natural gas development is capital intensive, and investors especially government needs to understand the dynamic relationship between gas consumption and economic growth, and the resulting effect of investment and consumption of gas on the overall economy. Even though it is clear that natural gas is very useful to the sectors of the economy, one needs to have a clear estimate of how the aggregate gas consumption can affect the economic performance in a country.

Many literature have been written to improve understanding of the relationship between energy consumption and economic growth in many case studies using different methodologies and data range. Some of these studies are discussed here to understand the disparity in the findings and how this research can improve in understanding this dynamic relationship especially with gas consumption in Nigeria. Having discovered the use of traditional methodologies like the single equation ordinary least square, Engle and Granger (1987), Johansen (1988), and Johansen and Juselius (1990) cointegration procedures in analysing the nexus between energy consumption and economic growth in Nigeria and in some other case studies, which they are not without numerous limitations. For example, Johansen (1988) cointegration restricts to the use of I(1) variables in the specification and it is sensitive to sample size [137]. The ARDL bound cointegration test that this research will use, address some of these limitations and provides more robust and sufficient estimates of these relationships, and allows for multivariate framework in the model [138], hence it is used in this research. This will be further discussed in the econometric analysis.

Another relevance of the reported literature is that, it made us to understand four contradicting findings relating to the relationship between gas consumption and economic growth; One, those literature that found that energy consumption relates and granger-causes economic growth, and concluded that the economic growth is dependent on energy consumption, and a decrease in the energy consumption can slack economic growth as stated in the work of Narayan and Smyth (2008) [139], and Olusegun (2008) and Ighodaro and Ovenseri (2008) in Nigeria. The second finding was that economic growth drives energy consumption, which indicates a country is not dependent on energy consumption for its economic growth, and this was concluded in many case studies that the economies of countries with this kind of relationship are not absolutely dependent on energy for their economic growth like in the work Kraft and Kraft (1987) in USA[140]. The third and fourth set of the findings were the ones that found causal and no causal relationship for both directions between energy consumption and economic growth respectively [141] [142] [143]. These findings are both found in similar case studies in different researches using different methods and data. Therefore, there is the need to use more sufficient techniques and updated data to verify the exact relationship between the disaggregated energy consumption and economic growth in specific case studies, which this research aim to achieve in Nigeria.

Apergis and James (2010) attempted to study 67 random countries to observe the relationship between gas consumption and economic development in these countries. Using the time series data between 1992 and 2005, they used GDP as the proxy for the economic development and they found that gas consumption has long run equilibrium cointegration with GDP, and using panel Vector Error Correction model, they found that both gas consumption and economic development cause each other. That is increase in gas consumption can also cause increase in economic development and vice versa. They concluded that 1% increase in gas consumption leads to 0.65% increase in GDP in these countries [144].

However, it may be inconsistent to have this level of relationship exactly in each of these countries. A country specific analysis of this relationship needs to be carried out, which Sahbi et al (2014) did for Tunisia, where they looked at the relationship between gas consumption and GDP (proxy for economic development) in Tunisia. They used other variables like trade and real gross fixed capital formation as additional independent variables in their Auto-Regressive Distributed Lag (ARDL) regression. Using the data between 1980 and 2010, they found long run cointegration between these variables, and using Toda-Yamamoto approach, they found bidirectional relationship between GDP and these variables in Tunisia. Precisely they found positive short run and long run relationship between gas consumption and GDP in Tunisia. They found that, 1% increase in gas consumption causes 0.028% and 0.04% increase in GDP in long run and short run respectively with high level of significance (5% level of significance).

The use of additional variables in observing this relationship differs, as some use traditional production theory using capital and labour as in Apergis N. and James E.P. (2010) and Kum H. et al (2012), while others use combination of other energy products or indicators like in Khan and Ahmad (2009). Kum et al (2012) tried to disaggregate the country causality, where they studied G-7 countries, and found variance in terms of causality between these countries.

They found that in Italy, there is unidirectional causality running from gas consumption to economic growth, and another causality running from economic growth to gas consumption in UK. They found bidirectional causality between gas consumption and economic growth in France, Germany and United States [145]. Their approach to identifying country specific relationship is an improvement on the work of Apergis and James (2010).

Isik (2010) looked at the cointegration between gas consumption and GDP in Turkey using the data between 1977 and 2008, and also found long term stable and positive cointegration between the two variables [146], however, using a bivariate framework may omit some vital variables in the long run relationships, as omission of relevant variables may lead to biased long run estimates [147]. Similar result was found in Korea as studied by Lim and Yoo (2012) who found bidirectional causality between natural gas consumption and economic growth in Korea [148].

Exports and CO_2 emissions were included in the work of Shahbaz et al (2013) when observing the effect of gas consumption on economic growth in Indonesia. They found cointegration between these variables using ARDL bound test model, and found that gas consumption granger causes economic growth. However, Yang (2000) found no cointegration between gas consumption and economic growth in Taiwan, but still found one-way causality from natural gas consumption to economic growth in the country. He found bidirectional relationship between the aggregate energy consumption and economic growth [141], and this was done by using the Granger causality test and data from 1954 to 1997[149].

In India, Aqeel and Butt (2001) found no cointegration and no causality between natural gas and economic growth (GDP) using the data for the period 1955 to 1996 [150]. However, Muhammad et al (2014) studied that of Pakistan using ARDL bound test approach and found high multiplier effect of gas consumption on the country's GDP, they found that 1% increase in natural gas consumption will cause GDP to increase by 0.3526% in the country using the data between 1972 to 2011[151]. Many studies were conducted on the cointegration and causality between gas consumption and economic growth in so many countries as highlighted in table 2.3.

Some few researches were conducted on the relationship between Nigerian energy consumption and economic growth. Ighodaro (2010) have used Johansen cointegration test to find the cointegration and causality between Nigerian disaggregated energy consumption using the data between 1970 and 2005 [152]. Though, Hjalmarsson and Osterholm (2010) questioned the use of Johansen test alone to verify whether there is presence of cointegration or not, apart from it being an outdated method [153].

Nevertheless, Ighodaro (2010) found unidirectional relationship from gas utilization to economic growth in Nigeria. He used health expenditure, money in supply and electricity consumption, which was not proper combination of variables given the main aim of the research. Combining electricity consumption and gas consumption on right side of the equation may cause biased estimates [154], as gas consumption can be used to predict electricity consumption as more than 50% of the country's gas consumption is used for electricity production [7]. He should have included capital formation as in Apergis (2010) [144], and exports would have been an appropriate variable in place of health expenditure, as Nigerian economy is largely reliant on the exports earnings especially from the oil and gas resources [155]. He also failed to estimate the multiplier effect of natural gas consumption on the economy.

In his earlier research, Ighodaro and Ovenseri (2008) using the data from 1970 to 2003, he still found unidirectional causality running from energy consumption to economic growth, but this time using electricity consumption as the proxy for energy consumption against GDP [156]. Coal and electricity consumptions were also paired to find their causality relationship with GDP in Nigeria, and it was found to have bidirectional causality [157] [158]. Olusegun (2008) used ARDL bound test cointegration approach to study the relationship between aggregate energy consumption and economic growth in Nigeria, which is the approach that this research will adopt. However, he used bivariate framework in his cointegration test, and also used the data up to 2005, which might be outdated due to the significant shifts and antecedents that happened post 2005, which caused changes to price and consumption of energy resources, which might change the earlier findings [159], and this necessitate updated research like this one [158].

Abalaba and Dada (2013) also attempted to study the relationship between energy consumption and economic growth in Nigeria, and found weak evidence to support the presence of relationship between them in the long run, they also found no causal effect in both ways between energy consumption and economic growth in Nigeria, but found evidence of short-run relationships. Their finding is consistent with Aliero and Ibrahim (2012) who found absence of causality between total energy consumption and economic growth in Nigeria using data from 1970 to 2009 [160]. Their findings also went contrary to the findings of Olusegun (2008) and Ighodaro and Ovenseri (2008) in Nigeria. They also used aggregated energy consumption, without considering the natural gas consumption as a standalone variable in their Johansen cointegration test [143].

This finding is also contrary to the findings of Ebohon (1996) who reported bidirectional causality between energy consumption and economic growth in Nigeria. Dantama et al (2012) [161] used the ARDL approach and found long run cointegration on disaggregated energy consumption using petrol, coal and electricity consumption with real GDP in Nigeria, and found their coefficients to be positive and significant in relation with the GDP except for the coal consumption coefficient, which is negative though statistically insignificant. Mustapha and Fagge (2015) stated that there has not been consensus on the dynamic nexus between energy consumption and economic growth in Nigeria [162], and as Ozturk (2010) mentioned, this could be as a result of difference in time periods used, unique features of the country, mix of variables and different econometric methods used.

Muhammad et al (2013) presented the following table (table 2.3) summarising some of the researches and findings on the topic of cointegration and causality between gas consumption and economic growth from different countries and period of observations [2]. Different results can be derived depending on the country, methodology, period of observation and variable mix. However, the ARDL bound test model is the most recent and preferred due its efficiency and ability to accept variables even at different order of integration and using any size of a data. It can also be used to determine the short run and long run multiplier effects of gas consumption on economic growth simultaneously [163] [164]. None of the studied literature have applied this method to study the cointegration and long run and short run relationship between gas consumption and economic growth in Nigeria in recent years. That is why this research will employ the use of the model and using appropriate variables in multivariate framework and recent data to analyse the dynamic relationship between gas consumption and economic growth in Nigeria. It will also deploy the use of impulse response and decomposition techniques that have not being applied in the consulted literature on the gas consumption and economic growth nexus in Nigeria.

Even though Mustapha and Fagge (2012) attempted to apply impulse response and variance decomposition on aggregate energy consumption and economic growth in Nigeria, but used

Cholesky method instead of generalised method, which provides more robust result than the orthogonalized impulse response method, and allows meaningful interpretation of the corresponding variance decomposition [165]. They also used aggregate energy consumption, and refused to provide clear explanation and policy implication of the impulse response and variance decomposition in their analysis, they should have followed the explanation used in the work of Kakali and Sajal (2014) in India, and Farzanegan, Markwardt (2009) in Iran [166]and particularly Essien (2011) in Nigeria. Even though, Essien studied CO_2 emissions and economic growth relationships in Nigeria [167], but his analytical approach is appropriate. None of the literature have conducted impulse response and variance decomposition on the nexus between domestic gas consumption and economic growth in Nigeria in recent years.

Authors	Countries	Sample Period	Variables	Cointegration	Causation
Yang (2000b)	Taiwan	1954-1997	Real GDP, Natural Gas Consumption	No	$G \rightarrow Y^{a}$
Aqeel and Butt (2001)	Pakistan	1955-1996	Real GDP, Natural Gas Consumption	No	$Y \times G^{c}$
Siddiqui (2004)	Pakistan	1970-2003	Real GDP, Natural Gas Consumption	-	$Y \times G^{c}$
Lee and Chang (2005)	Taiwan	1954-2003	Real GDP per Capita, Natural Gas Consumption	Yes	$G \rightarrow Y^{a}$
Ewing et al. (2007)	US	2001:1–2005:6	Industrial Production, Natural Gas Consumption	-	$G \rightarrow Y^{a}$
Zamani (2007)	Iran	1967-2003	Real GDP, Natural Gas Consumption	Yes	$G \leftrightarrow Y^{d}$
Sari et al. (2008)	US	2001:1–2005:6	Industrial Production, Natural Gas Consumption	Yes	$G \leftarrow Y^{b}$
Hu and Lin (2008)	Taiwan	1982:1 to 2006:4	Real GDP, Natural Gas Consumption	Yes	$G \leftrightarrow Y^{d}$
Reynolds and Kolodziej (2008)	Soviet Union	1928–1987,1988–1991, 1992–2003	Real GNP, Natural Gas Consumption	-	$G \rightarrow Y^{a}$
Adeniran (2009)	Nigeria	1980-2006	Rea GDP, Natural Gas Consumption	Yes	$G \leftarrow Y^{b}$
Amadeh et al (2009)	Iran	1973-2003	Real GDP, Natural Gas Consumption	Yes	$G \leftarrow Y^{b}$
Clement (2010)	Nigeria	1970-2005	Real GDP, Natural Gas Consumption	Yes	$G \rightarrow Y^{a}$
Yu and Choi (1985)	UK	-	Real GNP, Natural Gas Consumption	-	$G \leftarrow Y^{b}$
	US			-	$Y \times G^{c}$
	Poland			-	$Y \times G^{c}$
Fatai et al. (2004)	New Zealand	1960-1999	Real GDP, Natural Gas Consumption	No	$Y \times G^{c}$
	Australia			Yes	$Y \times G^{c}$
Zahid (2008)	Pakistan	1971-2003	Real GDP per Capita, Gas Consumption	Yes	$Y \times G^{c}$
	Bangladesh			No	$G \rightarrow Y^{a}$
	Indiça			No	$Y \times G^{c}$
	Nepal			No	$Y \times G^{c}$
	Sri Lanka			No	$Y \times G^{c}$
Apergis and Payne (2010)[e]	67 Countries	1992-2005	Real GDP, Natural Gas Consumption, Labor, Real capital	Yes	$G \leftrightarrow Y^{d}$
Shahbaz et al. (2013)	Pakistan	1972-2010	Real GDP, Natural Gas Consumption, Employment, Real capital	Yes	$G \rightarrow Y^{a}$

[a] Unidirectional causality running from natural gas consumption to economic growth.
[b] Unidirectional causality running from economic growth to natural gas consumption.
[c] No causal relationship.
[d] Bidirectional causality.

Figure 2:9: Summary of past literature on cointegration and causality between gas consumption and economic growth [2]

2.6 Overview of Nigerian Energy Situation

Looking at Nigeria where per capita electricity became very insignificant in previous years (see figure 2.10) below[168], and in order to complement the government effort in generating more electricity and attract investors, more gas development projects need to be developed to provide cheaper fuel feeds for the existing and new power plants in the country. Presently, there are thirteen open gas turbines and four combined cycle turbines in the country, even though only two of the combined cycle turbines are fully operational, one is partially operational and the other under construction. For the open gas turbines, only five are operational, another five are partially operational and three others are under construction. This is summarised in table 2.3 below [169].

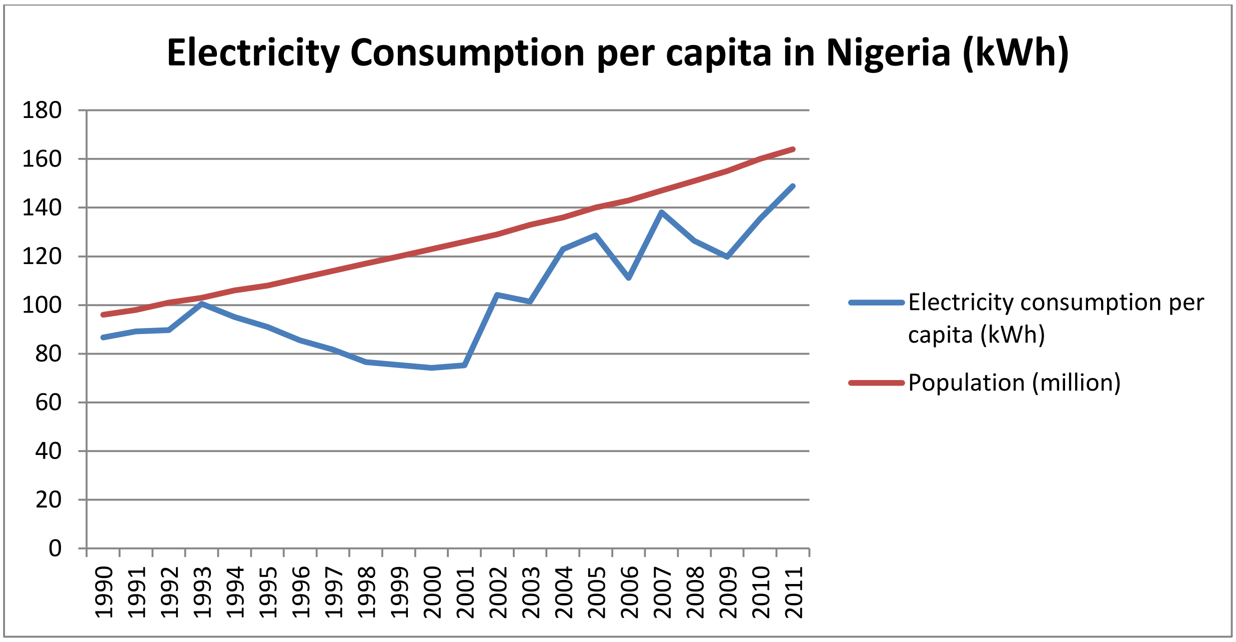


Figure 2:10: Nigerian per capita Electricity Consumption [168]

From figure 2.10, it shows that the Nigerian population has been increasing exponentially throughout the years, which indicates increasing energy demand. However, the electricity per capita has been volatile and low, with the highest-ever energy per capita being approximately 149kWh per person per year in 2011, and comparing this with Algeria's 1091kWh per person per year, and 3926kWh per person per year in Libya, this shows Nigerian energy per capita is very low. Yet Nigeria is the most populous country in Africa with close to 170 million people as at 2014. The red line indicates the population trend, while the blue line shows the electricity consumption per capita. It can be noticed that the electricity consumption has been fluctuating throughout the years, with long-term reduction from 1993 to 2000. Within these seven years, there have been shortages in the electricity supply in the country due to low supply of gas and low operational capacities of the gas turbines [170]. However, from year 2000, the trend continued to rise, but fluctuates, due to shortages of gas supply. Going by the increasing electricity demand in the country, we can observe a market failure due to large gap between supply and demand of electricity [168].

Power station	**Community**	**Type**	**Capacity**	**Status**	**Year completed**
AES Barge	Egbin	Gas turbine	270 MW	Operational	2001
Afam IV-V Power Station	Afam: Rivers State	Gas turbine	726 MW	Partially Operational	1982 (Afam IV)-2002 (Afam V)
Afam VI Power Station	Afam: Rivers State	Combined cycle gas turbine	624 MW	Operational	2009 (Gas turbines) 2010 (Steam turbines)
Alaoji Power Station	Aba	Combined cycle gas turbine	1074 MW	Under Construction	2013-2015 Abiastate.
Calabar Power Station	Calabar	Gas turbine	561 MW	Under Construction	2014 [8]NDPHC Presentation.
Egbema Power Station	Imo State	Gas turbine	338 MW	Under Construction	2012-2013
Egbin Thermal Power Station	Egbin	Gas-fired steam turbine	1320 MW	Operational	1985-1986
Ibom Power Station	Ikot Abasi	Gas turbine	190 MW	Partially Operational	2009
Ihovbor Power Station	Benin City	Gas turbine	450 MW	Under Construction	2012-2013
Okpai Power Station	Okpai	Combined cycle gas turbine	480 MW	Operational	2005
Olorunsogo Power Station	Olorunsogo	Gas turbine	336 MW	Partially Operational	2007
Olorunsogo II Power Station	Olorunsogo	Combined cycle gas turbine	750 MW	Partially Operational	2012
Omoku Power Station	Omoku	Gas turbine	150 MW	Operational	2005
Omotosho I Power Station	Omotosho	Gas turbine	336 MW	Operational	2005
Omotosho II Power Station	Omotosho	Gas turbine	450 MW	Partially Operational	2012
Sapele Power Station	Sapele	Gas turbine	450 MW	Partially Operational	2012
Ughelli Power Station	Ughelli	Gas turbine	360 MW	Operational	1966-2012

Table 2.3: List of gas power stations in Nigeria [169]

The Nigerian existing gas turbines have a combined estimated generating capacity of 3960 Megawatts (MW) as at 2012, but only 17,113,000Mwh was generated from gas plants at same year, which was 50% of their maximum installed capacity [168] [169]. This is still low considering the low energy mix in the country, as any sudden shock in gas turbine production; the energy supply will drastically be affected. Adding other sources of electricity from renewable energies including hydroelectric, wind, solar and biomass, the overall electricity generation capacity in the country was 6090MW as at 2012[171]. In terms of electricity generation, a total of 27266000Mwh was generated same year, which means 63% of electricity generation was from gas plants and 37% from renewables mainly from hydroelectric [171].

As stated earlier the low performance of the gas turbines in the country was as a result of low supply of natural gas to the plants as most of the gas produced are either being exported outside the country (as indicated in figure 2.11 below) or flared (see figure 2.12 and 2.13 below) [7]. Similarly, most of the oil and gas producers in the country prefer to produce oil than natural gas. The associated natural gas is often flared, thereby polluting the environment and wasting a precious resource that would have been used to improve the electricity supply in the country and even reduce the cost of producing the oil itself. The higher rate of oil production over natural gas is evidenced by the gap between the gas and oil production as presented in figure 2.14 [172] [29].

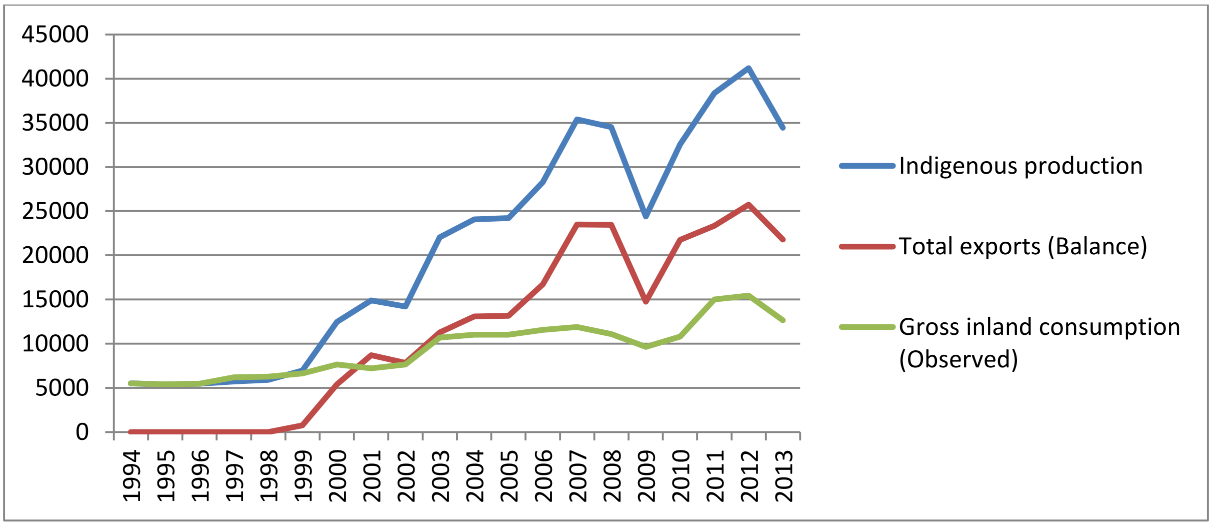


Figure 2:11: Natural Gas Balances in Nigeria in Terajoules [173]

With the few portion of the gas being utilized in the country, figure 2.11 has shown the trend of the gas production, domestic consumption and exports. The gas production (indicated by the blue line) has been increasing exponentially throughout the years except the 2008 decline; this was largely affected by the global economic crisis of the 2008. However, the domestic gas consumption has been relatively flat throughout the years and has been very insignificant. Lack of sufficient gas development infrastructures within the country has led to the low inland gas consumption and high exports of the natural gas. The red line (in figure 2.11) which followed the trend of the gas production indicates the gas exports.

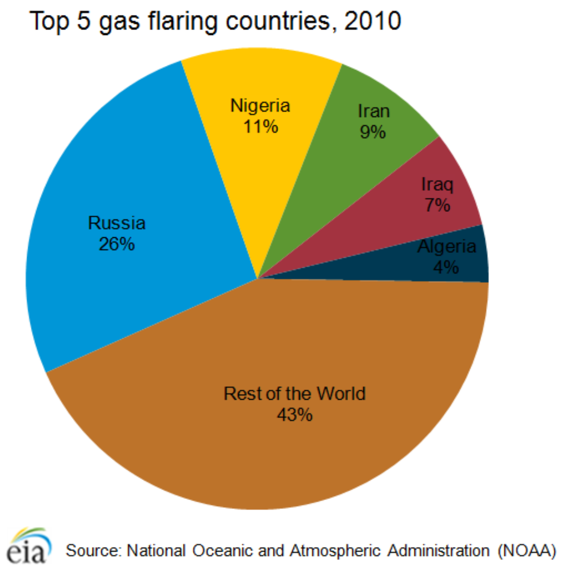


Figure 2:12: Nigerian position in terms of gas flaring

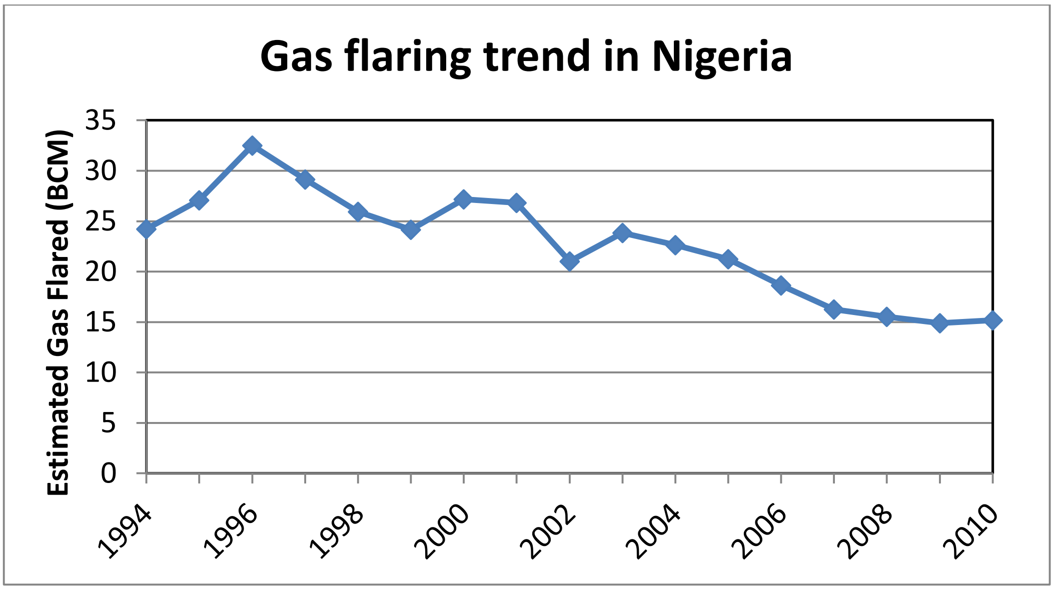


Figure 2:13: Gas flaring trend in Nigeria [11]

Figure 2.12 showed the position of the leading gas flaring nations in the world, where Russia and Nigeria were ranked first and second respectively. Since the concern is on the Nigerian scenario, figure 2.13 shows the historical trend of gas flaring in Nigeria. The figure shows that gas flaring has been fluctuating from 1994 to 2003, but from 2003, the trend continued to decline and remained constant from 2008 up to 2010 at 15 billion cubic metres of natural gas being flared annually, this was the lowest it has ever been. This is an improvement considering the gas production increase in these years (as shown in figure 2.14). In 2010, Nigeria's flared natural gas was worth $1.8 billion [12].

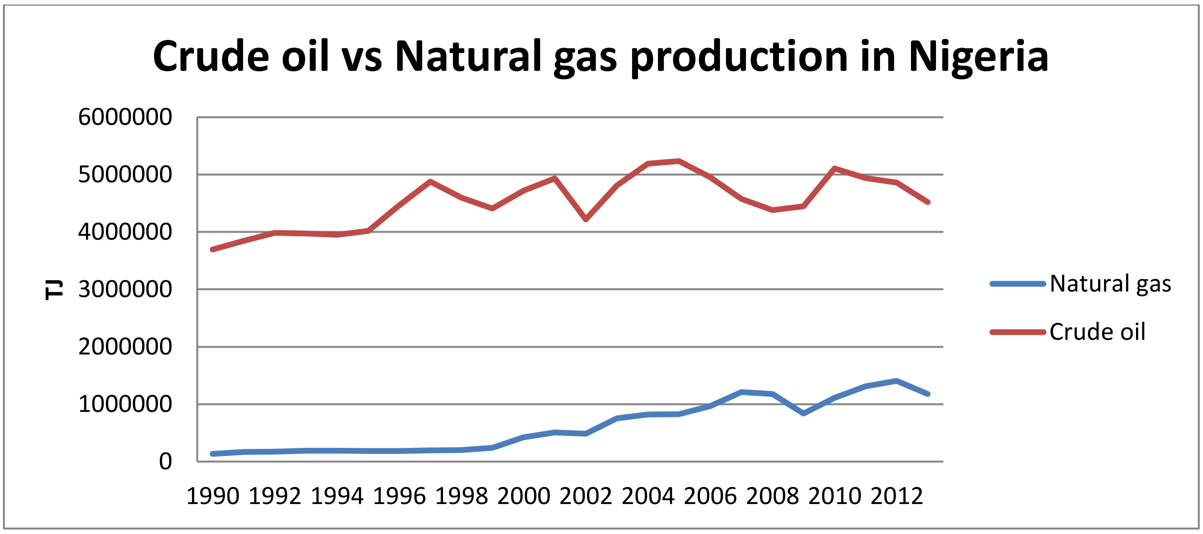


Figure 2:14: Comparison of oil and natural gas production in Nigeria [120]

Figure 2.14 shows the gap between oil production and gas production in Nigeria. Even though, Nigeria has more of gas reserves, it produces more of oil [171]. In order to ensure energy security, the level of gas production needs to be improved. In 2012, only 31% of the gas produced was supplied within the country, despite the fact that transport, residential and public service, agricultural and other non-energy use (including petrochemical feedstock) sectors did not consume any portion from the domestic supply [174].

Natural gas is a potential resource that can be a major energy source in the country if fully developed. Nigeria has 184tcf of high quality proven natural gas reserves as at 2014, which makes it the seventh largest gas reserve in the world. The gas reserves consist of associated and non-associated reserves, at 50:50 ratios. Gas exploration has not been undertaken for long time and there is no existing exploration in the country as at 2014. The current production rate is averagely around 5bcf per day [171]. Going by the current reserves to production ratio, the Nigerian gas has an R/P ratio of 100 years. It is projected that the demand and supply for this gas will explode dramatically up to 2020 as stated in figure 2.15 below [1].

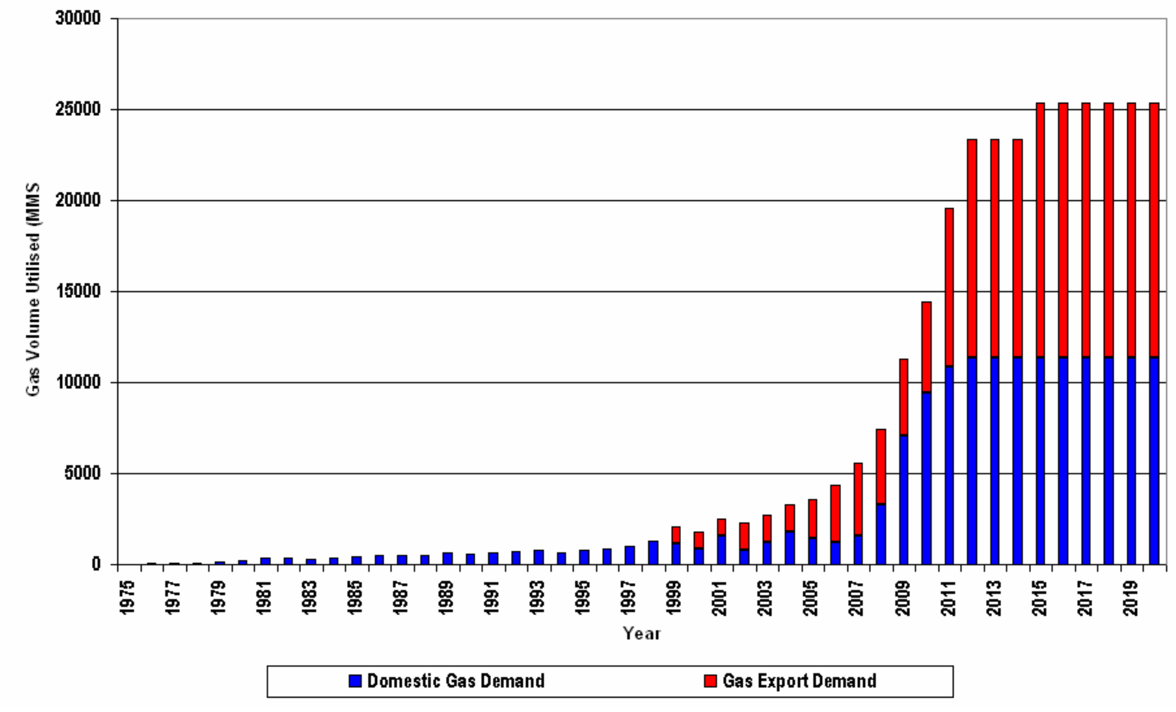


Figure 2:15: Gas demand boom forecast from 1975 to 2020 in Nigeria (mcf) [1]

Figure 2.15 forecast the future pattern of gas demand for export and domestic use, it depicts that from 2011, the domestic gas demand will cap at about12 bcf/d up to 2020, with almost equal proportion with the gas exports demand. It projects much higher gas production in the future. However, this projection was not realistic thus far, as in 2013 the Nigerian gas production was 3.5 bcf/d, this includes the domestic and exports demand. This is far below the projected amount [17]. Therefore, for Nigeria to accommodate this level of increasing gas demand especially domestic demand, it needs to invest more on the gas infrastructure, and hence the development of the Nigerian gas master plan, which provides blue print on how to go about this investment. However, this research will assess the economics of some of these gas development projects, to provide cost and profit framework of the pipeline systems proposed and the subsequent gas development projects respectively, so that it will help in providing the required investment information for quick decision-making and to motivate investors for domestic gas development.

Chapter 3. Economic Analysis of Gas development projects in Nigeria.

3.1. Introduction

This chapter analyses the economic costs and benefits of gas development projects in Nigeria. First, the chapter analysed the costs and benefits of the proposed gas pipeline routes in Nigeria, comparing the NPV, IRR, Payback period, gas delivery and initial investment costs of six different gas pipeline route combination options, with a view to recommend the optimal routes combination. Secondly, the chapter analysed and assessed the economic profitability of the other two gas development projects (GTL and CCGT) using Net Present Value, Internal Rate of Return and Payback Period accounting methods. Every methodology used is followed by relevant assumptions, data, results and discussions at the same time.

3.2. Possible routes options for gas transportation in Nigeria

This research considers the proposed Nigerian gas pipeline route options as contained in the gas master plan, which will be used to transport gas from the Niger Delta area (the Nigerian oil and gas rich region) to major expected gas demand areas within Nigeria. The Nigerian gas master plan proposed gas pipeline systems which will be constructed in a near future, and some possible future extensions. There is a trunk line proposed from South to North, which is an integral part of the near future plans as well as possible future extension plans. The trunk line is the system that will be supplying gas to the future gas pipeline extensions. Similarly, irrespective of the decision among these extensions, the trunk line is integral and is designed to provide a connecting system to the proposed trans-Sahara gas pipeline. Therefore, this trunk line will be considered as the Base Route Option (BRO), and will be assessed independently at first instance. The South-western extensions, which is part of the near future plan will be assessed separately and will be termed South-western Route Option (SRO), and then the future potential extensions will also be assessed separately and will be termed Northern Route Option (NRO). In addition, the BRO will be assessed in combination with SRO, which means all the near future gas pipeline plans together, which are termed BSRO, and then the BRO with NRO separately, which are termed BNRO. Finally, all the three possible options will be assessed together.

Assessment of value addition of these pipelines will be presented as well. The aim is to use economic models to estimate the investment costs of these six options, and then assess their costs and benefits using the indicators specified above. This will help in recommending the most viable route option or combination economically, so as to inform government and other prospective investors when investing in gas pipelines project in the country on the optimal route combination so as to optimise their investments. This will also justify which of the possible combination is optimal to build. In other word, to justify whether the combination of the near future pipeline networks are more optimal and cost effective than the other possible combinations.

The research does not consider costs associated with production, processing and/or purification of the gas. All models are built on the assumption that any volume of gas to be transported via any of the optional pipelines will be composed of the required gas specification suitable for the pipeline. Further geographical illustration of these options are presented below: Their starting pressure is estimated at 60 bar as specified in the plan.

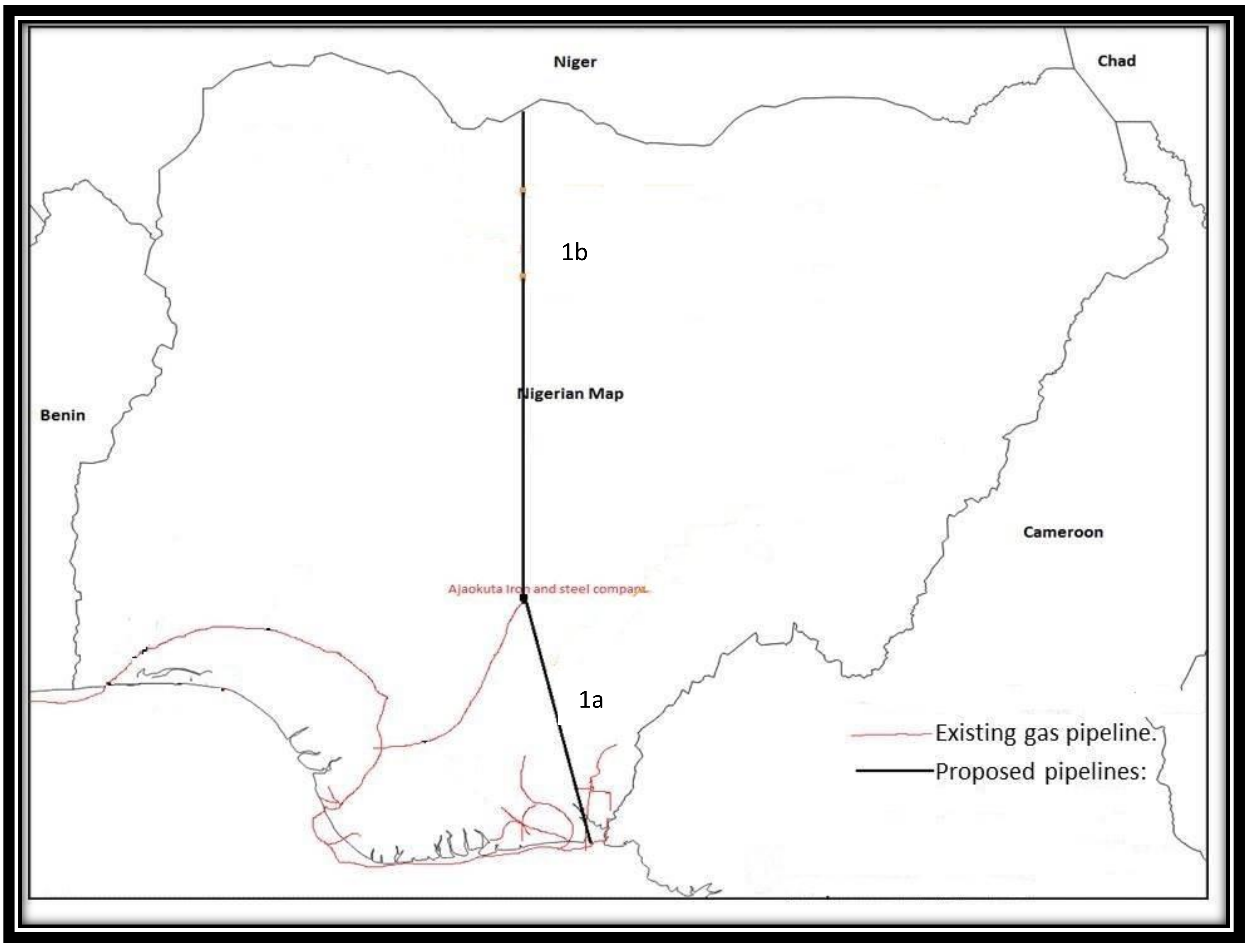


Figure 3:1: Base Route Option (BRO)

Pipeline	Diameter	Length (km)
1. South-North (Trunk Line):		
1a Calabar to Ajaokuta	56”	490
1b Ajaokuta to Kaduna	48”	495

Table 3.1: Specification of the BRO

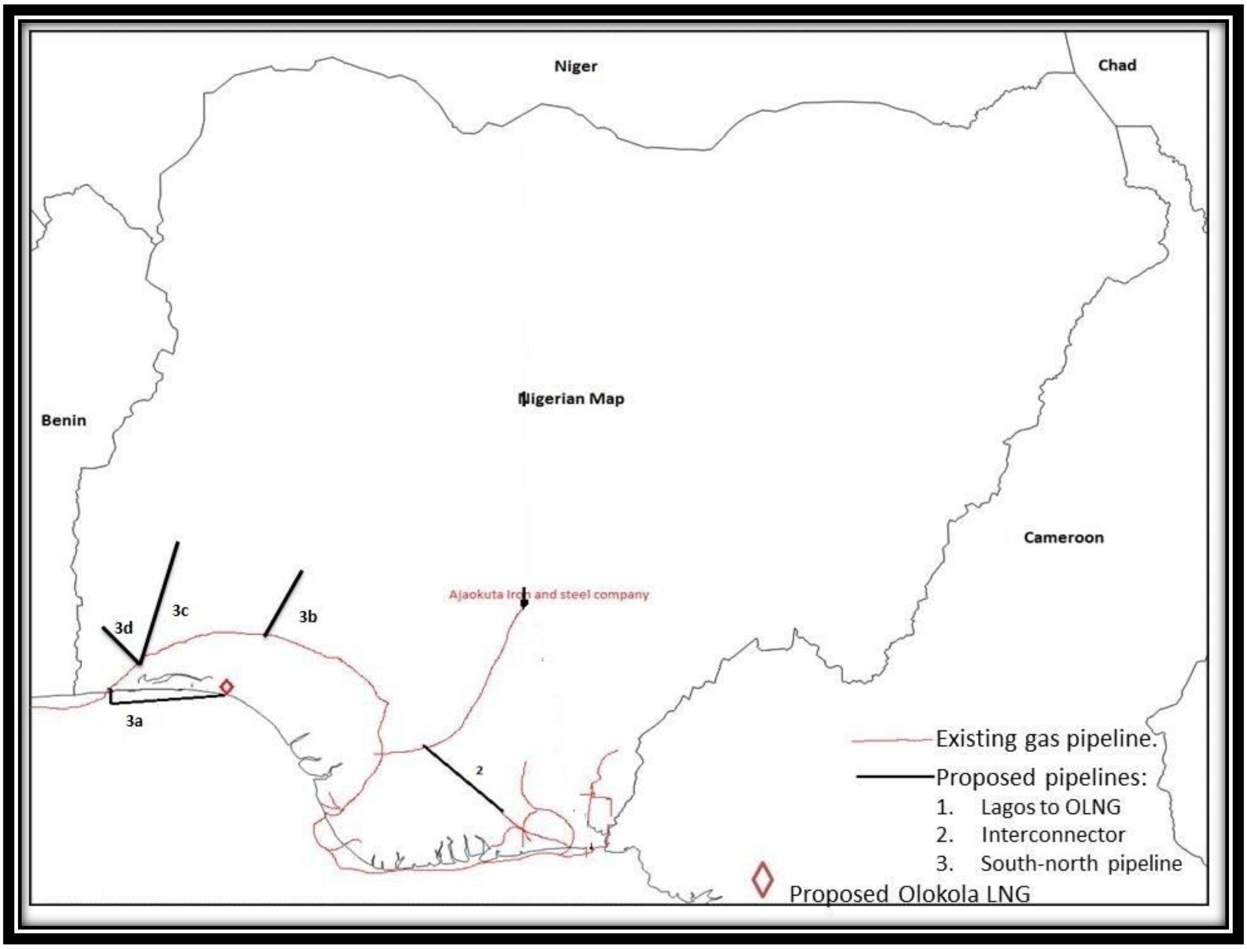


Table 3.2: South-Western Route Option (SRO)

Pipeline	Diameter	Length (km)
2. Interconnector: Obiafu-Oben Node	42”	100
3. Four segments of West-Escravos extensions		
3a: Warri-Shagamu	42“	200
3b: Ore-Ondo-Ekiti	24”	125
3c:Shagamu-Ibadan-Osun-Jebba	24“	321
3d: Shagamu -Papalantro	16“	40

Table 3.3: Specification of SRO

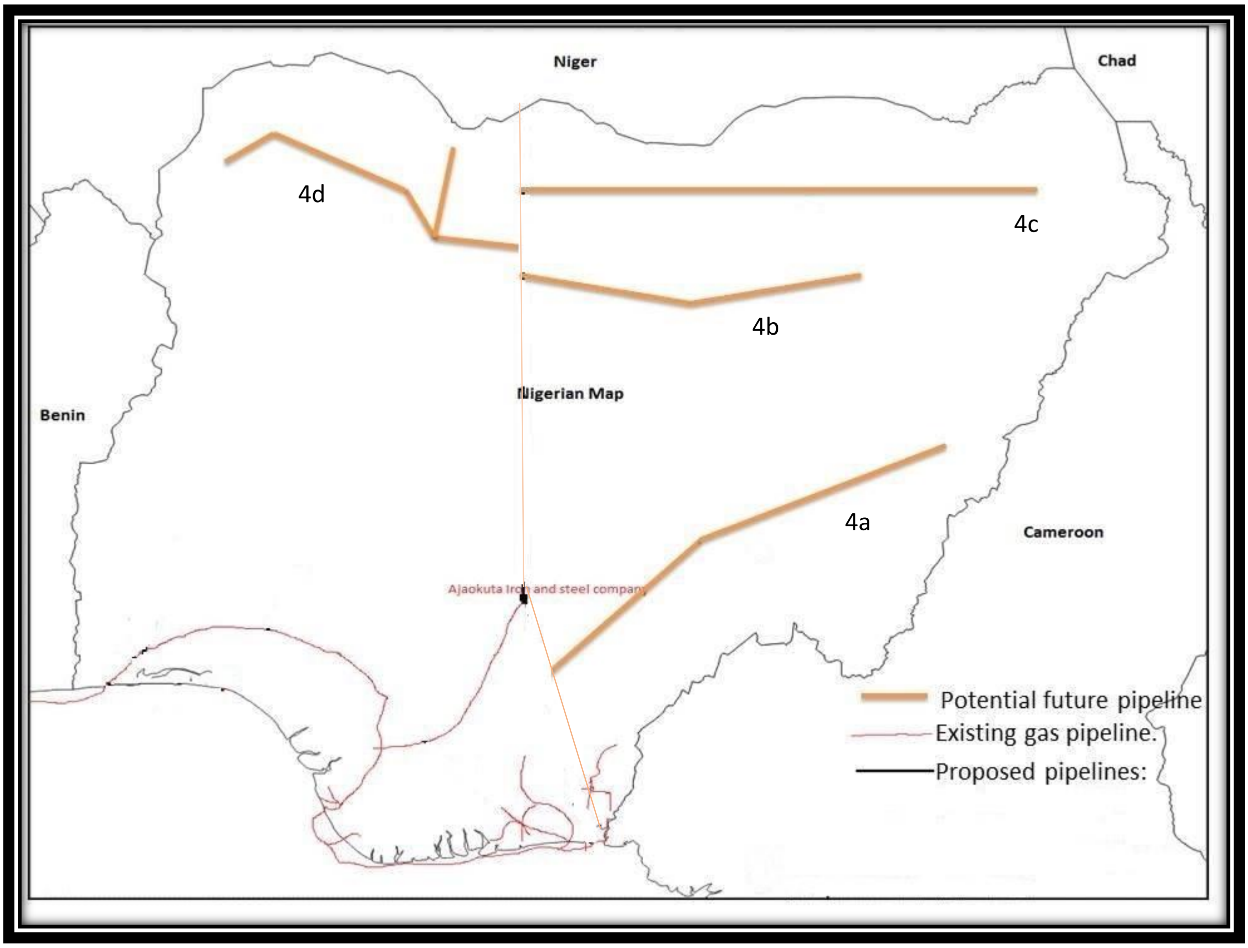


Figure 3:2:Northern Route Option (NRO)

*NRO cannot exist without the BRO, so its business model is established on the assumption that the BRO is already constructed.

