DEEPWATER PETROLEUM EXPLORATION AND PRODUCTION IN THE GULF OF GUINEA:

Comparative Analysis of Petroleum Fiscal Systems Performance

A

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ABSTRACT

Petroleum Fiscal System (PFS) is a major determinant of investment decision in the exploration and production of oil and gas in any country. It basically describes the profitability relationship between the host government of the producing community and the International Oil Companies (IOCs). The comparative analysis of the performance of the fiscal regimes becomes imperative as it affects the interest of the investor and the production of oil and gas. During the formulation of any fiscal regime a premium is placed on its outcome.

In this study, Petroleum Fiscal System (PFS) deepwater economic model is developed for the Gulf of Guinea. The approach incorporates a dynamic multipurpose input data page that automatically considers fiscal laws, taxation and stochastic analysis. Monte Carlo simulation using @risk software is used to account for risk and uncertainties in decision making.

This study addresses the industry structure, conduct and performance of fiscal regimes of countries in the Gulf of Guinea. Comparison of the effects of production delay, front ended government take, front loading index, and taxation show that the Gulf of Guinea is internationally competitive in all ramifications. A wide range of profitability indicators were used in the economic evaluation decision of this work such as Government Take (GTake), Contractor Take (CTake), Net Present Value (NPV), Internal Rate of Return (IRR), Profitability Index (PI), Savings Index (SI), Return on Investment (ROI), Payout Time (POT), Effective Royalty Rate (ERR), Growth Rate of Return (GRR), Discounted Net Cash Flow (DNCF), Front Loading Index (FLI). This avails investors, governments, petroleum economists, and so on great options of economic performance indicators in decision making. It is also found that as the risk in deepwater investment increases with water depth, return on investment rises significantly too in the Gulf of Guinea.

Analysis of all terms contained in the deep water economic model formulated (stochastic and deterministic) presents a useful tool to guide in investment decision making in the Gulf of Guinea. Recommendations on how the variations would give government equal take on any Petroleum Fiscal System are made. Usually the aim of the host government is to get as much economic rent as possible.

DEDICATION

This thesis study is dedicated to the entire Echendu family especially my only sister Blessing Echendu, Dad, Mum, and to you Wisdom Ezeugo.

To God be the Glory

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‘’Joseph is a fruitful bough…They shall be on the head of Joseph, and on the crown of the head of him that was separate from his brethren’’. Genesis 49 versus 22-26.

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CHAPTER ONE

1.0 INTRODUCTION

1.1. OVERVIEW

Deepwater offshore exploration as much as it is a breakthrough in Petroleum Exploration and Production as it offers significant benefits over onshore production, still poses challenges to the oil and gas industry. The Gulf of Guinea (GOG) is an attractive place for investment in the oil and gas sector, opportunities abounds for petroleum exploration and production. Exploration and production in deepwater offshore have been proven to produce more oil and gas, add to proven reserves and generate more income for such producing nations. In the long run, production in deep waters will help the growing economies hence the demand for oil and gas globally.

The analysis of fiscal regimes which is one of the determinants of investment decision in the exploration and production of oil and gas is imperative for the Gulf of Guinea as it affects the interest of the investor and the production of crude oil. Several authors such as Temmy D. and Tumbur P. (2002), Costa Lima G.A. et al (2010) due to its significance, analyzed profitability of Fiscal regimes in the Asia Pacific countries and Brazil respectively, however, risk and uncertainties were not accounted for.

The Gulf of Guinea is the arm of the Atlantic Ocean, western Africa, between Cape Palmas, at the south-eastern tip of Liberia, and Cape Lopez, Gabon. Among the many rivers that drain into the Gulf of Guinea are the Niger and the Volta. The coastline on the gulf includes the Bight of Benin and the Bight of Bonny. The Niger River in particular deposited organic sediments out to sea over millions of years which became crude oil. This region is now regarded as one of the world's top oil and gas exploration hotspots and most promising petroleum provinces (Microsoft Encarta, 2009). The countries of the Gulf of Guinea, an area in the West and Central Africa coast are made up of Nigeria, Equatorial Guinea, Gabon,

Ghana, Liberia, Togo, Cameroon, Benin, Ivory Coast, Angola, Congo, Guinea, and the islands of Sao Tome and Principe. Islands in the GOG that are part of Equatorial Guinea are Annobon, Bioko, Corisco, Elobey Grande and Elobey Chico (Wikipedia, 2011). Some countries like Nigeria and Angola are already producing from offshore areas in the GOG, while others are starting to conduct exploration activities. By some estimates, West Africa already has up to 547 major offshore oil and gas structures.