Pipeline	Diameter	Length (km)
4. Future potential pipelines:		
4a: Enugu-Makurdi-Yola	24	874.8
4b:Kaduna-Jos-Gombe	24	501.3
4c: Kano-Maiduguri	24	593.2
4d: Zaria-Funtua(then to Katsina)-Gusau-Sokoto-Birnin Kebbi	24	768.3

Table 3.4: Specification of NRO pipelines

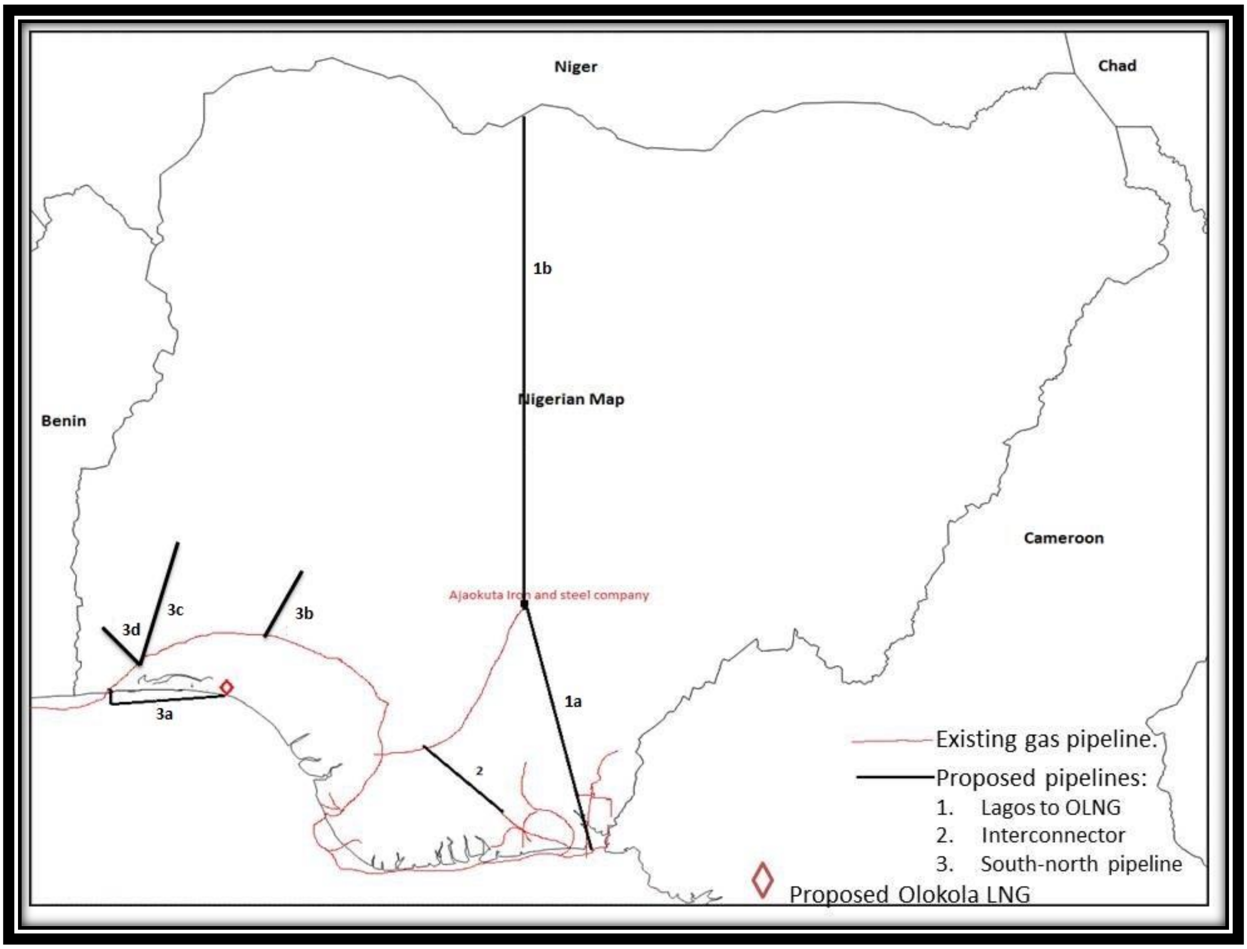


Figure 3:3: Combination of BRO and SRO pipelines (BSRO)

Pipeline	Diameter	Length (km)
1. South-North:		
1a Calabar to Ajaokuta	56”	490
1b Ajaokuta to Kaduna	48”	495
2. Interconnector: Obiafu-Oben Node	42”	100
3. Four segments of West-Escravos extensions		
3a: Warri-Shagamu	42“	200
3b: Ore-Ondo-Ekiti	24”	125
3c:Shagamu-Ibadan-Osun-Jebba	24“	321
3d: Shagamu -Papalantro	16“	40

Table 3.5: Specification of the combination of BRO and SRO pipelines (BSRO) [1]

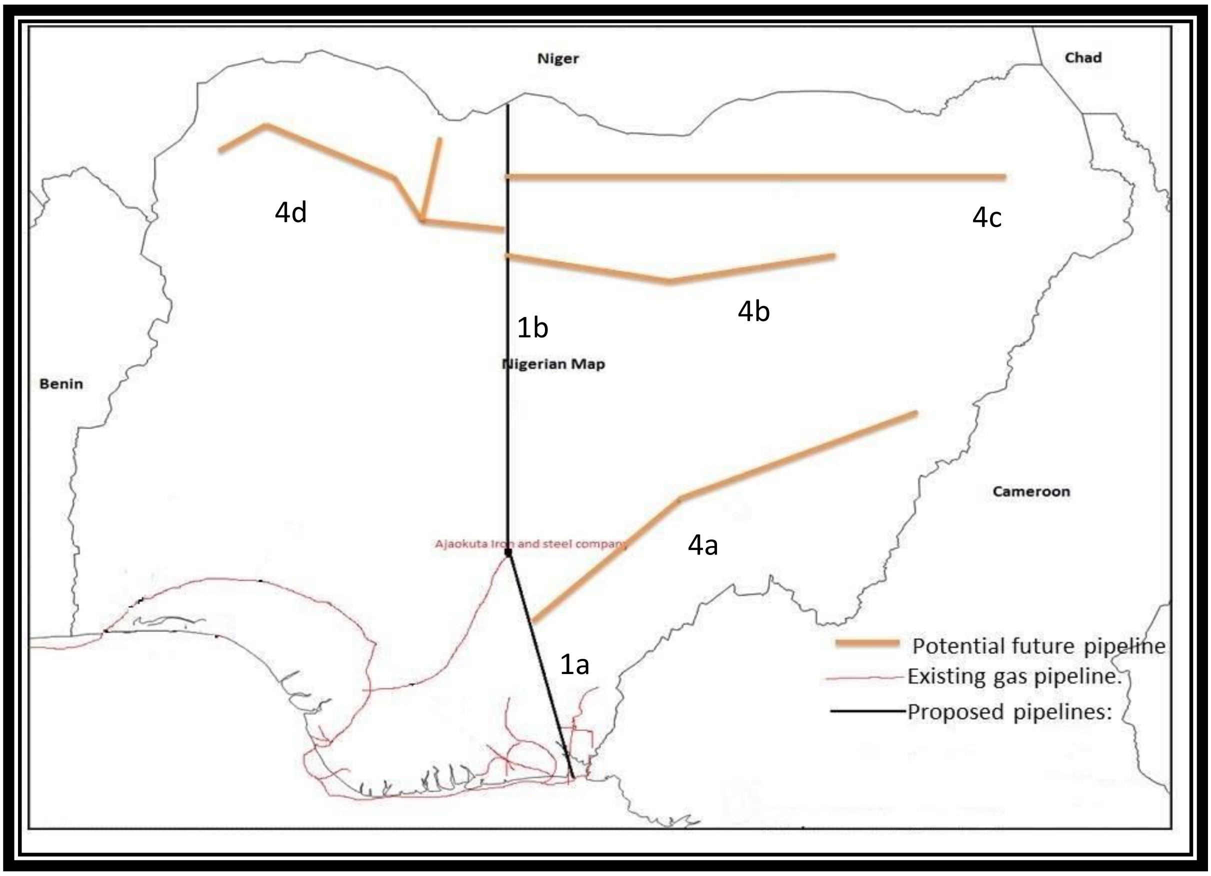


Figure 3:4: Combination of BRO and NRO (BNRO)

Pipeline	Diameter	Length (km)
1. South-North:		
1a. Calabar to Ajaokuta	56	490
1b. Ajaokuta to Kaduna	48	495
4. Future potential pipelines:		
4a: Enugu-Makurdi-Yola	24	874.8
4b:Kaduna-Jos-Gombe	24	501.3
4c: Kano-Maiduguri	24	593.2
4d: Zaria-Funtua(then to Katsina)-Gusau-Sokoto-Birnin Kebbi	24	768.3

Table 3.6: Specification of the combination of BRO and NRO (BNRO)

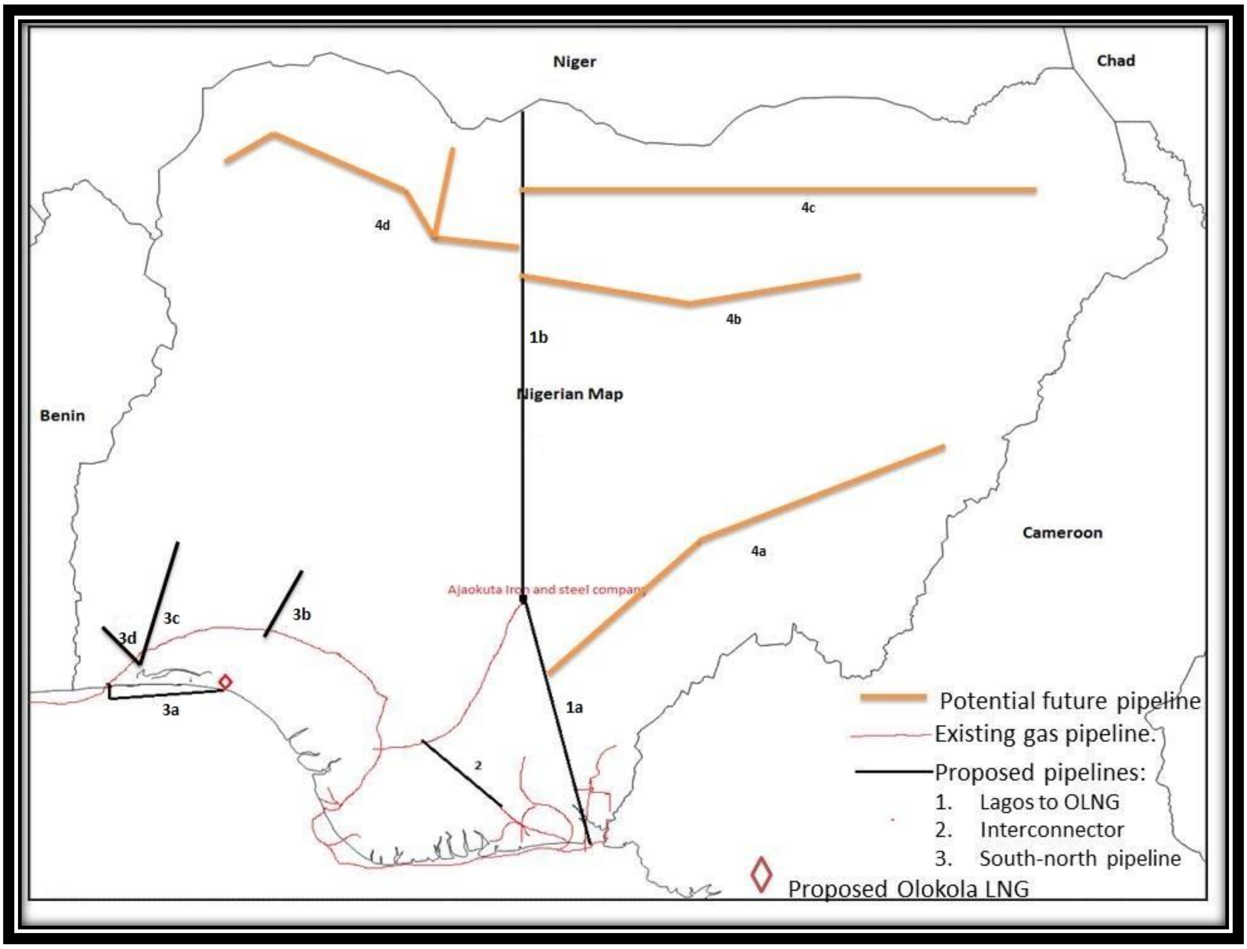


Figure 3:5: Combination of all the possible Pipeline routes

Pipeline	Diameter	Length (km)
1. South-North:		
1a Calabar to Ajaokuta	56”	490
1b Ajaokuta to Kaduna	48”	495
2. Interconnector: Obiafu-Oben Node	42”	100
3. Four segments of West-Escravos extensions		
3a: Warri-Shagamu	42“	200
3b: Ore-Ondo-Ekiti	24”	125
3c:Shagamu-Ibadan-Osun-Jebba	24“	321
3d: Shagamu -Papalantro	16“	40
4. Future potential pipelines:		
4a: Enugu-Makurdi-Yola	24”	874.8
4b:Kaduna-Jos-Gombe	24”	501.3
4c: Kano-Maiduguri	24”	593.2
4d: Zaria-Funtua(then to Katsina)-Gusau-Sokoto-Birnin Kebbi	24”	768.3

Table 3.7: Specification of Combination of all the possible Pipeline routes [1] [23]

3.3 Methodology

This subchapter reports on the economic methodology in assessing the economics of the gas pipelines, and for subsequent assessment of CCGT and GTL project in the country as will be discussed henceforth. To assess the costs and benefits of the six different gas pipeline routes combinations, first the investment cost comprising of gas pipeline material cost, pipe coating and wrapping cost, cost of constructing the compressor stations, and labour cost will be estimated using the models below. The gas delivery and cost of capital of each of the pipelines will be estimated as well as the annual costs and benefits for running the gas pipeline routes using the NPV, IRR and payback period methods. The initial investment cost of these pipelines are estimated using equation 3.1 [175].

$$Initial\ Investment\ costs(IIC) = E(CCP) + E(CCMS) \quad (3.1)$$

Where E (CCP) stands for the expected cost of constructing/laying down the gas pipelines and E (CCMS) is the expected cost of installing compressor stations. Cost of constructing the pipeline consists of the fixed cost of the system including the cost of material and right of way (ROW) if applicable. It consists of the costs of process equipment, supporting facilities, direct/indirect labour etc. The formula for pipeline construction cost is given as follows [175]:

$$E(CCP) = PMC + PCW + LC \quad (3.2)$$

Where PMC is the pipe material cost and PCW is the cost of pipe coating and wrapping and LC stands for the labour cost of installing the pipeline.

To estimate the cost of laying down a pipeline, i.e. E(CCP), we will adopt the model established by Shahi Menon (2005) [175], which suggested that the costs of constructing a pipeline include the costs of pipe materials, pipe coating and fittings, and the cost of labour for installation. These parameters were incorporated in equation 3.2, and are defined as follows:

$$PCW = PMC \times 5\% \quad (3.3)$$

Therefore, the PCW is 5% of the pipe material cost, which is defined in equation 3.4

$$PMC = 0.0246(D - T)TLC \quad (3.4)$$

Where:

D is the diameter (outside) of the pipe in millimetres (mm), L stands for the length of the pipe in km, T stands for the pipe wall thickness in mm and C is the pipe material cost in $/metric ton [99]. Estimating the labour cost during the installation can be difficult depending on the area where the pipe will be laid down and the contractor. It also depends on the length of the pipe and from where the pipes are brought. According to Mohitpour, et al (2003), the labour cost for laying the gas pipeline was estimated to be $316,800 per mile, which is $196,850.39 per kilometre. However, this may vary depending on the location and nature of the environment; the contractors normally study the nature of the work and fix cost for labour.

From historical data and some gas construction figures, a fixed amount is slated for every diameter and distance of the pipeline, which is normally $15, 000 as average labour cost during pipe installation [176]. This is based on the external labour cost of gas pipeline installations as the pipe installation company is expected to be a foreign company (likely from America), and the engineers will be paid based on the international labour cost. For the purpose of this estimation we adopt the following model [175].

$$LC = \$15,000 \times diameter\ (in) \times length\ (miles) \tag{3.5}$$

For the cost of constructing and installing the compressor stations, we still adopt the model established by Shahi Menon (2005) which estimates the compressor cost as $2000 per Horsepower capacity of the compressor. This is corroborated in the work of Yipeng Z. and Zhenhua R. (2014) [177]. Intervals between compressor stations are between 40 and 60 miles (64 and 161km) [178], and the minimal intervals is adopted in order to maintain high pressure in the gas. Therefore, the cost of compressors of a pipeline will be $2000 multiply by number of compressors and then multiply by the Horsepower capacity of the compressors.

$$E(CCMS) = \$2000 * Horsepower * number\ of\ compressors \tag{3.6}$$

The pipeline thickness (t) is derived through the following equation adopted from Shahi Menon (2005).

$$t = \frac{D_O - D_I}{2} \tag{3.7}$$

Where D_O is the diameter outside, and D_I is the diameter inside.

Depreciation and taxation are also accounted. Straight-line depreciation method is used, which is an accounting way of calculating the devaluation of an item at a fixed rate over a long period of time [179]. It is the opposite of declining balance method, where the asset depreciates more in the first year and then depreciates less every other year of its lifetime. Straight Line depreciation divides the total value of the asset by its operational period to derive the annual depreciation amount, which means at the end of the business period (40 years), the book value of the asset will be zero. However, because we will have a salvage value (SV) of the gas pipelines in our analysis, a salvage value will be considered, which is deducted from the value of the pipelines before applying the straight-line depreciation, and is given as follows [180] [181]:

$$SV = IIC * (1 - dr)^{lifetime} \tag{3.8}$$

Where

$$dr = \left(\frac{IIC}{life\ time} / IIC\right) \times 100 \tag{3.9}$$

Where dr is the depreciation rate.

Depreciation relates to taxation, because corporate tax rate is charged against the depreciation value of the asset to arrive at the tax benefit. Usually companies deliberately over depreciate their assets in order to pay less of their taxes [182]. Depreciation is deducted in the cost, thereby reducing the taxable income. Therefore, depreciation tax benefit is the relief or discount of a tax the gas pipeline operator receives for the depreciation of the pipeline, which will be considered as a benefit not a cost [127]. The tax benefit is derived by multiplying the tax rate by the annual depreciation value, which will then be deducted from the total tax payment to arrive at total tax payable [183]. Since the proposed gas pipelines are within Nigerian territory, the complexity of using different corporate tax rates will not arise.

Annual operating and maintenance costs (O and M) have to be considered even though the pipelines are not in operation, but an assumption can be made based on the existing literature, and adopt a fixed percentage of the investment cost (equation 3.1) to be the annual O and M costs. However, since the Nigerian pipeline will connect through the onshore land of the Nigerian territory, 2% of the costs of constructing the pipeline will be assumed to be the O and M costs annually [184] [185] [186]. O and M costs consist of costs of labour, supervision, energy, telecommunication, miscellaneous etc. The 2% was considered as a result of including the operation costs, otherwise the cost of maintaining the pipeline would have been below the 2% of the initial investment cost [175].

The capital structure of the gas pipelines investment will be 60% debt and 40% equity, and this is in line with the capital structure of the proposed domestic gas pipelines [23], and it is the capital structure of an average oil and gas listed companies in the country, with particular reference to Nigerian Oando plc [187]. However, the Nigerian government is recommended to own substantive part of the business [23]. Similar capital structure will be applied for the GTL project as there is no matured stock market for the GTL industry in the country. The capital structure of the CCGT plant will be 70% debt and 30% equity, and this is based on the capital structure of the Nigerian MYTO model as used by the Nigerian Electricity Regulatory Commission in identifying the cost of capital in the Nigerian power sector [188] [189].

Therefore, the cost of capital will be accounted through the cost of equity and cost of debt for all the investments appraisal. The cost of equity will be accounted using the Capital Asset Pricing Model (CAPM), and the after tax cost of debt will be used. To account for both cost of debt and cost of equity, the Weighted Average Cost of Capital (WACC) will be applied, and from which all the cash flows will be discounted [190] [191]. The WACC is used because it accounts for both costs of the two sources of capital, which are debt and equity [190] [191].

$$WACC = \frac{E}{C} * k_e + \frac{D}{C} * k_d\,(1 - TR) \tag{3.10}$$

Where E is the total value of the equity, C is the total value of the capital, D is the total value of the debt, k_e is the cost of equity, k_d is the cost of debt and TR is the tax rate, which is 30 percent in Nigeria [192]. Starting with the cost of debt, we will use the after tax cost of debt going by [191], which is:

$$k_d = r * (1 - TR) \tag{3.11}$$

Where, r is the prime lending rate of the Nigerian commercial bank, which is 16.90% as at March 2015 [193], and which has been the average prime lending rate for a decade [194]. This rate is used based on the assumption that the debt to fund these projects will be provided by a bank within Nigeria. The formula for cost of equity using CAPM model is stated in equation 3.12 [181].

$$k_e = r_f + \beta(r_m - r_f) \tag{3.12}$$

Where, k_e is the cost of equity, r_f is the risk free interest rate, r_m is the expected market portfolio return, and the difference between r_m and r_f is the equity risk premium (ERP), which measures the additional compensation to the investor for taking the risk of investing in a riskier business, and β accounts for responsiveness of the business to the average stock market change, hence how risky is the business. r_f is usually the interest rate of a relatively risk free investment, which the investor may wish to invest in, it is usually a government bond, which have higher level of security, and hence low risk. The higher the risk, the higher the expected interest rate [195]. The yield on the Nigerian government bond is used as the risk free interest rate. According to the trending economics, the yield on the Nigerian government bonds has averaged around 13.04 percent from 2007 to 2015. The return on the bonds changes frequently, and as at July 2015, the rate was 14.81 percent. The highest it has ever being was 17.30 percent in February 2015, and lowest it has been was 6.04 percent in March 2010. Due to these erratic fluctuation of the return on the bonds, the average return on the bonds from 2007 to 2015 will be used, which is 13.04 percent [196] [197].

The ERP as mentioned is the difference between the rate of return on a risk free investment and the expected market rate of return of the investment [195].The Nigerian estimated average ERP as contained in Moody's report and the Stalwart report as at January 2015 was 11.15 percent, so we will use the latest ERP for this analysis, which is 11.15 percent [198] [199]. Therefore, the expected market portfolio return can be assumed to be 11.15 percent plus 13.04 percent risk free rate, and this gives 24.19 percent as the expected market portfolio return. This will be the maximum return the investor will expect for investing in the riskier investment, and it will be the r_m in equation 3.12. The Risk Premium is higher compare to some other countries, and this may suit this kind of business due to some country risk factors associated with it, which includes the potentials of gas pipeline vandalism, which have been frequent recently causing loss of gas and extra cost of repair. There is also security risks associated with kidnapping and killings of oil and gas personnel by the militants. There are political and economic risks in the country, associated with changes of government and economic policies.

Now the next variable to identify is the β (Beta). Beta measures the reaction of a price of a share in a company to the change in the overall stock market. A Beta lower than 1 shows that the stock value is less volatile than the stock market, and if it is higher than 1, it shows that it is more volatile than the market. The formula for the Beta is given as the covariance between the unlevered return on the business (R_j) and that of the market (R_m), divided by the variance of the latter, which is presented as follows [195].

$$\beta_j = \frac{Cov(R_j,R_m)}{Var(R_m)} \tag{3.13}$$

Because there is no available data for Nigerian stock market for domestic gas pipeline investment, as there are no listed gas pipeline companies in the country, the average $Beta$ of seven listed oil and gas companies (BOC Gases Nigeria PLC, Conoil PLC, Eterna Plc, Forte Oil Plc, Mobil Oil Nigeria Plc, MRS Oil Nigeria Plc, Oando Plc) in the country is used as the proxy Beta for the investments, which was 0.86 as at July 2015 [200] [187] [201, 202]. Similar Beta will be used for the GTL project as there are no matured GTL industry in the country. This Beta is higher than what Usman (2006) assumed for Nigerian GTL project, where he adopted Beta of some major oil and gas companies in US in 2006, which was 0.77 [135].

For the investment in gas to power, a Beta used by the Nigerian Electricity Regulatory Commission for the Nigerian Electricity Supply Industry (NSEI) is applied as the Beta for the CCGT project, which is 0.50 [188]. "The Commission has selected a beta of 0.5 in the construction of its WACC. This is based on the assumption that the level of risk in the regulated Nigerian Electricity Supply Industry (NESI) will have a lower risk compare to the country's stock market risk. It is understood that the electricity sector is an infant industry where statistically significant Betas would be difficult to derive. Beta reflects the riskiness of an asset relative to the market as a whole (usually represented by the stock market). Equity betas will reflect the financial risks carried by shareholders, which is in turn influenced by the level of gearing since high levels of debt increases the risk to shareholders" [188].

Since debt is included in the capital structure, the amortization cost will be accounted using the following formula [201]

$$Annual\ amortization\ cost = \frac{Debt \times interst\ rate}{1-\left(\frac{1}{(1+interest\ rate)}\right)^{N}} \tag{3.14}$$

Where, N is the total number of period. To calculate the certified volume of gas/capacity of a pipeline (where applicable), the Weymouth formula is used as provided in pipeline rules of thumb [203], which assumed that the optimum number of compressors are in place to achieve the desired pressure level of the gas at the destination using the lowest compressor station intervals as stated earlier, and is presented in equation 3.15:

$$Q = \frac{(871)(d^{\frac{8}{3}})\sqrt{P_1^2-P_2^2}}{\sqrt{L}} \tag{3.15}$$

Where:

Q= Cubic feet of gas per 24 hours

d= pipeline inside diameter in inches

P_1= Psi (abs) at starting point

P_2=Psi (abs) at ending point

L = Length of the pipeline in miles

For the annual gas delivery of the gas pipeline, equation 3.16 applied the availability rate and the annual gas delivery capacity to arrive at the actual gas delivery of the pipeline. [127] [203].

$$\sum_{n=1}^{N} Availability\ factor \times annual\ pipeline\ capacity\ (Mcf) \qquad (3.16)$$

The Nigerian regulated gas transportation cost of \$0.80/Mcf is used [204] [205] [206]. This is almost similar to the estimated average cost of gas transportation for the five segments of the Nord stream (Gryazovets-Vyborg, Nord-Stream offshore, Opal, and Nel), which was estimated to have an average levelised cost of gas transportation of \$0.81/Mcf (\$28.7/thousand cubic metres) [127]. The regulated tariff in the country did not account for distance, and as such it is highly recommended to review this tariff and account for distance. For the availability/utilization rate, 80% is applied based on the existing pipelines average availability rate in the country, and this accounts for the number of days that the pipeline will be operational[106] [102] [103] [207]. Other non-operational period could be due to fall or stop in supply/patronage, or for holidays, or for maintenance purposes or as a result of vandalism etc

The Net Present Value (NPV) accounts for the difference between the initial investment cost and the present values of all the future cash inflows and cash outflows. Therefore, NPV is the difference between the present value of the future net cash flows and the initial investment cost. For the Internal Rate of Return (IRR), it is the maximum allowable rate of return on the investment, it is the discount rate that brings the business to breakeven, where NPV equals to zero. It is derived by trying so many discount rates, and the discount rate that makes the NPV zero is the IRR. Payback period is the number of years that the investor will have to wait to get back his/her initial investment [195].

The net present value and the IRR will be derived from these cash flows. The Net Present Value formula is presented as follows:

$$NPV = -C_0 + \frac{C_1}{1+r} + \frac{C_2}{(1+r)^2} \dots \dots \dots \dots \frac{C_T}{(1+r)^T} \quad (3.17)$$

Where, C_0 is the initial investment cost, Cs are the net cash flows of respective periods, r is the discount rate, and T is the end period. IRR is the discount rate at which the NPV equals to zero. The discounted payback period is derived by dividing the absolute value of the last negative cumulative discounted cash flow by the discounted cash flow value in the following year and then adding the period of the last negative cumulative discounted cash flow, this is presented in equation 3.18 below [183].

$$Discounted\ payback\ Period = A + \frac{B}{C} \quad (3.18)$$

Where A is the period where last negative cumulative discounted cash flow was recorded, B is the absolute value of the last negative cumulative discounted cash flow at period A, and C is the discounted cash flow value after the period A.

Using all the above costs and benefits inputs, an annual cash flow of these investments will be derived and discounted to arrive at the net present value, IRR and Payback period, which will be used for comparison. Value addition assessment will follow, which consider the coverage, potential of meeting future demand growth, supply potentials etc.

3.3.1 Costs and Benefits of the Combination of BSRO Pipelines (Near Future Plans)

The step by step analysis of the business option that combines the BRO and SRO will be presented. This combination is what represents the intended near future gas pipeline plan. Other options will follow similar step by step analysis, and their IIC compositions as well as their accounting estimation results will be presented.

Now, we will present step by step analysis of the combination of the BRO and SRO, which is abbreviated as BSRO. The equation for estimating initial investment costs (IIC) is already presented in equation 3.1:

First, we need to find the pipeline thickness (t), which is derived as follows following equation 3. 7. For the BSRO's 3a segment, which has 42 inch diameter, the following wall thickness is calculated, which will be used for the entire analysis, as thickness for other pipelines will be the same.

$$t_{BSRO_{1a}} \frac{42in-41in}{2} = 0.5in\ (12.7mm) \tag{3.19}$$

Equation 3.19 calculated the wall thickness of the 3a sub-segment of the BSRO pipelines network (Warri-Shagamu). We will adopt 0.5 inches as wall thickness on all other pipelines. We will also use the pipe material cost of $800 per tonne as sourced from Shahi Menon (2005), Mohitpour et al (2003) and Tianjin Yuheng Steel Co., Ltd. [176] [208] [175]. The PMC of the three segments and sub-segments of the BSRO are presented in table 3.8.

Pipeline	Diameter	Length (km)	Pipeline Thickness (mm)	Pipe material cost ($/metric ton)	PMC ($)
1. South-North:					
1a. Calabar to Ajaokuta	56	490	12.7	800	5,302,892.11
1b Ajaokuta to Kaduna	48	495	12.7	800	4,367,256.70
2. Interconnector: Obiafu-Oben Node	42	100	12.7	800	732,312.48
3. Four segments of West- Escravos extensions					
3a: Warri-Shagamu (offshore)	42	200	12.7	800	1,464,624.96
3b: Ore-Ondo-Ekiti	24	125	12.7	800	353,034.6
3c:Shagamu-Ibadan-Osun-Jebba	24	321	12.7	800	906,592.85
3d: Shagamu -Papalantro	16	40	12.7	800	32,991.552
Total					**13,159,705.25**

Table 3.8: Pipeline Material Cost of BSRO pipelines

Table 3.8 shows that the estimated material cost for the BSRO pipelines are approximately $13 million. Going by equation 3.5, the labour cost of installing the BSRO pipelines are estimated in table 3.9 below.

Pipeline	Diameter	Length (MILES)	Labour cost ($15,000)	Labour cost (subtotal $)
1. South-North:				
1a Calabar to Ajaokuta	56	304.486	15000	255,768,240
1b Ajaokuta to Kaduna	48	307.593	15000	221,466,960
2. Interconnector: Obiafu-Oben Node	42	62.14	15000	39,148,200
3a: Warri-Shagamu (offshore)*	42	124.28	15000	228,625,488
3b: Ore-Ondo-Ekiti	24	77.675	15000	27,963,000
3c:Shagamu-Ibadan-Osun-Jebba	24	199.4694	15000	71,808,984
3d: Shagamu -Papalantro	16	24.856	15000	5,965,440
Total				**850,746,312.00**

Table 3.9: Cost of labour for constructing BSRO pipelines

*The offshore gas pipeline labour cost is assumed to be 192% higher than the onshore gas pipelines [90]

PCW of the BSRO pipelines will then be 5% of the total in table 3.7, which will be $657,985.30. Therefore, $E(CCP)_{BSRO}$ will then be the summation of PMC, PCW and LC, as presented as follows:

$$E(CCP)_{BSRO} = \$13,159,705.25 + \$657,985.30 + \$850,746,312.00 = \$864,564,002.52 \quad (3.20)$$

Reference to equation 3.6, the cost of compressor stations of the BSRO pipelines are estimated in table 3.10. Due to very low distance of the fourth segment of the West-Escravos extension (3d segment), a compressor capacity of 2000 Horsepower (HP) is used, while 5000HP capacity is used for other segments. The costs of compressor capacity is used as $2000 per HP, which is all-inclusive costs, and include "material and equipment cost and the labour cost for installing the compressor equipment, piping, valves, instrumentation, and controls within the compressor stations" [209] [175]. The calculation is shown in table 3.9 below:

Pipeline	Diameter	Length (km)	Compressors (At each 64 km) Compressors (At each 64 km)	Horsepower	Cost of compressor ($2000*HP*num-ber of compressors) ($)
1. South-North:					
1a Calabar to Ajaokuta	56"	490	8	5000	80,000,000.00
1b Ajaokuta to Kaduna	48"	495	8	5000	80,000,000.00
2. Interconnector: Obiafu-Oben Node	42"	100	2	5000	20,000,000.00
3. Four segments of West-Escravos extensions					
3a: Warri-Shagamu (offshore)	42"	200	3	5000	30,000,000.00
3b: Ore-Ondo-Ekiti	24"	125	2	5000	20,000,000.00
3c:Shagamu-Ibadan-Osun-Jebba	24"	321	5	5000	50,000,000.00
3d: Shagamu - Papalantro	16"	40	1	2000	4,000,000.00
Total Compressor investment cost					**284,000,000.00**

Table 3.10: cost of constructing compressor stations E(CCMS) for BSRO pipelines

The total cost of compressor stations for the BSRO pipelines is $284 million. Reference to equation 3.1, the initial investment cost for the BSRO pipelines can be derived as follows:

$$IIC_{BSRO} = \$864{,}564{,}002.52 + \$284{,}000{,}000 = \$1{,}148{,}564{,}002.52 \quad (3.21)$$

Where, IIC is the estimated initial investment cost. Now to calculate the annual depreciation of the pipelines, a straight-line depreciation method is applied. The depreciation rate equation is given in equation 3.9 [210]:

$$dr_{BSRO} = \frac{\$1{,}148{,}564{,}002.52}{40} / \$1{,}148{,}564{,}002.52 = 2.5\% \ annually \quad (3.22)$$

Where, dr_{BSRO} is the depreciation rate for the BSRO pipelines. The result (2.5%) is the rate at which the value of the BSRO pipelines will depreciate annually. However, the pipelines are expected to have a salvage value (SV) at the end of its operation period. Salvage value is the residual value of the pipeline after depreciations, and it is calculated going by equation 3.8. The SV of the BSRO pipelines are given in equation 3.23.

$$SV_{BSRO} = \$1{,}148{,}564{,}002.52 * (1 - 0.025)^{40} = \$\ 417{,}195{,}705.00 \qquad (3.23)$$

That means the residual value of the BSRO pipelines will be $417 million after forty years of operation. Therefore, the total of $731,368,297.52 (the net value of the pipeline after salvage value is deducted) is going to be depreciated over the period of forty years using the SLD method, which gives $18,284,207.44 as the annual depreciation figure for the BSRO pipelines.

The annual tax benefit of BSRO pipelines is derived by multiplying the value of the annual depreciation by the tax rate. Adopting the corporation tax rate in Nigeria of 30% [211], the annual tax benefit will be $5,485,262.23.

For the annual operation and maintenance costs of the BSRO pipelines, which includes the maintenance of the compressor stations, we adopt 2% of the IIC value [184] [185] [186], which is $ 22,971,280.05 per annum. This figure is close to what Shahi (2005) and Francesco 2011 estimated to be the O and M cost of a pipeline [87] [95].

The O and M cost of a pipeline includes also the fuel costs for compressor stations, electric power, costs of equipment services and repair, pipe maintenance, pipe patrol, communication costs, meter stations maintenance, administrative and payroll. This is also expected to be low due to the low labour cost in Nigeria. There is no formal labour cost index in Nigeria. However, there is a minimum wage of $120 per month in the public sector. This is less than US dollar per hour. When compare with the USA's and UK's average minimum wages of $7.70 and £6.19 per hour respectively, we can expect lower labour cost in Nigeria than in USA and UK [212] [213].

The next figure is for the volume of gas to be transported through the BSRO pipelines. For the flow of gas in the pipelines, we will use an average ^{0}F 86 (30^{0}C) average annual temperature in Nigeria [214], and pressure of 60 bar at the starting point [1], with expected drop of pressure of 3.245 bar/100km (0.03245bar/km) provided the adequate number of compressors are provided based on our estimate of compressor intervals going by [215], [203] and [215].

Reference to equation 3.14, table 3.11 reports on the estimated gas capacity/volume of the segments of BSRO pipelines:

Pipeline	Diameter	Length (km)	Capacity mcm/yr
1. South-North:			
1a Calabar to Ajaokuta	56	490	22110.54
1b Ajaokuta to Kaduna	48	495	(14721.33)*
2. Interconnector: Obiafu-Oben Node	42	100	4906.73
3. Four segments of West-Escravos extensions			
3a: Warri-Shagamu (offshore)	42	200	6844.68
3b: Ore-Ondo-Ekiti	24	125	1229.30
3c:Shagamu-Ibadan-Osun-Jebba	24	321	1916.12
3d: Shagamu -Papalantro	16	40	238.60
*This figure is not added as it was already counted in 1a figure.			**37245.97**

Table 3.11: Gas Capacity for BSRO pipelines

The BSRO pipelines have a certified operating capacity of 37.24 bcm per year. "Certificated capacity represents an average level of service that can be maintained over an extended period of time, and not the maximum throughput capability of a system or segment on any given day" [207].

$$Cummulative\ gas\ volume\ in\ Mcf = \sum_{n=1}^{N}((37.24597\ \ 10^9\ \mathrm{m}^3\ \times 35.3146667) \times 0.80/1000) = 1{,}052{,}263{,}213.17\ \mathrm{Mcf} \qquad (3.\ 24)$$

Where, 35.3146667 is the conversion factor from cubic metres to cubic feet. Therefore, around 1.1 billion Mcf of gas will be transported along the gas pipelines annually.

The cost of capital will be accounted using the WACC, and from which the net cash flows will be discounted. We will first use CAPM as described in equation 3.12 to calculate the cost of equity of these gas pipelines [190] [191].

As earlier established, a Beta of 0.86 will be used for the gas pipelines, a risk free rate of 13.04%, and expected market portfolio return of 24.19% will be applied. For this project, and with reference to equation 3.12, the cost of equity (k_e) will be as follows:

$$k_e = 0.1304 + \ 0.86(0.2419 - 0.1304) = 0.2263(\ 22.63\%) \qquad (3.25)$$

The unweighted cost of equity is 22.63% for this project, this tells potential investors of the opportunity cost of capital of their current or intended investment elsewhere. The cost of debt for the gas pipelines is presented in equation 3.26 with reference to equation 3.11.

$$k_d = 0.169 * (1 - 0.30) = 11.83\% \qquad (3.26)$$

Therefore, with reference to equation 3.10, the weighted average cost of debt and equity for the gas pipeline investments will be:

$$WACC = (0.40 * 0.2263) + (0.60 * 0.1183) = \ 0.1615(\ 16.15\%) \qquad (3.27)$$

The WACC of the gas pipeline investments is 16.15% and will be used as the discount rate to account for the cost of capital and time value of money [195]. This will be similar to that of the GTL project as similar Beta, risk free rate, risk premium, interest rate and capital structure is used as already discussed under methodology. The amortization cost will then be, with reference to equation 3.14:

$$Annual\ amortization\ cost = \frac{\$689{,}138{,}401.51 \times 0.169}{1-\left(\frac{1}{(1+0.169)}\right)^{40}} = \$116{,}690{,}570.44 \qquad (3.28)$$

Approximately $117 million is the annual amortization cost for the BSRO pipelines. Table 3.12 below reports about the specific costs and benefits elements of the BSRO pipelines:

BSRO Pipeline system	Item
Capital cost ($)	1,148,564,002.52
Equity ($)	459,425,601.01
Debt ($)	689,138,401.51
Interest rate (prime lending rate)	16.90%
Cost of debt (after tax)	11.83%
Beta	0.86
Free risk rate	13.04%
Equity risk premium	11.15%
Market Portfolio Return	24.19%
Cost of equity (CAPM)	22.63%
WACC	16.15%
Amortization cost ($)	116,690,570.44
Depreciation rate	2.5%
Salvage Value ($)	417,195,705.00
Depreciating Value ($)	731,368,297.51
Annual Depreciation	18,284,207.44
Tax Rate	30%
Annual O and M cost	22,971,280.05
Annual Gas delivery (bcm)	37.25
Annual Gas delivery in Mcf	1,315,329,027.25
Availability factor (days of operation/yr)	80%
Actual Gas delivery (Mcf)	1,052,263,221.80
Transportation cost of Natural Gas $/Mcf	0.80
Annual Revenue ($)	841,810,577.44
Net Annual Revenue ($)	818,839,297.39
Gross tax payments ($)	245,651,789.22
Tax benefit from depreciation ($)	5,485,262.23
Tax Payable ($)	240,166,526.99
Annual Cash Flow ($)	578,672,770.40
Additional cash flow in final year	
Salvage value ($)	417,195,705.00
Tax on selling at salvage value ($)	125,158,711.50
Net Gain ($)	292,036,993.50

Table 3.12: Cost and Benefits of the BSRO pipelines

Table 3.12 represents summary of all the costs and benefits elements mentioned earlier. The table shows that $0.80 is charged for transporting each thousand cubic feet of natural gas along the pipelines as earlier established. It also showed that at the end year of the business, there will be additional cash flow as a result of the SV of the pipelines. The table shows that the BSRO pipelines have certified gas delivery capacity of 1.5 billion Mcf per year with availability factor of 80%. The annual O and M was estimated at $23 million, and after tax net cash flow of around $812 million was derived, which is used as the fixed annual cash flow for the duration of the business span, and then discounted in the NPV calculations as shown in table 3.13 below.

Year	Cash flow	Discount Factor	Discounted Cash Flow	Cumulative DCF
0	$ -1,148,564,002.52	1	$ -1,148,564,002.52	$ -1,148,564,002.52
1	$ 578,672,770.40	0.860958626	$ 498,213,313.18	$ -650,350,689.34
2	$ 578,672,770.40	0.741249755	$ 428,941,049.46	$ -221,409,639.88
3	$ 578,672,770.40	0.638185371	$ 369,300,496.48	$ 147,890,856.60
4	$ 578,672,770.40	0.5494512	$ 317,952,447.94	$ 465,843,304.54
5	$ 578,672,770.40	0.47305475	$ 273,743,902.64	$ 739,587,207.18
6	$ 578,672,770.40	0.407280567	$ 235,682,174.23	$ 975,269,381.42
7	$ 578,672,770.40	0.350651718	$ 202,912,600.85	$ 1,178,181,982.26
8	$ 578,672,770.40	0.301896621	$ 174,699,353.98	$ 1,352,881,336.24
9	$ 578,672,770.40	0.2599205	$ 150,408,915.72	$ 1,503,290,251.96
10	$ 578,672,770.40	0.223780796	$ 129,495,853.38	$ 1,632,786,105.35
11	$ 578,672,770.40	0.192666007	$ 111,490,571.97	$ 1,744,276,677.32
12	$ 578,672,770.40	0.165877461	$ 95,988,769.63	$ 1,840,265,446.95
13	$ 578,672,770.40	0.14281363	$ 82,642,359.19	$ 1,922,907,806.15
14	$ 578,672,770.40	0.122956627	$ 71,151,652.00	$ 1,994,059,458.15
15	$ 578,672,770.40	0.105860569	$ 61,258,628.53	$ 2,055,318,086.67
16	$ 578,672,770.40	0.09114157	$ 52,741,144.63	$ 2,108,059,231.31
17	$ 578,672,770.40	0.078469121	$ 45,407,943.41	$ 2,153,467,174.71
18	$ 578,672,770.40	0.067558666	$ 39,094,360.55	$ 2,192,561,535.27
19	$ 578,672,770.40	0.058165216	$ 33,658,626.94	$ 2,226,220,162.21
20	$ 578,672,770.40	0.050077845	$ 28,978,685.19	$ 2,255,198,847.40
21	$ 578,672,770.40	0.043114952	$ 24,949,448.98	$ 2,280,148,296.38
22	$ 578,672,770.40	0.03712019	$ 21,480,443.31	$ 2,301,628,739.69
23	$ 578,672,770.40	0.031958948	$ 18,493,772.95	$ 2,320,122,512.64
24	$ 578,672,770.40	0.027515332	$ 15,922,373.35	$ 2,336,044,885.99
25	$ 578,672,770.40	0.023689562	$ 13,708,504.68	$ 2,349,753,390.66
26	$ 578,672,770.40	0.020395733	$ 11,802,455.35	$ 2,361,555,846.01
27	$ 578,672,770.40	0.017559882	$ 10,161,425.74	$ 2,371,717,271.75
28	$ 578,672,770.40	0.015118332	$ 8,748,567.14	$ 2,380,465,838.88
29	$ 578,672,770.40	0.013016258	$ 7,532,154.34	$ 2,387,997,993.22
30	$ 578,672,770.40	0.01120646	$ 6,484,873.25	$ 2,394,482,866.47
31	$ 578,672,770.40	0.009648298	$ 5,583,207.56	$ 2,400,066,074.04
32	$ 578,672,770.40	0.008306786	$ 4,806,910.71	$ 2,404,872,984.74
33	$ 578,672,770.40	0.007151799	$ 4,138,551.24	$ 2,409,011,535.98
34	$ 578,672,770.40	0.006157403	$ 3,563,121.39	$ 2,412,574,657.37
35	$ 578,672,770.40	0.005301269	$ 3,067,700.09	$ 2,415,642,357.46
36	$ 578,672,770.40	0.004564173	$ 2,641,162.86	$ 2,418,283,520.32

37	$ 578,672,770.40	0.003929564	$ 2,273,931.94	$ 2,420,557,452.26
38	$ 578,672,770.40	0.003383192	$ 1,957,761.32	$ 2,422,515,213.58
39	$ 578,672,770.40	0.002912789	$ 1,685,551.50	$ 2,424,200,765.08
40	$ 870,709,763.90	0.002507791	$ 2,183,557.71	$ 2,426,384,322.79
		NPV	$ 2,426,384,322.79	

Table 3.13: Discounted Cash flow of the BSRO pipelines

The BSRO pipelines have a positive NPV of approximately $2.4 billion for the period of forty years of operation. This averaged around $61 million present value of operating net cash flows per annum. This means that the business cash flow can meet up with all the operating costs and still return a positive profit. This also means that the present value of the future cash inflows are higher than the present value of the current and future cash outflows by $2.4 billion. Its internal rate of return was estimated to be 50.38%, which is higher than the discount rate for the period of forty years. This means investment return of this business can return up to 50.38%. The investors can aim higher investment return up to 50.38% as the business only become at breakeven when the investment return is at 50.38%. This means that the business can be well preferred compare to other potential investments, which could offer lower IRR than 50.38%. The IRR is much higher than the discount rate, which means, the business will not be tight by allowing investment return at the calculated discount rate, and can even give higher investment return than the discount rate. The BSRO pipelines investment also has a discounted payback period of 2.60 years. These indicate that the BSRO pipelines are highly viable.

The major costs and benefits inputs and indicators of the remaining five options are presented in the following tables. The summary of capital cost elements of other gas pipeline options will be presented accordingly. Analytical comparison of the costs and benefits of these gas pipelines options as well as their estimated value addition and their sensitivities will be presented.

3.3.2 Costs and Benefits of other gas pipeline route options

Having looked at the costs and benefits of the near future planned route option (BSRO), other possible gas pipeline routes options will be assessed in the same manner. The capital cost components of the remaining five options are presented in table 3.14 below:

Pipelines	All possible Pipeline routes option	BRO	SRO	NRO	BNRO
PMC ($)	20,891,445.42	9,670,148.81	3,489,556.44	7,731,740.17	17,401,888.98
PCW ($)	1,044,572.27	483,507.44	174,477.82	386,587.01	870,094.45
Labour cost ($)	1,836,282,312.00	477,235,200.00	373,511,112.00	985,536,000.00	1,462,771,200.00
Cost of Compressor stations($)	714,000,000.00	590,000,000.00	124,000,000.00	430,000,000.00	590,000,000.00
Gas Delivery (bcm/yr)	47.74	22.11	15.13	10.49	32.60
IIC ($)	2,572,218,329.69	1,077,388,856.25	501,175,146.27	1,423,654,327.18	2,071,043,183.42

Table 3.14: Initial Investment Cost elements of the Gas pipelines route options

Table 3.14 enumerates the different capital cost elements of the other five gas pipeline route options. The combination of all the possible gas pipeline routes obviously has the highest initial investment costs, which is around $2.57 billion. The combination of BRO and NRO (BNRO) is the second most expensive option with $2.07 billion as its IIC. The combination of BRO and SRO (BSRO) as earlier presented is less expensive than the BNRO, which costs $1.15 billion. This means among the three options that combine two different possible routes options, the BSRO is less expensive, and this is attributed to the low distance of the SRO segments. Looking at the possible single routes options, The SRO is less expensive than BRO and NRO as it was estimated to cost $501 million. The most expensive single route option is the NRO, which was estimated to cost $1.42 billion.

The weighted average cost of capital for both options are assumed to be the same, because it is the same business environment and proportion of the capital sources will be the same, and the alternative or comparative investment return is the same risk free rate. So the WACC will be constant in all the scenarios. Similarly, the 2.5% depreciation rate is applied using straight line depreciation method, after deducting the SV of the pipelines. All other procedures applied in the case of BSRO pipelines are applied in the other possible route options, and summary of their costs and benefits are presented in table 3.15 below. Availability rate of 80%, gas transportations cost of $0.80/Mcf and tax rate of 30% are equally applied.

BSRO Pipeline system	BSRO	All pipelines route options	BNRO	BRO	SRO	NRO
Capital cost ($)	1,148,564,002.52	2,572,218,329.69	2,071,043,183.42	1,077,388,856.25	501,175,146.27	1,423,654,327.18
Equity ($)	459,425,601.01	1,028,887,331.88	828,417,273.37	430,955,542.50	200,470,058.51	569,461,730.87
Debt ($)	689,138,401.51	1,543,330,997.81	1,242,625,910.05	646,433,313.75	300,705,087.76	854,192,596.31
Amortization cost ($)	116,690,570.44	261,329,471.86	210,411,618.28	109,459,394.46	50,917,853.58	144,638,901.43
Depreciation rate	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Depreciating Value ($)	731,368,297.51	1,637,905,189.87	1,318,773,114.80	686,046,273.29	319,132,075.08	906,536,892.36
Annual Depreciation ($)	18,284,207.44	40,947,629.75	32,969,327.87	17,151,156.83	7,978,301.88	22,663,422.31
Annual O and M cost ($)	22,971,280.05	51,444,366.59	41,420,863.67	21,547,777.12	10,023,502.93	28,473,086.54
Annual Gas delivery (bcm)	37.25	47.74	32.60	22.11	15.13	10.49
Annual Gas delivery in Mcf	1,315,329,027.25	1,685,846,395.34	1,151,376,875.70	780,826,340.63	534,469,519.63	370,550,535.07
Actual Gas delivery (Mcf)	1,052,263,221.80	1,348,677,116.27	921,101,500.56	624,661,072.51	427,575,615.70	296,440,428.06
Annual Revenue ($)	841,810,577.44	1,078,941,693.01	736,881,200.45	499,728,858.00	342,060,492.56	237,152,342.45
Net Annual Revenue ($)	818,839,297.39	1,027,497,326.42	695,460,336.78	478,181,080.88	332,036,989.64	208,679,255.90
Gross tax payments ($)	245,651,789.22	308,249,197.93	208,638,101.03	143,454,324.26	99,611,096.89	62,603,776.77
Tax benefit from depreciation ($)	5,485,262.23	12,284,288.92	9,890,798.36	5,145,347.05	2,393,490.56	6,799,026.69
Tax Payable ($)	240,166,526.99	295,964,909.00	198,747,302.67	138,308,977.21	97,217,606.33	55,804,750.08
Annual Cash Flow ($)	578,672,770.40	731,532,417.42	496,713,034.11	339,872,103.67	234,819,383.31	152,874,505.83
Additional cash flow in final year						
Salvage value ($)	417,195,705.00	934,313,139.82	752,270,068.63	391,342,582.96	182,043,071.19	517,117,434.82
Tax on selling at salvage value ($)	125,158,711.50	280,293,941.95	225,681,020.59	117,402,774.89	54,612,921.36	155,135,230.45
Net Gain ($)	292,036,993.50	654,019,197.87	526,589,048.04	273,939,808.07	127,430,149.83	361,982,204.37
NPV ($)	2,426,384,322.79	1,947,786,895.83	998,262,864.07	1,022,543,778.19	949,524,031.76	-478,505,650.40
IRR	50.38%	28.44%	23.98%	31.55%	47%	11%
Discounted payback period (yrs)	2.60	5.62	7.49	4.80	2.83	-

Table 3.15: Costs and Benefits of other gas pipeline routes

Table 3.15 lists all the costs and benefits of the other gas pipelines routes. The NPV of the BSRO pipelines is the highest, which is approximately $2.4 billion. This means that, the BSRO pipelines have higher economic benefit than other options. The next must viable option is the all gas pipeline routes option, because it has the second highest NPV, which is approximately $1.9 billion. The third most viable option is the BRO pipelines which has an NPV of approximately $1 billion. The fourth and fifth most viable options are the BNRO pipelines and SRO pipelines which have an NPV of approximately $998 million and $950 million respectively. The least and unviable option is the NRO pipelines which have the negative NPV of $479 million, which means the pipelines are not viable. The hierarchy of the viability of these projects based on NPV are presented in figure 3.6 below.

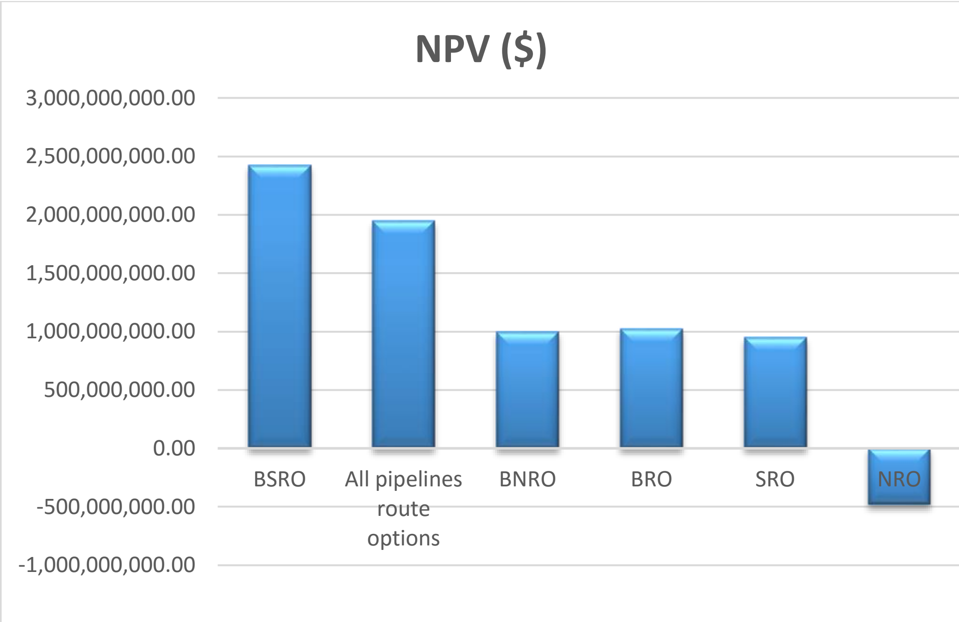


Figure 3:6: Graphical presentation of the NPV of the gas pipeline options

Figure 3.6 shows the hierarchy of the viability of all the gas pipeline route options based on NPV, showing the BSRO as the most viable option, followed by other gas pipeline routes in the following order: combination of all the pipeline route options, BRO, BNRO, SRO, and NRO as already discussed above. The NPVs of all the gas pipelines options are positive except for the NRO pipelines, which means they are all viable except the NRO pipelines.

Similarly, the IRR of all the investment options except for the NRO pipelines are higher than the discount rate (16.15%), which is considered the hurdle rate, the minimal rate of return for all the project options, which means the IRR is also showing that all the gas pipeline options are viable except the NRO gas pipelines. Using the IRR in ranking the project options, the hierarchy changed, where the BSRO pipeline maintained its positions as the most viable with the highest IRR of 71%. The graphical presentation of this hierarchy is presented in figure 3.7

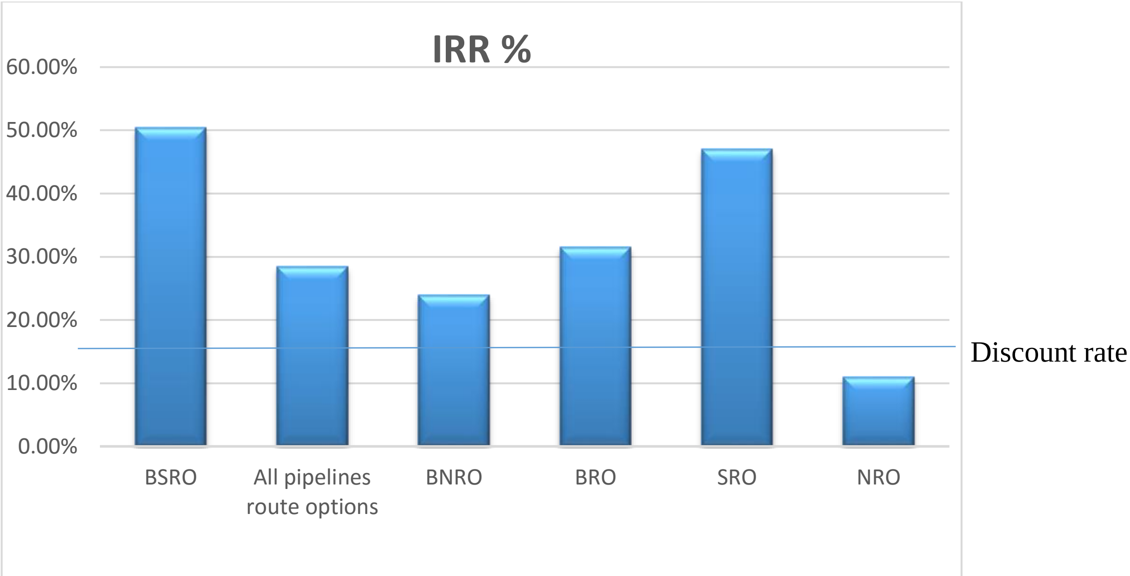


Figure 3:7: Graphical presentation of the IRR of the gas pipeline options

Figure 3.7 shows the IRR of the gas pipelines, where the BSRO has the highest IRR of 50.38%. The second highest IRR is that of SRO pipelines (47%), which were ranked fifth going by the NPV. The third most viable option going by IRR are the BRO pipelines that have an estimated IRR of 31.55%. All gas pipeline routes option and BNRO pipelines are ranked the fourth and fifth by the IRR, which have an IRR of 28.44% and 23.98% respectively. The least viable option is the NRO pipelines, which have IRR rate of 11%. All the IRR were above the discount rate expect the IRR of NRO pipelines.

The IRR shows the rate of return where the NPV equals to zero, this means that the BSRO and SRO has the potential of offering higher investment return at breakeven. In other word, the IRR can be viewed as the maximum percentage rate that can be earned on each dollar invested at a period [216]. The two methods have discrepancy in ranking the projects, which is possible because of a possible difference in the size of the investment, or timing of the positive net cash flows [217]. In this scenario, the discrepancy is attributed to the differences in the size of the businesses as well as the size of the cash flows, as the NPV accounts for difference between discounted cash flows and initial investment, which means higher initial investment might cause lower NPV, and higher cash flows can return higher NPV, while the IRR estimates the rate of return at which the discounted cash inflows will equate the initial cash outflows. Therefore, both techniques might have different ranking order. However, some recommended to go by NPV method, as the IRR rate is an arbitrary rate, which signals the maximum possible rate of rate, which might not be attainable given the business scenarios [218] [219] [220]. IRR favours investments that return initial investment quicker, which makes it more agreeable to the Payback period method [216].

The Payback period ranking is similar to the ranking of the IRR, BSRO pipelines have the lowest payback period of 2.60 years, and then BRO pipelines have payback period of 4.80 years. Others have payback period of 2.83, 5.62 and 7.49 years for SRO, all pipeline route option and BNRO pipelines respectively. NRO pipelines are not recoverable, so their initial investment costs cannot be recovered within the operational period. All the three accounting indicators suggest that BSRO pipelines are the most viable option

Joining the ranking outcome of NPV, IRR and Payback period, figure 3.7 illustrates the heights of the ranking of these investments

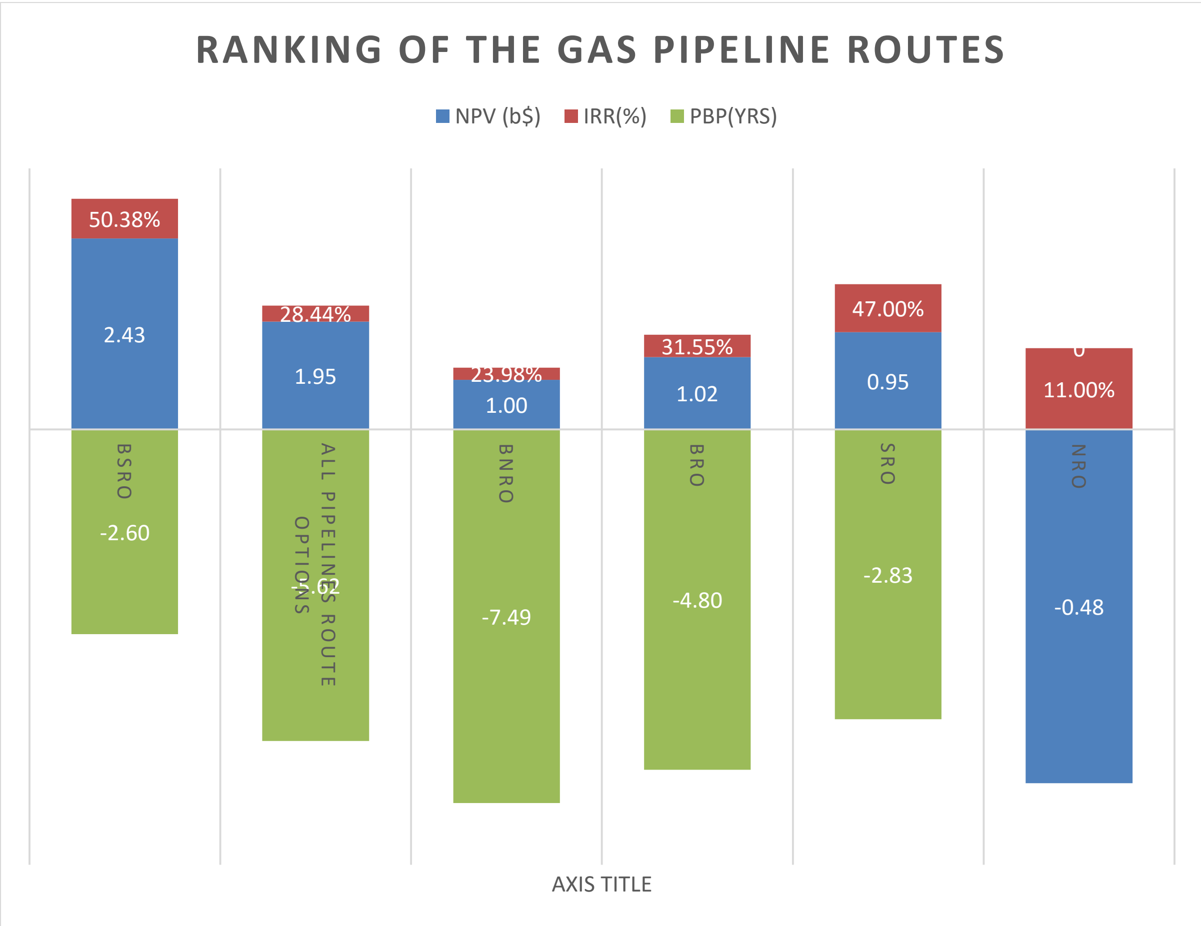


Figure 3:8: Ranking of the gas pipeline route options using the three accounting indicators

From figure 3.8, the top two business investments going by the top height above zero when combing the effects of IRR and NPV together are; BSRO and all gas pipelines option. Considering the green bar, which is the payback period and is expected to be shorter for the most viable option, the BSRO pipelines still have shorter height of -2.60, which means it has shorter payback period and more preferred than all the other options. NPV is largely the most considerable method compare to other techniques as explained earlier as it accounts for exact magnitude of the return and it is more precise estimate of the returns than the IRR [219] [220]. Relying on one criteria may not reflect the effect of other criteria in the judgement, which could be influential in ranking the projects.

Therefore, to harmonise the different ranking positions based on these criteria, the ranking positions are added and the pipeline with the lowest ranking position will be the most viable. The lowest point matters because lower points mean most viable, for example, the most viable option at a time is always ranked as number 1. Table 3.16 shows the ranking position of each of the gas pipeline options.

Pipelines	Ranking position
BSRO	
NPV	1
IRR	1
PAYBACK PREIOD (YRS)	1
Points	**3**
All possible pipeline routes option	
NPV	2
IRR	4
PAYBACK PREIOD (YRS)	4
Points	**10**
BNRO	
NPV	4
IRR	5
PAYBACK PREIOD (YRS)	5
Points	**14**
BRO	
NPV	3
IRR	3
PAYBACK PREIOD (YRS)	3
Points	**9**
SRO	
NPV	5
IRR	2
PAYBACK PREIOD (YRS)	2
Points	**9**
NRO	
NPV	6
IRR	6
PAYBACK PREIOD (YRS)	6
Points	**18**

Table 3.16: Ranking positions based on the three profit indicators

Table 3.16 shows the different ranking positions of each of the pipeline options as indicated by the three accounting methods. For each method, ranking was made, with the most viable being the number 1. Summing the ranking positions for each project, the BSRO pipelines have the lowest ranking points, which is 3. This is because it was ranked 1st in all the three accounting indicators. This makes it the most viable option among the six options based on the harmonised ranking positions. The second most viable options based on this ranking are the BRO and SRO pipelines, which both have the harmonised ranking points of 9. All gas pipeline options and BNRO are ranked 3rd and 4th respectively, with the harmonised ranking points of 10 and 14 respectively. The Least and unviable is the NRO pipelines, which has the harmonised ranking point of 18. This ranking will also be observed in all the eight sensitivity scenarios under sensitivity analysis below.

Therefore, BSRO pipelines are the most viable option among the six projects. All the project options except the NRO pipelines were viable at the base scenario. It is recommended not to consider this option (NRO) alone, even in the future, the best recommendation is to combine it with the BRO pipelines, since BRO pipelines are likely to be constructed soon, it is advisable to include the NRO pipelines. This academic finding justifies the intention of the government to consider investing on the BSRO pipelines.

However, in terms of coverage and ability to supply more gas to more locations, the all gas pipeline option is more recommendable. The all gas pipeline option covered the whole country, and this enables spread of potentials for gas development sites and job creations. The spread of the gas power turbines can be well achieved if all the gas pipeline options are considered. Concentration of industries in the south has caused migration from the north, and making the northern economy less active. This is because access to industrial inputs are easier in the south as the oil and gas production take place in the region. The electricity shortages was also partly attributed to the low transmission capacity and transmission losses. Around 20% of the existing transmission capacities are not operational [221], and 8.05% of electricity generated is lost in the process of transmission [222]. The over reliance on the transmission networks can be highly reduced if the all gas pipeline routes option is constructed ,and as a result, more distributed gas power turbines can be constructed, which can be connected to the distribution lines. This will enhance sub-regional power generations and investment in distribution lines, and will motivate establishment of industries across the country, and avoid unnecessary migration of labour forces. This will also facilitate spread of higher productivity of the industrial, commercial and residential sectors in every region as the access to natural gas is equally provided. The value addition as a result of the wide spread of the gas supply, which can be achieved through all the gas pipeline route option can offset the lower viability of the option compare to the BSRO pipelines.

The all gas pipeline route option is equally viable, and its NPV is not much lower than the BSRO pipelines, its IRR is 28.44%, and has payback period of 5.62 years, as such, it is worth considering. Therefore, the all gas pipeline routes option is highly recommended. If all the gas pipelines routes are considered together, the NRO pipelines will not be singled out, which if singled out, the NRO pipelines will be unviable.

3.4: Sensitivities for Gas pipeline projects

In order to account for market fluctuations and changes in the parameters in the cost and benefit analyses, a sensitivity analysis was administered to observe the responsiveness of the benefits of these gas pipelines to changes in the business parameters. The sensitivity analysis was administered on the discount rate, capacity, cost of transportation and ICC.

The discount rate, which is the cost of capital, accounting for the cost of debt and equity, and this rate could vary based on the cost of equity and debt, and this is why the discount rate is adjusted assuming a higher and lower rate. The base scenario used discount rate of 16.15% as derived using WACC, a 20% higher discount rate of 19.38% and another 20% lower discount rate of 12.92% were used.

Capacity utilization/availability rate of the pipelines are significant in this analysis and determines the level of benefit, because we have estimated the average capacity that can be maintained over the lifetime of the pipelines, we will then have two scenarios, one assuming 20% lower capacity level and the other assuming 20% higher capacity level. The result of these two scenarios are the same as the scenarios where the availability rate is decreased and increased by the same 20% respectively. Since similar variation in capacity and availability rate give similar outcome, the variation in capacity will be used instead. These will also account for the frequency of disruptions resulting from unexpected technical issues, vandalism, short of gas productions, political or social instability, price shocks, etc.

For the cost of gas transportation, we will assume an upward and downward review of the cost by 20% each, which is \$0.64/Mcf and \$0.96/Mcf respectively. The current cost of gas transportation is \$0.8/Mcf as earlier mentioned. Similarly, the initial investment cost, will be varied by 20% higher and 20% lower. Table 3.17 summarises the result of these sensitivity scenarios.

Gas pipelines	Base scenario	Discount rate lower scenario12.92%	Discount rate higher scenario 19.38%	Capacity scenario: 20% lower	Capacity scenario: 20% higher	Cost of gas transportation: Lower scenario $0.64/Mcf	Cost of gas transportation: Higher scenario $0.96/Mcf	IIC 20% Lower scenario	ICC 20% higher scenario
BSRO									
NPV	2,426,384,322.79	3,297,889,483.09	1,835,108,758.89	1,698,453,420.49	3,154,315,225.09	1,698,453,420.49	3,154,315,225.09	2,669,038,360.53	2,183,730,285.05
IRR	50.38%	50.38%	50.38%	40.12%	60.64%	40.12%	60.64%	63.21%	41.83%
PAYBACK PREIOD (YRS)	2.60	2.45	2.76	3.46	2.07	3.46	2.07	1.97	3.27
All pipelines route options									
NPV	1,947,786,895.83	3,050,997,507.92	1,199,846,686.60	1,014,803,845.76	2,880,769,945.90	1,014,803,845.76	2,880,769,945.90	2,491,212,566.73	1,404,361,224.93
IRR	28.44%	28.44%	28.44%	22.56%	34.31%	22.56%	34.31%	35.78%	23.54%
PAYBACK PREIOD (YRS)	5.62	4.99	6.48	8.42	4.26	8.42	4.26	4.01	7.75
BNRO									
NPV	998,262,864.07	1,747,778,996.11	490,271,031.40	361,066,549.95	1,635,459,178.18	361,066,549.95	1,635,459,178.18	1,435,806,605.37	560,719,122.77
IRR	23.98%	23.98%	23.98%	18.99%	28.96%	18.99%	28.96%	30.21%	19.82%
PAYBACK PREIOD (YRS)	7.49	6.38	9.34	12.68	5.47	12.68	5.47	5.12	11.26
BRO									
NPV	1,022,543,778.19	1,534,941,888.64	675,098,554.82	590,417,967.16	1,454,669,589.22	590,417,967.16	1,454,669,589.22	1,250,160,833.58	794,926,722.80
IRR	31.55%	31.55%	31.55%	25.05%	38.04%	25.05%	38.04%	39.66%	26.13%
PAYBACK PREIOD (YRS)	4.8	4.35	5.40	6.92	3.71	6.92	3.71	3.51	6.45
SRO									
NPV	949,524,031.76	1,303,261,694.95	709,605,494.97	653,737,295.81	1,245,310,767.72	653,737,295.81	1,245,310,767.72	1,055,405,961.36	843,642,102.16
IRR	46.85%	46.85%	46.85%	37.30%	56.41%	37.30%	56.41%	58.80%	38.89%
PAYBACK PREIOD (YRS)	2.83	2.67	3.01	3.80	2.27	3.80	2.27	2.15	3.60
NRO									
NPV	-478,505,650	-246,749,501.33	-635,166,001.46	-683,576,153.48	-273,435,147.31	-683,576,153.48	-273,435,147.31	-177,734,017.23	-779,277,283.56
IRR	10.59%	10.59%	10.59%	8.13%	13.00%	8.13%	13.00%	13.59%	8.55%
PAYBACK PREIOD (YRS)									

Table 3.17: Results of all the sensitivity scenario

Table 3.17 shows the results of all the sensitivity scenarios, for each pipeline. NPV, IRR and Payback period was calculated for each gas pipeline option and for each scenario, including the base scenario. The highest NPV of each pipeline was when the discount rate was lower at 12.92%. The highest IRR and lowest payback period of all the gas pipelines options were when the IIC was reduced by 20%. Payback period is less flexible than the other indicators. This means that the gas pipelines are highly responsive to discount rate and IIC. The pipelines are also highly responsive to the capacity and cost of gas transportation as the second highest NPVs, IRRs as well as second least payback periods were recorded when the capacity was increased by 20% and when the gas transportation was reduced by 20%.

To better analyse the responsiveness or sensitivities of these gas pipelines to these parameters, percentage changes in each of these accounting indicators in relation to the percentage changes in these parameters were considered. This is done using sensitivity indicator (SI), which is a scientific method of calculating the responsiveness of an accounting indicator of a project to the percentage change in the input or business parameters. SI in relation to NPV is defined as follows [223]:

$$SI_{NPV} = \frac{(NPV_b - NPV_1)/NPV_b}{(X_b - X_1)/X_b} \tag{3.29}$$

Where, NPV_b is the value of NPV in the base scenario, NPV_1 is the value of the NPV in the sensitivity test. X_b is the value of the market/business parameter in the base scenario, X_1 is the value of the market/business parameter in the sensitivity test. The SI in relation to IRR, which compares the percentage change in IRR above the discount rate with the percentage change in a variable or combination of variables is defined as follows [223]:

$$SI_{IRR} = \frac{(IRR_b - IRR_1)/(IRR_b - d)}{(X_b - X_1)/X_b} \tag{3.30}$$

Where, IRR_b is the value of IRR in the base scenario, IRR_1 is the value of the IRR in the sensitivity test, and d is the discount rate. The SI in relation to NPV and IRR are presented for all the eight scenarios in table 3.19. Before that, table 3.18 shows the percentage changes in the accounting indicators as a result of the change in the respective parameters.

Gas pipelines	Base scenario	Discount rate lower scenario1 2.92%	Discount rate higher scenario 19.38%	Capacity scenario: 20% lower	Capacity scenario: 20% higher	Cost of gas transport: Lower scenario $0.64/Mcf	Cost of gas transport: Higher scenario $0.96/Mcf	IIC 20% Lower scenario	ICC 20% higher scenario
BSRO									
NPV	0%	36%	-24%	-30%	30%	-30%	30%	10%	-10%
IRR	0%	0%	0%	-20%	20%	-20%	20%	25%	-17%
PAYBACK PREIOD (YRS)	0%	-6%	6%	33%	-20%	33%	-20%	-24%	26%
All pipelines route options									
NPV	0%	57%	-38%	-48%	48%	-48%	48%	28%	-28%
IRR	0%	0%	0%	-21%	21%	-21%	21%	26%	-17%
PAYBACK PREIOD (YRS)	0%	-11%	15%	50%	-24%	50%	-24%	-29%	38%
BNRO									
NPV	0%	75%	-51%	-64%	64%	-64%	64%	44%	-44%
IRR	0%	0%	0%	-21%	21%	-21%	21%	26%	-17%
PAYBACK PREIOD (YRS)	0%	-15%	25%	69%	-27%	69%	-27%	-32%	50%
BRO									
NPV	0%	50%	-34%	-42%	42%	-42%	42%	22%	-22%
IRR	0%	0%	0%	-21%	21%	-21%	21%	26%	-17%
PAYBACK PREIOD (YRS)	0%	-9%	12%	44%	-23%	44%	-23%	-27%	34%
SRO									
NPV	0%	37%	-25%	-31%	31%	-31%	31%	11%	-11%
IRR	0%	0%	0%	-20%	20%	-20%	20%	25%	-17%
PAYBACK PREIOD (YRS)	0%	-6%	6%	34%	-20%	34%	-20%	-24%	27%
NRO									
NPV	0%	-48%	33%	43%	-43%	43%	-43%	-63%	63%
IRR	0%	0%	0%	-23%	23%	-23%	23%	28%	-19%
PAYBACK PREIOD (YRS)									

Table 3.18: Percentage changes in the accounting indicators

Table 3.18 shows the percentage changes of the accounting indicators as a result of a change in market parameters. All the gas pipelines' NPVs have higher percentage changes when the discount rate was reduced by 20%. Their IRRs have higher percentage changes when the IIC was reduced by 20%. The payback period's higher percentage changes were recorded when the gas transportation cost and capacity were reduced by 20%. The second scenarios that the NPV and IRR indicators are highly responsive to are the changes (upward and downward) in capacity and cost of gas transportation. The payback periods' second highest responsive scenario was when the IIC was increased by 20%. Therefore, investors interested in NPV as the indicator of business viability should carefully consider the cost of capital of the business in predicting future viability and cash flows of these investments. This entails bargaining and predicting the optimum cost of equity and debt, as the businesses' NPVs are highly responsive to the discount rate, which is derived through the cost of capital. Therefore, the higher the cost of capital the lower the NPVs and vice versa.

For investors, who are concerned about the IRR, then IIC is the most important parameter to consider, the IRR of these investments are more responsive to IIC, and higher IIC reduces the IRR and vice versa. Gas transportation cost and capacity affect the payback period of these investments highly, as such, investors interested on how quick their investment comes back to them should be concerned more about the capacity of these pipelines as well as the cost of gas transportation, as they have negative relationship with the payback period.

Another way of looking at the level of sensitivity is by looking at the SI as indicated earlier, which helps to further assess the sensitivities of these accounting indicators to the market parameters. So, the SI compares the percentage change in the accounting indicator with the percentage change in the business parameter. A higher SI indicates that the accounting indicator of the project is more sensitive to the particular market/business parameter. The SIs of every scenario is presented in table 3.19.

Gas pipeline options	Discount rate 20% lower scenario	Discount rate 20% higher scenario	Capacity scenario 20% lower	Capacity scenario: 20% higher	Cost of gas transportation: Lower scenario $0.64/Mcf	Cost of gas transportation: Lower scenario $0.96/Mcf	IIC 20% Lower scenario	ICC 20% higher scenario
BSRO								
NPV	179.59%	-121.84%	-150.00%	150.00%	-150.00%	150.00%	50.00%	-50.00%
IRR	0.00%	0.00%	119.09%	-119.15%	119.09%	-119.15%	-148.93%	99.24%
PAYBACK PREIOD (YRS)	-28.17%	30.37%	165.14%	-101.29%	165.14%	-101.29%	-120.61%	129.48%
All pipelines route options								
NPV	283.20%	-192.00%	-239.50%	239.50%	-239.50%	239.50%	139.50%	-139.50%
IRR	0%	0.03%	139.08%	-138.95%	139.08%	-138.95%	-173.69%	115.89%
PAYBACK PREIOD (YRS)	-56.45%	76.50%	248.87%	-120.70%	248.87%	-120.70%	-143.19%	189.43%
BNRO								
NPV	375.41%	-254.44%	-319.15%	319.15%	-319.15%	319.15%	219.15%	-219.15%
IRR	0%	-0.01%	149.70%	-149.49%	149.70%	-149.49%	-186.85%	124.71%
PAYBACK PREIOD (YRS)	-73.99%	123.29%	346.64%	-135.15%	346.64%	-135.15%	-158.48%	251.65%
BRO								
NPV	250.55%	-169.89%	-211.30%	211.30%	-211.30%	211.30%	111.30%	-111.30%
IRR	0%	0.09%	134.08%	-133.86%	134.08%	-133.86%	-167.35%	111.74%
PAYBACK PREIOD (YRS)	-46.89%	62.48%	220.50%	-113.86%	220.50%	-113.86%	-134.26%	171.39%
SRO								
NPV	186.27%	-126.34%	-155.76%	155.76%	-155.76%	155.76%	55.76%	-55.76%
IRR	0%	0.00%	120.82%	-120.82%	120.82%	-120.82%	-151.02%	100.68%
PAYBACK PREIOD (YRS)	-29.12%	31.91%	170.85%	-99.96%	170.85%	-99.96%	-119.87%	135.59%
NRO								
NPV	-242.17%	163.70%	214.28%	-214.28%	214.28%	-214.28%	-314.28%	314.28%
IRR	0%	0.00%	375.53%	-365.57%	375.53%	-365.57%	-456.03%	311.93%
PAYBACK PREIOD (YRS)	0%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 3.19: Sensitivity indicators to NPV, IRR and Payback Period

Using the SI, table 3.19 shows the level of sensitivities for each scenario, with the higher absolute percentage indicating higher level of sensitivity. The SI results confirm the level of sensitivities as observed under the percentage changes in table 3.18. Based on the sensitivity scenarios, the harmonised ranking positions of these projects are presented in Appendix B, and the judgment is similar as in the harmonised ranking positions in the base scenario as earlier shown in table 3.16. Generally, the sensitivities are ranked in the following order starting with the most sensitive parameters: Discount rate, then Capacity/gas transportation cost, and then IIC.

The NRO pipelines are not viable alone in all the scenarios, it can only be viable if the IIC is reduced by 40% everything being equal. The BSRO is the most viable option in all the scenarios, but can be unviable if the IIC is increased by 50%, cost of gas transportation decreased by 50% everything being equal. The all gas pipeline routes option, which is recommendable because of its coverage is viable in all the scenarios. It can only be unviable if the IIC is increased by 20% and cost of gas transportation is reduced by 50%.

3.5 Potential Natural Gas Pipeline value addition:

If the recommended gas pipelines are constructed, and as a result, natural gas is adequately supplied, the following value addition can be achieved:

A Electricity generation:

According to World Bank report on sustainable energy for all, only 48 percent of Nigerians have access to electricity in 2010 [224], which means 52% of the country's population did not have access to electricity and may only have option of using traditional way of meeting their energy needs. Even among those that have access to the electricity, the availability was low, which is why the country is ranked 185th in terms of access to electricity per capita in 2014 [28]. In 2011, the Nigerian electricity consumption per capita was 189kWh per year[28]. This lowered economic opportunities in the country and makes the cost of production more expensive, where cost of energy is estimated to contribute 40% of the cost of production in the manufacturing sector [225]. Nigeria is ranked third and second in terms of sales lost due to electrical outages and duration of outages by IEA African Energy Outlook 2014 report as shown in figure 3.9.