Currently, offshore production accounts for up to 30% of the world's oil and gas production. That percentage is expected to rise in the future. Estimates indicate that the GOG and African countries already supplies about 11% of world's oil and gas needs and holds about 10% of the world's proven reserves (PWC, 2010). However, this number is expected to grow, given that exploration is only now commencing in some offshore areas.

1.2. STATEMENT OF THE PROBLEM

Several studies have been done on the comparative competitiveness of Petroleum Fiscal Systems (PFS) in the Gulf of Mexico (GOM), Brazil, Australia, Malaysia, etc., but none has been done for the GOG. Though Merak Projects PEEP has fiscal models for some GOG countries, they are in isolation for commercial purposes. Therefore, in this study, an integrated PFS of various fiscal regimes in the GOG will be modelled; implemented and proposed PFS in countries in the GOG will be analyzed as well as the uniqueness of each country. The same field data (hypothetical or real) will be used to forecast production and costs. The major types of fiscal regimes in the GOG will be discussed. Elements of each country's fiscal regime will be captured not leaving out recent developments of the regime. Detailed economic analysis of each regime will be done; this will include formulation of a dynamic economic model factoring in all fiscal laws and taxations, stochastic simulation analysis of the Host Government Take (HGT) and contractor as well as risks and

uncertainties of investment. The analysis to be presented will be useful in guiding investment in the GOG and add to knowledge.

1.3. OBJECTIVES

The objectives of this thesis would be to:

- Review the E&P industry structure, conduct, performance (reserves, production capacity, market production) for each country
- Review and describe available petroleum fiscal system terms and instruments in the Gulf of Guinea
- Develop (deterministic and stochastic) deepwater economic models for both concessionary and contractual arrangement for each country in the Gulf of Guinea. Contribution is to attempt to formulate a generic model that you can apply to this country with a drop menu.
- Analyze the concessionary and contractual systems and compare their variations and how it affects government and contractors in each country.
- Make recommendations on how the variations (if any) would give government equal take on any PFS
- The progressive or regressive effects of the PFS would be analyzed using appropriate fiscal instruments.
- Perform simulation analysis on the economic model.

CHAPTER TWO

2.0 LITERATURE REVIEW

2.1 OVERVIEW

Energy is an indispensable input for economic growth and social development. Two-thirds of global energy requirements are met with oil and gas supplies. Remarkably, the three non-renewable fossil fuels, oil, natural gas, and coal, constitute almost 90 percent of commercial energy consumed globally.

Africa currently supplies about 11% of the world's oil and boasts of significant untapped reserves estimated at between 9% - 10% of the world's proven reserves. It is expected that the region will pass North America in 2011 and become the third largest producing area after the Middle East and Central/ Eastern Europe. Total global oil consumption decreased by around 2% in 2009 yet remained steady in Africa and is expected to grow globally, and in African regions by around 2% in 2010 (PWC Africa Oil and Gas Survey, 2010). The sustainable development of oil and gas resources requires policies, principles, and practices that support the utilization of resources in a manner that does not prevent future generations from benefitting from the resources. A great challenge, particularly for oil producing African countries, is to ensure sufficient, reliable, and environmentally responsible supplies of oil, at prices that reflect market fundamentals (ADB/AU Oil and Gas in Africa, 2009). This research focuses on the conduct and performance of fiscal regimes of countries in the Gulf of Guinea (GOG) region.

2.2 PETROLEUM EXPLORATION AND PRODUCTION COMPETITIVENESS

Several authors have written about the comparative competitiveness of the Petroleum Fiscal Systems (PFS) in their countries or regions. Temmy Dharmadji, et al. (2002) wrote about the Asian pacific region. They compared the competitiveness fiscal regimes of five

countries in the region; Australia, China, India, Indonesia, and Malaysia. The factors highlighted as affecting the results of the analysis are; bonuses, royalty, cost recovery, contractor profit split, taxes, and domestic market obligations. Using economic indicators such as Net Present Value (NPV), Rate of Return (ROR), Payout Period (POP), and Profit Investment Ratio (PIR), they concluded that:

1. The Australian regime ranked very favourably, followed by China, India, Malaysia and Indonesia
2. Each of every fiscal regime's terms affects the contractor cash flow, NPV and contractor take. Cost Recovery Limit and Contractor Profit Split have the most significant effect on contractor cash flow.
3. Contractor needs a good understanding of fiscal terms in order to make a good investment decision.
4. Government needs to understand its country and other countries in the region in order to develop a competitive fiscal terms.