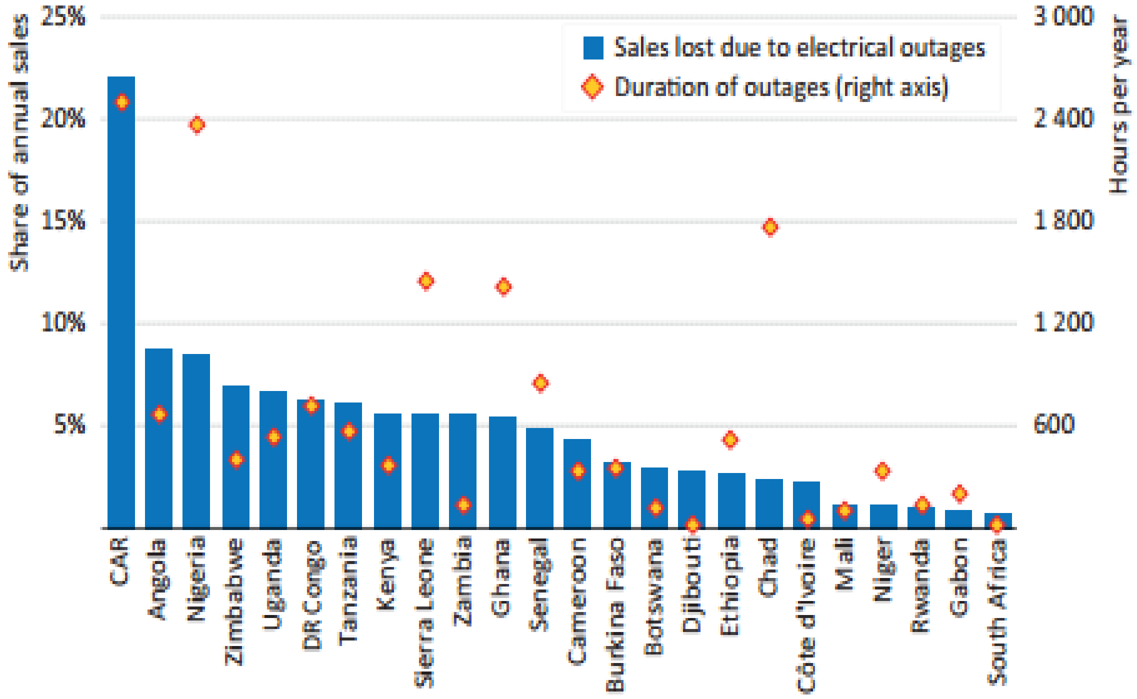


Figure 3:9: Sales lost due to electric outages and duration of outages in Africa [3]

Figure 3.9 shows how African countries are paired in terms of economic lost resulting from the electric outages as well as the duration of outages, Nigeria is third after Angola and Central Africa Republic (CAR) in terms of economic lost (sales lost) due to electric outages, and it is ranked second in terms of duration of electric outages in terms of hours per year in 2014. These are the gaps that adequate supply of gas through these pipelines will help filled. The value addition of these pipelines will come though converting these economic lost to economic gains. In 2014, the share of sales lost due to electric outages in Nigeria was around 9% of annual sales. The limited number of gas power turbines in the country operate below average capacity due to the inadequate supply of natural gas and transmission networks [170].

The construction of the gas pipelines can help motivate development and efficiencies of more gas power turbines, which will help reduce the cost of businesses and increase the utility revenues. The IEA report on Africa recommended for more infrastructural development in the power generation segments, which include more gas transmission pipelines. The power improvement as a result of adequate supply of gas through these pipelines can help reduce the cost of purchase and maintenance of electric backup generator. The cost of fuelling private electric generators was estimated to be averagely around $18 billion a year in five years up to 2014, which is enough to cover more than the estimated IIC of the recommended option (all the gas pipeline routes option), which covers the whole country [226]. If the future estimated improvement in terms access to electricity is to be achieved, then these gas pipelines need to be in place to provide adequate gas feeds to the emerging gas power turbines. It was equally estimated that natural gas will contribute up to 70% of the electricity to be generated in 2030 [227].

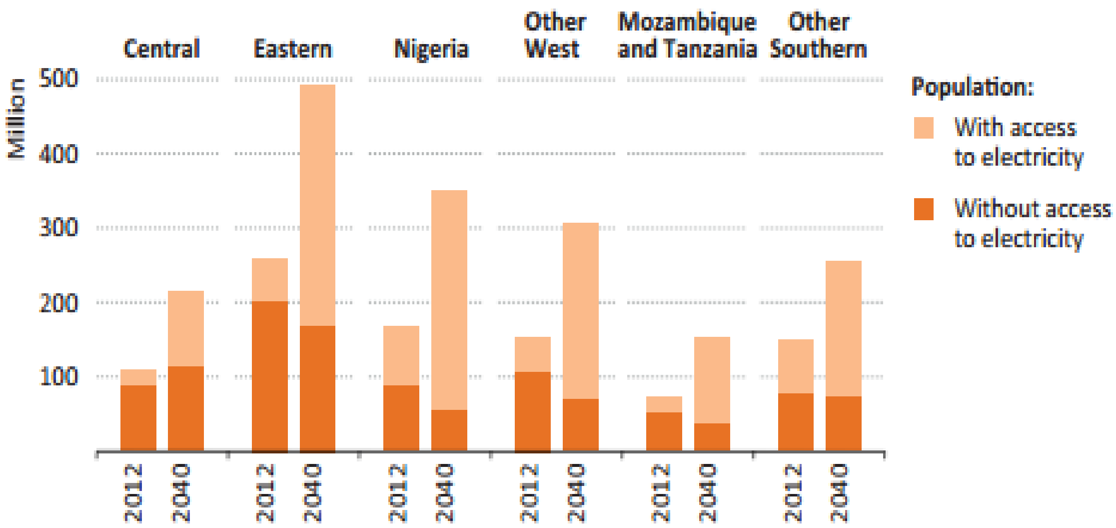


Figure 3:10: Present and future access to electricity in Africa [3]

Figure 3.10 shows the current and future number of population with and without access to electricity in some African countries. Of interest to this research is Nigeria, there are more people without access to electricity than people with access to electricity in the country as at 2012. It is estimated that this proportion will change, where larger number of population in the country will have access to electricity in 2040. Despite this projected development, there will still be a number of population without access to electricity. Therefore, there is need to maximise the investment in infrastructural development to achieve the maximum possible improvement in access to electricity, which justifies the investment in the all gas pipelines routes option, which supply the gas to all parts of the country, and hence encourage investment in gas power turbines.

The current gas power plants in the country rely on the gas supply from the gas producing region, and contribute 63% of the total electricity generated in the country in 2011. They are concentrated in the southern part of the country, which makes transmission of the electricity a big issue, where despite the existing electricity transmission capacity of 6000MW, only 4, 800MW of the capacity is operational [221], which cannot meet up the rising demand for the electricity in the country, and it was observed that additional transmission capacity will cost from $441,760/km in the country as at 2012 for a double 380kV overhead line [225, 228, 229].

Building these gas pipelines to supply gas across the country will help the establishment of small distributed power plants across the regions and reduce electricity loss associated with the transmission lines as these small power plants can supply direct to distribution lines. It will also help in supplying gas for other uses in other sectors of the economy. In 2015, the electricity transmission loss was 8.05% of the total electricity output [222]. The gas pipelines can encourage and make the establishment of micro gas power plants viable, which can connect to distribution lines and avoid the loss associated with the long-distance electricity transmission. Therefore, building gas pipelines will reduce the reliance on the transmission networks, thereby reducing the total energy loss in the system, and fill the gap created by electricity transmission capacity inadequacy.

Additionally, the gas loss in the gas transmission systems is lower than the electricity transmission loss. The estimated gas loss due to fugitive emissions on the gas transmission lines is 3.4 tonnes per km [230]. Using the all gas pipeline route option with reference to table 3.20 below, the gas loss will be 3.4 tonnes*4,508.60km (distance of the pipeline), which is equal to 15329.24 tonnes. Comparing this with the 47.74 bcm capacity of the all gas pipeline route option (as shown in table 3.20), which is equivalent to 34 million tonnes, the gas loss fraction will be 0.05%, which is far lower than the 8% electricity loss on the electricity transmission system. So, the gas transmission has lower loss fraction. Though, in Nigeria the gas loss could be higher due to possibility of theft and sabotage, as these pipeline vandalisms were reported previously in Nigeria [21]. However, theft and sabotage are also possible on the electricity distribution systems.

The above benefits comes with additional costs, which include additional average capital and operation costs for using the micro power plants. It is acknowledged that there is a reduction in capital productivity when multiple smaller plants are built in place of full-size power plants. For example, using capital cost of $1.2 million per MW for 400MW plant, which cost $480 million [231] [188], and using the power rule for scaling capital cost with an exponent of 0.60 [232], the cost of a 20MW plant will be approximately $80million ($480 million X (20MW/400MW)^0.6). Therefore, the average capital cost for the 20 MW plant is $4 million per MW as against $1.2 million per MW for a 400MW power plant. This means that the average capital cost is three times higher in the case of micro plant.

For the additional operation cost for using micro plant, it was established under the cost data of a CCGT plant that the O and M cost of the plant is around 4% of the investment cost [233], and from this a 400MW plant will have operational cost of $0.00721/kWh after accounting for availability and capacity factor. This is further discussed and elaborated under CCGT economic analysis in subsequent subchapter. However, the operational cost of the micro plant will cost up to $0.016/kWh [234] [235] [236]. This means there will be up to $0.00879/kWh operational cost increment for using micro plant.

Table 3.20 reports on the estimated monetary benefits for using gas transmission lines to supply gas to micro power plants. The table assumed that 60% of the gas supplied by each of the six possible gas pipeline routes will be used to produce electricity, and 30% of this coming from the distributed small power plants, and the remaining 70% from the big power plants, and using 60% thermal efficiency. It shows the potential energy loss saving (for not using the transmission networks) as a result of using the small distributed generation that connect to distribution networks directly. The remaining 40% of the gas supplied could be available for GTL plants, chemical and cement industries etc. The maximum allowable distributed micro generation capacity in Nigeria is 20MW per plant, which is now been proposed to be increased to 50MW and which have an average thermal efficiency of 32% [228] [229] [237]. There will still be electricity transmission losses as small distributed plants may not be able to produce sufficient quantity of electricity, and it will be complemented by some bigger gas power plants that connect to the transmission lines. The distribution losses are not considered here and might not change much in the process. This value addition analysis and recommendations are for the overall approach to using gas in the country, and are independent of the subsequent comparisons between the GTL and CCGT plants at a certain scale.

Pipelines	KM	Gas Delivery (bcm/yr)	Potential of electricity output MWh from centralised system (60% thermal efficiency)	Potential of electricity output MWh from distributed small plants (32% thermal efficiency)	Potential energy loss saving for not using transmission networks MWh	Monetary saving for electricity loss avoidance ($)
BSRO	1,771.00	37.25	103,245,829.69	23,599,046.79	1,899,723.27	120,518,444.01
All possible Pipeline routes option	4,508.60	47.74	132,329,330.69	30,246,704.16	2,434,859.68	154,467,498.39
BNRO	3,722.60	32.60	90,376,520.51	20,657,490.40	1,662,927.98	105,496,150.89
BRO	985.00	22.11	61,290,416.09	14,009,237.96	1,127,743.66	71,544,057.54
SRO	786.00	15.13	41,952,810.17	9,589,213.75	771,931.71	48,971,347.50
NRO	2,737.60	10.49	29,086,104.42	6,648,252.44	535,184.32	33,952,093.35

Table 3.20: Potential electricity generation and loss saving from the gas pipelines

From table 3.20, 60% of the gas supplied from each of the six possible gas pipeline options are expected to be used for power generation, and converting that to electricity output using 60% thermal efficiency of a power plant, the combination of all gas pipeline routes option have higher electricity output generation, and higher electricity loss saving for not using the transmission networks. This is followed by the BSRO pipelines, and other pipelines in the following ranking order: BNRO, BRO, SRO, and NRO pipelines respectively. Similar ranking order is maintained looking at the electricity loss savings.

In order to quantify the energy loss avoidance for not using the transmission networks as a result of 30% electricity supply from distributed small generation plants in monetary figures, the all gas pipeline routes option will save up to $154 million per year. This means that approximately 2.4 million MWh of electricity loss can be evaded in a year, and this is derived using the wholesale electricity cost of $63.44/MWh [238]. For BSRO and BNRO pipelines, the saving is $121 million and $105 million respectively. The saving will also be worth $71 million, $49 million and $34 million for BRO, SRO and NRO pipelines respectively.

That was to quantify the electricity loss avoidance, acknowledging other associated additional costs as earlier explained. Similarly, there are still other added values for using gas transmission and micro power plants, which include adequate gas supply for other energy and commercial usage, more investment opportunities for micro-power generations and other gas processing plants, increased access to electricity and petroleum products, job creation as a result of more energy production and distribution activities in all parts of the country, etc. So, in order to minimise the additional costs for using micro plants, measures such as optimisation of the efficiencies of the micro power plants, and increasing the minimal micro power generation capacity to enhance economy of scale should be considered. In addition, smart security and protective measures of the gas pipelines could be applied to minimise the risks of theft and sabotage.

The gas pipelines are essentials in meeting the future energy demand growth in the country as it was estimated that the Nigerian future electricity demand will rise up to 1,000,000GWh (1 billion MWh) in 2030 as presented in figure 3.11 below [227], and going by this, even the all gas pipeline route option, which has the highest potential electricity output (based on the above estimation) cannot supply enough gas to meet this high level of demand.

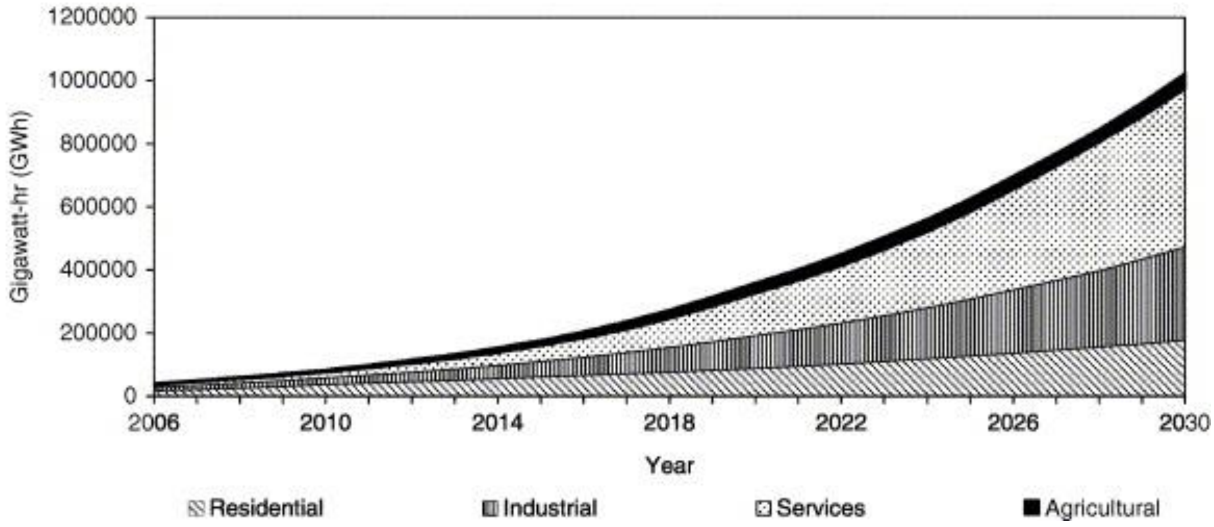


Figure 3:11 Future electricity demand in Nigeria [227]

Figure 3.11 shows the sectorial future electricity demand in Nigeria with service/commercial sector demanding higher, which is followed by industrial and residential sectors respectively. The overall electricity demand is estimated to be 1 billion MWh in 2030, and is expected to keep rising, and this underlines the need for the gas pipelines, which will help in transporting gas to various part of the country, which will be used for electricity generation to meet these rising electricity demand. This is because the gas is expected to be the future most reliable source of electricity in the country to meet these demands as shown in figure 3.9 below:

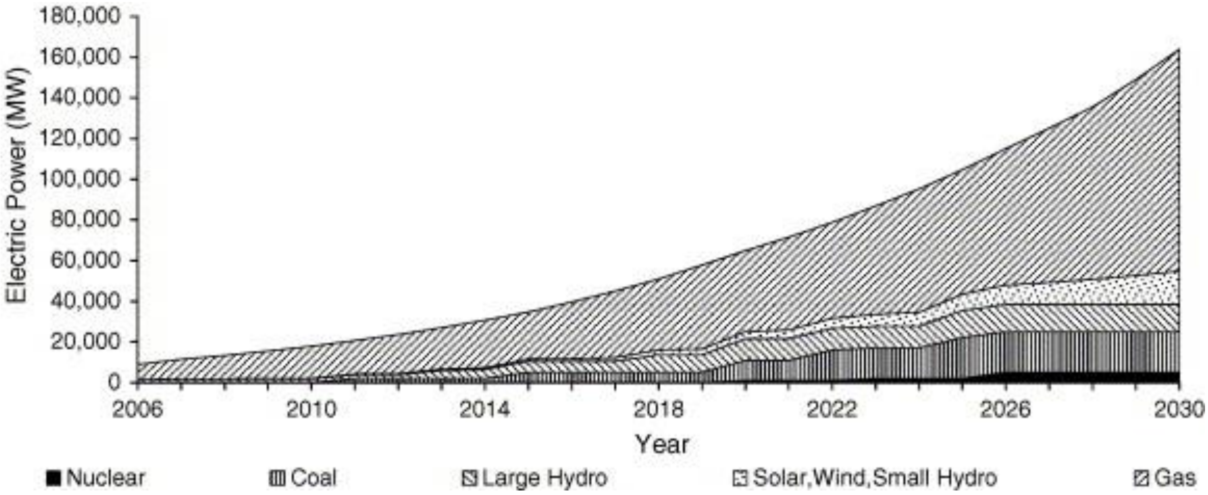


Figure 3:12 Future electricity generation mix in Nigeria [227]

From figure 3.12, natural gas is estimated to be the most dominant source of electricity in the country contributing close to 70% of electricity to be produced in the country in 2030, which is around 120,000 MW of electric power in the same year. This will amount to approximately 1 billion MWh in 2030 (assuming 95% availability rate), which is four times higher than the potential electricity output of the combination of all gas pipeline routes option. This will amount to the need of input energy equivalent of 1.67 billion MWh, which is equivalent to 157 bcm of natural gas, which is higher than the average potential capacity of the gas pipelines options under considerations. This shows that even the capacity of the combination of all the gas pipeline routes option may not meet the future gas input demand.

With the wide gap in access to electricity, future rise in demand for electricity and continues dominance of gas as a source of electricity in the future as clearly discussed above, investment in all the value chain for electricity generation is significant especially the gas pipelines as well as the CCGT plants, which is why the CCGT plant is considered in the other comparative assessment of the of the gas development projects in the subsequent sub-chapter.

Therefore, building the pipelines are essentials, and building the power plants across the regions are more energy and cost effective, and can enhance industrial potentials and job opportunities, and this cannot be possible without adequate supply of the gas, which can be provided by the gas pipelines. Therefore, the value addition of these gas pipelines is significant as enhanced access to electricity will make factors of production relatively cheaper, boost industrial growth, create more jobs, and develop the economy. Based on the assumption that there will still be a number of population not having access to electricity by

2040, and the assumption that 70% of the electricity generation will come from gas in 2030 as well as the assumption that there will be electricity demand of 1 billion MWh in 2030 without having highly competing alternative source of energy as indicated above, then there is need to invest more on the gas development projects especially the gas pipelines. Similarly, there is need to maximise the supply of the gas, which can be achieved by constructing all the gas pipeline routes option in the country, as the future energy demand can still surpass the estimate.

B Gas Supply to GTL plants

Building gas pipelines can provide opportunities for more investment in GTL projects. Once gas supply is sufficient, investment on GTL project could be attracted, because there could be huge market demand for the GTL products in the country. With the continues debates about the sustainability of the existing fuel subsidy in Nigeria, there is high possibility that the petroleum subsidy could be removed by the new administration because of the rising subsidy burden on the government and falling oil prices [239]. The price of existing major transport fuel in many filling stations in the country does not reflect the regulated price, and is considered unaffordable to some consumers due to their low level of economic status. Creating a substitute or alternative transport fuel from natural gas will not only make the gas useful, but will provide a formidable alternative fuel and create market competition between the two fuels. Similarly, because 70% of domestic petroleum products are imported from abroad, the petrol price is high because of the transportation and refining costs abroad [22]. Generating a diesel fuel within the country using the GTL technology will help provide relatively cheaper fuel. To reduce the transport cost of the GTL products, the GTL plants can be constructed in different parts of the country. Therefore, this can be facilitated by the gas pipelines that will supply sufficient gas feeds to the proposed distributed GTL plants in the country.

The GTL products can help improve access to cleaner petroleum product and can help substitute the dominance of oil motor gasoline as a major transport fuel as highlighted in figure 3.13.

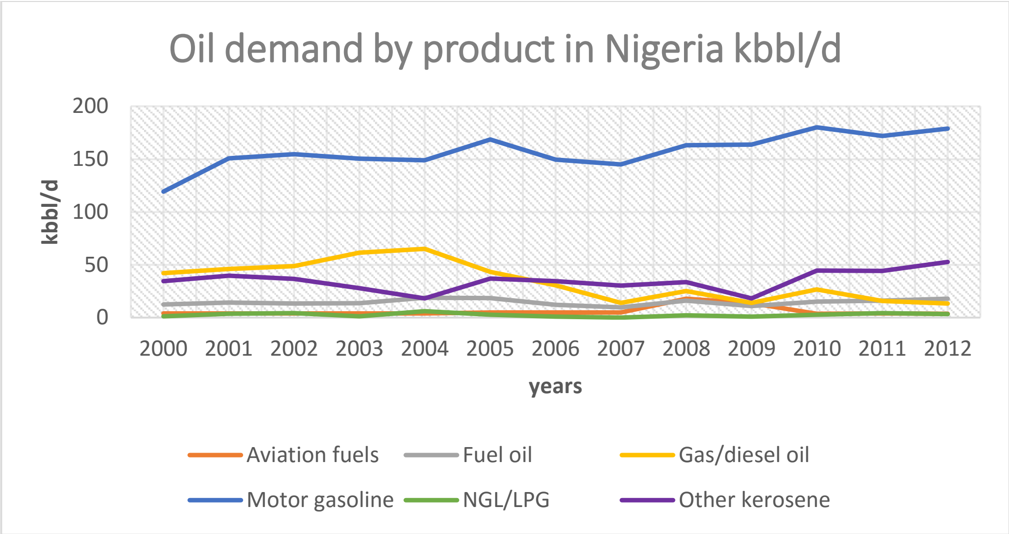


Figure 3:13: Oil product demand in Nigeria [240]

Figure 3.13 shows the oil product demand mix in Nigeria for twelve years, and over the years motor gasoline is the most demanded oil product, followed by diesel oil and until recently by other kerosenes, which include other hydrocarbons, refinery gas, petroleum cok, white spirit, lubricants, bitumen, parappin, waxxes and others such as tar, sulpur, grease etc [240]. The high energy demand in the country could not be met by oil products despites its dominance in the market, as the country has the largest consumption of solid biomass for cooking in the sub-saharan Africa as at 2012. This is shown in figure 3.14 below.

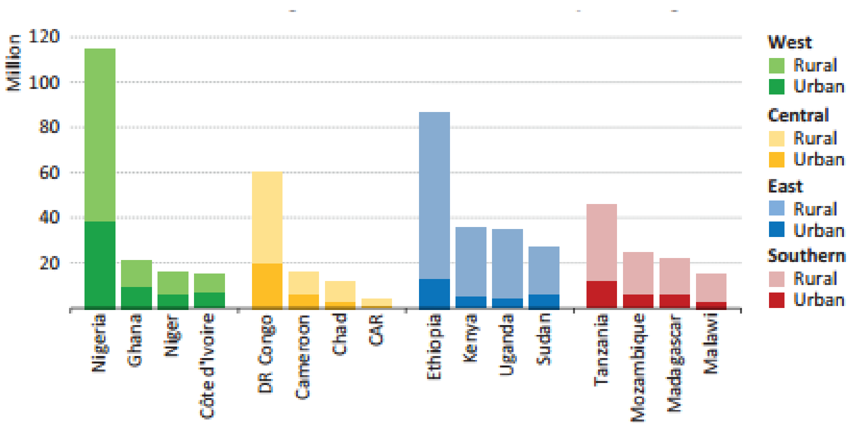


Figure 3:14: Use of solid biomass for cooking in sub-Saharan African in 2012 [3]

As figure 3.14 shows, Nigeria has the largest usage of the solid biomass in the sub-Saharan Africa, where over 117 million people use traditional way of using solid biomass. Therefore, with continues dominance of oil transport fuels and solid biomass for cooking, as well as future estimate of increasing energy demand, which is expected to increase by 78% in 2040 in the country as shown in table 3.21, the need to increase supply of natural gas is significant so as to facilitate provision of alternatives and cleaner fuels. This level of percentage increase was estimated based on the existing policies as at mid-2014, which IEA termed as the "new policies scenarios", but in the event of a more ambitious but possible energy policies and practices in place, which is termed "new century case", the level of energy demand increase will be almost 99%, table for the future energy balance under this scenario is presented in Appendix C. The share of natural gas in the energy demand mix is also estimated to overtake that of the oil, and this cannot be achieved without the required gas pipelines to supply natural gas across the country.

Nigeria: New Policies Scenario

	Energy demand (Mtoe)							Shares (%)		CAAGR (%)
	2000	2012	2020	2025	2030	2035	2040	2012	2040	2012-40
TPED	**88**	**141**	**173**	**188**	**205**	**224**	**251**	**100**	**100**	**2.1**
Coal	0	0	1	3	5	9	12	0	5	23.9
Oil	12	20	25	29	33	39	46	14	18	3.1
Gas	6	13	22	28	35	44	58	9	23	5.6
Nuclear	-	-	-	-	-	-	-	-	-	n.a.
Hydro	0	0	1	2	3	5	5	0	2	8.8
Bioenergy	70	108	123	125	127	125	124	77	50	0.5
Other renewables	-	-	0	1	2	3	5	-	2	n.a.

Table 3.21: Estimate of future energy balance in Nigeria [3]

With the existing energy policies in the country, Total Primary Energy Demand (TPED) is estimated to keep rising up to 251 Mtoe in 2040 (from 141Mtoe in 2012) as indicated in table 3.21, with the share of natural gas demand (23%) overtaking that of oil (18%), it is important to notice the bioenergy proportion (50%), which are mainly fuelwood and charcoal dominating the energy demand mix in the country in 2040. However, in the African century case, the proportions are as follows: bioenergy (42%), natural gas (28%) and oil (22%) (see appendix C), and for the country to achieve this level of mix, the gas pipelines need to be constructed, otherwise the expected level and share of gas demand may not be feasible. So the value addition of these pipelines is to enhance the proportion of natural gas in the energy demand mix by taking off the portion that would have been used by the bioenergy and oil, which are less clean than the gas. Looking at the transport sector, natural gas will not contribute in the transport fuel mix as the entire energy demand in the transport sector is estimated to come from the oil, and in order to introduce natural gas in the transport fuel mix in the country, infrastructures that will facilitate development of GTL products production for transport sector need to be in place and this significantly include the gas pipelines.

Therefore, the distributed GTL projects as facilitated by the gas pipeline projects are significant as they will help the country in a paradigm shift from traditional use of solid biomass and dominance of oil products to a cleaner, cheaper and diversified energy mix in the country. The GTL products can be used in both residential, transport and industrial sectors, whose consumption are estimated to rise especially in the industrial and transport sectors as shown in table 3.22, and these increase in consumption can be achieved even more if the GTL products are supplied in the market, and this can be optimised with the development of gas pipelines.

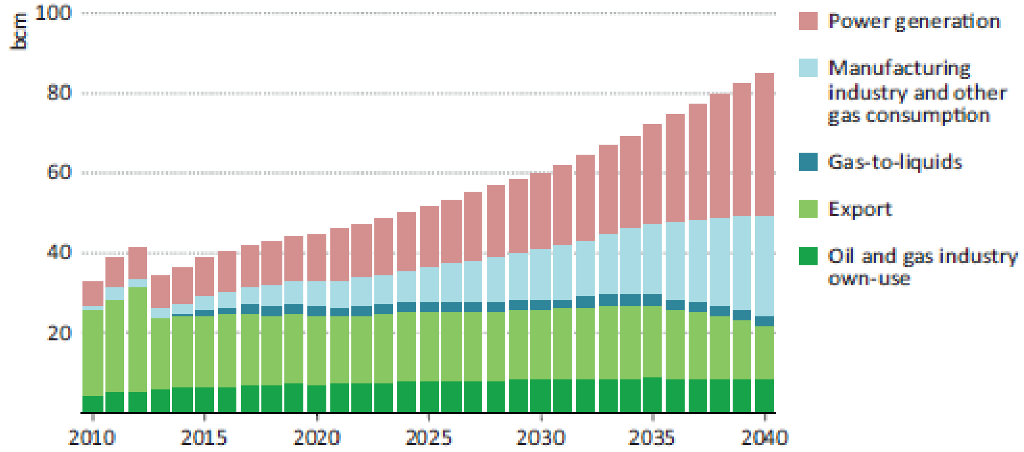
2012	Residential	Transport	Productive uses*	Total
Africa	307	90	142	538
North Africa	27	42	47	116
Sub-Saharan Africa	280	48	94	422
West Africa	120	16	26	161
Nigeria	93	10	18	121
Central Africa	24	3	7	33
East Africa	74	6	8	88
Southern Africa	62	24	54	139
Mozambique and Tanzania	19	2	6	26
South Africa	17	17	39	72

2040	Residential	Transport	Productive uses*	Total
Africa	435	161	313	909
North Africa	51	53	83	187
Sub-Saharan Africa	384	109	230	722
West Africa	152	40	93	286
Nigeria	99	26	73	198
Central Africa	43	6	17	67
East Africa	90	19	23	132
Southern Africa	99	43	96	238
Mozambique and Tanzania	36	5	24	64
South Africa	25	28	50	102

* Productive uses includes industry, services, agriculture and non-energy use.

Table 3.22: Total final energy consumption in Africa (Mtoe) [3]

Table 3.22, shows the estimate of the total final energy consumption in Africa under the current policy scenario, and portrays that of Nigeria to be higher than any other country in Africa, where the country's productive sector and residential sector consume more than the transport sector. In 2040, the resdiential sector will have energy consumption of 99 Mtoe, and 26 Mtoe for the transport sector and 73 Mtoe for the productive sector. The productive sector include the industrial, services, agriculture and non-energy use. With the Distributed GTL plants facilitated by the gas pipelines, the share of transport sector will increase as GTL diesel and gasoline will increase energy consumption in the sector, and by extention residential and industrial sectors will also have access to alternative fuels. This will then require huge investment in the gas sector to meet up with the expected level of gas production and supply in the country, which was estimated to increase significantly in the future in figure 3.15.



Notes: The drop in 2013 gas production was caused by an industrial dispute that interrupted operation of the LNG export terminal and also by the need during the year to repair theft-related damage to pipelines. It also reflects in part an underlying shortage of recent investment in gas field developments.

Figure 3:15: Future gas consumption by sector in Nigeria [3]

Figure 3.15 shows the level of gas production up to 2040 in Nigeria, with the assumption that the required investment are provided, which was estimated to be around $15-20 billion in the gas development infrastructures [3]. It shows that there will be increasing usage of natural gas in manufacturing industry and for some other gas consumption purposes, it shows decline in the exports signalling more gas utilisation within the country. Usage of gas in electricity will also keep rising. Therefore, GTL projects and gas pipelines can help facilitate the consumption in manufacturing industries, power sectors and for other gas consumptions. This is why both the GTL and CCGT plant were considered in the subsequent subchapter. The forecast shows relatively slow and steady increase in the GTL production, but this level of growth can increase with the eventual distributed GTL plants across the country as a result of the gas pipelines constructions.

C Other industrial uses and job creations:

As the productive sector in the country is estimated to be the second most energy consuming sector by 2040 after the residential sector, the gas pipelines will help provide industrial inputs and enhanced access to energy to the sector, it will help supply gas to the commercial sectors as well. Gas supplied by the gas pipelines will be used to produce Naphtha via GTL plant, and use in chemical industries and for chemical fertiliser plants. Nigerian economy needs to be diversified to avoid over reliance on oil and likely problem of resource curse. Agriculture is a potential sector that the economy can rely on, and provision of nitrogen fertilizers from the natural gas supplied through these pipelines can help enhance the productivity of the sector and facilitate more jobs. With these gas pipelines in place, ammonia processing plants can be built across the country to enhance agricultural productivity and facilitate all year round agricultural activities. This will also help put back many of the unemployed young people back to work, and potentially help reduce the unemployment rate in the country.

Construction of these gas pipelines can help improve gas supply that can be used for domestic usage for cooking, cooling, heating and micro power generation. Hospitals and academics can also be supplied with the natural gas to generate electricity. This will increase efficiency and productivity in these sectors. It will enhance job creations, as the gas pipeline constructions including the construction of subsequent distribution lines will create job opportunities. Maintenance of the gas pipelines and the compressor stations will provide job opportunities. And if the economic sectors are efficient and can produce more as a result of more gas supply, their potentials to create more jobs will be enhanced as the cost of production will be low.

The Nigerian textile industry that used to provide job for many have for long crippled down due to the increasing cost of production and largely caused by the cost of energy. The proposed gas pipelines construction can help supply gas to the cluster of these textile firms, which can be used to generate an exclusive electricity for their production, and thereby restoring jobs and productivity in the sector. Similarly, there will be a spread of industries across the country as the industrial inputs and access to energy is improved as a result of these gas pipelines.

D Energy Diversification and emission abatement:

In 2013, Nigeria produced 4.5 million TJ of crude oil equivalent, and produced only 1.2 million TJ of natural gas, and out of the produced natural gas, 44% are flared to the air, and this is because there are no sufficient gas development infrastructures to help move the gas to the demand areas [120] [241]. The Nigerian gas reserves stood at 5.2 tcm as at 2013, and which is far higher than the proven crude oil reserves of 37 billion barrels. Despite the relative larger gas reserves in the country, crude oil is being largely produced instead of the natural gas. Therefore, building the gas pipelines will help reduce the gas flaring and enhance more gas production in the country, thereby creating fuel diversification in the country. In 2013, Nigeria flared 12 bcm of natural gas, which represents 0.36% of the global gas production in the same year, and this volume is approximately close to the capacity of the of the NRO and SRO pipelines, which means if these pipelines are in place, they could have conveyed the flared natural gas to a market place, and avoid the loss. The loss attributed to the Nigerian gas flaring in 2012 was estimated to be around $1.8 billion [12], which is higher than the initial investment cost of the SRO, BRO, BSRO and NRO pipelines, but a bit higher than the BNRO and all possible gas pipeline routes option. This means the economic values of these pipelines are indirectly lost through gas flaring. Therefore, these gas pipelines if constructed can help avoid these losses by transporting the gas to the market place, which will eventually provide alternative fuel for various energy use.

Specifically in terms of emission reduction, there will be some level of reduction as a result of switch from using some conventional combustion fuels especially from the use of oil gasoline to natural gas gasoline. In 2012, around 45 million pounds of CO_2 were estimated to have come from using oil gasoline for road transport [242]. Natural gas emits lower CO_2, and if a proportion of such road transport fuels were used from natural gas, it would have reduced the level of emissions, because for every quantity of product switch, there will be between 25% and 30% reduction in emission [78]. There is zero use of natural gas for road transport in Nigeria, and if these gas pipelines will come on board, the 25%-30% emission reduction can be achieved, as the gas supply will be enhanced, and eventually promote production of natural gas products. Table 3.23 shows the level of emissions from each of the fuels per unit of energy [78].

Fuel	Pounds of CO_2 per MMBtu
Oil Gasoline	157.2
Oil Diesel fuel	161.3
Oil Jet kerosene/fuel	156.3
Natural gas	117

Table 3.23: CO_2 emission by fuels [78]

From table 3.23, according to EIA, natural gas has lower pounds of air pollutions per MMBtu, which is 117 compare to that of 157.2 for oil gasoline, 161.3 for diesel fuel and 156.3 for jet kerosene. Therefore, natural gas is 26%, 27% and 25% lower in terms of CO_2

emissions compare to that of gasoline, diesel, and jet kerosene respectively. Specifically, replacing conventional diesel with GTL diesel will cause the level of emissions to reduce significantly. Despite the very low sulphur of the GTL diesel, the following emissions are lower when using the GTL diesel compare with the conventional diesel fuel.

Emission	GTL Diesel Fuel g/kw-hr	Conventional Diesel Fuel g/kw-hr
Hydrocarbons (HC)	0.21	0.25
Carbon Monoxide (CO)	0.67	0.94
Nitrogen Oxides (NO_x)	6.03	7.03
Particulate Matters (PM)	0.08	0.15

Table 3.24: Emissions from GTL and conventional fuels [243]

From table 3.24, it shows lower emissions from GTL diesel fuel compare with the conventional diesel fuel, and it shows if GTL diesel fuel is used instead of conventional diesel fuel, there will be 16% reduction in Hydrocarbons, 29% reduction in Carbon Monoxide, 14% reduction in Nitrogen Oxides, and 47% reduction in Particulate Matters. And these reductions can be achieved if there are competitive GTL plants that produces different GTL products, and for these plants to operate, there is need for reliable supply of natural gas, which the gas pipelines will help provide. Even if complete switch is not possible, a reduction in consumption of oil product for gas products can help reduce the level of carbon emissions in the country. It is estimated that the share of total CO_2 from oil products will reduce by 2040 in the country, and this will be attributed to the lower growth rate in oil consumption as compare to that of the gas in the future with the assumption that more gas investment will take place.

	CO_2 emissions (Mt)							Shares (%)		CAAGR (%)
	2000	2012	2020	2025	2030	2035	2040	2012	2040	2012-40
Total CO_2	49	84	124	155	192	244	312	100	100	4.8
Coal	0	0	4	13	22	36	49	0	16	24.1
Oil	35	58	71	80	92	110	133	68	42	3.0
Gas	14	27	50	62	77	98	131	32	42	5.8
Power generation	12	24	35	49	64	88	122	100	100	5.9
Coal	-	-	4	13	22	35	48	-	39	n.a.
Oil	5	10	9	8	6	6	7	42	5	-1.5
Gas	7	14	22	28	36	47	68	58	56	5.8

Table 3.25: Future CO_2 by source in Nigeria [3]

Table 3.25 shows the future estimates of the environmental cost of using oil, gas and coal in Nigeria up to 2040, it shows 38% decline in total CO_2 from oil consumption, and 31% increase in CO_2 from gas consumption. This is attributed to the estimated increase in gas production and consumption as indicated in figure 3.15, which means there will be substitution of oil products with the gas products, and as a result the decline in the share of CO_2 from oil consumption reduction is higher than the increase in the share of CO_2 from increase in the gas consumption. The coal will by then contribute 16% of the total emissions. More of these reduction of CO_2 can be achieved if the substitution come from natural gas, as it is cleaner than both oil and coal, and these can only be achieved if the identified gas development projects are implemented.

3.6 Financial Benefit of Gas Development Projects in Nigeria

Since the main concern of this research is domestic gas supply in Nigeria, only three of the previously discussed gas development projects, which are related to the domestic gas supply will be considered for the costs and benefits analysis. These three projects are Gas to Power (GTP), Gas to Liquid (GTL) and Gas Pipeline. Gas pipeline costs and benefits analysis were already discussed, which is the case study for gas transportation project in this research. The costs and benefits analysis of the case studies for the gas transformation/development projects will be discussed in this sub-chapter i.e. GTP and GTL.

The natural gas can be used for its energy value or it can be used for its chemical value, and since one of the research enquiries is the economic analysis of the relevant and specific gas uses or development projects, this research tries to explore the economic costs and benefits of one case study each for the two types of the gas uses (energy and chemical use), which are Gas to Power for the energy use and Gas to Liquid for the chemical use. The specific choice of electricity and synthetic fuels projects is justified by their ability to transform the lives of the population in the country, through improved access to electricity, cleaner and competitive transport fuels as well as industrial feedstock, which will help improve the welfare and productivity of the economy. More specific justifications for this two projects are mentioned below.

A. CCGT project:

The CCGT project is used as the case study for the energy use of the gas, and it was selected for this comparison, because Nigeria is lacking sufficient electricity supply. Like highlighted earlier, only 48% of Nigerians have access to electricity in 2010 [224], and in 2014, Nigeria was ranked 185th in terms of access to electricity per capita [28]. In 2011, the Nigerian electricity consumption per capita was 189kWh [28]. This lowered economic opportunities in the country and makes the cost of production more expensive, where cost of energy is estimated to contribute 40% of the cost of production in the manufacturing sector [225]. Similarly, 63% of the electricity production comes from the gas turbines in 2012 [168], and this proportion is estimated to reach up to 70% in 2030 [227]. Some of the existing gas turbines are not operating at optimum level due to technical issues and shortage of gas supply, and they are largely concentrated at one region (South) [170]. This led to the increasing loss of energy in the process of transmitting the electricity, and also pose the challenge of the limited operational capacity of the Nigerian electricity transmission networks, which is 4, 800MW in 2015 [222]. As shown previously in figure 3.11, the electricity demand will grow up to 1 billion MWh by 2030, where it showed that there will be significant increase in demand for energy in the residential, industrial and service sectors, which all necessitate for consideration for more efficient sources of energy, which the CCGT project can help achieved.

Therefore, in order to enhance electricity supply and accessibility in the country, which will lead to cheaper cost of production, more efficient gas power plants need to be established. This will also help spread the electricity production across the country, and help create job opportunities and reduce the electricity loss in the process of transporting the electricity to far distance places. Improving electricity will help encourage foreign and local investment, which will eventually boost the economic productivity. Therefore, the CCGT projects are essential for economic development and for improvement of domestic gas utilization in line with the objective of the gas master plan, hence the choice of the project in this comparison.

A. GTL project

In 2012, more than 80% of the Nigerian total primary energy consumption came from traditional solid biomass and waste [16]. The residential sector largely use traditional biomass for cooking purposes, and these cause harmful effect on the health of the households and cause deforestations. The supply of the cooking kerosene and gas are not sufficient and unaffordable to many households. Air transport is increasing with many airports and airliners are now operating in the country, the demand for jet kerosene is also increasing. "GTL kerosene is an alternative to conventional oil-based kerosene. It can be used for heating and lighting, but its primary use is expected to be for aviation, contributing to the diversification of the aviation fuel supply" [244]. The diversification of sources of a cleaner heating and jet kerosene will help provide more affordable access to the energy products due to the resulting competition and low cost as a result of domestic production, and it will end the dominance of the oil products. This will also help enhance movements of goods and services within and outside the country due to improved supply of transport fuels, it will also help improve the wellbeing of the people and improve the environmental condition in the country due to use of cleaner fuel. Therefore, the GTL project is essential in providing alternative fuel that can be used in residential and commercial sectors of the economy, which were estimated to consume more of energy as earlier mentioned. The export of gas is also projected to slightly reduce as shown in figure 3.15, which indicates possibilities of more demand within the country that will necessitate domestic supply, which the GTL can help facilitate.

Similarly, 70% of the Nigeria's domestic petroleum products are imported from abroad, thereby making the price of these products relatively expensive. Motor gasoline is largely consumed for road transport, and the government subsidises consumption of this product, and this costs government around $7 billion in 2012 [239]. In order to provide alternative to the motor gasoline, reduce the cost of importing the petroleum products, increase domestic supply of petroleum products, provide cleaner product and reduce the cost of subsidy, GTL gasoline need to be supplied at relatively competitive volume. The GTL products supply chain has the potential to create job opportunities as well. These are also reasons why the GTL project is considered in this comparison.

In addition, Nigeria is at the process of diversifying its economy and establishing more manufacturing industries, and with the new administration in 2015, there are hopes that the existing refineries will be optimised and new ones built. One of the industrial inputs that can be used to facilitate production of many petroleum products in manufacturing sector and refineries is Naphtha, which GTL plant produces. "GTL Naphtha is an alternative to high quality feedstock for chemical manufacturing that make the building blocks for plastics. It offers superior yields of ethylene/propylene and lower feedstock costs than conventional Naphtha"[244]. GTL Naphtha can be used "to produce additional high-octane gasoline components, and it can be used as solvents, cleaning fluids, paint and varnish diluents, asphalt diluents, rubber industry solvents, dry-cleaning, cigarette lighters, and portable camping stove and lantern fuels. It can also be used in the petrochemicals industry as feedstock to steam reformers and steam crackers for the production of hydrogen (which may be converted into ammonia for fertilizers), ethylene and other olefins" [31].

This means the GTL Naphtha can be used in production of ammonia for fertilizer production, which will help boost agricultural productivity, and help substitute the oil and gas sectors as the major sources of income in the economy. The GTL products do not require unique transportation infrastructures and can be mixed with the conventional petroleum products. These are the reasons why the GTL plant is considered important, and it is in line with delivering economic advantage using the natural gas, which is the main concern of this research. Therefore, the viability of the two identified important projects will now be assessed in order to inform investors and government of the business profitability of these projects in the country.

Based on the above mentioned relevance of these two projects, an economic assessment of the viability and sensitivity of these projects in Nigeria were made, so that investors can make informed decision when deciding among these two important projects in the country. The viability assessment is also useful in order to identify the less viable and less attractive project among the two, so as to provide recommendations and possibilities of incentivizing investment for the unviable project (if any) given its relevance as earlier mentioned.

3.6.1 Profit Comparisons of GTP and GTL Projects

The two projects are assumed to be completely opened for private investments to complement the effort of the government in exploring the necessary gas utilization potentials in the country. The decision for private investment is always motivated by the level of economic returns on the investment, hence the need to assess the viability of these two investment opportunities in the country. Therefore, profit comparisons will be administered on the two projects (Gas to Power using CCGT project and GTL) using NPV, IRR and payback period techniques. The three profit comparison techniques are essential as each of the techniques has a peculiar advantage and possibly different finding.

3.6.2 Data and parameters

A CCGT plant in Nigeria

In order to analyse the net cash flows of a CCGT plant in Nigeria, we will need to have an idea of the plant's maximum capacity, the investment cost of each capacity (per MW or GW), the rate of energy output in one year (MWh or GWh), and the electricity price per unit of electricity sold (MWh or GWh). First we will assume that a single CCGT plant with a capacity of 400 MW, where multiple of these plants in one site gives us one power station. The assumption for 400 MW capacity per plant was made in line with Cosic M. and Puharic, M. (2011), who stated that "the commonly used CCGT power plant installed capacity is around 400 MW" [245]. The proposed Nigerian power stations are projected to be located at gas pipelines' ends, making it possible for a more distributed power stations in the country. If these power stations can be developed, it can meet the highest capacity target in the country.

For this analysis, the Nigerian Domestic Supply Obligation (DSO) gas price will be used, which is the transitional regulated gas price at which gas suppliers must sell for the domestic power generation, this ensures minimal of 15% profit margin on the cost of the gas production. Under the DSO, the gas suppliers must also sell a portion of their produced gas to the domestic market before selling abroad. On 2nd August, 2014, the Nigerian government adjusted the DSO gas price to $2.50/MMBtu from $2.00/MMBtu [189]. This made the DSO gas price closer to the market price, but still lower as at that time. The market gas price in the country was then (in 2014) $3.50-$4 per MMBtu, and as at June 2015 the market price of natural gas in the country was $2.87/MMBtu [246]. The DSO gas price is adjusted regularly, but last adjustment as at July 2015 was in August 2014. Similarly, the cost of transporting the gas to the power plant need to be accounted in the fuel cost, as the DSO gas price does not include the cost of transporting the gas. Like already established under the gas pipeline economics, the gas transportation cost in Nigeria is $0.80/MMBtu, and the total fuel cost will then be $3.30/ MMBtu.

We will use a single plant in estimating the annual cash flows, and the net cash flows of one plant can be multiplied by the number of the plants in the station. For the estimated maximum annual energy output of the plant, we will multiply the plant's capacity by the total number of hours in one year. Therefore, there will be 3,504,000 MWh of electricity if the plant is to operate at the maximum capacity in particular year (8,760 hours in a year multiplied by 400MW of the plant's maximum power generating capacity). However, we have to account for the plant's capacity factor, which is the ratio of the actual energy output of a plant to its maximum potential output. For example, the CCGT average capacity factor in the UK between 2007 and 2012 as estimated by the UK department of energy and Climate Change was 56% [247]. In USA, it was observed to be around 70% in the first seven months in 2014 [248]. Due to low energy mix and supply of electricity in Nigeria, the Nigerian Bulk Electricity Trading Company set up 80% as capacity factor for new CCGT plants, availability rate of 95% [237] and a thermal efficiency of 60%, going by the work of Carapellucci, R. and L. Giordano (2013) and Seebregts A.J. (2010) [52] [249]. From 2001 to 2010, the average capacity factor of existing power plants in Nigeria was between 20.8% and 78.2%. Some of the plants were not fully operational due to technical issues or short of gas supply. However, if these plants would have been in good technical conditions and have sufficient gas supply, they would have an average capacity factor of 80%, hence the choice of 80% as capacity factor in our analysis [250] [251].

For the wholesale electricity price, we will use the data as internally sourced from the Nigerian Bulk Electricity Trading Company (NBET) for 2015 for a new entrant, which is stipulated at N12, 615/MWh, and converting this to US dollars using exchange rate as at June 2015 (N198.85=$1) [252] [253], the wholesale contract price per MWh is $63.44 [238].

For the investment cost, we will adopt $1.2m per Megawatt capacity as sourced from the NERC [231]. EIA reported $962 thousand per Megawatt capacity as investment cost for Nigeria in 2009, which is 25% increase in four years compare to the 2013 figure reported by NERC [254]. IEA reported $1.1m per Megawatt capacity in 2009 [255]. The estimate by the Energy Technology Systems Analysis Programme (ETSAP) is also similar to that of IEA. ETSAP estimated it to be $1.1m per Megawatt capacity [249]. The estimate by NERC will be adopted because it is the official electricity regulatory body in Nigeria, and its figure is peculiar to Nigeria and is more recent. The investment cost includes the cost for "engineering, building, procurement, construction of transmission and fuel delivery facilities, etc." [256].

This means that the capital cost of the referenced plant with 400 MW plant capacity is $480 million, without consideration of carbon capture technology [257]. This amount is not so much different with the reported cost figure of CCGT plant in US with 483 MW capacity by the congregational research service, as they used $1,200/kW as capital cost to estimate the capital cost of $530 million for the Avenal Power Project [256]. For the annual operation and maintenance costs, we will adopt the cost percentage reported by International Energy Agency (IEA) in 2010, which is 4% of the investment costs per year, and which is $19.2 million [255]. Operation and maintenance costs include but not limited to periodic servicing of machines, wages to staff and engineers who operates the machines, supervision of workers, safety and security, communications, chemical supplies, facility fees, administrative expenses, plant transport equipment, electric charges, lubricants, leases, insurance, periodic overhauls and overheads [258].

Now to generate 2,663,040 MWh (at 95% availability rate and 80% capacity factor of 3,504,000 MWh) of electricity, we will need 15132772.03 MMBtu of natural gas feeds, which is derived by dividing the 2,663,040 MWh by 60% thermal efficiency and then multiply by approximately 3.41 as a conversion factor from MWh to MMBtu [249, 259]. This gives the total fuel cost of approximately $50 million (averagely $18.75/MWh as fuel cost per MWh) in a year. Where $7.21/MWh is going to be the average O and M cost per MWh [233].

The choice of 30 years as operational period of the plant was informed by the work of Carapellucci, R. and L. Giordano (2013), Yu. A. Radin, and Kontorovich T. S.(2012), and Seebregts, A.J. (2010), who argued that the average economic lifetime of a CCGT power plant is 30 years. However, the operational period of CCGT plant can be more than 30 years[52] [260] [249].

The CO_2 from the energy combustion in the plant is going to be 53.07kg/MMBtu (53.07*15132772.03 MMBtu), which is equals to 803096211.5kg of CO_2. According to Ewah O. et al (2011), there is no emission/carbon tax for power plants in Nigeria, which is why carbon tax will not appear in the plant's costs. Several other searches and contacts also proved absence of the carbon tax for power plants in Nigeria [57]. However, there are emission taxes for gas flaring at production sites, which is about $3.5 per Mcf of gas flared as at 2008 reviewed regime [261] [12].The price and share of feed gas cost underlines the rising concern about the costs of running a CCGT plant especially in a place where the price of feed gas is very expensive. CCS technology is not assumed on the referenced CCGT plants, but in the case of future installations, CCGT plants with CCS technology are 35%- 60% more expensive than the CCGT plants without it [60] [59]. Even though, this is an American multiplier, but few researches on the cost of CCS technology in Nigeria have shown that there will be a similar cost percentage increase in the overall costs of the CCGT plant in Nigeria [262] [263].

Similarly, the Nigerian corporation tax rate of 30% is used as a tax rate against the gross annual profit. The Nigerian Electricity sector is regulated by the Nigerian Electricity Regulatory Commission (NERC) who operates a Multiyear Tariff Order (MYTO), which set up the final electricity tariff constant for over long period of time (15 years) with little adjustment annually to capture the inflation effects and accommodate any sudden change in the price of natural gas [231, 264].

The Nigerian prime lending interest rate of 16.90% as at March 2015 is used, as the investment capital is assumed to be funded through a capital structure of 70:30 for debt and equity as already established and assumed in the current Nigerian MYTO model [188] [189]. The prime lending rate is used because of the capital intensiveness of the projects and long period of the loan. In addition, because the government want to encourage investment in the gas development projects, and as such can encourage commercial bank to give loans aim for investment in the gas development sector at the prime lending rate. Therefore, the cost of debt for the CCGT plant after tax will be:

$$k_d = 0.169 * (1 - 0.30) = 11.83\% \tag{3.31}$$

The cost of equity as defined in equation 3.12 will capture the expected investors return and the business risk. The business Beta of 0.50 for the Nigerian new CCGT plant is adopted from the Nigerian MYTO II model as already explained under methodology [188]. The business Beta measures the level of risk or reaction of a price of a share in a company to the overall stock market [195]. Like already discussed under the gas pipeline capital cost analysis, the free risk rate of 13.04 percent, which is the average yield of a government bond in the country [196] is used, and an expected market return of 24.19 percent is assumed, which is in line with the estimated Equity Risk Premium (ERP) of 11.15 percent accounting for the country's risks factors as already discussed under cost of capital methodology discussion for the gas pipeline analysis. The expected market return is a combination of the ERP and the risk free rate. Therefore, the cost of equity for the CGGT plant will be:

$$k_e = 0.1304 + \ 0.5(0.2419 - 0.1304) = 0.18615(\ 18.62\%) \tag{3.32}$$

Now, the weighted average cost of capital will be:

$$WACC = (0.30 * 0.1862) + (0.70 * 0.1183) = \ 0.13867(\ 13.87\%) \tag{3.33}$$

Therefore, 13.87% will be the weighted average cost of capital for the project and will be used to account for cost of capital and time value of money in the cash flows of the project.

This will then be used as the discount factor, which will be used to deflate the annual cash flows to account for cost of time and capital. With reference to equation 3.9, a depreciation rate of 3.33% was derived, which is the rate at which the plant depreciate annually to arrive at a book value of zero at the end of the period. However, the plant is expected to have a salvage value of $174 million, which was derived with reference to equation 3.8. The remaining capital value of the asset was depreciated using the straight line depreciation method as earlier explained, which is around $10 million as annual depreciation. The tax saving as a result of depreciation is approximately $3 million, which is deducted from the total tax payment to arrive at total tax payable. The tax benefit was derived by multiplying the tax rate by the annual depreciation figure. The annual cash flow of $73 million was derived by deducting the fuel cost, operating cost and total tax payable from the total revenue. These are all summarised in table 3.28.

B GTL plant in Nigeria

For the Nigerian GTL plant assumptions, we will consider a GTL plant capacity that is equivalent to the CCGT plant's capacity considered above, this is because, we want to rank the two projects in Nigeria to see which one will be more profitable at the prevailing economic situation in the country. We will convert the CCGT plant's maximum annual capacity of 3504000 MWh into barrels per year, which is 2,067,360 barrels per year (using conversion factor of 1 MWh equals to 0.59 of oil barrel equivalent). Still adopting the 60% thermal efficiency, 95% availability factor and 80% capacity factor, the annual output will then be 1,571,193.6 barrels per year.

Therefore, our referenced GTL plant's annual operational output will be 1,571,193.6 barrels per year of oil diesel, kerosene and naphtha. The plant total output is assumed to be shared between the three products on the ratio of 53 percent to 20 percent and to 27 percent for oil diesel, kerosene and naphtha respectively going by the relevance of their uses and this is in line with the proposed Nigerian E-GTL plant scheduled output.[48]. That means, the plant will be producing 832,732.61 barrels of oil diesel, 314,238.72 barrels of kerosene and 424,222.27 barrels of naphtha yearly for the period of 30 years, similar economic lifetime with the CCGT plant is adopted. The oil diesel will serve as a substitute to the conventional transport fuels, and the Kerosene will be used for jet fuel in the aviation industry, and can be used for heating, lighting. The Naphtha is for industrial and petrochemical feedstock [47]. However, it is important to note that this level of output is used just for the purpose of comparison with the CCGT plant. It is at low level considering the average GTL plant capacities in the world. The on-going Nigerian Escravos GTL project has the proposed capacity of 34,000 barrels per day at the initial stage [35].

The amount of gas feeds of 14537115.85 MMBtu is required, which is derived by dividing the annual output of 1,571,193.6 barrels by the 60% thermal efficiency and then multiplied by the conversion factor of approximately 5.5 MMBtu per barrel. This amount is almost similar to the quantity of gas as required by the CCGT plant. Similarly, the cost of the gas feeds of $3.30 per MMBtu is used as the price of gas as already established, which constitute the DSO gas price and transportation cost. The total amount for the gas feeds for a year will be approximately \$48 million.

For the capital cost, the average capital cost of the Nigerian Escravos GTL (EGTL) plant is adopted. As mentioned above, Nigerian Escravos GTL plant is proposed to have the annual output of 12410000 barrels per year (34000 barrels per day), and it has the estimated capital cost of \$8.4 billion as at the final review of the capital cost. The EGTL plant initial estimated cost was \$1.7 billion, which was revised twice. In the first review, the project was escalated to \$5.9 billion, and in the second review it escalated to \$8.4 billion [48] [69, 174]. Therefore, the latest figure, which is \$8.4 billion for Nigerian GTL plant is adopted. That means the per capita capital cost will be \$8.4 billion divided by the number of barrels in a year (12410000), which gives us \$677 per barrel. Pearl GTL plant faced similar cost escalation from \$5 billion to \$18 billion [265]. Now, for our referenced GTL plant that has the annual estimated maximum capacity of 2,067,360 barrels per year will then have the capital cost of \$1,399,602,720.00 (2,067,360 barrels per year multiplied by \$677). For the annual operating cost, we will adopt the \$5 per barrel of yearly output as reported in many literature and in GTL economic reports [266] [35] [135].

For the prices of the products; the GTL products prices are influenced by the crude oil price, as the crude oil price affects the prices of oil products, which are substitute to gas products, and also affects the cost of the gas feeds used in the GTL plant, being substitute commodities. Therefore, the GTL products' prices are gauged with the crude oil value at the refinery gate, which is the cost of the crude oil plus the transportation cost and other fees paid by the refiner [243], which is termed crude oil refinery acquisition price (RAC). Some additional amount are also added to account for the GTL products' treatment and higher cleanness. For the GTL distillate prices (in this analysis, Diesel and Aviation Turbine kerosene (ATK)), an additional cost was suggested to be between \$4-\$8/bbl on top of the crude oil price (RAC) [267]. Alsalchi (2008) and Fleisch (2002) suggested an additional cost for wholesale GTL distillate to be around \$5.60/bbl, which this research will adopt, because it is also the approximate average of the range proposed by Chedida (2007) [243] [268]. For the Naphtha wholesale price, an additional cost of \$4/bbl is used going by the work of Michael (2005) [269].

The projected average crude oil price for the period of 29 years from 2012 to 2040 is used, which is projected to be averaged around \$100.43/bbl as reported in the Annual Energy Outlook 2015 by US EIA [270] using West Texas intermediate spot and 2013 constant dollar.

The period of this projection is very close to the period of the project's lifespan of 30 years, and the projection covers the current realities of the market. The crude oil price was above $100/bbl in 2008, 2011, 2012, 2013 and up to mid-2014 for the Nigerian Forcados spot price as reported in the 2015 BP statistical review for world energy [4], therefore, it is not surprising to have the average forecast real price of oil up to $100/bbl.

Therefore, the crude oil RAC price can be derived by adding the Nigerian crude oil transportation cost of $1.5 per barrel, which is assumed to be constant for the period [271], which means the crude oil RAC price will be $101.93 per barrel. The idea of using projected price was informed by the work of Chedida and Ghaja (2007), and because the business is estimated for the future period. The crude oil price is fluctuating, and the price might go higher or lower than the forecast, which will affect the price of the GTL products. Therefore, for the price of GTL Diesel and ATK, it will be $107.53/bbl, and for the Naphtha price, it will be $105.93/bbl. Using the crude oil price as at July 2015, which was $43.87/bbl, and comparing what would have been the price of the domestic GTL diesel ($50.97/bbl) with the Nigerian oil diesel maximum indicative benchmark depot price of $89.68 (N112.16/litre) as at 16th July 2015 [272], the GTL diesel price will be lower by $38.71/bbl. The price of the Nigerian oil diesel also fluctuates regularly [272] [273].

Comparing with the Nigerian ATK, according to the Nigerian petroleum product pricing regulatory agency, the landing cost of the ATK was N103.76 per litre as at 16th July 2015, which was $82.96 per barrel using the specified exchange rate ($1=N198.85) [274] [275]. This means the cost of domestic GTL ATK at this oil price level is $31.99/bbl lower. This is again likely due to the low crude oil price in 2015 as highlighted above. Comparing the GTL Naphtha price with the European Naphtha price of $66 per barrel [276], which is the average price for June 2015, the price of the Nigerian GTL Naphtha at the July 2015 oil price would have been lower by $16.63/bbl. The European Naphtha price is used, because there is no active Naphtha market in Nigeria. This price is similar to that of the US, which was also $66 per barrel [277] [278] [279] [280]. A corporation tax payment of 30% is also applied to the gross annual profit as applied in the CCGT plant.

With reference to equation 3.9, a depreciation rate of 3.33% is the rate at which the plant depreciates annually to arrive at a book value of zero at the end of the period. However, the plant is expected to have a salvage value, which was derived with reference to equation 3.8 as $506 million. The remaining capital value of the asset was depreciated using the straight line depreciation method as earlier explained, which is approximately $30 million as annual depreciation. The tax saving as a result of depreciation is approximately $9 million, which is deducted from the total tax payment to arrive at total tax payable. The tax benefit was derived by multiplying the tax rate by the annual depreciation figure.

The cost of capital for the GTL plant will also account for the cost of debt and equity, as the project's capital structure of 60:40 for debt and equity is applied, and this is in line with the capital structure of an average oil and gas listed companies in the country, with particular reference to Nigerian Oando plc [187] [23]. To arrive at the weighted average cost of capital, the cost of debt and cost equity will be calculated as follows. The after tax cost of debt for the GTL plant using the prime lending rate of 16.90% as earlier explained will be:

$$k_d = 0.169 * (1 - 0.30) = 11.83\% \quad (3.34)$$

The cost of equity as defined in equation 3.12 will capture the expected investors return and the business risk. Because there is no available data for Nigerian stock market for GTL business, as there are no listed GTL companies in the country, the average $Beta$ of a seven listed oil and gas companies (BOC Gases Nigeria PLC, Conoil PLC, Eterna Plc, Forte Oil Plc, Mobil Oil Nigeria Plc, MRS Oil Nigeria Plc, Oando Plc) in the country is used as the proxy Beta for the investment, which was 0.86 as at July 2015 [200] [187] [201, 202]. This Beta is higher than what Usman (2006) assumed for Nigerian GTL project, where he adopted a Beta of some major oil and gas companies in US in 2006, which was 0.77 [135].

Like already discussed under the gas pipeline's capital cost analysis, the free risk rate of 13.04 percent, which is the average yield of a government bond in the country [196] is used, and an expected market return of 24.19 percent is assumed, which is in line with the estimated equity risk premium of 11.15 percent accounting for the country's risks factors as already discussed under cost of capital methodology discussion for the gas pipeline analysis. The expected market return is the combination of the ERP and the risk free rate. Therefore, the cost of equity for the GTL project will be:

$$k_e = 0.1304 + \ 0.86(0.2419 - 0.1304) = 0.22629\ (22.63\%) \quad (3.35)$$

Now, the weighted average cost of capital will be:

$$WACC = (0.40 * 0.2263) + (0.60 * 0.1183) = \ 0.1615\ (\ 16.15\%) \quad (3.36)$$

Therefore, 16.15% will be the weighted average cost of capital for the project and will be used to account for cost of capital and time value of money in the cash flows of the project, by using it as a discount rate. The project's annual cash flow of $88 million was derived and these are all summarised in table 3.26.

3.6.3 Net Present Value:

Using NPV in assessing investment projects provides opportunity to measure the real time value of money. Monetary values of investment projects are adjusted (discounted) based on timing. For example, an investor will prefer to have $100 today than $110 in a later day, in order to avoid the risk of something going wrong before the later date or to provide him/her the opportunity to make another investment that will generate more revenue before the later date. The NPV technique accommodates the possibility of currency devaluation due to the natural rate of inflation. Over a period of years, purchasing power of every unit currency reduces no matter how little, that is to say the money at hand today is preferred than money at hand on later date. So in order to appraise the future capital investment return, there is need to adjust (discount) the future monetary returns to the present value of the money today, so that investor can have idea on the real future cash flow of the business based on the present value of the cash flows [281].

GTL products being a substitute to the existing petroleum products in the country especially petrol can have a favourable market in the country. The supply of the GTL products especially GTL diesel will immediately create its demand. The GTL products can be well preferred as long as there is a relative lower price of crude oil and gas feeds. To academically prove the project's profitability in the country, a Fischer Tropsch GTL project is assumed to be established in Nigeria based on the parameters identified above.

Table 3.26 indicates all the project assumptions as well as the estimated cash flows of the GTL project in Nigeria, other assumptions are adopted from the work of Nwaoha et al (2014) and Michael (2005) [43] [117].

GTL maximum output (bbl/yr)	2,067,360
Capacity Factor	80%
Operational availability	95%
Annual GTL output (bbl/yr)	1,571,193.6
Thermal Efficiency	60%
Gas feeds (MMBtu)	14,537,115.85
Natural Gas Feedstock price ($/MMBtu)	3.3
Crude oil price (projected average $2013) $/bbl	100.43
Crude oil RAC price $/bbl	101.93
Diesel Price ($/bbl) whole sale	107.53
Naphtha Price ($/bbl)	105.93
Aviation Turbine Kerosene Price ($/bbl)	107.53
Period of the business covered (years)	30
Capital Cost ($)	1,399,602,720
Debt ($)	839,761,632
Equity ($)	559,841,088
Cost of Equity	22.63%
Cost of debt	11.83%
WACC	16.15%
Tax rate	30%
Operation and transportation cost ($/bbl)	5
Annual diesel output (bbl)	832,732.61
Annual Naphtha output (bbl)	424,222.27
Annual ATK output (bbl)	314,238.72
Annual sales ($)	168,271,692.17
Annual operating cost ($)	7,855,968.00
Annual cost of feed gas ($)	47,972,482.32
Gross profit ($)	112,443,241.85
Depreciation rate	3.33%
Salvage Value ($)	506,182,437.96
Annual Depreciation ($)	29,780,676.07
Annual Tax saving from depreciation ($)	8,934,202.82
Annual tax payment ($)	33,732,972.56
Net Tax payable ($)	24,798,769.74
Annual Cash flow ($)	87,644,472.12
Additional cash flow in final year	
Salvage value ($)	506,182,437.96
Tax on selling at salvage value ($)	151,854,731.39
End year Net Gain ($)	354,327,706.57

Table 3.26: Annual Cash flow of the GTL project in Nigeria

Table 3.26 summarises the basic inputs and the cash flows of the GTL plant in Nigeria, which will be used for the NPV calculations. The GTL project will have an after tax annual cash flow of approximately $88 million. This will then be discounted using the WACC of 16.15% every year as earlier established. The investment capital as earlier mentioned is funded through debt and equity. The sum of $840 million will come from debt and the sum of $560 million will come from equity. Therefore, going by the nominal annual net cash flow, the business will earn around $3 billion for the period of 30 years. The end year cash flow will have an addition of after tax net cash flow of $354 million as a result of the sale of the plant at the salvage value. Other parameters in table 3.26 were earlier discussed. Table 3.27 shows the NPV calculations of the GTL in the country.

Years	Net cash flow	Discount factor	Discounted net cash flow	Cumulative DCF
0	- 1,399,602,720.00	1	-1,399,602,720.00	- 1,399,602,720.00
1	87,644,472.12	0.8609586	75,458,264.27	- 1,324,144,455.73
2	87,644,472.12	0.7412498	64,966,443.51	- 1,259,178,012.22
3	87,644,472.12	0.6381854	55,933,419.93	- 1,203,244,592.29
4	87,644,472.12	0.5494512	48,156,360.35	- 1,155,088,231.94
5	87,644,472.12	0.4730547	41,460,633.83	- 1,113,627,598.11
6	87,644,472.12	0.4072806	35,695,890.33	- 1,077,931,707.78
7	87,644,472.12	0.3506517	30,732,684.68	- 1,047,199,023.10
8	87,644,472.12	0.3018966	26,459,569.97	- 1,020,739,453.13
9	87,644,472.12	0.2599205	22,780,595.00	- 997,958,858.12
10	87,644,472.12	0.2237808	19,613,149.77	- 978,345,708.36
11	87,644,472.12	0.192666	16,886,110.47	- 961,459,597.89
12	87,644,472.12	0.1658775	14,538,242.46	- 946,921,355.43
13	87,644,472.12	0.1428136	12,516,825.25	- 934,404,530.17
14	87,644,472.12	0.1229566	10,776,468.67	- 923,628,061.50
15	87,644,472.12	0.1058606	9,278,093.66	- 914,349,967.85
16	87,644,472.12	0.0911416	7,988,054.76	- 906,361,913.08
17	87,644,472.12	0.0784691	6,877,384.65	- 899,484,528.43
18	87,644,472.12	0.0675587	5,921,143.64	- 893,563,384.79
19	87,644,472.12	0.0581652	5,097,859.69	- 888,465,525.10
20	87,644,472.12	0.0500778	4,389,046.27	- 884,076,478.83
21	87,644,472.12	0.043115	3,778,787.25	- 880,297,691.58
22	87,644,472.12	0.0371202	3,253,379.48	- 877,044,312.10
23	87,644,472.12	0.0319589	2,801,025.12	- 874,243,286.98
24	87,644,472.12	0.0275153	2,411,566.74	- 871,831,720.24
25	87,644,472.12	0.0236896	2,076,259.19	- 869,755,461.05
26	87,644,472.12	0.0203957	1,787,573.26	- 867,967,887.80
27	87,644,472.12	0.0175599	1,539,026.61	- 866,428,861.18
28	87,644,472.12	0.0151183	1,325,038.24	- 865,103,822.94
29	87,644,472.12	0.0130163	1,140,803.10	- 863,963,019.84
30	441,972,178.69	0.0112065	4,952,943.54	- 859,010,076.30
	2,983,661,870.11		**-859,010,076**	

Table 3.27: NPV of the GTL plant in Nigeria

Reference to table 3.27, investing the sum of approximately $1.4 billion in a Nigerian GTL project with the combined production output of 1571193.6bbl/yr for diesel-oil, jet kerosene, and Naphtha, at a discount rate of 16.15%, an NPV after tax of negative $859 million was derived. Despite the positive cumulative nominal net cash flow of around $3 billion in addition with the salvage value after 30 years, once the cost of capital and time value of money are accounted, the cumulative discounted cash flow becomes negative of $859 million. This means that the GTL project is not viable in Nigeria based on the specified market parameters and time value of money, because the difference between the present values (discounted value) of future net cash flows and the current initial investment is negative. Meaning that, the present value of future net cash flows cannot meet up the initial investment cost. The investor will therefore have negative cumulative discounted cash flows, and hence the negative NPV.

For the CCGT plant, the summary of its market inputs and assumptions are presented in table 3.28.

CCGT POWER PLANT	Figure
Plants maximum capacity (MW)	400
Annual maximum output (MWh)	3,504,000
Capacity factor (%)	80%
Availability Factor	95%
Annual output (MWh)	2,663,040
Thermal Efficiency	60%
Gas feeds (MMBtu)	15,132,772.03
Interest rate	16.90%
Cost of debt ($)	11.83%
Capital cost ($)	480,000,000
Debt ($)	336,000,000
Equity ($)	144,000,000
Cost of Equity	18.62%
Cost of debt	11.83%
WACC	13.87%
Price per $/MWh	63.44
Annual operating cost (4% of capital cost) ($)	19,200,000
Fuel cost ($)	49,938,147.69
Annual sales revenue ($)	168,943,257.60
Depreciation rate	3.33%
Salvage Value ($)	173,597,526.46
Annual depreciation ($)	10,213,415.78
Tax Rate	30%
Annual Tax saving from depreciation ($)	3,064,024.74
Annual tax payment ($)	29,941,532.97
Net tax payable ($)	26,877,508.24
Annual cash flow ($)	72,927,601.67
Additional cash flow in final year	
Salvage value ($)	173,597,526.46
Tax on selling at salvage value ($)	52,079,257.94
End of year Net gain ($)	121,518,268.52

Table 3.28: Annual Cash flow of the CCGT project in Nigeria

Table 3.28 summarises the inputs and the cash flow calculation of the CCGT plant in Nigeria, which will be used for the NPV calculations. The CCGT project will have an after tax annual cash flow of approximately $73 million, with the end year having additional cash flow as a result of salvage value of the plant. The investment capital as earlier mentioned is funded through debt and equity with a prime lending interest rate of 16.90%. However, the weighted average cost of capital of 13.87% is used as already explained, which will then be used as the discount rate, which will be used to deflate the annual cash flows to account for cost of time and capital. The end year cash flow will have an addition of after tax net cash flow of $122 million as a result of the sale of the plant at the salvage value. Other parameters in the table were earlier discussed. Table 3.29 shows the NPV calculations of the CCGT project in the country.

Year	Cash flow	Discount factor	Discounted net cash flow	Cumulative DCF
0	- 480,000,000.00	1	-$480,000,000	- 480,000,000.00
1	72,927,601.67	0.878229139	64047144.81	- 415,952,855.19
2	72,927,601.67	0.77128642	56248068.83	- 359,704,786.36
3	72,927,601.67	0.677366209	49398693.04	- 310,306,093.32
4	72,927,601.67	0.594882742	43383371.65	- 266,922,721.67
5	72,927,601.67	0.522443358	38100541.12	- 228,822,180.56
6	72,927,601.67	0.45882498	33461005.41	- 195,361,175.14
7	72,927,601.67	0.402953467	29386429.97	- 165,974,745.18
8	72,927,601.67	0.353885477	25808019.08	- 140,166,726.10
9	72,927,601.67	0.310792537	22665354.37	- 117,501,371.73
10	72,927,601.67	0.272947062	19905374.65	- 97,595,997.08
11	72,927,601.67	0.239710064	17481480.03	- 80,114,517.04
12	72,927,601.67	0.210520363	15352745.15	- 64,761,771.89
13	72,927,601.67	0.184885117	13483228.15	- 51,278,543.73
14	72,927,601.67	0.162371497	11841363.85	- 39,437,179.88
15	72,927,601.67	0.14259938	10399430.78	- 29,037,749.11
16	72,927,601.67	0.125234931	9133083.134	- 19,904,665.97
17	72,927,601.67	0.109984965	8020939.735	- 11,883,726.24
18	72,927,601.67	0.096592001	7044222.996	- 4,839,503.24
19	72,927,601.67	0.08482991	6186441.895	1,346,938.65
20	72,927,601.67	0.074500099	5433113.537	6,780,052.19
21	72,927,601.67	0.065428158	4771518.623	11,551,570.81
22	72,927,601.67	0.057460915	4190486.691	15,742,057.50
23	72,927,601.67	0.05046385	3680207.517	19,422,265.02
24	72,927,601.67	0.044318823	3232065.478	22,654,330.50
25	72,927,601.67	0.038922082	2838494.081	25,492,824.58
26	72,927,601.67	0.034182506	2492848.213	27,985,672.79
27	72,927,601.67	0.030020073	2189291.939	30,174,964.73
28	72,927,601.67	0.026364503	1922699.974	32,097,664.70
29	72,927,601.67	0.023154075	1688571.142	33,786,235.85
30	194,445,870.20	0.020334583	3953975.715	37,740,211.56
	2309346318.72		**$37,740,212**	

Table 3.29: NPV of the CCGT plant in Nigeria

Using net present value accounting method for the CCGT plant, where the future values of the cash flows were discounted at 13.87%, the plant reported a positive NPV figure of approximately $38 million. That is to say, investing $480 million for 30 years in CCGT plant in Nigeria, the plant will generate a profit of approximately $38 million at present value. This means the investor will have a positive $38 million as the difference between the discounted future net cash flows of the investment and the initial investment cost for the 30 years. The present value of the future cash inflows can meet up all the present and future cash outflows with even a surplus, which means the project is viable.

In summary, using NPV to estimate profitability of the two projects, GTL and CCGT plants returned negative $859 million and positive $38 million respectively. The GTL project is found to be not viable due to its negative NPV, while CCGT project was found to be viable due to its positive NPV value.

However, GTL project is equally important project as its products can provide an affordable and cleaner alternative fuels for residential and commercial usage, which will be significant in boosting the economic performance, safeguarding the environment and improving the wellbeing of the people in the country. Similarly, with more gas pipelines to be in place, potentials for GTL plants will increase, where we earlier estimated 40% of the gas supply from the gas pipeline can be used for GTL projects, chemical and cement industries etc. GTL project is very essential, and should also be considered. Therefore, the government should consider providing some investment incentives to offset the potential loss in the project. More judgement, specific recommendations and sensitivities will be made after looking at the IRR and payback periods of the projects.

Depending on the accounting method used, investor’s decision can be different under different accounting methods. The investor’s choice will be determined by his personal or corporate ambition, some investors will only consider the nominal annual cash flows, some will consider how quickly they can recover their investment, and some will base their decisions on the present value of their future returns. Now we will consider the other two methods, which are Internal Rate of Return (IRR) and payback method.

3.6.4 Internal Rate of Return:

Internal rate of return is one of the commonly used accounting techniques to analyse the profitability of a business investment. Rate of Return signifies how quickly the money invested comes back to the investor. It is usually given in percentage per annum. It is easy to calculate the rate of return if the return on investment is constant, but in a situation where the annual returns varies and is not continues, then the rate of return becomes Internal Rate of Return (IRR) [216] [282]. IRR considers the cash flows as derived under the NPV calculations to derive the maximum possible rate of investment return. The IRR is the rate of return where NPV is close to or equals to zero. Net present value gives information on how much at present value an investor earns or loses for opting to making such investment decision rather than investing the money in an alternative venture.

In order to optimise the investor's decision, IRR is important as it reveals the discount rate at which present values of future cash flows and the initial investment cost are the same. This means that, there is no lost or gain in the investment considering the time value of money. IRR is used to compare viability of two or more investment projects. Projects with higher IRR are favoured and opted among other alternative ventures. Higher IRR is desirable as currencies devalue relatively at low rate, the higher the IRR the safer the investment. If the discount rate is below the IRR, then the investment is recommended, conversely, if the discount rate is above the IRR, then the investment is not recommendable. IRR is usually driven through trial and error until when the NPV becomes equals or close to zero or using the excel formula. The discount rate, which is also the rate at which an investor wants his investment returns, is preferred to be high but not above IRR, therefore if IRR is high, then the investor can achieve higher investment rate of return. If the calculated IRR is higher than the discount rate then the investment is viable.

Using the previous NPV calculations for the GTL and CCGT projects above, an excel formula for the IRR was applied, and for the GTL project in Nigeria, 5.17% was derived as its IRR, which is lower than the discount rate of 16.15% as used in the NPV calculation. This means that any discount rate or investment return above 5.17%, the investment is not profitable. This means the project is not viable because the IRR is lower than the discount rate and the investment cannot meet the investor's expected rate of return.

For the CCGT plant, the IRR is 15.02%, which means that the project's discount rate (13.87%) is lower than the IRR, which makes it viable. This means that the investor can choose any investment rate of return below 15.02% and yet have a positive NPV. Therefore, based on the IRR accounting technique, the CCGT plant is again the viable project among the two projects in Nigeria.

3.6.5 Payback Period

Payback period accounts for the length of period required to recover the initial capital investment from the annual cash flow. This is one of the popular accounting techniques, which investors use to assess business ventures. It gives signals on how fast the money invested comes back to the investor. This method is important because most of the initial capital investments are borrowed from bank and the longer the period of the loan, the higher the interest paid, so investors will do their best to reduce the period of interest payments. Payback period technique then is the appropriate accounting technique that informs the investor on the period of cash recovery, so that the terms or the period of bank loan will be as short as possible.

Using the payback period method is significant in countries where there is propensity of political or social instability, where investor wants to make use of the available short-term stability to hit and run. Payback period will then be the best viability indicator for business investments in those circumstances. It is simple to apply, and it is related to the NPV technique, because the NPV reports the running annual cash flows.

Considering the two projects in Nigeria (CCGT and GTL projects) and applying the annual discounted cash flow (adopted from the NPV calculations in table 3.27 and 3.29), the period within which the initial cash investment is recovered can easily be identified. Reference to table 3.27 where the discounted cash flows of GTL projects were presented, there is no positive cumulative discounted cash flows, which means the project cannot pay back its investment going by the discounted cash flows, and hence the negative NPV. It is therefore non recoverable (NR) investment. For CCGT project and reference to table 3.29 and equation 3.8, the discounted payback period is calculated as follows:

$$Payback\ Period_{CCGT} = 18 + \frac{-(-4{,}839{,}503.24)}{6186441.90} = 18.78 \qquad (3.32)$$

The discounted payback period of the CCGT project is 18.78 years. This means that CCGT project which already has positive NPV value will be able to pay back the investor at approximately 19 years of the project operation while GTL project cannot.

Finally, having considered the three different accounting techniques in analysing the capital investment and profitability of the two gas projects in Nigeria (CCGT and GTL projects) in the base scenario, table 3.30 below summarises all the results, and CCGT project is the recommended gas development project in Nigeria compare to the GTL project going by the viability indicators.

Investment Indicator	**CCGT Project**	**GTL Project**
Initial Capital Cost	$480 million	$1.4 billion
NPV	$38 million	-$859 million
Internal rate of Return	15.02%	5.17%
Payback period	18.78 Years	NR

Table 3.30: Summary of results from the four accounting techniques

Table 3.30 summarised the viability of the two projects, it shows that the GTL project is not viable, while CCGT project is viable. It is recommendable that incentives be provided to facilitate investment in the GTL project, as its products and its value addition is essential in providing cleaner alternatives to the conventional energy products. Specific recommendations will be made after identifying the most sensitive parameter to the project so that appropriate recommendation can be offered based on the most sensitive parameters.

3.7 Sensitivities for GTL and CCGT projects

In order to understand the robustness or the level of responsiveness of the projects' viabilities to any change in the market parameters, some of the business parameters were altered in order to observe the sensitivity of the business viability to market changes. Apart from the base scenario, ten other scenarios were observed, where five parameters were varied two times, 20% increase and 20% decrease, where for every scenario, other variables were held constant. These parameters are: initial investment cost, discount rate, output, products prices (crude oil price and electricity wholesale price), and cost of feed gas. The result of each of these scenarios are presented in table 3.31. A sensitivity indicator will then be used in assessing the level of sensitivities. The SI compares the percentage change in the NPV with the percentage change in a variable/parameter. SI towards IRR compares percentage change in IRR above the discount rate with percentage change in a variable/parameter. These were defined in equation 3.29 and equation 3.30.

Project	**GTL**	NPV	IRR	**CCGT**	NPV	IRR	Payback period
Base scenario		-859,010,076.30	5.17%		37,740,211.56	15.02%	18.78
Capital cost 20% lower		-590,823,994.80	6.86%		147,908,275.30	19.46%	9.55
Capital cost 20% higher		-1,127,196,157.81	3.99%		-72,427,852.18	11.99%	NR
Lower discount rate (20%)		-729,686,151.12	5.17%		154,621,490.73	15.02%	12.46
Higher discount rate (20% increase)		- 947,831,608.62	5.17%		-44,825,940.12	15.02%	NR
Output 20% lower		- 955,394,142.55	3.75%		-79,975,894.50	11.37%	NR
Output 20% higher		-762,626,010.06	6.53%		155,456,317.62	18.58%	10.48
Product Prices 20% lower		-994,268,726.84	3.15%		-129,373,137.13	9.79%	NR
Product Prices 20% higher		-723,751,425.77	7.06%		204,853,560.26	20.06%	9.00
Gas feedstock 20% lower		-817,889,037.48	5.76%		87,137,454.20	16.52%	13.784
Gas feedstock 20% higher		-900,131,115.13	4.57%		-11,657,031.08	13.51%	NR

Table 3.31: Sensitivities of the projects' accounting indicators

From table 3.31, the NPV of the GTL project has been negative in all the ten different economic scenarios. The highest negative NPV was -$1.1 billion, which was when the capital cost was increase by 20%. The GTL project can be profitable if the capital cost is reduced by 65%, which is approximately at $490 million as capital cost given the market conditions, which means even at 20% reduction in capital cost GTL project was still unviable. Similarly, none of its IRR is above its discount rate of 15.17%, as its highest IRR was 7.06%, which was when the product prices were increased by 20%. This means, the GTL project is sensitive to the product prices i.e crude oil price. For the CCGT project, its NPV has been positive in five scenarios and negative in five scenarios: Its NPVs were positive when capital cost, discount rate and cost of gas feedstock were reduced by 20% each as well as when the output and products prices were increased by 20%, other parameters being constant. Its NPVs were negative when capital cost, discount rate and gas feed cost were increased by 20% as well as when output and electricity price were reduced by 20%, other parameters being constant. When the CCGT's NPVs were negative, its IRRs were also below the project's discount rate of 15.02%, which indicates unviability at these scenarios. In other five positive NPV scenarios, the IRR of the CCGT project remained above its discount rate.

For the payback period, since the GTL project does not have positive NPVs and its IRRs have been below the discount rate, the investment is non-recoverable (NR) within the specified period. The CCGT project has the lowest payback period of 9 years when the electricity price was increased by 20%. It was at this scenario that the highest NPV and IRR of CCGT project as well as shortest payback period were also recorded, which were $205 million as NPV, 20.06% as IRR and 9 years as payback period. Among the viable sensitivity scenarios for the CCGT project, the second shortest payback period and second highest NPV were recorded when the capital cost was reduced by 20% and when output was increased by 20% respectively. The second highest IRR of the CCGT project in all scenarios was when the capital cost was reduced by 20%. This primarily indicates strong sensitivity of CCGT project to electricity price, capital cost and output changes, while GTL project is more sensitive to changes in products' prices and capital cost. In order to broadly assess the level of sensitivity of each parameter or scenario, a sensitivity indicator is calculated for each scenario. Sensitivity indicator is shown in table 3.32, and clearly shows the level of responsiveness in each scenario.