In their works, they failed to incorporate risk analysis which is inevitable in today's investment decision making world and the economic indicators used were too few.

Michael J. Back (2003), reviewed and compared the effect of typical international fiscal regimes with both traditional project ranking and more modern portfolio management techniques used in the exploration and production (E&P) capital investment process selection for corporate planners, but limited to Australia's concessionary fiscal regime and Malaysia's production sharing fiscal regime. The conclusion was that differences in individual project at a field development level do not have a measurable effect when considered in the broader context of a portfolio of projects at different start dates and equity interests. The work was limited in not including extensive analysis using more robust statistical simulation tool to develop a distribution of value and risk measures for the portfolio.

Empirical evidences were used by Iledare O. O. (2008) to analyze the profitability of deepwater petroleum leases in the U.S. Gulf of Mexico (GOM) offshore region. In the descriptive and discounted cash flow analysis of lease specific data, the report suggests that the risk associated with deepwater lease development increases with water depth, and return on investments rises significantly with water depth as well. The empirical analysis showed that profitability index increased on the average giving an indication to investment decision makers on the choice to invest in GOM. As a result of the proposed Brazilian fiscal systems for pre-salt areas of Santos Basin, Costa Lima et. al. (2010) used the opportunity to do a comparative study of gain and loss of government and companies in deepwater Brazil. Their work showed a comparison between the existing Royalty & Tax (R&T) and proposed existing PSC and concluded that company share and cost recovery limit are two important variables that determine what the new PFS can generate. It also showed that government take is dependent on oil price. An increase in oil price will reduce government take, whereas a decrease will increase it heavily. Also if cost recovery limit exceeds 50%, the PSC may generate a lower government take than R&T system in Brazil. Though sensitivity analysis was done on cost recovery limit, the work fails to acknowledge the input of risk analysis in the projections/forecast especially on oil price. Other authors such as P.O. Chukwu (1991) and Iledare O.O. (2010) analyzed the effects of fiscal policies in Nigeria.

2.3 OVERVIEW OF EXPLORATION AND PRODUCTION STRUCTURE IN THE GULF OF GUINEA

No doubt Africa is endowed with vast quantities of both fossil and renewable energy resources. According to an African Development Bank report (ADB/AU 2009), Africa is the main continent in the world with frequent and substantial new findings of oil and gas. In the past 20 years, oil reserves in Africa grew by 25 percent, while gas grew by 100 percent. Oil

production in the continent is expected to continue to rise at an average rate of 6% per year for the foreseeable future. The majority of oil reserves (and production) in Africa comes from Libya, Nigeria, Algeria, Angola, and Sudan, which together produce more than 90 percent of the continent's reserves. Nigeria's deepwater oil reserves and underdeveloped natural gas reserves and significant oil deposits found in the western part of offshore Ghana are a logical target of international oil companies (IOCs) in the sector. The top foreign oil companies operating in the Gulf of Guinea are US-based ChevronTexaco and ExxonMobil, France's Total, UK's BP, UK /Dutch Shell, and Italian Agip/Eni oil companies.

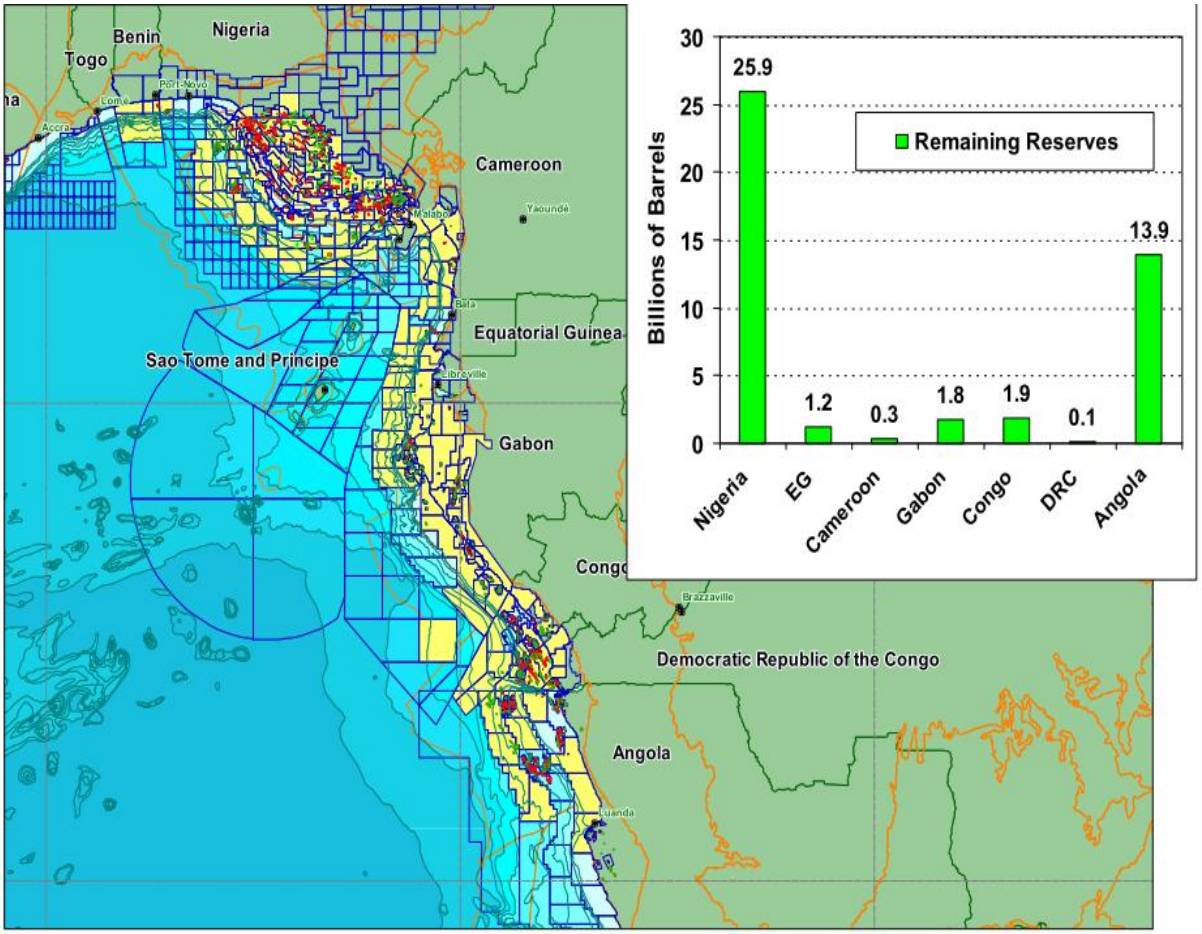


Figure 2.1: Gulf of Guinea region and remaining reserves as at 2005 (www.pfcenergy.com OTC May 2007)

2.3.1 NIGERIA E&P STRUCTURE

The Nigerian oil and gas reserves have grown tremendously since the discovery of hydrocarbon in 1956 in Oloibiri. The growth was from a modest figure of 0.184 billion barrel of oil and 2.26 billion cubic feet of gas in 1958 to 25.93 billion barrels of oil, 3.8 billion barrels of condensate and 158 trillion cubic feet of gas (NNPC 2008), as at December 2000. Nigeria's production capacity has grown from a modest 5100 barrels of oil per day (BOPD) in 1958 to 2 million BOPD in 1972 and peaking at 2.4 million BOPD in 1979. Nigeria thereafter, attained the status of a major oil producer, ranking 7th in the world in 1972, and grown since to become the 6th largest oil producing country in the world (OPEC 2011).

A 2003 estimate showed recoverable crude oil reserves at 34 billion barrels. The reserve base is expected to increase due to additional exploration and appraisal drilling. Already, over 900 million barrels of crude oil of recoverable reserves have been identified. Nigeria has an estimated 159 trillion cubic feet (TCF) of proven natural gas reserves, giving the country one of the top ten natural gas endowments in the world (NNPC 2010). In 2011, according to OPEC, Nigeria has a proven oil reserve of 37.2 billion reserves.