Project	**GTL**	NPV	IRR	**CCGT**	NPV	IRR	Payback period
Capital cost 20% lower		-156%	127%		1460%	-695%	-246%
Capital cost 20% higher		156%	-89%		-1460%	475%	NR
Lower discount rate (20%)		-75%	0%		1548%	0%	-168%
Higher discount rate (20%)		52%	0%		-1094%	0%	NR
Output 20% lower		56%	-107%		-1560%	572%	NR
Output 20% higher		-56%	102%		1560%	-557%	-221%
Product Prices 20% lower		79%	-152%		-2214%	819%	NR
Product Prices 20% higher		-79%	142%		2214%	-789%	-260%
Gas feed cost 20% lower		-24%	44%		654%	-235%	-133%
Gas feed cost 20% higher		24%	-45%		-654%	237%	NR

Table 3.32: Sensitivity indicators of the GTL and CCGT projects

Table 3.32 compares the level of responsiveness of the accounting indicators with the percentage changes in the parameters. Higher sensitivity indicator indicates high level of sensitivity. Starting with the GTL project, the highest SI with respect to its NPVs was 156%, which was recorded when the capital cost was changed upward and downward respectively. The second must sensitive scenarios to the project is the products' prices, which recorded second highest SI of 79% in its two scenarios. Lower discount rate by 20% is the third must sensitive scenario, which has SI of 75%. The fourth most sensitive scenarios to the GTL project are the two changes in output. The fifth most sensitive scenario is when the discount rate was increased by 20%. The least sensitive scenarios are the upward and downward changes in the cost of gas feed, which have the SI of 24%. The first and second most sensitive scenarios to the project's IRR were when the product prices were decreased and increased by 20% respectively. The third most sensitive scenario to the project's IRR is when the capital cost was decreased by 20%. The increase and decrease in output are the fourth and fifth sensitive scenarios to the GTL project respectively, while decrease in capital cost by 20% is the sixth most sensitive scenario to the project. The changes in gas feed cost are the least sensitive scenarios. The IRR of the project was not sensitive to the level of changes in discount rate because its SI was 0%.

For the CCGT project's NPV, the most sensitive parameter to its NPV is the electricity price, and then output and followed by capital cost and discount rate, cost of gas feed is also the least sensitive to the project's NPV. The most sensitive parameter to its IRR was equally the electricity price and then the capital cost (at 20% reduction), and then outputs. The most sensitive parameter to its payback period is also the electricity price. Capital cost and output are the second and third most sensitive parameters to the payback period of the CCGT project in the country respectively. Based on the SI figures reported in table 3.32, table 3.34 shows the ranking of the sensitivity for each parameter and scenario, with 1 being the most sensitive scenario and 10 being the least sensitive scenario to the respective accounting indicator, the table considered the NPV and IRR, as the payback period method's SI are not complete in the case of CCGT project and not completely available in the case of GTL project. The table also harmonised the ranking points and ranked the sensitivities accordingly.

Parameters	**GTL**	NPV	IRR	Ranking points	Ranking position	**CCGT**	NPV	IRR	Ranking points	Ranking position
Capital cost 20% lower		1	3	4	2		4	3	7	4
Capital cost 20% higher		1	6	7	3		4	6	10	5
Lower discount rate (20%)		3	9	12	6		3	9	12	6
Higher discount rate (20%)		5	9	14	8		5	9	14	8
Output 20% lower		4	4	8	4		2	4	6	**3**
Output 20% higher		4	5	9	5		2	5	7	4
Product Prices 20% lower		2	1	3	**1**		1	1	2	**1**
Product Prices 20% higher		2	2	4	**2**		1	2	3	**2**
Gas feed cost 20% lower		6	8	14	8		6	8	14	8
Gas feed cost 20% higher		6	7	13	7		6	7	13	7

Table 3.33: Harmonised ranking points and positions of the level of sensitivities

Table 3.33 shows the ranking position of every sensitivity scenario, with point 1 being the most sensitive scenario. The ranking points of each accounting indicator at a particular scenario is summed up to give the cumulative points. Based on the cumulative points, the ranking was made, where the scenario ranked 1st is the most sensitive to the particular project. Starting with the GTL project, the parameters are ranked according to their sensitivities in this order: Product prices, capital cost, output, discount rate, and then gas feed cost. This means that product prices (crude oil price) are the parameters that must be given careful thought and consideration, and perhaps a more logical and careful forecast of their prices for the duration of the project's operation will be significant. The capital cost is also very important in determining the profitability of the project as already stated that any capital above $490 million, the project would not be viable based on the market conditions applied.

Maximizing the output of the GTL project is important for maximising the viability of the project, as its profitability is very sensitive to the output as well.

Therefore, in order to incentivise GTL investment and make it viable in the country, the prices of the products and the capital cost requirements need to be looked it and incentivised. For example based on the random sensitivity analysis, we found that if the prices of the crude oil can increase by 20% and the capital cost reduced by 54%, the project will be viable in the country, at which the IRR will be 16.16%, the NPV will be $351 thousand and payback period will be 29.88 years. The crude oil at this scenario will then be $121/bbl. The nominal crude oil price fluctuates and can likely reach or exceed this price level in the future.

For the reduction in cost, a careful study is required on why the GTL capital cost keep increasing. As mentioned earlier, the capital cost has increased twice, the first increment was 200% more and the second one was by 40%. If the capital cost can be reduced by 54% and the above crude oil price is achieved while other parameters remain constant, then GTL can be viable in the country. The government and investors might consider reviewing the capital cost with a view to reducing the cost of the GTL projects in the country. The cost reduction can also be achieved by reducing the cost of feed gas cost (this could be in form of subsidy), lowering the interest rate, increasing the thermal efficiency and producing at optimal level. Producing at optimal level is possible because the products can be stored using the conventional petroleum storage facilities. Tax rate can be reviewed for this particular project. Local content can be enhanced where local experts are hired and equipment acquired locally if possible to reduce cost. Research and development is underway to reduce overall cost of the GTL process as mentioned by Wood et al (2012) [43], and if this is achieved the GTL project will be viable in the country.

The order of the parameters in terms of their sensitivity to the CCGT project's viability is as follows: Product price, output, capital cost, discount rate, and then gas feed cost. The product prices (crude oil and electricity prices) are the most sensitive parameters to both projects, while discount rate and gas feed cost are the second to the last and the last sensitive parameters to both projects respectively. A 20% reduction in price of electricity can make the CCGT project unviable in the country. Therefore, electricity price has to be above $60.27/MWh for the CCGT to be viable in the country other things being equal.

3.8 Summary

This chapter used accounting models to assess the economic costs and benefits of six different possible gas pipeline routes in Nigeria based on investment cost, gas deliveries, NPV, IRR and payback period. Based on the harmonised ranking points of the economic indicators, it was found that the BSRO pipelines are more economically viable. NRO pipelines are not viable, and it is recommended not to consider this option alone, even in the future, the best recommendation was to combine it with the BRO pipelines option. This academic finding justifies the intention of the government to consider investing on the BSRO pipelines. However, in terms of coverage and ability to supply more gas to more locations, all gas pipeline route option is more recommendable. The BSRO and all gas pipeline route options are more sensitive to discount rate, cost of gas transportation and capacity. Assessment of value addition of these pipelines were also presented, and found that the gas pipelines have direct and indirect value addition to the economy through facilitation of improved power supply, industrial inputs supply, alternatives energy fuels supply, emission reductions, job creation, economic diversification etc. The chapter also applied three different accounting techniques (NPV, IRR and payback period) to assess the viability of CCGT and GTL projects in Nigeria. All the applied accounting techniques have suggested that CCGT project is viable in Nigeria. GTL project was found to be unviable, but incentives for its investment cost and products prices were recommended to make it viable due to the relevance of its products in providing energy alternatives that will help improve the wellbeing of the people in the country. The sensitivity analysis also showed that both projects are more sensitive to their product prices, while output and capital are the medium most sensitive parameters, and discount rate as well as gas feed cost are the least most sensitive parameters to the projects' viabilities.

Chapter 4. Econometric Analysis of Domestic Gas Consumption and Real Economic Growth in Nigeria

4.1. Introduction

The previous sub-chapters analysed the costs and benefits of some strategically selected gas development projects in Nigeria. It is hypothesised that once these gas development projects are implemented, the demand for natural gas will emerge, and that will positively affect the economy depending on the outcome of the following cointegration test. Investing huge amount of resources on natural gas development infrastructure requires a compelling multiplier effect on the economy, so that government and investors will really know the value they are adding to the economy. If gas development for domestic use has no positive multiplier effect or has no cointegration with the economic development, then perhaps there may not be a serious need for such investment. Now, having analysed the economic viability of these gas development projects, there is a need to analyse the effect of gas development or consumption on the economy.

This chapter will assess the cointegration, long run and short run relationship between the inland gas demand and the overall economic performance in Nigeria using a multiple regression model called Autoregressive Distributed Lag (ARDL) bound test as developed by Pesaran et al.(2001) [138]. This model has been used for many years, and it is becoming more favourable among econometricians in estimating relationships, which will be discussed in this chapter [163]. However, despite some of the reported advantages of the model it has some limitations. One of the limitation of the ARDL model is that, it does not provide robust results in the presence of variables that are integrated of order two, that is I(2). If any of the underlying variable is I(2), such variable cannot be used in the ARDL model, therefore, it restricts the use of only variables that are of I(0) or I(1) or combination of them.

4.2. Choice of variables

As one of the main target of the research is to identify the cointegration and relationship between gas consumption and economic growth in the country, which is in line with the research question of using the natural gas to foster national development. This examination is significant in proving the exact impact of natural gas consumption on the real economic growth in the country.

Therefore, the primary variable of consideration is the domestic gas consumption (GC), and the objective is to assess how it relates to the real GDP as the proxy for real economic growth, hence the inclusion of gas consumption among the explanatory variables. The relationship between these two variables will be examined in the presence of other relevant and influencial macroeconomic indicators. Exports (XP) is included, adopting the neo-classical production function that considers exports as one the drivers to the economic growth and demand driven factor in an economy as widely used in literature [2] [283]. Similarly, because Nigerian economy is largely reliant on the exports earnings especially from the oil and gas resources [155] [284].

Despite the fact that Nigerian economy is mainly reliant on the oil and gas resources, the crude oil production is not considered in the first specification, because oil and gas commodities made up of up to 91% of the country's exports basket, as such considering them as a separate variables in the same model specification may not be optimal [285]. The domestic crude oil usage is insignificant as over 97% of the crude oil produced are exported outside [286]. Largely, the effect of crude oil production can be captured in exports variable as majority of it is exported, and it makes up the dominant commodity in the exports basket. The exports variable includes other goods and services exported from the country, which could affect the economic growth.

The exports variable is used as a controlled variable and represents the external sector in the equation and is not the primary variable of interest, as it is used as a potential factor that could influence economic growth. The ARDL model will report valid t-statistic and unbiased long run estimation even in the presence of endegenous variables[137] [287]. Odhiambo (2009) stated that "The ARDL technique generally provides unbiased estimates of the long run model and valid t-statistics even when some of the regressors are endogenous (see also Hariss and Sollis, 2003"[287] [137]. Though Exports are endognous to economic growth especially for a country like Nigeria where the production is little diversified and it is highly dependent on the export of oil, and the fact that exports is determined by some of the variables in the model, but there is no concern about the endogeneity of the exports variable in the model going by Odhiambo (2009), Harris and Sollis (2003) and Pesaran Shin and Smith (2001) [138]. The Nigerian exports is commodity based largely, and it is a source of revenue to deliver many development projects and to finance some of the industrial product importation to the country, which helps increase demand and propel economic output in the country. Looking at the supply side of the economy, as the neo-classical economic growth theory stated, the source of economic growth depends on the factor input increase and efficiency improvement. Feder (1983) considered economy to be of two sectors, export sector and domestic sector, and export sector helps improve efficiency and facilitate factor input increase [288] [289].

However, to include an oil related variable that could account for the movements of oil production and consumption in the country, the price of crude oil is included in the model specification. Oil price (PR) is a major determining factor of the country's generated revenue, whose movements can significantly affect the economy of the country given the dominance of the oil industry in the country, and hence the choice of the variable. This variable is also considered as a key macroeconomic indicator to economic growth in many literature [290].

Gross Fixed Capital Formation (CF), which is the difference between the total fixed assets acquired and disposed in the economy over a period of time is also included. The CF variable was introduced to make the model robust and capture other important GDP determinants. Having more variables makes the model efficient and enhances the precision of the model in predicting the dependent variable [291], as the influencial variables that explain the GDP are captured in the equation. We chose CF because it is widely used as an economic indicator and a factor of production as well as proxy for investment. Kin S. et al (2013) [292] Liddle B. (2013) [293], and Ocal O. et al (2013) [294] and many other researchers have included gross fixed capital formation (investment) as explanatory variable to the GDP in addition to the primary variable(s) of interest.

The above variables will make up the initial model specification allowing broad inclusion of relevant variables. This general model was chosen to account for major likely influencial variables on the real economic growth, with a view to asses the relationship of the domestic gas consumption in the midst of these major variables. Domestic gas consumption has been low over the years, and may not be sufficient alone to explain real economic growth. However, irrespective of the cointegration test outcome from this model specification, another model specification will be estimated using gas cosumption and crude oil production as explanatory variables in order to observe the relationship of oil production and gas consumption to the real GDP. This is to test research hypothesis that says crude oil production that has dominated the petroleum sector in the country may not have direct positive effect to the domestic productive output but natural gas consumption does, and may likely not lead to economic growth as the revenue from exporting crude oil may not necessarily be translated in to improved economic productivity in the country. Similarly, among the country's petroleum resources, crude oil is produced more than the other resources, and that lead to more foreign direct investment in the oil upstream sector, which relatively lead to low investment in the inrfastructures of other energy resource sectors especially natural gas, which could be responsible for lower domestic gas consumption. Therefore, the second model specification will observe the impact the oil production and gas consumption on the real GDP.

Similarly, the choice of these variables was also informed by the theory of endogenous growth, which claimed that economic development of a country is geared by the internal factors [295] [296]. This may include domestic production, labour efficiency, economic policies etc. We could potentially consider other variables like national expenditure, population, interest rate, security and political stability, renewable energies, etc, but in order to avoid over parameterisation in the model which could lead to higher standard errors and large number of insignificant coefficients in the estimate, we stick to the explanatory variables above, and the influence of other non-considered variables can be explained in the residual or error term. Some important diagnostic tests like the serial correlation and stability tests will be run to check for the efficiency of the ARDL models. Once it is efficient, the problem of partial multicollinearity or presence of endogenous regressors will not affect the model, as the ARDL model test for the cointegration will provide unbiased estimates of the long-run model and valid t-statistics even in the presence of endogenous regressors [137].

The coefficients of theses variables will be presented in log form, the sign "l" will be attached to each variable, which represents the natural logarithm of the variables both regressand and regressors. This will make the respective coefficients of the explanatory variables in form of elasticity. The use of percentage changes is useful as it is an easy way of understanding the strength of the relationships.

4.3 Data descriptions:

The data used in this research covers the period of 1981 to 2013 and they are for Nigeria particularly. The gas consumption, which is in million cubic metres (mcm) and crude oil production in ktoe were sourced from the IEA database as produced by the UK data service [173] [286]. Crude oil price using the historical Brent crude oil spot price in current US dollars as converted to 2005 constant dollars were sourced from BP statistical review of world energy for 2014 [17]. The nominal gross domestic product (GDP) and capital formation were sourced from World Bank as produced by UK data service, and they were both in current US dollars, but converted to 2005 constant dollars [297]. Exports data was sourced from the database of UNCTAD (United Nation Conference on Trade and Development), and it was in current US dollars too, but converted to 2005 constant dollars [298]. In order to convert the data to real values, a CPI index for US dollars was used using 2005 as base year. Therefore, all the data that are in monetary value, were converted to 2005 constant dollars. The CPI index was sourced from the UNCTAD database [299]. The real values of the data are presented in appendix D, the gas consumption and crude oil price are in volume.

Let lgdp, lgc, lop, lcf, lxp and lpr represent the logarithm of real GDP, gas consumption, oil production, real capital formation, real exports, and real crude oil price. The descriptive statistics of these variables are presented in table 4.1 and figure 4.1 below.

Statistical property of the data.

	LGDP	LGC	LCF	LXP	LPR	LOP
Mean	25.02118	8.747270	22.85198	10.20676	3.677408	11.47514
Median	24.68610	8.728750	22.53607	9.987278	3.475686	11.55839
Maximum	26.80420	9.645105	24.87119	11.36914	4.570579	11.73655
Minimum	23.78408	7.729296	21.67300	9.159584	2.723924	11.03981
Std. Dev.	0.821099	0.538684	1.012072	0.667908	0.532243	0.209667
Skewness	0.791068	-0.050826	0.854481	0.457097	0.238240	-0.679415
Kurtosis	2.612504	1.892040	2.444215	1.925823	1.755858	2.175874
Observations	33	33	33	33	33	33

Table 4.1: Statistical description of the data

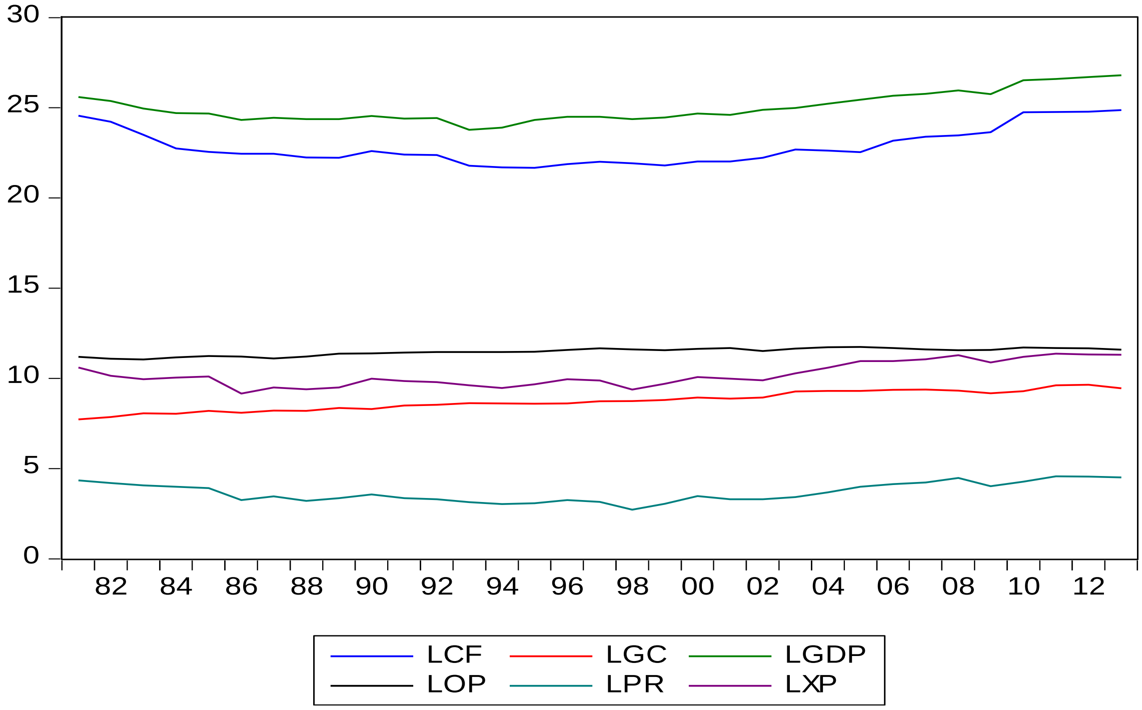


Figure 4.1: Graphical presentation of the trend of the data

4.4. Models Choice Justifications and Specifications

In order to examine the long run cointegration between the economic growth and natural gas consumption as well as with other relating variables as earlier justified under choice of variables, the Autoregressive Distributed Lag (ARDL) bound testing method will be used, which "is a general dynamic specification, which uses the lags of the dependent variable and the lagged and contemporaneous values of the independent variables, through which the short-run effect can be directly estimated, and the long run equilibrium relationship can also be estimated" [300]. As developed by Pesaran et al (1999) [301] and subsequently elaborated by Peseran et al (2001)[138], this cointegration examination method has added advantage over other methods like Engle & Granger and Johansen cointegration test because of the following reasons [137] [287] [302] [300]: Its limitation were earlier explained.

1. It ruled out the indecision about the selection of order of the integration among the underlying variables. The model can be efficient even if the variables under consideration are of different order of integration, which is to say even if they are stationary at different order of integration, but not up to two. The model does not put restrictions that all of the variables must be of the same order of integration. It

therefore permits for having different optimal lags among variables. Even if the variables are of the same order of integration, the model is still sufficient.

2. The model is not sensitive to the choice of deterministic components in the specification.
3. The model is suitable for simultaneously estimating the long run and short run components within a particular VECM.
4. The model cannot be distorted by the diversity of the variables, and some challenges involved in testing unit root test can be avoided. Stationarity exists when the distribution (mean, variance and covariance) of a variable is independent of time. Unit root exists when these distributions changes with time, making the variable non-stationary, which is not desirable.
5. The model is also convenient because it allows us to apply on whatever size of the data, either big or small. It does not have restrictions, unlike other cointegration tests like, Engle Granger test and Johansen Vector Error Correction Models, which are sensitive to the sample size for their efficiency. It is ideal to use ARDL model for use of a small sample size like in the case of this research.
6. The model use a single reduced-form equation unlike other techniques where they estimate within system equations.
7. The model provides unbiased estimates of the long run relationship even if there are presence of endogenous regressors in the specification [164] [303].

4.4.1 Model specification and procedure:

The relationship between domestic gas consumption and economic growth is studied, while incorporating the effects of other likely influential variables as explained earlier in the following two model specifications. The ARDL model includes estimating an unrestricted error correction model as follows, following the work of [301] [138, 304].

$$\Delta lgdp_t = a_0 + \sum_{i=1}^{p} a_{1i}\Delta lgdp_{t-i} + \sum_{i=0}^{q1} a_{2i}\Delta lgc_{t-i} + \sum_{i=0}^{q2} a_{3i}\Delta lcf_{t-i} + \sum_{i=0}^{q3} a_{4i}\Delta lxp_{t-i} + \sum_{i=0}^{q4} a_{5i}\Delta lpr + \sigma_1 lgdp_{t-1} + \sigma_2 lgc_{t-1} + \sigma_3 lcf_{t-1} + \sigma_4 lxp_{t-1} + \sigma_5 lpr_{t-1} + \varepsilon_t. \quad (4.1)$$

$$\Delta lgdp_t = b_0 + \sum_{i=1}^{p} b_{1i}\Delta lgdp_{t-i} + \sum_{i=0}^{q1} b_{2i}\Delta lgc_{t-i} + \sum_{i=0}^{q2} b_{3i}\Delta lop_{t-i} + \delta_1 lgdp_{t-1} + \delta_2 lgc_{t-1} + \delta_3 lop_{t-1} + \varepsilon_t. \quad (4.2)$$

Where Δ stands as the first difference operator. Where a_0 and b_0 are the constants, other a_i, and b_i are the coefficients of the differenced variables, and σ_i and δ_i are the coefficients of the lagged variables, which are significant in testing for the long run cointegration. The dependent variable is lagged up to p times (the maximum time lag of the dependent variable), and qs are the optimal number of lags for the respective independent variables. These are called the “autoregressive terms and distributed lag terms” respectively. Therefore, we have ARDL (p, qs). The ε_t is the error term at the current period t.

The procedure will have equations 4.1, and 4.2 estimated using the ARDL approach by using f-statistics to test for the joint significance of the derived coefficients of the specified lagged variables so as to establish the presence of long run relationship between the set of variables in each of the above models. We will be testing for the following null hypotheses that suggest that there is no cointegration among these variables in equation 4.1. and 4.2 respectively.

$H_0 : \sigma_1 = \sigma_2 = \sigma_3 = \sigma_4 = \sigma_5 = 0$

$H_0 : \delta_1 = \delta_2 = \delta_3 = 0$

The alternative hypothesis H_1 suggests that the σ_i and δ_i are not equal to zero, and if that is the case, we can conclude at least a long-run relationship among these variables. F-test will be applied to determine the presence of cointegration between these variables. The F-test do not have a standard distribution under the identified null hypothesis as it depends on the order of integration of the variables, the number of the explanatory variables, presence of intercept and/or trend as well as the size of the sample. This is why Peseran et al (1999) and Peseran et al (2001) developed two different set of critical F values for different set of specifications. One of the F critical value assuming that all the underlying vaiables are integrated of order zero (I(0)), and the other critical value assuming them to be of order one (I(1)). These are called lower bound and upper bound respectively and they are provided at both levels of significance. The decision rule is when the computed F statistic is higher than the upper bound, the null hypothesis can be rejected and we can conclude there is presence of the cointegration withiout concern whether the variables are I(0) or I(1). The decision will be inconclusive if the computed F-statistic falls within the specified F critical values and if it falls below the lower bound, then the null hypothesis of no cointegration will be accepted [138].

If long run cointegration is found, then the following long run and short run coefficients will be estimated, but if there is no cointegration, we can either conclude inconclusive about the presence of cointegration or report absence of the cointegration, depending on where the F value falls. Alternatively, we can further run VAR to analyse the impulse response and variance decomposition among the variables [304].

$$lgdp_t = d_0 + \sum_{i=1}^{p} d_{1i} lgdp_{t-i} + \sum_{i=0}^{q1} d_{2i} lgc_{t-i} + \sum_{i=0}^{q2} d_{3i} lcf_{t-i} + \sum_{i=0}^{q3} d_{4i} lxp_{t-i} + \sum_{i=0}^{q4} d_{5i} lpr + \varepsilon_t. \quad (4.3)$$

$$lgdp_t = e_0 + \sum_{i=1}^{p} e_{1i} lgdp_{t-i} + \sum_{i=0}^{q1} e_{2i} lgc_{t-i} + \sum_{i=0}^{q2} e_{3i} lop_{t-i} + \varepsilon_t. \quad (4.4)$$

The long run coefficients d_i and $e_i$will be estimated from equation 4.3, and 4.4. The shortrun coefficients will be estimated using the following equations:

$$\Delta lgdp_t = f_0 + \sum_{i=1}^{p} f_{1i} \Delta lgdp_{t-i} + \sum_{i=0}^{q1} f_{2i} \Delta lgc_{t-i} + \sum_{i=0}^{q2} f_{3i} \Delta lcf_{t-i} + \sum_{i=0}^{q3} f_{4i} \Delta lxp_{t-i} + \sum_{i=0}^{q4} f_{5i} \Delta lpr + \theta ect_{t-1} + \varepsilon_t. \quad (4.5)$$

$$\Delta lgdp_t = g_0 + \sum_{i=1}^{p} g_{1i} \Delta lgdp_{t-i} + \sum_{i=0}^{q1} g_{2i} \Delta lgc_{t-i} + \sum_{i=0}^{q2} g_{3i} \Delta lop_{t-i} + \emptyset ect_{t-1} + \varepsilon_t. \quad (4.6)$$

From equation 4.5, Where

$$ect_{t-1} = lgdp_{t-1} - h_0 - h_1 lgc_t - h_2 lcf_t - h_3 lxp_t - h_4 lpr_t \quad (4.7)$$

From equation 4.6, Where

$$ect_{t-1} = lgdp_{t-1} - i_0 - i_1 lgc_t - i_2 lop_t \quad (4.8)$$

The coefficients θ and $\emptyset$ will confirm the presence of the short run relationships and other short run coefficients can be determined accordingly. If coefficients of any of the variables in both long run and shortrun equations is significant, then the particular variable can be said to have strong relationship with the dependent variable. The coefficients of the error correction term (ect), needs to be negative and statistically significant to confirm the short run relationships, which also signifies the speed of adjustment toward equilibrium.

4.4.2 Serial correlation and stability test:

Serial correlation and stability of the ARDL models will be tested using Breusch-Godfrey (BG) autocorrelation test and CUSUM stability test respectively. Serial correlation means that the error term is related or influenced by its values in the past, it means error terms are interrelated, which is not desirable [305]. There are three ways of testing for serial correlation, one is through plotting graph of the error term, which is a rough and easy way of observing the behaviour of the error term ε_t. However, because the ε_t cannot be observed directly unless through the use of one of its components (the residual) which estimates the error term, the plotting graph method cannot be reliable [306]. The second method (DW's h statistic) is the one which is developed by Durbin and Watson, which introduces d statistic as an indicator for the presence of autocorrelation. This is widely used by econometricians, and it is defined as folllows [291]:

$$d = \frac{\sum_{t=2}^{t=n}(e_t - e_{t-1})^2}{\sum_{t=1}^{t=n} e_t^2} \tag{4.9}$$

Where d is the ratio of the squared summation of the differences between the residuals to the squared summation of the residual [291]. The d value lies between 0 and 4, the closer is it to 0 the more proof for the presence of autocorrelation, and the closer it is to 4 the less proof for the presence of autocorrelation, and if it lies in the middle, it is incoclusive about the presence of autocorrelation. Durbin and Watson is restricted to only nonstochastic regressors and for testing the first-order autoregressive model for the regression errors. This restricts the use of the lagged values of the dependent variable among the explanatory variables, which is not suitable for ARDL models. It also did not explain whether a regression with d statistic of 2 is consistent or not, which are some of the weaknesses of this method. The method that this research will use is BG-LM autocorrelation test, which avoided the tight restrictions of the DW's h statistic, and which is statistically more powerful than DW's h statistic. BG test is generous as it accommodates infinite number of lags for both dependent and independent variables.

The BG autocorrelation test is administered by running the auxiliary regression; that is after acquiring the residual from the estimated equation (including all the variables) using OLS, where the error term is assumed to be uncorrelated, and then used it as dependent variable on the unrestricted equation to acquire the nR^2 . Where n is the difference between the number of observations and number of lags of the error term (recommended to be 2 for annual time series [154]), which is then multiplied by the R^2 as acquired from the auxiliary regression, and which follows the chi-square distribution ${\chi^2}_h$ with h degrees of freedom. The BG-LM test is therefore [154]:

$$LM = (n-h){R^2}_U \sim {\chi^2}_h \tag{4.10}$$

Where n is the sample size and h is the number of lags of the error term. Therefore, LM is asymptotically distributed as ${\chi^2}_h$ under the null hypothesis of no serial correlation. Therefore, if LM is greater than the critical chi-square at the particular level of degrees of freedom, then the null hypothesis will be rejected, and if the LM is less than the critical chi-square then, the null hypothesis will be accepted.

Similarly, according to Gujarati (2013), F-statistic from the auxiliary regression is also a test that tells if there is serial correlation in the model under BG autocorrelation test, i.e. testing the null hypothesis of no autocorrelation as stated in equation 4.12. He stated that "we can use F value obtained from the auxiliary regression to test the null hypothesis of no serial correlation of any order. This F value has $(h, n-k-h)$ degrees of freedom, where k is the number of parameters in the restricted equation including the intercept. If the computed F value exceeds the critical F value for a given level of significance, we can reject the null hypothesis of no autocorrelation, and this applies equally to the chi-square value derived from the same auxiliary regression. These two tests give similar results, which should not be surprising in view of the relationship between F and χ^2 statistics" [154].

The error term as defined in equation 4.11 can make the estimated coefficients inconsistent if it is influenced by its past, which is what the LM test is trying to verify, that is if $\rho_i \neq 0$ or not.

$$\varepsilon_t = \rho_1 u_{t-1} + \rho_2 \varepsilon_{t-2} + \cdots + \rho_p \varepsilon_{t-p} + u_t \tag{4.11}$$

Where the ρ (rho) is assumed to be not equal to zero in the unrestricted euqation [291] and u_t is the error term that follows the usual classical assumptions, and the ρ coefficient illustrates the magnitute of the relationship betweeen the error term of one period and the preceeding periods. The hypothesis is that the ρ values have to be zero so that u_t will be automatic estimator of the composite error terms u_t and it can be said that there is no autocorrelation. The null hypothesis is presented as follows:

$$\rho_1 = \rho_2 = \cdots \rho_p = 0 \tag{4.12}$$

That is all the ρ in equation 4.10 are zero, meaning that there is no serial correlation. When using BG test, 11 lagged error terms will be applied if the data is monthly, if it is quarterly, 3 lagged error terms will be applied, and for annual time sieries data (like in this case), two lagged error terms will be used [307]. Presence of serial correlation can also be decided by looking at the critical chi-square value or critical F value and comparing it with the acquired chi-sqaure or F value respectively after running the BG test as described ealirer.-

Apart from testing the serial correlation, stability test of the model will be applied using Cumulative sum of recursive residuals.

Cumulative sum of recursive residuals (CUSUM) test is the the stability test introduced by Brown et al (1975) to establish the structural breaks on linear models as estimated using least squares methods, as having presence of cointegration does not mean the model is stable. It is based on the cummulative sums

$$W_r = \sum_{t=k+1}^{r} \frac{w_t}{s},\ r = k+1, \ldots, n, \tag{4.13}$$

Where s^2 is the OLS estimate of σ^2 in a model $y = X\beta + \varepsilon$ over the full data sample by means of all n observations. w_t is the recursive residuals. A model can be said to be properly stated if w_t/σ are independent with distribution $N(0,1)$, so as to have W_r roughly distributed as $N(0, r-k)$. A particular value of W_r can differ significantly from zero if $|W_r| > 2\sqrt{r-k}$ at particular level of significance usually 5%. It is equally possible to examine for the combined significance of the set of values $W_r, r = k+1, \ldots, n$. “It can be shown that this set of values indicates that the model is mispecified or not stable if at that level of significance there exists a point r at which $|W_r| > 0.948\ (1 + 2\frac{r-k}{n-k})\sqrt{n-k}$.” [308] [309] [310]. The anticipations of CUSUM statistics are zero under the H_o of constant parameters. “It is plotted with 5% significance bounds, where if the CUSUM statistics spin around zero inside its confidence bounds, then the H_o of parameter constancy will be accepted[310].

4.4.3 Optimum lag selection

One of the ways to identify the optimal number of lags is through the use of Schwarz’s Information Criterion (SIC) developed by Schwarz (1978), which assesses the fitness of models, and the lower the SIC the more fit the models will be [311]. However, the criterion is more restricted/ harsher than its alternative Akaike Information Critrion (AIC). SIC has higher tendency of reporting higher value depending on the number of variables [307]. AIC performs similar task as the SIC, and most times the two criteria recommend the same level of lag selection, but sometimes SIC may choose model A, and AIC may choose model B. Gujarati (2012) advised that it is better to use AIC theoretically, and practically he recommends SIC, and this is why both creteria will be used for identifying the optimum lag length selection. AIC is defined in equation 4.14 [310].

$$\mathrm{AIC(p)} = \log\left(s_p^2\right) + \frac{2p}{n} \tag{4.14}$$

Where p is the number of regressors included and s_p^2 is the maximum likelyhood estimator of the error variance in the model, and n is the number of observations. The target is to have a small value of AIC, therefore the more the p, the less likely to have small value of AIC. The SIC is defined as follows [310]:

$$\mathrm{SIC(p)} = \log\left(s_p^2\right) + \frac{p\log(n)}{n} \tag{4.15}$$

The two creteria include a penalty term for the number of the paramters in the model. Usually the lowest value of the two creteria is chosen. If the variables are greater or equals to eight, the SIC levies a greater penalty on extra variables than AIC, which means the SIC has higher tendency of choosing the smaller model than AIC [312] [310]. Now, the optimal number of lags using both creteria will be applied in the stationarity and coitegration tests.

4.4.4 Stationarity test

It is significant to first identify if the variables under consideration are stationary or not, and to find out if they are stationary at zero order or first order. This is because the ARDL model cannot accept variables that are stationary at second order, i.e I(2), we have to confirm if none of the variables is stationary at I(2) [138].

Stationarity test tests whether our variables have the propensity of persistent shocks. If a variable is non-stationary (has stochastic process), then its estimated coefficient does not follow the normal t distribution, meaning, “it does not have an asymptotic normal distribution” (constant variance). If a variable is non-stationary (presence of unit root), it means that it does not have constant variance, meaning that there is a possibility that the variable has divergent mean, and it is influenced by time. This makes it difficult to be predicted due to its heteroscedastic nature. For a particular variable, let us say y with the following autoregressive model (AR), it indicates that the value of y this period is dependent on certain portion of its value in the previous year and the error term (random variable) [154].

$$y_t = py_{t-1} + \mu_t \tag{4.16}$$

Where,

$$\mu_t = \rho\mu_{t-1} + \varepsilon_t \tag{4.17}$$

The error term (μ_t) or the value of the disturbance term in period t is equal to *rho (ρ)* times its value in the previous period plus the purely random error term (ε_t)"[154]. *Rho* is the coefficient of autocovariance, and the error term accounts for other random variables that influence the value of y in period t. The error term becomes serially uncorrelated if $\rho = 0$. Until this is verified the error term cannot be said to be serially uncorrelated. The value of p is between 0 and 1. A unit root exists when p (not ρ) is equals to 1. If this happens, the problem can be corrected by deducting y_{t-1} from y_t, that is converting the variable y to its first difference. This is shown as follows:

$$y_t - y_{t-1} = py_{t-1} - y_{t-1} + \mu_t \tag{4.18}$$

$$\Delta y_t = (p-1)y_{t-1} + \mu_t \tag{4.19}$$

$$\Delta y_t = \delta y_{t-1} + \mu_t \tag{4.20}$$

Where δ (delta) is equal to $p - 1$, the symbol Δ indicates that the variable y_t is at first difference. In this case our unit root test will examine if the value δ is zero, which indicates that the value p is 1, meaning that the variable is non-stationary (it has unit root problem), If the value of δ is confirmed to be zero, then the variable y_t will be subject to the error term alone [154].

$$\Delta y_t = (0)y_{t-1} + \mu_t \tag{4.21}$$

$$\Delta y_t = \mu_t \tag{4.22}$$

However, if δ is less than 1 that means p is not equals to 1, meaning that the variable is stationary at first difference (no unit root). In other words, If δ is lower than 1, it means the y_t variable is stationary, which is desirable. Like mentioned earlier, none of the variables should be stationary at second difference.

In order to investigate the order of integration of these variables, the research will employ the use of Kwiatkowski-Phillips-Schmidt-Shin (KPSS) and Augmented Dickey-Fuller (ADF) unit root tests. The ADF is testing the null hypothesis that says the variables have unit root against an alternative that says all the variables have no unit root, while KPSS is testing the null hypothesis that says the variables are stationary against an alternative that says there is presence of a unit root. ADF test is formulated as follows:

$H_0: \delta = 0$ $(stochastic\ trend)$, $H_1: \delta < 0$ $(deterministic\ trend)$

The ADF test is implemented by F-test or by the t-test on the δ. Using the two tests is to have a robust results [313] [154]. The unit root tests involve three procedures to arrive at a decision. Using these types of tests, we cannot be satisfied that a particular variable is stationary at any level unless it is confirmed to be so in three different circumstances. That is testing the stationarity of the variable when the variable is just a random walk, then when it becomes a random walk with drift, and then when it is random walk with drift and a deterministic trend. These three different scenarios are shown in equation 4.23, 4.24, and 4.25 below, which all must agree on a common decision about the stationarity of the variable [313].

When a variable is random walk

$$\Delta y_t = \delta y_{t-1} + \mu_t \tag{4.23}$$

When it is random walk with drift

$$\Delta y_t = a_1 + \delta y_{t-1} + \mu_t \tag{4.24}$$

"When it is random walk with drift and deterministic time trend, so called because a deterministic trend value a_2 is added for each time period" [307]

$$\Delta y_t = a_1 + a_2 t + \delta y_{t-1} + \mu_t \tag{4.25}$$

However, the Augmented Dickey-Fuller (ADF) test added the lagged values of the dependent variable so as to make the error term uncorrelated [313].

$$\Delta y_t = a_1 + a_2 t + \delta y_{t-1} + \beta_1 \sum_{i=1}^{N} \Delta y_{t-i} + \mu_t \tag{4.26}$$

Where, $\Delta y_{t-1} = (y_{t-1} - y_{t-2})$, $\Delta y_{t-2} = (y_{t-2} - y_{t-3})$ up to *nth* term. Summing these lagged differences to the end term will include sufficient terms to make the error term uncorrelated. KPSS test has only two procedures to verify, one with the intercept and the other with intercept and trend. The optimum number of lags used in determining the stationarity is allowed to be determined by AIC and SIC, but the maximum lag was chosen for the criteria, which is 2 as our series are annual time series [291]. The t-statistic is used to test for the hypothesis. In ADF test, if the t-statistic is higher than the critical value of t-statistic, then the null hypothesis of a presence of unit root will be rejected. For the KPSS test, if the computed t-statistic is lower than the critical value of t-statistic, then the null hypothesis that says the series are stationary will be accepted. The computed t-statistics are presented in tables 4.2 -4.6, each of the reported t-statistic was compared with the critical t-statistic at 5% level of significance, and decision about the stationary was made accordingly as shown in the last columns of the tables. The critical t-statistics using the degree of freedom of 33-1 (32) and 5% level of significance is 1.6939.

Results of Unit Root Test					
1. Intercept and trend included					
ADF	AIC		SIC		Stationarity Status
Variables	Level	First Difference	Level	First Difference	
LCF	-2.088	-4.378	-2.088	-5.262	I(0)
LGC	-3.773	-4.852	-3.773	-5.804	I(0)
LGDP	-2.138	-6.732	-2.138	-6.732	I(0)
LPR	-1.956	-5.433	-1.956	-6.516	I(0)
LXP	-3.004	-5.542	-3.004	-6.488	I(0)
LOP	-1.031	-5.016	-1.854	-6.635	I(1)I(0)

Null hypotheses are rejected at 5% level of significance

Table 4.2:ADF stationarity test including intercept and trend using t-statistics

Results of Unit Root Test					
2. Intercept					
ADF	AIC		SIC		Stationarity Status
Variables	Level	First Difference	Level	First Difference	
LCF	-0.932	-3.846	-0.71	-3.846	I(1)
LGC	-1.451	-4.852	-1.451	-5.836	I(1)
LGDP	0.368	-5.079	0.368	-5.079	I(1)
LPR	-1.165	-5.794	-1.165	-5.794	I(1)
LXP	-0.838	-6.26	-0.838	-6.26	I(1)
LOP	-2.179	-6.141	-1.431	-6.141	I(0)I(1)

Null hypothesis are rejected at 5% level of significance

Table 4.3: ADF stationarity test including intercept only using t-statistics

Results of Unit Root Test					
3. without Intercept and trend					
ADF	AIC		SIC		Stationarity Status
Variables	Level	First Difference	Level	First Difference	
LCF	0.264	-3.901	0.126	-3.901	I(1)
LGC	2.417	-4.955	2.417	-4.955	I(0)
LGDP	0.829	-5.015	0.829	-5.015	I(1)
LOP	1.808	-5.618	1.808	-5.618	I(0)
LPR	-0.044	-5.883	-0.044	-5.883	I(1)
LXP	0.348	-6.273	0.348	-6.273	I(1)
LOP	-1.808	-5.618	1.808	-5.618	I(0)

Null hypothesis are rejected at 5% level of significance

Table 4.4: ADF stationarity test not including intercept and trend using t-statistics

Results of Unit Root Test			
1. Intercept and trend included,			
	KPSS		Stationarity Status
Variables	Level	First Difference	
LCF	0.156	0.053	I(0)
LGC	0.062	0.038	I(0)
LGDP	0.15	0.071	I(0)
LPR	0.143	0.077	I(0)
LXP	0.152	0.072	I(0)
LOP	0.140	0.051	I(0)

Null hypothesis are acceped at 5% level of significance

Table 4.5: KPSS stationarity test including intercept and trend using t-statistics

Results of Unit Root Test			
2. Intercept			
	KPSS		Stationarity Status
Variables	Level	First Difference	
LCF	0.411	0.662	I(0)
LGC	0.39	0.101	I(0)
LGDP	0.803	0.728	I(0)
LPR	0.22	0.441	I(0)
LXP	0.337	0.334	I(0)
LOP	0.349	0.110	I(0)

Null hypothesis are accepted at 5% level of significance

Table 4.6: KPSS stationarity test including intercept and trend using t-statistics

Tables 4.2 to 4.6 shows results of different procedures used in determining the order of integration for each of the variables. The decisions of rejecting or accepting the null hypothesis were made using 5% level of significance while comparing the computed t-statistic with the asymptotic critical value for the t-statistic as stated above. ADF and KPSS tests were applied, for the ADF test, AIC and SIC were both used in choosing the optimum lag for each procedure. Similarly, the stationarity test was conducted while including intercept and trend, and then including intercept alone and then without including both intercept and trend. When trend was included, all variables became integrated of order zero, and when trend was not included, the variables became integrated of order one. The inclusion of trend produced contrary outcome, where variables integrated of order zero when trend was included became integrated of order one when trend was not included in the ADF test, as shown in table 4.2 and 4.3. The two lag selection criteria were consistent with each other in table 4.2 and 4.3 except for oil production (OP) variable. When trend was included, OP variable was integrated of order one as judged by AIC, and it was integrated of order zero by SIC in table 4.2. The discripancy was the other way round when including only the intercept in table 2.3 for OP variable. When intercept and trend were not included, combination of orders of integration between zero and one were found as shown in table 4.4.When no intercept and trend were included, the decisions about the order of integration of the variables under ADF were consistent for both the lag selection creteria. The decision rules was already presented earlier. Based on this rule, combinations of order of integration not up to order two were found, which satisfies the condition for using the ARDL model. Similarly, using the KPSS test, all variables were integrated of order zero.

Therefore, we can confirm that none of the variables is I(2), and we can conclude the presence of combination of I(0) and I(1) variables in the above scnearios, which further justifies the use of the ARDL model for the long run cointegration examination.

4.5 Empirical results

4.5.1 Cointegration test

In order to examine the long run cointegration between these variables, there is need to identify the order of lags that will be applied in the first differenced variables as in equation 4.1 and 4.2, and same way, the SIC and AIC will be used to determine the optimum lag selection for the ARDL model as suggested by Peseran et al (2001). This will also be examined in the presence sof the trend and without the trend.

ARDL distributed lag selection					
With trend and intercept	*Lag length based on AIC*	*Lag length based on SIC*	**With intercept**	*Lag length based on AIC*	*Lag length based on SIC*
Model 1: Variables			Variables		
LGDP	1	0	LGDP	1	1
LGC	0	0	LGC	1	1
LCF	1	0	LCF	1	1
LXP	0	0	LXP	0	0
LPR	1	0	LPR	1	1
Model 2: Variables			Variables		
LGDP	1	1	LGDP	1	1
LGC	0	0	LGC	0	0
LOP	2	0	LOP	0	0

Table 4.7: ARDL lag order selection and diagnostic tests

Starting with the first model specification (equation 4.1) and including trend and intercept, the AIC and SIC had suggested different lag order selection, which was ARDL(1,0,1,0,1) as selected by AIC and ARDL(0,0,0,0,0) by the SIC. However, removing the trend made the two criteria to have harmony in terms of the lag order selections, which was ARDL (1, 1, 1, 0, 1), and this is why both scenarios will be tested, that is with trend and without the trend, and F-statistic generated using both information criteria and both scenarios will be analysed. The second model specification (equation 4.2) will have an ARDL order of selection as ARDL (1, 0, 2) suggested by AIC or ARDL (1, 0, 0) as suggested by SIC when trend is included. When trend is not included as in equation 4.2, the SIC's order of lag selection was maintained that is ARDL (1, 0, 0) as suggested by both AIC and SIC.

These orders of lag length are applied to the ARDL models (equations 4.1 and 4.2), using the AIC and SIC order of lag selection. After running the ARDL model using these lag selection orders, the bound test will be applied, from which the calculated f-statistic will be used to test for the joint significance of the derived coefficients of the specified lagged variables, and this is done by comparing it with the upper and lower bound asymptotic critical value of f-statistic as provided by Peseran et al (2001) as earlier explained, and presented in table 4.8.

Asymptotic critical values: intercept and trend			
5%		10%	
I(0)	I(1)	I(0)	I(1)
3.05	3.97	2.68	3.53
Asymptotic critical values: with intercept			
5%		10%	
I(0)	I(1)	I(0)	I(1)
2.56	3.49	2.20	3.09

***Asymptotic critical value bounds acquired from table F-statistic in appendix CI(ii) and C(iv) for k=4 (Peseran et al (2001)p.300).**

Table 4.8: Bound test critical values for cointegration for ARDL equation 4.1

Asymptotic critical values: intercept and trend			
5%		10%	
I(0)	I(1)	I(0)	I(1)
3.88	4.61	2.38	4.02

Asymptotic critical values: intercept and no trend			
5%		10%	
I(0)	I(1)	I(0)	I(1)
3.10	3.87	2.63	3.35

***Asymptotic critical value bounds acquired from table F-statistic in appendix CI(ii) and CI(iv), for k=2 (Peseran et al (2001)p.300).**

Table 4.9: Bound test critical values for cointegration for ARDL equation 4.2

Peseran et al (1999) and Peseran et al (2001) developed the above sets of critical F values for different set of specifications. One of the F critical values, the lower bound assuming that all the underlying vaiables are integrated of order zero (I(0)), and the other critical value, the upper bound assuming them to be of order one (I(1)). These values are provided for when including and when not including the trend. The above bound F-critical values for the ARDL estimation were provided for comparison with the computed F-statistic. These bound values will be used in the ARDL bound test to decide about the presence of cointegration among the two different set of model specifications, whose calculated F-statistics testing for the joint significance of the derived coefficients of the specified lagged variables are presented in table 4.10.

1. $F_{lgdp}(lgdp\|lgc, lcf, lxp, lpr)$	F-statistic	p-value	Cointegration?
With trend			
AIC	1.22	[0.3428]	No*
SIC	1.91	[0.1342]	No*
Without trend			
AIC	1.04	[0.4268]	No*
SIC	1.04	[0.4268]	No*
2. $F_{lgdp}(lgdp\|lgc, lop)$			
With trend			
AIC	2.83	[0.0647]	No*
SIC	2.07	[0.1326]	No*
Without trend			
AIC	4.73	[0.0098]	Yes(at 5% and 10% level of significance)
SIC	4.73	[0.0098]	Yes(at 5% and 10% level of significance)

*means it falls below the threshold.

Table 4.10: ARDL bound test results

From table 4.10, the computed F statistics from the ARDL bound test for equation 4.1 is 1.22 using AIC and 1.91 using SIC when intercept and trend are included. When only intercept is included, the F-statistic was 1.04 for both AIC and SIC. All the reported F-statistics in this model are below the threshold at both levels of significance as per table 4.8. Therefore, we have to accept the$H_0 : \sigma_1 = \sigma_2 = \sigma_3 = \sigma_4 = \sigma_5 = 0$, and conclude that the $\sigma_i = 0$. This means we cannot confirm presence of cointegration in the first model specification. As the decision rule states, if the computed F-statistic is lower than the lower critical value, then presence of cointegration cannot be confirmed. So, we can assume that these sets of I(0) and I(1) variables (LGDP,LGC,LCF,LXP, and LPR) are not cointegrated, there is absence of a direct long run and short run relationship between them. This means that these sets of variables does not share one common trend, and the specified ARDL model will lead to spurious estimation. It implies that the direction of their movements is different from each other over time. Therefore, a vector autoregression will be used to identify the impulse response and contribution of each of these variables to a shock or innovation in each of them so as to further analyse the dynamic relationship between them.

For the second model specification (eq.4.2), presence of cointegration was found, since the calculated F-statistic of 4.73 has exceeded the threshold of the critical values at both levels of significance with reference to table 4.9. This is so for both AIC and SIC. This means that $H_0 :$ $\delta_1 = \delta_2 = \delta_3 = 0$ can be rejected, and we can confirm that there is cointegrating relationship between the variables (LGP, LGC and LOP). In the event of adding trend to the equation, cointegration was not found, where the F-statistic of 2.83 and 2.07 was found for AIC and SIC respectively, which are below the threshold at both levels of significance, and as such we have to accept the null hypothesis at this scenario.

We can now conclude there is no cointegration in equation 4.1, and there is cointegration in equation in 4.2. So, in order to move with the long run and short run estimations, only equation 4.2 will be used for further long run and short run estimations, because that is the equation that has presence of cointegration between the variables. Having found cointegration in ARDL equation 4.2, a serial correlation and stability tests were applied on the overall ARDL model specification from which the long-run and short-run coefficients will be derived, and the result of the test for this particular model is summarised in table 4.11.

Null Hupothesis: no serial correlation			
BG LM statistics	2.102947	Prob. Chi-Square(2)	0.3494
F-statistic	0.800508	Prob. F(2,22)	0.4618
Critical Chi-square (2,5%)	5.991	Prob. RESID(-1)	0.8554
Critical F-statisitc	3.4434	Prob. RESID(-2)	0.4163

Table 4.11: Serial correlation test for equation 4.2 ARDL model

From table 4.11, it shows the serial correlation test result for equation 4.2, and from the results we cannot reject the null hypothesis, which says$\rho_{p=}0$, meaning that none of the ρs in equation 4.11 is different from zero, as such they are all zero, and this signifies absence of serial correlation in the model. The BG-LM test of 2.102947 does not exceed the critical chi-square value of 5.991 at degree of freedom of 2 (the number of lags of the error term) and 5% level of significance, and as such we accept the null hypothesis, and conclude no autocorrelation of any order. Looking at the Chi-square's p-value of 0.3494, which is above 5% and even 10% level of significance, which signifies that the chi-square value is not significant, as such we can confirm acceptance of the null hypothesis. Similar decision is made using F-statistic. The coefficients of the lagged error terms are also not significant as their p-values are both above 5% level of significance, which further justifies the absence of serial correlation. So the ARDL model are efficient and fit. The first ARDL model specification was also found to have no serial correlation using the same approach. The CUSUM test was also applied to test for the stability of the model as follows:

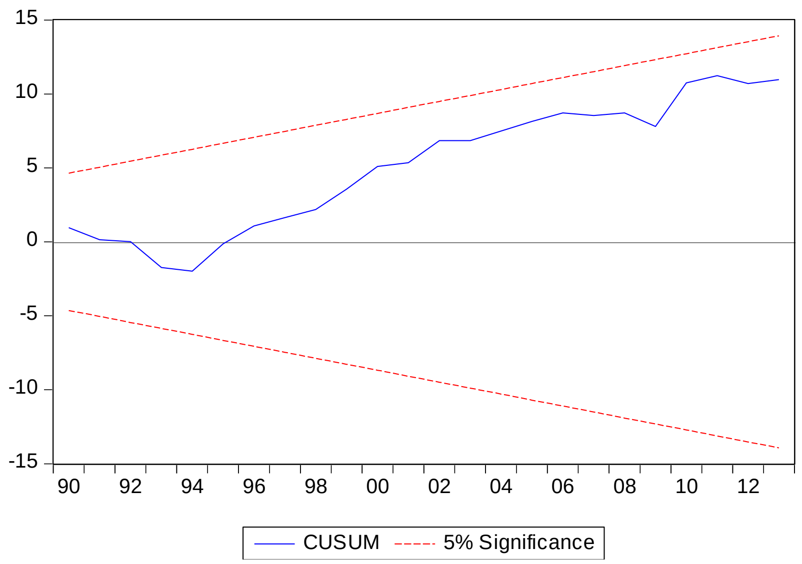


Figure 4.2: CUSUM stability test for equation 4.2 ARDL result

From figure 4.2, the CUSUM stability test results to the residual of equation 4.2 fell within critical boundaries at 5% level of significance, which confirms that all the coefficients of the ARDL model are stable. After observation $i = 96$ the recursive residuals were mostly positive, which indicates that the predicted GDPs are smaller than the actual GDPs, but still within the acceptable range at 5% confidence bounds, the null hypothesis of parameter constancy will not be rejected here.

4.5.2 Long-run impact

The subsequent empirical result for long run impact of gas consumption and crude oil production on real GDP in Nigeria from the ARDL model are presented in table 4.12, where it showed that gas consumption has positive and statistically significant effect on the real economic growth in the country in the long run. It shows that if there is persistent 1% increase in domestic gas consumption, there will be around 2.89% increase in real economic growth in the long run, and this is true at 5% and 10% level of significance. This means that real economic growth is relatively elastic to changes in gas consumption in the long run as continues percentage increase in gas consumption causes higher percentage increase in real economic growth. This result is consistent with some theoretical point of views, like the Keynesian economic school of thoughts who argue that economic growth is demand driven. The domestic gas consumption can stimulates demand for many industrial and energy products, it can help boost capital investment as factors of production will be cheaper to due to improved access to energy resulting from more gas consumption. This can make the general price level to go down, and trigger more demand, which will make businesses and markets to flourish in the country. The endogenous growth theory that holds that economic growth comes as a result of factors within an internal system, which beliefs that new technology and effective as well as efficient factors of production can be achieved with improvement of human capital, which boost the economy. Gas consumption can facilitate new technology as a result of more access to energy and adequate supply of industrial inputs, which could enhance efficiency of the economy and provide effective factors of production.

Looking at the pragmatic point of view of this result, this shows that low domestic gas consumption could potentially cost the country more economic growth, and if more investment are provided to create more demand for natural gas in the country, the economy will grow faster. Despite the fact that during the period under analysis, the domestic gas consumption was relatively below the potential level due to lack of infrastructures, but it still shows a very potential significant link with real economic growth in the event of persistent improvement in gas consumption. Similar positive and statistically significant linkage was found in the work of Apergis and James [144], where they found positive and significant relationship between gas consumption and GDP in some selected 67 countries. Muhammad S. et al (2013) also found positive and strong conneection between gas consumption and economic growth in Pakistan [2]. In Tunisia, similar relationship was found in the work of Sahbi F. et al (2014) [314]. The effect of gas consumption on real economic growth is likely to be statistically significant and visible in countries that have low industrial growth, or reliant on oil products. This is because the relative cleaness of the natural gas and its ability to fulfil many industrial and commercial energy demand will serve as an alternative energy fuel, which will precipitate increased productivity due to the resulting cheaper and efficient factors of production [314]. The long run coefficients are presented in table 4.12.

ARDL(1,0,0) selected based on SIC&AIC, dependent variable is lgdp

Regressor	Coefficient	Standard Error	T-Ratio[Prob]
LGC	2.8864	1.1052	2.6118[.015]
LOP	-.77797	3.4559	-.22512[.824]
C	8.7596	35.9721	.24351[.809]

Table 4.12: Estimated long run coefficients using the ARDL model eq. 4.2

The positive and statistically significant relationship between gas consumption and economic growth is shown in table 4.12 due to positive sign of the gas consumption coefficient and its low probability value as explained above. However, the oil production has statistically insignificant negative impact on the real economic growth. According to the estimate persistent 1% increase in oil production can cause 0.78% decrease in GDP everything being equal, this is a sign of likely presence of resource curse in Nigeria, as more crude oil production could potential hinders economic productivity. If this is statistically significant, it could have been in line with theoretical point of view of resource curse theory which postulates that countries with abundance of non-renewable energies and relying largely on them at the cost of other industries are likely to have a stagnant growth or economic contraction. The Nigerian economy being so much dependent on the crude oil production, from which revenue is supposed to be used to finance some development projects and provide capital formation, but it is likely to be negatively affected due to the volatility of the oil markets and mismanagement of the revenue [315]. Producing oil alone may not necessarily precipitate increased economic output especially in other sectors of the economy like the manufacturing sector. The effect of increased crude oil production may not impact of the economic growth as the revenue may not necessarily be translated in to improved access and affordable factors of production, as the country was accused of huge corruption and misappropriation of the oil revenue [315]. Similarly, the revenue received from oil exports is used to fund importation of petroleum products, and this is exacerbated by the expensive funding of government petroleum subsidy, which makes the export revenue less than the liabilities. However, this negative relationship between real economic growth and oil production is not statistically significant in the long run.

This finding confirms the early findings of Galbraith (1962), who found inverse relationship between real economic growth and resource abundance. He raised the simple questions of many resource poor countries performing well economically and some resource rich countries are not. This idea was termed “resource curse” by Auty (1993) [316], and many researches like that of Boulhol et al (2008) [317] and Robinson et al (2006) [318] confirm negative relationship between oil resource abundance and economic growth in some economies. This means increasing oil production may likely impact little on the economy compare to what continues increase in natural gas production meant for domestic consumption may likely to impact if fully developed in Nigeria.

4.5.3 Short-run impact

Looking at the short run estimates in table 4.13, the important coefficient is that of the error correction model (ecm), which is -0.16 approximately, the sign is negative, but it is not statistically significant even at 10% level of significance. The negative coefficient of the ecm indicates the speed of adjustment from any disequilibrium in the previous year toward the long run equilibrium, the speed is slow as it is just 16%, and it is also statistically insignificant. In other word, 16% of any disequilibrium in the previous year is corrected in the current year, though statistically insignificant. The statistical insignificance of the ecm also shows that the relationship between these variables is not statistically significant in the short-run, this is so looking at the probability values of the short-run coefficients, which are all statistically insignificant.

ARDL(1,0,0) selected based on SIC&AIC, dependent variable is Δlgdp			
Regressor	Coefficient	Standard Error	T-Ratio[Prob]
ΔLGC	.45249	.30838	1.4673[.154]
ΔLOP	-.12196	.59717	-.20423[.840]
ΔC	1.3732	6.3761	.21537[.831]
ecm(-1)	-.15677	.10596	-1.4794[.151]

Table 4.13: Error Correction Representation for the selected RDL model eq 4.2

The long-run and short-run estimations reveal that, the cointegration exists in the long-run, but not in the short-run. The coefficient of gas consumption is still positive in the short-run even though statistically insignificant. The statistically insignificant connection between these variables in the short-run is not quite surprising due to the low level of gas consumption under the period under study and lack of direct economic impact of oil production on the economy as already perceived and explained under the long-run coefficients explanations. In addition, the gas sector development would require resources and time to develop, and the linkage or impact can take place in the long-run. This also indicates that both in the short-run and long-run, the oil production does not impact the economy positively, and is a further indication of a possibility of resource curse in the country, though this cannot be statistically significantly justified. This is manifested in the low growth of the manufacturing sectors and overcrowding of human and capital investment in the oil sector in the country, which makes the manufacturing sector less attractive and less productive.

4.6: Generalised Impulse Response and Variance Decomposition

Since there is no cointegration between the variables specified in equation 4.1, further examination of their relationships are examined through the impulse response function and variance decomposition to observe the pattern and magnitude of the reaction of these variables resulting from a shock within them. “Impulse responses trace out the response of current and future values of each of the variables to a unit increase in the current value of one of the VAR structural errors, assuming that this error returns to zero thereafter” [319]. Variance decomposition examines the contribution of a shock in each variable to the fluctuations of other variables. It shows the responsiveness of a variable due to a shock in another variable(s).

From equation 4.1, in line with the research question, we will be interested in examining the reactions of real GDP and gas consumption to shocks in each of the specified variables in the equation. A shock in this context would refer to a sudden change in some of these variables.

For illustration purpose, a y variable is defined using a classical linear regression model where it depends on a variable x, in a sample size of $n(j = 1,2, \ldots\ldots n)$. To identify the coefficient of the x variable lets say β, an ordinary least square can estimate that, and from any period, the observed value of the y variable could differ from what the x variable could explain βx, and this difference is called the error term (ε), in other word the innovation. In our examination, a one-time standardised shock will be enforced on the innovation at time t, that is shock of one standard deviation to the innovation. The resulting reaction of the variables under study will be traced for some future time period. In order to achieve this, we will estimate vector autoregression (VAR) model for these variables, and we will apply the impulse response analysis as a method for accounting for the corresponding innovation [320].

The VAR model will have both stationary ΔLGDP, ΔLGC, ΔLCF, ΔLXP and ΔLPR as endogenous variables. The conventional orthogonalized impulse responses, under which the shocks in the VAR system are orthogonalized by using the Cholesky decomposition prior to the impulse response and the variance decomposition will not be considered in this examination as its sensitive to the order of the variables. We will use the generalised impulse response method, which is not sensitive to the above restrictions, it does not need orthogonalisation of shocks and it is invariant to VAR order of the variables [165].

We will have five equations from the following VAR(p) equation having each of the variable as a dependent variable as determined by its past values and past values of other variables, and since we have confirmed that these variables are integrated of order one as shown in table 4.3, we will have them in first difference [307].

$$\Delta lgdp_t = a_0 + \sum_{i=1}^{p} a_{1i}\Delta lgdp_{t-i} + \sum_{i=1}^{p} a_{2i}\Delta lgc_{t-i} + \sum_{i=1}^{p} a_{3i}\Delta lcf_{t-i} + \sum_{i=1}^{p} a_{4i}\Delta lxp_{t-i} + \sum_{i=1}^{p} a_{5i}\Delta lpr + \varepsilon_t. \quad (4.27)$$

In matrix representation, the equation is compacted as:

$$g_t = a_0 + \beta(L)g_t + \varepsilon_t \quad (4.28)$$

Where the g_t is the 5×1 vector of the variables under examinations, a_0 is the contant term vector, ε_t is the corresponding disturbance vector (i.e. ε_{it} are the shocks to the variables) and L represents the lag operator. If we consider the following moving average representation of the multiple equations VAR (p) where the constant terms may be ignored going by Peseran and Shin (1998) and Bradley et al (2007) [165] [321].

$$g_t = \Psi(L)\varepsilon_t \quad (4.29)$$

Letting that the shocks are contemporaneously correlated, the generalised impulse response function of g_i to a unit (one standard deviation) shock in g_j is given by:

$$\Psi_{ij,h} = (\sigma_{ii})^{-\frac{1}{2}}(e'_j\Sigma_\varepsilon e_i) \quad (4.30)$$

Where σ_{ii} is the ith diagonal element of Σ_ε, e_i is a selection vector with the ith element equal to 1 and all other elements equal to 0 and h is the periods to be observed post shock.

The advantage of the generalised impulse response function is not changing to the order of the variable presentation in the VAR, because orthogonality is not imposed, the method permits clear understanding of the initial reaction of each of the variables to shocks up to when it stabilises. It allows meaningful interpretation of the corresponding variance decomposition. It provides more robust result than the orthogonalized impulse response method [320] [307].

4.6.1 Results of the impulse response

The five equations used ΔLGDP, ΔLGC, ΔLCF, ΔLXP and ΔLPR as dependent variable respectively, including constant parameter and past values of the other independent variables up to the length of the lags that will be defined by the information criteria. The first difference of these variables are used as they are I (1) as already established in table 4.3. SIC being used in many literature and as recommended for the generalised impulse method by Bradley et al (2007) is used for the lag length selection [322]. The AIC will also be considered for robust check. The lag lengths are jointly selected for the variables going by Peseran (1998) and Bradley et al (2007). Similarly, Gujarati (2012) mentioned that in most cases same number of lagged terms is use in each equation in the VAR system (p.311 [307]). Therefore, similar lagged terms will be applied, and this will be checked if its optimum by running the VAR residual serial correlation LM test. All the lag length selection criteria suggested one lag length, therefore, we will have a VAR (1) models. Similarly, to verify the optimum lag selection, each variable is tested for its lag selection individually, and all of the variables were found to have one lag length as jointly suggested by both AIC and SIC. The result of the optimum lag selection is presented in table 4.14.

Lag	LogL	LR	FPE	AIC	SC	HQ
0	-9.960169	NA	1.87e-06	0.997345	1.230877	1.072054
1	90.39164	160.5629*	1.26e-08*	-4.026109*	-2.624912*	-3.577854*
2	101.3561	13.88838	3.74e-08	-3.09041	-0.521548	-2.268609
3	129.8017	26.54920	4.60e-08	-3.320115	0.416412	-2.124768

Table 4.14: Optimum lag selection for the VAR system

The result of the VAR model is presented in table 4.16, and the tool to interpret the VAR result is through the impulse response and the variance decomposition, which will enable us to examine the further dynamic relationship among these variables. However, from the VAR estimation result, we can see that only the coefficient of the lagged D(LCF) in D(LCF) equation as well as constant parameters in D(LGDP), D(LGC) and D(LCF) equations are statistically significant, while others are not. This further explains the non-cointegration between these variables. The residual serial correlation using LM test shows that there is no serial correlation and that using one lag length is optimal. The result is shown in table 4.15

Lags	LM-Stat	Prob
1	36.12417	0.0697
2	27.15054	0.3484
3	14.34624	0.9554
4	16.95348	0.8835
Probs from chi-square with 25 df.		

Table 4.15: Residual serial correlation from the VAR model

From the serial correlation test results, the calculated LM statistic at lag 1 is lower than the Chi-square critical value (37.652) at degree of freedom of 25 and at 5% level of significance. Therefore, the null hypothesis of no serial correlation will be accepted. For the impulse response function, we applied for 10 periods, which means there is going to be 9 periods after the shock. In order to determine the level of significance of each reactions, a confidence interval of +/- two standard deviations are used. The confidence bands is set that if it does not intersect zero at a particular period, then the response is statistically significant, and is assumed to be statistically different from zero at 5% level of significance. The impulse response results are show in Fig 4.3.

	D(LGDP)		D(LGC)		D(LCF)		D(LXP)		D(LPR)	
D(LGDP(-1))	-0.19407	[-0.49766]	0.127682	[0.69867]	-0.24057	[-0.48984]	0.288823	[0.61774]	0.236672	[0.61247]
D(LGC(-1))	-0.60009	[-1.25234]	-0.04267	[-0.19003]	-1.35571	[-2.24652]	-0.25728	[-0.44783]	-0.14576	[-0.30698]
D(LCF(-1))	0.263071	[1.17668]	0.050866	[0.48549]	0.426750**	[1.51563]	0.021303	[0.07947]	0.079722	[0.35985]
D(LXP(-1))	0.157400	[0.41109]	-0.00319	[-0.01780]	0.111398	[0.23101]	-0.38885	[-0.84705]	-0.24137	[-0.63616]
D(LPR(-1))	-0.20203	[-0.39807]	-0.1589	[-0.66808]	0.090213	[0.14114]	0.189410	[0.31128]	0.023862	[0.04745]
C	0.086093*	[1.46061]	0.049827*	[1.80385]	0.106844*	[1.43930]	0.050666	[0.71695]	0.015594	[0.26699]
R^2	0.139411		Adj. R^2	0.032707						

There are 31 observations after adjustments, t-statistics are shown in brackets. * means significance at 10% level of significance, and ** means significant at 5% level of significance.

Table 4.16: Vector Autoregression results

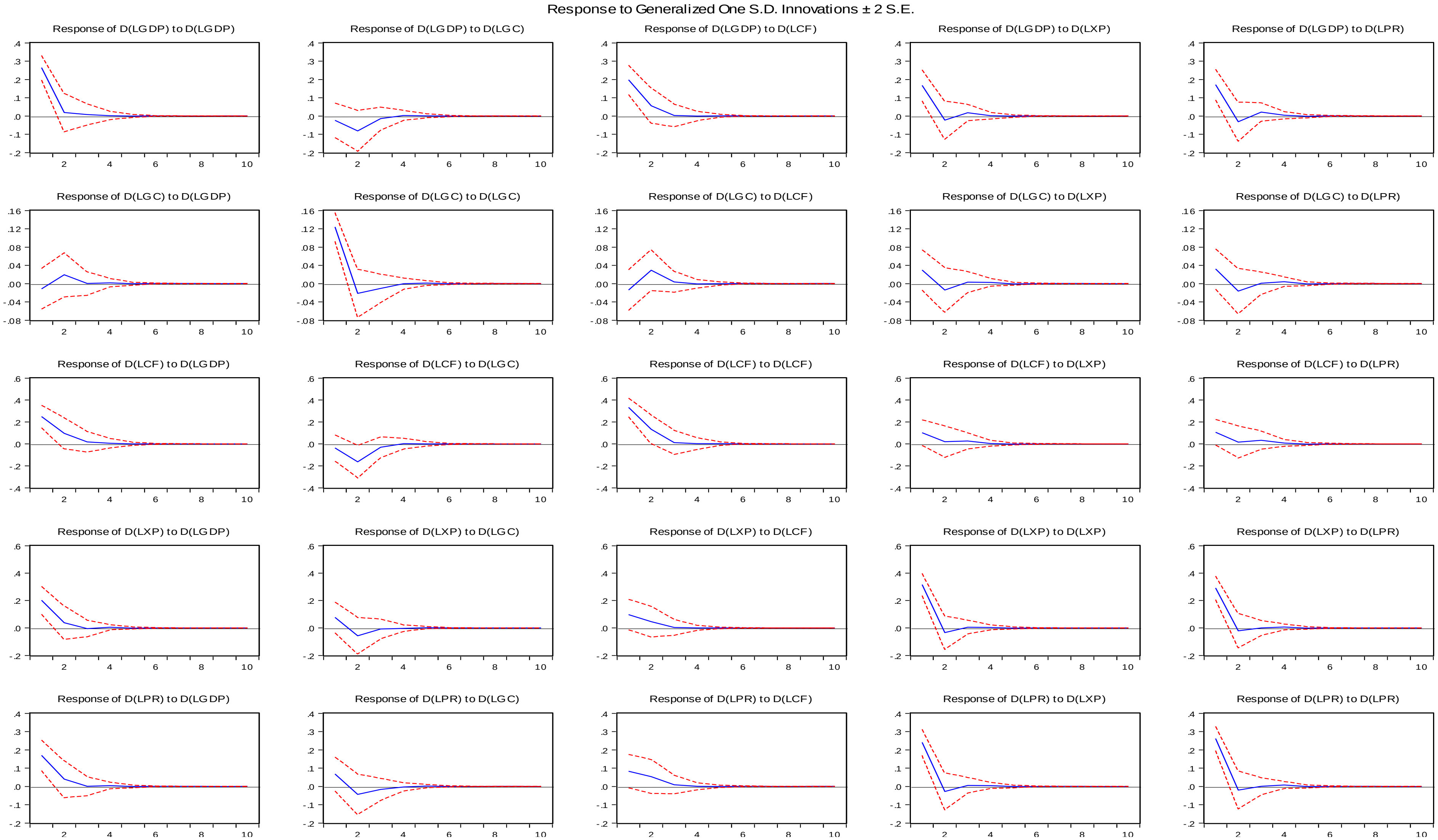


Figure 4.3: Generalised impulse response functions

Of interest to the research, the impact of shocks in ΔLGC and response of ΔLGC to other shocks will be primarily considered, that is the second column and second row respectively. Starting with the second column, ΔLGDP responded negatively in the first three periods after shock in ΔLGC with statistical significance, and eventually at period 3 aftershocks, it stabilised and returned to equilibrium. The ΔLGC responded to its own shock positively during the period of the shock with statistical significance, and then in the subsequent 3 periods it declined and returned to equilibrium. ΔLCF responded negatively to a shock in ΔLGC immediately after the shock as well as in subsequent two periods before it returned to equilibrium, even though not statistically significant. ΔLXP and ΔLPR responded the same way to a shock in ΔLGC, where they reacted positively in the period of shock with some marginal statistical significance and then negatively in the subsequent two periods with statistical significance.

In terms of the response of the ΔLGC to other shocks, ΔLGC responded positively immediately as result of shocks in its own self and shocks in ΔLXP and ΔLPR with statistical significance. However, it reacted negatively to shocks in ΔLGDP and ΔLCF also with statistical significance at the period of the shock. However, the reverse was the case in the following period, where it responded positively to shocks in ΔLGDP and ΔLCF with statistical significance. In the second period after the shock, the ΔLGC responded negatively only to its own self, and positively to other variables' shocks with statistical significance. It converged to equilibrium at the third period after the shocks.

The resulting effect of a shock in change in gas consumption lead to decrease in change in LGDP in the period of the shock and subsequent two periods, with initial and third response being statistically significant. This means that, an unexpected increase in change in LGC can cause decrease in change in LGDP at least for short period, and this could be as a result of transfer of capital or investment from some sectors and capital projects sector to the development of gas unexpectedly, which might create vacuum. Industries can consume natural gas, but the value added to the economy may not be visible at least in the short run, which means their sudden expenditure for gas consumption increase and the subsequent capital transfer lag in other investment could result to temporary adverse effect on the economy.

In addition, in the short run, gas development projects require huge amount of investment and energy own use, and may take couple of times to develop. This means putting resources or consuming energy without a yield, which is a temporary loss that explains the negative response in the change in the GDP as a result of sudden shock in the change in gas cosumption. In orther words, to achieve this sudden increase (shock) in the change in GC, more infrstructures may have to be in place which might consume some amount of energy and resources that would have been used in other sectors. Therefore, the tradeoff between other sectors and the gas development sector might cause this negative shock response in the change in GDP in the fisrst three period [144] [323] [324]. In Nigeria, the economy is largely fueled by oil products, and consumption in natural gas is minimal due to low gas development infrastrures, and for the country to have a sudden change (increase) in gas consumption, it would mean redirection of some huge resources from other sectors to the gas development sectors, which might cause negative effect on the economy initially, but the eventual effects could further restore the economy back to the equilibrium and even cause significant positive impact on the real economic growth.

Similarly, the impulse response of the ΔLGC to an unexpected change in LGDP is negative in the period of the shock, and then positive in the subsequent three periods, which is not surprising as the sudden increase in real GDP may be the resulting effect of more consumption of the oil products to fuel the economy (as a dominant fuel), which might cause reduction in the gas consumption being a substitute fuel. This is in line with the consumer theory that states that, the demand for substitute commodities increases as the demand for the other substitute commodity decreases, other things being equal. But it eventually responded positively in the following three periods, as increased GDP could eventually trigger more gas consumption to meet up with the increasing demand for energy to fuel the growing economy. The increased demand for the oil products might also cause their prices to go up, and people may resort back to use of gas as an alternative option, which explains the subsequent positive increase in gas consumption as a result of shock in GDP.

Overall, all the responses happened within only three periods, all variables returned to normal on the fourth period. This means that the effect of shocks within these variables does not last long, and the response of ΔLGC to its own shock (positive) is the highest response in the system. This signifies the significant influence of direct policy and investment intervention in the gas development sector, as it has high positive response once interventions are made within the sector as shown in the result. The development of domestic gas consumption might not significantly come as a result of shocks or intervention in the other sectors, it has to be a deliberate actions and interventions to enhance the gas development. So in order to use natural gas to deliver economic advantage, the improvement should come from the gas sector initially. To understand more of other potential sectors that may contribute to the movement of gas consumption within the VAR system, a variance decomposition is applied to understand the contribution of each of the variable to the movement of other variables within a time horizon.

4.6.2 Variance Decomposition analysis

The impulse response functions explains how long and to what extent does the dependent variable response to shocks in the independent variables, it also provides the directional response of the variables to shocks in them. Variance decomposition allows for the examination of the measureable contribution of each shock to the movements in the variables. It helps for further understanding of the interrelations of these variables in the presence of these shocks, the variance decomposition is calculated to show the extent to which shocks in these variables contribute to a volatility or variance in one another. The variance decomposition result from the estimated VAR result is presented in table 4.17 and discussed accordingly.

Starting with the contribution of the shock of ΔLGC to other variables' fluctuations, a shock in ΔLGC contributed to 0%, 99%, 0.21%, 9.06% and 10.15% of the volatility in ΔLGDP, ΔLGC, ΔLCF, ΔLXP and ΔLPR respectively in the period of the shock. This means that the immediate effects of the shock in ΔLGC is more responsible for its own volatility, and apart from its own contribution, it contributed more to movements in change in oil price than to any other variable. It also contributed more to movement in ΔLXP and contributed nothing to the movements of change in LGDP. This is not surprising as there is a strong link between the oil price, exports and gas consumption. Oil price influences the crude oil production and gas consumption as they are substitute commodities, and crude oil exports constitute the large proportion of the exports basket (91%) in the country. The absence of statistical significance of the contribution of the shock in ΔLGC to the movement of changes in LGDP is likely due to lack of dependence on the natural gas in the economy, as oil products dominates the energy sector, and the effect of gas consumption may not be noticeable at least immediately.

However, the shock in ΔLGC contributed within the range of 7% to 8% to the movements of the ΔLGDP in the subsequent periods, which means the connection between the ΔLGC and ΔLGDP is not immediate. This contribution is higher than that of the other variables' contribution to the movement of ΔLGDP in the subsequent period after shock. The shock in ΔLGC also contributed between 89% and 90% of its own volatility in other periods. It also contributed 16%, 11% and 11% of the movements of the ΔLCF, ΔLXP and ΔLPR respectively in other periods. This means in other periods and apart from its own fluctuations, it contributed more to the fluctuation in ΔLCF. Similarly, apart from its own shock, the fluctuations in ΔLGC was more explained by shock in ΔLXP more than any other variable which is explained by about 4%, and this is due to the influence of crude oil production being an alternative energy resource to the gas, which influences the exports in the country being the major contributor to the exports basket. Any sudden change in export, hence oil production can have effect on gas production, so exports can explain about gas consumption in the country in the event of shock. Change in GDP is the second variable that explains more about the movements of changes in gas consumption apart from its own contribution.

The shock in ΔLGDP contributed 100% of its own variance in the period of the shock, which means its fluctuation is solely explained by its own shock in the period of shock, and this is because, it takes some periods to actualise effects of shocks in other variables on the change in the GDP. However, the shock in ΔLGDP contributed 0.83%, 56%, 40% and 42% of the variance of the ΔLGC, ΔLCF, ΔLXP and ΔLPR respectively in the same period of shock. In the remaining periods, the shock in ΔLGDP contributed between 86% and 87% of its own variance. It also contributed about 3%, 46%, 38% and 40% for the fluctuations in ΔLGC, ΔLCF, ΔLXP and ΔLPR respectively. This means shock in GDP contribute less in the movement in gas consumption, and this is due to lack of dependence on the gas resource in the country as well as low gas development infrastructures. However, apart from its own shock, the fluctuations in GDP is more explained by shock in ΔLGC which is by 8% in the subsequent periods as earlier mentioned. This means that in the events of these shocks and excluding the contribution of the ΔLGDP's own shock, the ΔLGC has contributed more to the movements of ΔLGDP more than other variables post shock. This indicates the possible bond between GC and real GDP in the country being an energy resource that facilitates other factors of production. We can now conclude that among these variables, change in gas consumption has more significance to the movements in the GDP in the subsequent periods after shock, which further discover a unique relationship between the gas consumption and economic growth in the country in the event of shocks.

Therefore, changes in GDP can be more explained by changes in gas consumption among the variables under consideration other than itself. Similarly, other than its own contribution, changes in gas consumption can be more explained by changes in exports, which had a positive and negative impulse response to changes in exports in the period of shock and a period after shock respectively. Once exports is suddenly increased in the country, it might implies increase in crude oil exports, which might be caused by increasing oil price going by the law of supply, and since the low efficient refineries in the country cannot meet up the increasing energy demand, the imported oil products prices will be high as well, and people will resort to using alternatives like the natural gas at a short term, which explains the positive response to exports increase. Even though, the impulse response of change in GDP as a result of innovation in change in GC is negative in the short-run due to the reasons earlier specified, but, change in GDP returned to equilibrium two years after the innovation in GC. This means the effect is temporary. The change in GC responded positively to innovation in GDP except in the period of the shock and then it converged to equilibrium in the subsequent three period. It also contributed about 8% of the movement in real GDP. This means that sudden shocks in gas consumption can explain about the change in GDP more than other variables, and this suggests the close link and how much gas consumption can potentially affect the economic growth in the country, and this confirms the potential of natural gas consumption as a tool to deliver economic advantage in the country, and this is in line with the finding of Abdulkadir and Ilhan (2015) [324]. This implies that interventions in gas development sector can affect the changes in real economic growth, and justifies the need for more investment in the gas development sector.

4.7 Summary:

The chapter studied the cointegration between gas consumption and real economic growth in Nigeria in two different multivariate specifications. The first specification added real capital formation and real exports, and found no cointegration among the specified variables. As a result, further analysis was administered to observe the impulse response and contribution of each of these variables to a unit shock in one another. It was found that change in real GDP was not explained by any of the variables in the period of the shock, but change in gas consumption in the period of shock was explained largely by changes in its own self and then by changes in real GDP but not explained by any change in other variables. However, the change in gas consumption responded negatively to shock in the change in real GDP and vice versa in the period of the shock, but in subsequent period change in gas consumption responded positively to change in GDP. All the responses were temporary and lasted only within three period before returning to equilibrium. The result also shows that among these variables, change in gas consumption has more significance to the movements in the GDP in subsequent periods after shocks. However, in the second model specification, where oil production, gas consumption and real GDP were used, cointegration was found, and positive and significant long run relationship was found between gas consumption and real economic growth, where a persistent 1% increase in gas consumption in the long run can cause 2.89% increase in real GDP. It was also found that the country could likely to be facing the economic problem of a resource curse due to adverse effect of crude oil production on real GDP even though statistically insignificant. Therefore, one of the research hypothesis that says oil production does not directly positively affect the economy could not statistically significantly justified. Similarly, short run relationship between real GDP, gas consumption and oil production is statistically insignificant. Therefore, the country's economy needs to be diversified to tackle the likely problem of resource curse. We concluded that, despite the fact that during the period under analysis, the domestic gas consumption sector was relatively below the potential level due to lack of infrastructures, but it still shows statistically significant link with real economic growth in the event of persistent improvement in gas consumption in the long-run.

Variance Decomposition of D(LGDP):					
Period	D(LGDP)	D(LGC)	D(LCF)	D(LXP)	D(LPR)
1	100.0000	0.000000	0.000000	0.000000	0.000000
2	87.30399	7.930605	4.261518	0.032918	0.470966
3	86.15316	8.056485	4.251521	0.692373	0.846463
4	86.08550	8.062447	4.262715	0.701662	0.887680
5	86.07781	8.061912	4.265612	0.702714	0.891948
6	86.07711	8.062428	4.265615	0.702908	0.891941
7	86.07704	8.062422	4.265629	0.702918	0.891988
8	86.07704	8.062424	4.265629	0.702920	0.891988
9	86.07704	8.062424	4.265629	0.702920	0.891989
10	86.07704	8.062424	4.265629	0.702920	0.891989

Variance Decomposition of D(LGC):					
Period	D(LGDP)	D(LGC)	D(LCF)	D(LXP)	D(LPR)
1	0.837100	99.16290	0.000000	0.000000	0.000000
2	2.880986	90.13231	2.586462	3.046615	1.353627
3	2.836386	89.38949	2.698220	3.724535	1.351373
4	2.849626	89.19103	2.751759	3.722256	1.485326
5	2.849743	89.18672	2.751851	3.725760	1.485926
6	2.849725	89.18604	2.752169	3.725722	1.486344
7	2.849725	89.18598	2.752169	3.725763	1.486363
8	2.849725	89.18597	2.752171	3.725762	1.486367
9	2.849725	89.18597	2.752172	3.725763	1.486368
10	2.849725	89.18597	2.752172	3.725763	1.486368

Variance Decomposition of D(LCF):					
Period	D(LGDP)	D(LGC)	D(LCF)	D(LXP)	D(LPR)
1	56.10139	0.208039	43.69057	0.000000	0.000000
2	46.94970	16.06660	36.06518	0.868848	0.049672
3	46.12275	16.29528	35.27071	1.629345	0.681922
4	46.09328	16.28271	35.24661	1.629993	0.747404
5	46.08994	16.28154	35.24755	1.630994	0.749982
6	46.08950	16.28208	35.24722	1.631217	0.749974
7	46.08946	16.28207	35.24720	1.631232	0.750035
8	46.08946	16.28207	35.24720	1.631234	0.750035
9	46.08946	16.28207	35.24720	1.631234	0.750036
10	46.08946	16.28207	35.24720	1.631234	0.750036

Variance Decomposition of D(LXP):					
Period	D(LGDP)	D(LGC)	D(LCF)	D(LXP)	D(LPR)
1	40.37972	9.063384	5.514366	45.04253	0.000000
2	38.66061	10.98938	5.539876	44.50395	0.306176
3	38.43008	10.97879	5.615102	44.61106	0.364961
4	38.40905	10.96968	5.632996	44.56139	0.426881
5	38.40803	10.97074	5.633375	44.56023	0.427619
6	38.40798	10.97084	5.633406	44.56013	0.427654
7	38.40797	10.97084	5.633405	44.56013	0.427659
8	38.40797	10.97084	5.633405	44.56013	0.427660
9	38.40797	10.97084	5.633405	44.56013	0.427660
10	38.40797	10.97084	5.633405	44.56013	0.427660

Variance Decomposition of D(LPR):					
Period	D(LGDP)	D(LGC)	D(LCF)	D(LXP)	D(LPR)
1	42.18975	10.15311	5.463163	28.66808	13.52590
2	40.53977	11.40634	6.520531	29.19551	12.33785

3	40.08003	11.63556	6.656690	29.38229	12.24542
4	40.03838	11.62383	6.676285	29.33657	12.32493
5	40.03685	11.62586	6.676232	29.33654	12.32453
6	40.03669	11.62593	6.676362	29.33640	12.32462
7	40.03667	11.62595	6.676358	29.33641	12.32462
8	40.03666	11.62595	6.676359	29.33641	12.32462
9	40.03666	11.62595	6.676359	29.33641	12.32462
10	40.03666	11.62595	6.676359	29.33641	12.32462

Table 4.17: Variance decomposition results from the VAR model

Chapter 5. Granger Causality test between gas consumption and economic growth in Nigeria

5.1. Introduction

The previous chapter studied the cointegration, long run and short run equilibrium relationships between gas consumption and economic growth in Nigeria in the presence of some related variables in two separate models. It was found that there is long run cointegration between gas consumption and economic growth in the second model specification. In the first model specification where no cointegration was found in the presence of the variables specified, it was found that gas consumption helps in explaining movements of economic growth more than the other variables under study in the event of shocks. In the second model specification, it was found that continuous 1% increase in gas consumption leads to 2.89% increase in real GDP. The policy implication of this means, persistent increase in gas consumption can boost the economic performance in the country. However, there is need to find out if economic activity can also be used to predict gas consumption and vice versa. This will inform policy makers in designing economic policies and setting priorities among variables that have causal effects. It is important to understand the directional relationship between variables, so that policy makers can understand which variables are useful in forecasting other variables and vice versa. Knowing the causality between gas consumption and economic activity will help in understanding the behaviour of each of the variables based on their past. If increase in economic activity causes gas consumption, then increased in economic growth can predict increase in gas consumption. Therefore, it is vital to understand the direction of this relationship.

"Causal relations are studied because policy makers need to know the consequences of the various actions they take or about to take"[149]. "Variable X is said to granger cause variable Y , if variable Y is best predicted using the histories of both Y and X than it can be predicted using the history of Y alone" [325]. Knowing the causality between X and Y enables the policy makers to know that when controlling X, they are by implication controlling for Y. This is useful in allocating limited resources optimally, to minimise/avoid misplacement of resources. According to Gujarati (2012), "The distinction between the dependent variable Y and one or more X variables, the regressors, does not necessarily mean that the X variables cause Y. Causality between them, if any, must be determined externally" [307], and these are the reasons why the test for causality between gas consumption and economic growth is important.

5.2. Granger Causality test using VAR

Granger causality test predicts variable based on its lagged values and lagged values of other determining variables. This is presented below [312]:

$$Y_t = A_{0_t} + \sum_{i=1}^{m} A_1 Y_{t-i} + \sum_{j=1}^{m} B_1 X_{t-j} + \mu 1_t \quad (5.1)$$

$$X_t = A_{1_t} + \sum_{i=1}^{m} \gamma_1 X_{t-i} + \sum_{j=1}^{m} \delta_1 Y_{t-j} + \mu 2_t \quad (5.2)$$

Where $\mu 1_t$ and $\mu 2_t$ are assumed to be uncorrelated [307] [312]. There are four different possible conditions from equation 5.1 and equation 5.2. and these are as follows:

1. If $\delta_1$is not close to zero and B_1 is close to or equals to zero, then it can be said that variable Y causes variable X.
2. If B_1 is not close to zero, and $\delta_1$is close to or equals to zero, then it can be said that variable X causes variable Y.
3. If both δ_1 and B_1 are not close to zero, then it can be said that both Variable X and Y causes each other.
4. When both the δ_1 and B_1 are close to or equals to zero, then it can be said that variable Y and X are independent of each other.

For the purpose of this research, Y as the real GDP, which is the proxy for economic growth, and X as gas consumption will be considered. In order to do the granger causality test for these two variables the following steps as developed by Gujarati (2012) will be followed.

The optimum number of lags to be used in the VAR model will be selected, using both AIC and SIC. The VAR is a model that identifies the "linear interdependency" of one or two variables, by estimating each of the variables separately accounting for its own lagged values and lagged values of other relating variables [154]. The VAR estimation is going to be based on the two variables under consideration, i.e. stationary Δlgdp and Δlgc. These variables are carried forward from the previous chapter, where their statistical description were presented.

Lag	LogL	LR	FPE	AIC	SC	HQ
0	-26.21883	NA	0.032773	2.257507	2.355017	2.284552
1	20.76402	82.68983*	0.001055*	-1.181122*	-0.888592*	-1.099986*
2	23.94265	5.085798	0.001136	-1.115412	-0.627861	-0.980186
3	27.31513	4.856381	0.001218	-1.065211	-0.38264	-0.875895

Table 5.1: Optimum lag selection

Based on table 5.1, the AIC and SIC are suggesting the use of one number of lags for the causality test, which means, the following models will be tested.

$$\Delta lgdp_t = A_{0_t} + \sum_{i=1}^{1} A_1 \Delta lgdp_{t-i} + \sum_{j=1}^{1} \gamma_1 \Delta lgc_{t-j} + \mu 1_t \tag{5.3}$$

And

$$\Delta lgc_t = B_{0_t} + \sum_{i=1}^{1} B_1 \Delta lgc_{t-i} + \sum_{j=1}^{1} \delta_1 \Delta lgdp_{t-j} + \mu 2_t \tag{5.4}$$

The rule of decision is that if computed F static value is more than that of the critical F statistic, the null hypothesis that says δ_1 and $\gamma_1$are zero will be rejected [307]. In order to complete the procedure, equation 5.3 and equation 5.4 will be treated separately.

From equation 5.3 using Δlgdp, and from equation 5.4 using Δlgc as the dependent variables, the restricted regressions will be estimated by removing the lagged value of Δlgc and Δlgdp from those equations respectively thereby making it look like this:

$$\Delta lgdp_t = A_{0_t} + \sum_{i=1}^{1} A_1 \Delta lgdp_{t-i} + \mu 1_t \tag{5.5}$$

$$\Delta lgc_t = B_{0_t} + \sum_{i=1}^{1} B_1 \Delta lgc_{t-i} + \mu 2_t \tag{5.6}$$

From equation 5.5 and 5.6, the restricted residual sum of square (RSSr) will be derived. Then equation 5.3 and 5.4 will be estimated to get their unrestricted residual sum of square (RSSu), so as to identify if $\delta_1 = 0$ and $\gamma_1 = 0$ using F statistic. The F statistic formula as given by Gujarati (2012) and Dougherty (2011) and it is presented as follows:

$$F = \frac{(RSSr - RSSu)/m}{RSSu/(n-k)} \tag{5.7}$$

Where m is the number of lags and n is the number of observations which is 33 (observations between 1981 and 2013) and k is the number of parameters estimated in the unrestricted equations (5.3 and 5.4) which is 3.

5.2.1 Presentation of results and discussion

The estimates for equation 5.5 and 5.3 are as follows, from which the RSSr and RSSu for the Δlgdp equations were acquired and presented in table 5.2.

Restricted	D(LGDP)	Unrestricted	D(LGDP)
D(LGDP(-1))	0.075632	D(LGDP(-1))	0.078980
	(0.18201)		(0.17834)
	[0.41553]		[0.44285]
C	0.043653	C	0.082013
	(0.04779)		(0.05346)
	[0.91353]		[1.53413]
Sum sq. resids	2.015362	D(LGC(-1))	-0.622619
			(0.41883)
			[-1.48658]
		Sum sq. resids	1.867934

Standard errors in ( ) & t-statistics in [ ]

Table 5.2: Estimates of the restricted and unrestricted Δlgdp VAR models

The estimates for equation 5.6 and 5.4 are as follows, from which the RSSr and RSSu for the Δlgc equations were acquired and presented in table 5.3.

Restricted	D(LGC)	Unrestricted	D(LGC)
D(LGC(-1))	-0.153802	D(LGC(-1))	-0.156195
	(0.19771)		(0.19801)
	[-0.77792]		[-0.78881]
C	0.060444	C	0.057731
	(0.02508)		(0.02527)
	[2.41023]		[2.28417]
Sum sq. resids	0.431183	D(LGDP(-1))	0.080695
			(0.08432)
			[0.95703]
		Sum sq. resids	0.417526

Standard errors in ( ) & t-statistics in [ ]

Table 5.3: Estimates of the restricted and unrestricted Δlgc VAR models

Therefore,

$$F_{1H_0} = \frac{(\,2.015362 - 1.867934)/1}{1.867934/(33-3)}$$

F_{1H_0}=2.37

$$F_{2H_0} = \frac{(\ 0.431183 - \ 0.417526)/1}{0.417526/(33-3)}$$

F_{2H_0}= 0.98

For the first null hypothesis that says gas consumption does not granger-cause real GDP, the computed F statistic is 2.37. The degree of freedom will be m and n-k (1, 30), where m is the number of lags in gas consumption, n is the sample size (33) and k is the number of parameters in the unrestricted equation (3). Therefore, the critical F statistic is 4.17 at 5% level of significance, which means the computed F statistic does not exceeds the critical F value. Therefore, the null hypothesis that says gas consumption does not granger-cause GDP will not be rejected, meaning that gas consumption does not granger causes GDP in Nigeria. This is so even at 10% level of significance. It can be confirmed that $\gamma_1 = 0$. That is to say, gas consumption cannot predict economic growth in Nigeria. This is in line with the no cointegration result in the first equation in chapter four. It is also consistent with the non-significance of the error correction term and non-significance of the gas consumption coefficient in the short-run for equation two of the previous chapter. Despite the positive long run relationship as found in equation 4.2, where a future continues positive increase in gas consumption can cause a positive increase in real GDP, but at the current trend, the gas consumption cannot predict real GDP growth in Nigeria. This is not surprising due to the very little development and utilization of the gas in the country, and due to over reliance of the country's economic growth on the oil sector. The result is also consistent with the finding of Adeniran (2009) and contrary to what Ighodaro (2010) found in Nigeria[326], it also contradicts some findings in some other countries as studied by Muhammad S. et al (2014), Sahbi et al(2014), Farhani S. et al (2014) and Apergis N. et al (2010) [151] [314] [327] [144].

For the second hypothesis that says real GDP does not granger cause gas consumption; the computed F statistic is 0.98, and the critical F statistic is the same as in the first hypothesis, which is 4.17. This means that the computed F statistic for the second hypothesis does not exceed the critical F statistic, which means that the null hypothesis that says $\delta_1 = 0$ cannot be rejected, meaning that real GDP does not granger cause gas consumption. This is so even at 10% level of significance. Therefore, there is no causality from GDP to gas consumption in Nigeria, and the condition that applies to these two scenarios is condition number 4 stated above, and it can be said that the two variables are independent of each other. This is in line with the neutral causality findings between energy consumption and economic growth in the work of Aliero (2012) and Abalaba (2013) in Nigeria, Erol and Yu (1987) [142] in USA, Mushtaq K. et al (2007) in Pakistan [328], and Ozturka and Acaravcib (2010) in Turkey [329]. This also contradicts the findings of Olusegun and Ovenseri (2008) in Nigeria. It is also not consistent with the finding of Apergis N. et al (2010) and Muhammad S et al (2014) who found bidirectional relationship between gas consumption and economic growth in some 67 randomly selected countries and Pakistan respectively. Similarly, the result of this analysis contradicts the work of Abid M. and Mraihi R. (2014) [330], who found unidirectional causality running from gas consumption to economic growth in Tunisia. The finding also went contrary to the finding of Das A. et al (2013) and Payne J.E. (2011), who found only a unidirectional relationship running from GDP to Gas consumption in Bangladesh and US respectively [331] [332]. This is because the causality direction differs from one country to another, which requires country specific causality test.

For robust check to see how the result of the causality will change in the presence of other variables, real oil price and oil production were included in the VAR specifications. This will also confirm if both oil production, oil price and gas consumption can jointly predict real economic growth in the country. The optimal number of lags for the specifications was suggested to be one by both lag selection criteria as presented in table 5.4, and it was found to be an optimal number of lag going by the LM statistics and its probability value.

Lag	LogL	LR	FPE	AIC	SC	HQ
0	6.064516	NA	1.02e-05	-0.14238	0.046212	-0.083316
1	85.16573	130.9261*	1.33e-07*	-4.494188*	-3.551225*	-4.198864*
2	100.5733	21.25188	1.49e-07	-4.453334	-2.756001	-3.92175
3	114.2382	15.07847	2.11e-07	-4.29229	-1.840587	-3.524447
4	128.3234	11.65672	3.64e-07	-4.160235	-0.954162	-3.156133

Table 5.4: Optimum lag selection

Therefore, the unrestricted specifications including these additional variables will be:

$$\Delta lgdp_t = C_{0_t} + \sum_{i=1}^{1} C_1 \Delta lgdp_{t-i} + \sum_{j=1}^{1} \emptyset_1 \Delta lgc_{t-j} + \sum_{j=1}^{1} \emptyset_2 \Delta lpr_{t-j} + \sum_{j=1}^{1} \emptyset_3 \Delta op_{t-j} + \mu 3_t \quad (5.8)$$

And

$$\Delta lgc_t = D_{0_t} + \sum_{i=1}^{1} D_1 \Delta lgc_{t-i} + \sum_{j=1}^{1} \varphi_1 \Delta lgdp_{t-j} + \sum_{j=1}^{1} \varphi_2 \Delta lpr_{t-j} + \sum_{j=1}^{1} \varphi_3 \Delta lop_{t-j} + \mu 4_t \tag{5.9}$$

That means the f-statistic will be testing the null hypotheses that say the coefficients $\emptyset_i$ and φ_i are zero, meaning that the history of the specified independent variables are not significant in explaining the respective dependent variables at current time. The result of the VAR estimations for the two unrestricted equations (GDP and gas consumption equation) including these additional variables are presented in appendix E. The calculated F-statistic after estimating the above VAR models are presented as follows:

$$F_{3H_0} = \frac{(2.015362 - 1.838190)/1}{1.838190/(33-5)}$$

F_{3H_0}=2.69877

$$F_{4H_0} = \frac{(0.431183 - 0.386406)/1}{0.386406/(33-5)}$$

F_{4H_0}= 3.24471

Therefore, the third null hypothesis will be testing if gas consumption, real oil price and oil production cannot jointly granger cause real GDP, and the fourth null hypothesis will be testing if real GDP, real oil price and oil production cannot jointly granger cause gas consumption. The critical F-value for the degree of freedom of m and n-k (1, 28) is 4.196 at 5% level of significance and 2.893 at 10% level of significance. Therefore, the third null hypothesis cannot be rejected because the computed f-statistic is below the critical f-statistics at both 5% and 10% level of significance, which means gas consumption, real oil price and oil production do not jointly granger cause real GDP, meaning that they cannot predict real economic growth in Nigeria at both level of significance.

The fourth hypothesis can only be rejected at 10% level of significance. At this level of significance, the computed f-statistic (3.24) is higher than the critical value of the f-statistic(2.89). This means, that real GDP, real oil price and oil production can jointly granger cause gas consumption, and as such they can predict gas consumption in the country. However, they cannot granger cause gas consumption at 5% level of significance. Therefore, we can rely on the result based on 10% level of significance and conclude that real GDP, real oil price and oil production can jointly granger cause gas consumption in Nigeria. This is not surprising as the consumer theory states that price and supply of a substitute commodity (oil production) affect the demand for the other substitute commodity (gas consumption). Joining with the effect of real economic growth, where increase in productivity or output can cause increase in input demands (including gas inputs), and increase in oil price due to shortages of oil supply can affect the demand for natural gas in the country, hence, the joint causality of these variable on gas consumption in the country.

5.3. Summary

This chapter analysed the long run causal relationship between gas consumption and economic growth in Nigeria. Using lagged regression equations to determine the significance of the coefficients of the lagged values of the independent variables on the dependent variable. Two different equations were initially estimated, one estimating the real GDP that is a proxy for economic growth and the other estimating gas consumption using a past data between 1981 and 2013 in Nigeria. Each of the dependent and independent variable was lagged up to one time as suggested by both the AIC and SIC.

F statistic was used to determine the causality between these two variables. Restricted and unrestricted sums of squares residuals were used to determine the computed F statistic values for the two equations. Both the computed F statistic of 2.37 for the first null hypothesis and 0.98 for the second null hypothesis did not exceed the critical F statistic value of 4.17, which means the null hypothesis that says the coefficients of gas consumption variable and coefficients of real GDP in the ΔLGDP and ΔLGC equations respectively are not significantly different from zero. This means gas consumption is not significant in predicting real GDP in Nigeria and vice versa. Therefore, there is no causality between the two variables. The result of causality test was found to be country specific as different directions of causality were found in different countries.

Therefore, this result is consistent with the statistical insignificance of the short run coefficients of the change in gas consumption and the error correction term in relation to change in GDP as derived in the previous chapter. The absence of causality between gas consumption and economic growth is not surprising as both gas consumption and economic growth are independent of each other in the country. The Nigerian economy rely more on the oil sector and hence the low gas consumption history in the country.

The implication of this result is that despite the identified positive long run coefficient in the event of continues increase in gas consumption, gas consumption cannot predict movement of the Nigerian economy at the current trend. However, if more investment and further infrastructures are provided in the gas sector in the country, the gas sector can then start to feed in more in the economic productivity, and thereby making the economy dependent on the gas sector eventually due to continues increase in gas consumption, and then the significant link between gas consumption and real economic growth can be created. Flaring gas should be stopped so as to channel the produced gas to improve power supply and provide inputs to industries and manufacturing sector, and then the causality could be eventually created. Deliberate policies should be in place to enhance gas development and consumption within the country in order to sustain the increase in gas consumption and help create its connection with real economic growth.

For robust check, real oil price and oil production were added to the specification, and it was also found that, gas consumption, real oil price and oil production cannot predict real GDP at both level of significance. However, it was found that real GDP, real oil price and oil production can predict gas consumption in the country at 10% level of significance. This implies that economic growth, price and supply of oil have causal effect on the gas consumption in the country.

Chapter 6. Summary and Conclusion

Natural gas is one of the most promising energy resources that give hope for the future; it is favoured due to possible depletion of oil reserves (oil being the leading global energy resource), relative immaturity of many renewable energy technologies, and concerns about the security of nuclear energy. In addition, emissions of carbon dioxide (per unit of energy delivered) from natural gas are much lower than coal, which makes natural gas environmentally friendly compare to other fossil fuels. However, natural gas faces some challenges that threaten its potential of becoming the leading energy resource globally. One of the major challenges of developing gas is capital intensiveness of its projects and geographical concentration of its reserves. There is also a huge capital requirement for gas transporting systems. LNG and international pipelines have been the two major options for transporting gas to distant locations globally at large scale. Therefore, countries with these important reserves stand an economic opportunity of meeting its domestic energy demand and even exporting it outside to increase their hard currency earnings.

Some developing countries endowed with this energy resource do not utilize it to the fullest; rather the gas is flared in the process of producing the associated oil. This is why the demand for gas in these countries is latent and huge economic benefit is wasted. Nigeria has the largest gas reserve in Africa (which represents 2.5% of the global share of gas reserves), yet it is the second worst country in terms of gas flaring. Since 1999, Nigeria has been exporting its natural gas to European countries as LNG and until recently through gas pipelines to some African countries. However, despite the Nigerian reputation for gas reserves and gas production, there have been reports of wide gap between energy demand and supply in the country. This is because the gas produced is exported and the remaining portion of the gas is flared. Consequently, this research studied how the gas can be developed within the country in order to stimulate the demand for it, and make the country one of the leading gas consumers in the world. In addition, to make full and effective use of its natural gas resources within energy mix that supports necessary and sustainable economic growth. This is motivated by the objective of the Nigerian gas master plan that is aimed at increasing domestic gas utilization and stoppage of gas flaring.

The research studied how Nigeria can utilize its natural gas reserves to stimulate latent demand and thereby derive economic advantage and address its energy demand concerns within its territory. Since Nigeria has the advantage of not have to import natural gas, the research identified three major gas development projects that Nigeria can develop to fully utilize its natural gas reserves within its territory. The projects that are key to achieving the objective of the country's gas master plan (ensuring domestic gas utilization in the country) were identified to be domestic gas pipelines, gas to power projects (CCGT) and gas to liquid projects. Consequently, this study analysed the costs and benefits of six possible domestic gas pipelines route options on the scale of the total investment costs, gas delivery as well as costs and benefits using NPV, IRR and Payback period, and found that BSRO pipeline option is the optimal pipeline routes combination. However, in terms of coverage and ability to supply more gas to more locations, all gas pipeline route option is more recommendable, which is the third most viable among the six options. The summary of these economic indicators for each of the gas pipeline options are presented in table 6.1

Indicator	BSRO	All pipelines route options	BNRO	BRO	SRO	NRO
Capital cost ($)	1.15 billion	2.57 billion	2.07 billion	1.08 billion	501.18 million	1.42 billion
Gas Delivery (bcm/yr)	37.25	47.74	32.60	22.11	15.13	10.49
NPV ($)	2.43 billion	1.95 billion	998 million	1.02 billion	950 million	-479 million
IRR	50.38%	28.44%	23.98%	31.55%	47%	11%
Discounted payback period (yrs)	2.60	5.62	7.49	4.80	2.83	-

Table 6.1: Economic indicators of the gas pipelines routes options

The total investment cost of the BSRO pipelines option was estimated to be $1.15 billion and its annual gas delivery was estimated at 37.25 billion cubic metres of natural gas. The NPV, IRR and payback period of the BSRO pipelines option were estimated to be approximately $2.43 billion, 50.38% and 2.60 years respectively. It was discovered to have the potential of supplying gas directly to approximately 50 million populations as it cuts the country into two parts, supplying the gas directly to extreme northern part of the country from the Niger Delta. These indicators have found the BSRO pipeline options to be more economically viable compare to other pipelines route options. Using the harmonised ranking points from each of these indicators, the BRO and SRO pipelines option were ranked second most viable. However, in terms of coverage and ability to supply more gas to more locations, the all gas pipeline route option is more recommendable. The route option that combined all pipelines routes was ranked 3rd most viable, which has the estimated NPV of $1.95 billion, IRR of 28.44%, payback period of 5.62 years and can supply gas up to 100 million population. Therefore, Nigerian government is encouraged to consider constructing the whole gas pipeline route options, and private investors should be encouraged to invest in the gas pipeline constructions. The option that is not viable is the NRO pipelines option, and it is recommended not to consider this option alone, even in the future, the best recommendation was to combine it with the BRO pipelines option.

This empirical finding justifies the decision of the Nigerian government to opt for the construction of the BSRO pipelines, but it is recommended to consider all the pipeline options at a time. Both pipelines are more sensitive to discount rate, cost of gas transportation and capacity. Assessment of value addition of these pipelines were also administered, and found that these pipelines can help improve gas supply, which can be used to generate the more needed electricity in the country. They can also supply gas for spread gas development projects especially GTL projects that can produce an alternative transport fuels in the country. The pipelines if constructed can stimulate more gas demand, and they can create direct and indirect jobs in many sectors of the economy. Another value addition of these pipelines, is the resulting reduction in CO_2 emissions as a result of the eventual substitution of oil for gas, which the pipelines can facilitate. It is expected that if all the pipelines routes options are constructed, there will be several potential spots for building gas to power and gas to liquid plants across the country, which private investors can invest and yield economic benefits.

If the recommended gas pipelines are built within the country, the next question is how to encourage investors to invest in other gas development projects especially gas to power and gas to liquid projects. One way of encouraging private sector investment is to project the possible economic return for each of these projects; this is why this research also studied whether these projects can be profitable in Nigeria, and if so, which of the two projects is more economically viable. The two projects were assessed using net present value, internal rate of return and payback period accounting techniques. Summary of the findings are summarised in table 6.2.

Investment Indicator	CCGT Project	GTL Project
Initial Capital Cost	$480 million	$1.4 billion
NPV	$38 million	-$859 million
Internal rate of Return	15.02%	5.17%
Payback period	18.78 Years	NR

Table 6.2: Economic indicators of the CCGT and GTL projects

The research applied these accounting techniques to assess the profitability of CCGT and GTL project in Nigeria. All the applied accounting techniques have suggested that CCGT project is viable in Nigeria. GTL project was found to be unviable, but incentives for investment for the project were recommended due to the relevance of its products in providing energy alternatives that will help improve the wellbeing of the people in the country. Therefore, in order to incentivise GTL investment and make it viable in the country, the prices of the products and the capital cost requirements were advised to be further reviewed and incentivised. For example based on the random sensitivity analysis, we found that if the prices of the crude oil can increase by 20% above the average forecast real oil price of $100.83/bbl and its estimated capital cost reduced by 54%, the project will be viable in the country, at which its IRR will be 16.16%, its NPV will be $351 thousand and its payback period will be 29.88 years. The crude oil at this scenario will then be $121/bbl. The crude oil price fluctuates and can likely reach or exceed this price level in the future. Similarly, a 20% reduction in price of electricity can make the CCGT project unviable in the country. Therefore, electricity price has to be above $60.27/MWh for the CCGT to be viable in the country other things being equal.

For the reduction in GTL cost, a careful study is required on why the GTL capital cost keep increasing. As mentioned, the Nigerian GTL capital cost has increased twice in the past, the first increment was 200% more and the second one was by 40%. If the capital cost can be reduced by 54% and the above crude oil price achieved while other parameters remain constant, then GTL project can be viable in the country. The government and investors might consider reviewing the capital cost with a view to reducing the cost of the GTL projects in the country. It is recommended that the proposed incentivised gas pricing regime for GTL projects should be strictly implemented, as it will help reduce the cost of GTL project in the country.

In addition, lowering the interest rate, increasing the thermal efficiency and production at optimal level can also help in further reduction of the cost of GTL project in the country. Tax rate can also be reviewed for this particular project. Local content can be enhanced where local experts are hired and equipment acquired locally if possible to reduce cost. The sensitivity analysis also showed that both projects are more sensitive to their product prices, while output and capital are the medium most sensitive parameters, and discount rate as well as gas feed cost are the least sensitive parameters to the projects' viabilities. One of the recommendations of this research is that, government should own substantial business interest of the gas pipelines projects in order to avoid market distortion and exploitation, as well as to ensure easy supervision of the sector, and so that gas supply to GTL and CCGT plants can be adequate.

Developing gas reserves for domestic consumption (through Gas pipeline, GTL and CCGT) can provide alternative source of energy, thereby creating competition to the major conventional energy fuels (e.g. petrol). It can also boost the industrial and commercial sectors of the economy and attract more foreign investment into the country through cost-effective utilities provision, which will generally improve the economic performance in the country. Consequently, this research also analysed the relationship between the real economic growth and domestic gas consumption in the country.

The research studied the cointegration between gas consumption and real economic growth in Nigeria in two different multivariate specifications. The first model specification added real capital formation and real exports, and found no cointegration among the specified variables. As a result, further analyses were administered to observe the impulse response and contribution of each of these variables to a unit shock in one another. It was found that change in real GDP cannot be explained by any of the variables in the period of the shock, but change in gas consumption in the period of shock can be explained largely by changes in its own self and then by changes in real GDP. However, the change in gas consumption responds negatively to shock in real GDP and vice versa in the period of the shock, but in subsequent period change in gas consumption responded positively to change in GDP. All the responses were temporary and lasted only within three period before returning to equilibrium. We concluded that among these variables, change in gas consumption has more influence to the movements in the real GDP, which further discovered the unique relationship between the gas consumption and real economic growth in the country in the event of shocks. Gas consumption is highly and positively responsive to its own innovation, which means direct investment in the sector can result to significant improvement in the gas consumption. The development of domestic gas consumption might not significantly come as a result of shocks or intervention in the other sectors, it has to be a deliberate actions and interventions to enhance the gas development.

However, in the second model specification, where oil production, gas consumption and real GDP were used, cointegration was found, and positive and significant long run relationship was found between gas consumption and real economic growth, where a persistent 1% increase in gas consumption in the long run can cause 2.89% increase in real GDP. It was also found that the country could likely be facing the economic problem of a resource curse due to adverse effect of crude oil production on real GDP even though not statistically significant. Therefore, the country's economy needs to be diversified to avoid any likely problem of resource curse. Similarly, short run relationship between gas consumption and economic growth is statistically insignificant. We concluded that, despite the fact that during the period under analysis, the domestic gas consumption was relatively below the potential level due to lack of infrastructures, but it still shows a very potential significant link with real economic growth in the event of persistent improvement in gas consumption in the long-run. Therefore, the research recommends deliberate and significant investment in the domestic gas development sector in the country. The hypothesis that says oil production may not directly impact positively on the real economic growth in the country could not be statistically significantly justified.

In terms of causality between domestic gas consumption and real economic growth, neutral causality was discovered between these two variables. Meaning that, there is no causality between them. The absence of causality is not surprising as both gas consumption and real economic growth are independent of each other in the country. The Nigerian economy rely more on the oil sector and hence the low gas consumption history in the country. For robust check, real oil price and oil production were added to the specification, and it was also found that, gas consumption, real oil price and oil production cannot predict real GDP at both level of significance. However, it was found that real GDP, real oil price and oil production can jointly predict gas consumption in the country at 10% level of significance.

The implication of this result is that despite the identified positive long run coefficient in the event of continues increase in gas consumption, gas consumption cannot predict real economic growth in the country. However, if more investment and further infrastructures are provided in the gas sector in the country, the gas consumption can then start to feed in more to the economic productivity, and thereby making the economy dependent on the gas sector eventually, due to continues increase in gas consumption, and then the significant link between gas consumption and real economic growth can be created. Flaring gas should be stopped so as to channel the produced gas to improve power supply and provide inputs to industries and manufacturing sector, and then the causality can be eventually created. Deliberate policies should be in place to enhance gas development and consumption within the country in order to sustain the increase in gas consumption, so that the significant positive connections discovered in the research between gas consumption and real economic growth can be actualised. In addition, direct investment in gas development can lead to high positive impact on the gas consumption as discovered in this research. Natural gas should be supplied to residential and commercial sectors to stimulate more domestic gas demand through gas pipelines, CCGT and GTL projects. The findings of this research further justified the Nigeria gas master plan's objective and serves as an academic guide toward actualizing and extending the objective of the plan in the country.

6.1 Further work:

From this research, further studies need to be carried out to identify how each of the gas utilisation projects identified individually influences the economic growth. How can Nigeria support the growth in transport system diversity that is necessary for economic growth using natural gas? What are the challenges in fuel switch in Nigeria? Is there a role for electric vehicles at the lighter end? To what extend Nigeria can really exploit its gas reserves to preserve the environment? What is the implication of Shale gas discovery on the price and production rate of natural gas in Nigeria? And how much level of gas can be utilised to influence economic growth in the country?

Appendices

Appendix A: List of GTL plants in the world [35]

Country	Company/Technology Provider and Location	Project	Capacity Plant (B/D)	Status	Comments
Argentina	Shell	GTL-FT	75,000	Study	
Australia	Syntroleum,Barrup Peninsula	GTL-FT	11,500	FEED	a.k.a Sweetwater; seeking financing
	Shell,NW Shelf	GTL-FT	75,000	Study	
	Sasol Chevron	GTL-FT	30,000	Study	
	GTL Resources	GTL-FT	10,000	Study	Floating offshore plant — NW Shelf
	Methanex, Darwin	GTL-CH_3OH	24,000*	FEED	
	DME International Ltd	GTL-DME	10,000–20,000 *	Planning	Consortium of 8 companies lead by NKK Corp, includes TotalFinaElf
	Japan DME Int'l	GTL-DME	20,000–35,000*	Study	Mitsubishi Gas Chemical, JGC, Itochu and Mitsubishi Heavy Industries
Bolivia	GTL Bolivia/Deane Group	GTL-FT	10,000	Study	FT technology from Rentech
Chile	Syntroleum,Puntas Arenas	GTL-FT	10,000	Study	Empresa Nacional del Petroleo (Chile) and Advantage Resources (Denver, CO)
Egypt	Shell	GTL-FT	75,000	Study	
Iran	Shell	GTL-FT	70,000	Study	
	Narakangan GTL/Sumitomo	GTL-FT	34,000	Study	
India	India DME Consortium	GTL-DME	26,000	Study	Indian Oil Corp; Gas Authority of India and IIP. Plant Location could in the Middle East/Gulf Region
Indonesia	Shell	GTL-FT	75,000	Study	
Italy	EniTechnologie and IFP,Sannazzaro de Burgondi	GTL-FT	20	Operating	Pilot Plant
Japan	NKK, Kushiro	GTL-DME	25	Operating	NKK Corp, Taiheiyo Coal Mining Co and Sumitomo Metal Industries
Malaysia	Shell, Bintulu	GTL-FT	12,500	Operating	May 1993 startup. 1997 temporary shutdown. Restarted May 2000.
New Zealand	Mobil/NZ Synfuels Corp(Initially)	GTL-G	14,500(Gasoline)		Stopped making gasoline in late '90s. Converted to producing 4,400 TPD
	Methanex (current)	GTL-CH_3OH	16,000* (CH_3OH)	Operating	Methanol for chemicals market
Nigeria	Sasol Chevron	GTL-FT	34,000	FEED	
Peru	Syntroleum	GTL-FT	5,000	Study	
Qatar	Sasol	GTL-FT	34,000	FEED	Feb. 2002 announced FEED completed; seeking EPC Bid
	ExxonMobil	GTL-FT	80-90,000	Study	June 2001 Letter of Intent signed
	Ivanhoe Energy /Mitsui & Co	GTL-FT	80,000–185,000	Study	Using Syntroleum GTL technology
	Shell	GTL-FT	75,000–110,000	Study	Letter of Intent signed in 1Q 2002
	Conoco	GTL-FT	60,000	Study	Capacity expansion up to 250,000 B/D
	Marathon	GTL-FT	N.A.	Study	Capacity not available
South Africa	Mossgas	GTL-FT	22,500	Operating	Reached full production January 1993
	Sasol, Secunda and Sasolburg	Coal-FT	150,000	Operating	
	Rentech/Forest Oil	GTL-FT	10,000	Study	
Trinidad & Tobago	Atlas Methanol	GTL-CH_3OH	20,000 *	Under construction	
	Shell	GTL-FT	75,000	Study	
United States	BP, Nikiski Alaska	GTL-FT	300	Under construction	2Q 2002 startup
	Conoco, Ponca City, OK	GTL-FT	400	Under construction	Late 2002 startup
	Syntroleum, Port of Catoosa, OK	GTL-FT	70	Under construction	2003 startup; DOE Clean-Fuels Program with Syntroleum and Marathon Oil
	Rentech, Sand Creek CO	GTL-FT	1,000		
	ANGTL, Prudhoe Bay, Alaska	GTL-FT	50,000	Study	Using Sasol technology; Proposed at Cook Inlet, integrated IGCC/GTL
Venezuela	PDVSA	GTL-FT	15,000	Study	
Totals		GTL-FT	954,500–1,104,500		
		GTL-Oxygenates	116,000–141,000 BCOE/D		
		Total	1,069,500–1,244,500		

Appendix B: Harmonised Ranking positions of the sensitivity scenarios.

Gas pipeline options	Base scenario	Discount rate lower scenario 12.92%	Discount rate higher scenario 19.38%	Capacity scenario: 20% lower	Capacity scenario: 20% higher	Cost of gas transportation: Lower scenario \$0.64/Mcf	Cost of gas transportation: Lower scenario \$0.96/Mcf	IIC 20% Lower scenario	ICC 20% higher scenario	Total ranking points	Harmonised ranking position
BSRO											
NPV	1	1	1	1	1	1	1	1	1	9	1
IRR	1	1	1	1	1	1	1	1	1	9	1
PAYBACK PREIOD	1	1	1	1	1	1	1	1	1	9	1
Points											3
All pipelines route options											
NPV	2	2	2	2	2	2	2	2	2	18	2
IRR	4	4	4	4	4	4	4	4	4	36	4
PAYBACK PREIOD	4	4	4	4	4	4	4	4	4	36	4
Points											10
BNRO											
NPV	4	3	5	5	3	5	3	3	5	36	4
IRR	5	5	5	5	5	5	5	5	5	45	5
PAYBACK PREIOD	5	5	5	5	5	5	5	5	5	45	5
Points											14
BRO											
NPV	3	4	4	4	4	4	4	4	4	35	3
IRR	3	3	3	3	3	3	3	3	3	27	3
PAYBACK PREIOD	3	3	3	3	3	3	3	3	3	27	3
Points											9
SRO											
NPV	5	5	3	3	5	3	5	5	3	37	5
IRR	2	2	2	2	2	2	2	2	2	18	2
PAYBACK PREIOD	2	2	2	2	2	2	2	2	2	18	2
Points											9

NRO											
NPV	6	6	6	6	6	6	6	6	6	54	6
IRR	6	6	6	6	6	6	6	6	6	54	6
PAYBACK PREIOD	6	6	6	6	6	6	6	6	6	54	6
Points											18

Appendix C: Future Energy Balance in Nigeria: African Century Case

Nigeria: African Century Case

	Energy demand (Mtoe)					Difference (ACC minus NPS)		Shares (%)	CAAGR (%)
	2020	2025	2030	2035	2040	2030	2040	2040	2012-40
TPED	**170**	**183**	**201**	**236**	**281**	**- 4**	**30**	**100**	**2.5**
Coal	1	3	5	9	12	0	0	4	24.0
Oil	27	33	39	48	61	6	14	22	4.1
Gas	24	32	42	56	79	7	21	28	6.8
Nuclear	-	-	-	-	-	-	-	-	n.a.
Hydro	1	2	4	5	5	0	0	2	8.9
Bioenergy	116	111	109	115	118	- 18	- 6	42	0.3
Other renewables	0	1	2	4	5	0	1	2	n.a.
Power generation	**16**	**23**	**33**	**46**	**64**	**4**	**10**	**100**	**6.9**
Coal	1	3	5	9	12	-	-	18	n.a.
Oil	2	2	2	2	2	- 0	0	4	-1.1
Gas	11	15	19	27	38	4	9	60	6.7
Nuclear	-	-	-	-	-	-	-	-	n.a.
Hydro	1	2	4	5	5	0	0	8	8.9
Bioenergy	0	0	1	1	1	0	0	2	n.a.
Other renewables	0	1	2	3	5	0	1	8	n.a.
Other energy sector	**18**	**23**	**26**	**28**	**30**	**1**	**1**	**100**	**2.6**
Electricity	*1*	*2*	*3*	*4*	*5*	*0*	*1*	*18*	*7.2*
TFC	**144**	**149**	**162**	**190**	**228**	**- 5**	**30**	**100**	**2.3**
Coal	0	0	0	0	1	0	0	0	11.1
Oil	23	29	36	44	57	6	14	25	4.9
Gas	7	10	15	23	33	5	13	15	8.9
Electricity	7	11	16	24	35	4	10	15	9.0
Bioenergy	107	98	94	99	102	- 20	- 8	45	0.1
Other renewables	0	0	0	0	0	0	0	0	n.a.
Residential	**99**	**91**	**86**	**91**	**96**	**- 19**	**- 3**	**100**	**0.1**
Coal	-	-	-	-	-	-	-	-	n.a.
Oil	4	5	6	7	8	1	1	8	4.1
Gas	0	0	1	1	1	0	0	1	n.a.
Electricity	3	5	7	10	15	2	4	15	8.8
Bioenergy	92	80	72	73	72	- 22	- 8	75	-0.7
Other renewables	0	0	0	0	0	0	0	0	n.a.
Transport	**13**	**17**	**21**	**27**	**36**	**4**	**10**	**100**	**4.9**
Coal	-	-	-	-	-	-	-	-	n.a.
Oil	13	17	21	27	36	4	10	100	4.9
Gas	-	-	-	-	-	-	-	-	n.a.
Electricity	-	-	-	-	-	-	-	-	n.a.
Biofuels	-	-	-	-	-	-	-	-	n.a.
Productive uses	**31**	**41**	**54**	**72**	**95**	**10**	**23**	**100**	**6.1**
Coal	0	0	0	0	1	0	0	1	11.1
Oil	6	8	9	11	13	2	3	13	5.5
Gas	7	10	14	22	32	4	13	34	8.7
Electricity	4	6	9	14	20	2	6	21	9.1
Bioenergy	15	18	22	26	30	2	0	31	3.8
Other renewables	-	-	-	-	-	-	-	-	n.a.

Appendix D. Raw data used for the regression analysis

Year	DGC (mcm)	Oil price ($2005)	Gross fixed capital formation ($2005)	Exports ($2005)	GDP ($2005)	Oil Production (ktoe)
1981	2274	77.17	46203984190	40316.97	131182075183.70	72603.00
1982	2605	66.72	33236412805	25614.62	104015498407.07	65029.00
1983	3179	57.94	15992279886	21093.28	69512001323.96	62306.00
1984	3075	54.1	7621070331	23102.67	53579062324.43	70184.00
1985	3630	50.04	6272404350	24382.01	52421880172.47	75585.00
1986	3267	25.71	5594787193	9505.1	36919968874.05	73956.00
1987	3668	31.69	5634864623	13378.73	41409915445.81	66716.00
1988	3635	24.64	4562248288	11954.08	38431619200.88	73169.00
1989	4250	28.72	4482364678	13269.62	38172722715.10	86550.00
1990	4000	35.47	6551047952	21748.03	45971811979.61	88249.00
1991	4878	28.68	5394190196	18842.37	39279955280.00	91829.00
1992	5132	26.89	5198807178	17875.89	40780798759.27	95166.00
1993	5605	22.94	2892252437	14968.92	21344984322.30	94905.00
1994	5493	20.84	2660662471	12951.33	23829471000.35	94407.00
1995	5385	21.81	2585024944	15817.25	36585254274.15	95998.00
1996	5457	25.74	3175708984	20979.22	43562990622.06	106632.00
1997	6178	23.23	3642132184	19458.7	43583043118.85	116493.00
1998	6269	15.24	3298118356	11806.6	38343035425.04	109783.00
1999	6640	21.07	2941353127	16244.61	42054730934.20	105323.00
2000	7646	32.32	3691844605	23776.25	52606261961.53	112792.00
2001	7202	26.96	3689957476	21667.11	48681022463.86	117778.00
2002	7644	27.16	4499223354	19691.62	64183636838.18	100831.00
2003	10694	30.61	7113486805	29140.27	71823989286.10	114916.00
2004	11027	39.57	6715085728	39394.86	90825775240.28	123902.00
2005	11036	54.52	6127632109	56994.19	112248324603.24	125060.00
2006	11564	63.1	11645357678	57382.43	140884928512.88	118326.00
2007	11894	68.18	14501307647	63560.4	156777048575.37	109315.00
2008	11077	88.22	15708614917	79814.73	188726596938.21	104651.00
2009	9658	56.14	18649344209	53147.74	154277720912.66	106230.00
2010	10786	71.2	56160442619	72521.66	330534252904.27	121980.00
2011	15008	96.6	57121503273	86607.72	357475043166.18	117924.00
2012	15446	94.99	57599803731	83432.8	393808303877.13	116091.00
2013	12636	91.09	63302157745	81424.36	437436058005.74	108016.00

Appendix E. Estimates of the unrestricted VAR including additional variables

Unrestricted	D(LGDP)	Unrestricted	D(LGC)
D(LGDP(-1))	0.154145 (0.25395) [0.60700]	D(LGC(-1))	-0.02037 (0.21943) [-0.09283]
D(LGC(-1))	-0.546194 (0.47860) [-1.14124]	D(LGDP(-1))	0.196937 (0.11643) [1.69144]
D(LOP(-1))	0.255763 (0.62434) [0.40965]	D(LOP(-1))	-0.046945 (0.28625) [-0.16400]
D(LPR(-1))	-0.137211 (0.27890) [-0.49198]	D(LPR(-1))	-0.18433 (0.12787) [-1.44154]
C	0.071671 (0.05769) [1.24243]	C	0.047161 (0.02645) [1.78313]
Sum sq. resids	1.838190	Sum sq. resids	0.386406

Standard errors in ( ) & t-statistics in [ ]

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