Oil and gas production in Nigeria commenced in 1958. The potential of the Nigeria deepwater was not recognized until the 1970's. Anticipating that reserves offshore West Africa would at least be similar to those across the Atlantic in the Brazilian Campos and Santos basins, for instance, Government opened up the Nigeria deepwater areas for competitive bidding for oil prospecting licenses (OPL). Exploration efforts started in 1993 with the award of 18 blocks to 12 concessionaires. To date 34 exploration wells have been drilled in the deep offshore out of which 6 wells found oil in quantities for hub-class development while a further 5 wells penetrated potentially commercial oil volumes. With a major contribution from the deepwater discoveries so far, the aspiration to increase the national reserves base to 40 billion barrels recoverable oil and a daily production of 4 million

BOPD appears realizable. Presently, Bonga (SNEPCO) - the first discovery in the deep offshore Nigeria - and Abo (NAE) have reached field development stages, while most of the remaining identified commercial oil discoveries are in an advanced stage. This success story has been associated with the great encouragement given to investors by the Nigerian Government's existing fiscal regime.

With an increased understanding of the hydrocarbon system in Nigeria, deepwater exploration has resulted in a series of giant discoveries such as Agbami (1998), Erha (1999), Akpo (2000), and Bonga-SW (2001), and a number of encouraging wells also such as Chota (1998)/ Bolia (2002) and Nnwa (1998) / Doro (1999). As part of their increased understanding of the turbidite basin most major multi-national companies perform regional basin studies: only through these are they able to target the most attractive prospects for drilling, and thereby increase the exploration success rate. These multi-national companies applied the benefits of global learning continuously to the Nigerian scene, thus providing them leverage in exploring and developing the deepwater of Nigeria for the benefit of all stakeholders.

The Department of Petroleum Resources (DPR) is the government agency charged with the responsibility of regulation and supervision of all the operations being carried out under licenses and leases in the oil and gas industry. The Nigerian National Petroleum Corporation (NNPC) is vested with the exclusive responsibility for upstream and downstream development, which entails exploiting, refining, and marketing Nigeria's crude oil (NNPC 2008).

Nigeria has several fiscal arrangements such as Joint Development Zone (JDZ) PSC 2003, 1993, 2000, 2005 PSCs, and so on. There is also a proposed Petroleum Industry Bill (PIB) before the National Assembly. In the fiscal terms specifications annual surface rental, signature bonus, commercial discovery and production bonuses are negotiable. Royalty is

jumping scale in the existing fiscal instruments but may change to sliding scale in the proposed PIB. Cost recovery limit is 80% in the JDZ 2003 and PSC 2005 but, 100% in PSCs 1993 and 2000. Profit sharing follows a sliding scale pattern based on R-Factor for JDZ and 2005 PSC. The 1993 and 2000 PSCs have jumping profit sharing formula. Income tax depends on the PSC. The PFS is ring fenced around the block for cost recovery and profit sharing. Nigeria also has R/T (2000) fiscal instrument (Meraks, 2010).

2.3.2 GHANA E&P STRUCTURE

In 2007, Ghana announced her first oil discovery in the Cape 3 Points region of the country's coastal waters, the Tano basin in the Gulf of Guinea. The exploration area covers 3,500 square kilometers, which corresponds to approximately eight exploration blocks on the Norwegian continental shelf. Water depths in the area range from 2,000 to 3,000 meters (Mbendi, 2011). Several other discoveries have been made in the same region like the Jubilee deepwater field which has demonstrated the commercial potential of Ghana's continental shelf as shown in figure 2.2. Jubilee with an estimate of over a billion barrels of oil in these offshore waters is one of the largest offshore oil fields discovered in the past five years. South Deepwater Tano shares much of the promising geology found at Jubilee. However, South Deepwater Tano is located further offshore in the Gulf of Guinea and at greater water depths than Jubilee.

Ghana's coastline – Map

Figure 2.2: Ghana offshore oilfield (www.oxfamamerica.org)

The Model Petroleum Agreement (MPA) is a product of the Petroleum Exploration and Production Law, PNDC Law 84. It serves as a guide to negotiating terms and conditions of petroleum agreements among government, Ghana National Petroleum Corporation (GNPC) and the oil companies. As such, the MPA contains provisions on the license area (Block), the period of exploration, work programme, cost of work, monitoring, relinquishment, decommissioning, fiscal provisions (tax) among others. Under PNDC Law 84 and the MPA, the fiscal package consists of royalty, carried interest, paying interest, additional oil entitlement, petroleum income tax and annual surface rental. There are also "indirect tax" obligations in the form of "local content" requirements, domestic supply obligations and decommissioning (Hackman, N. A., 2007).

2.3.3 EQUATORIAL GUINEA E&P STRUCTURE

The Republic of Equatorial Guinea is a country located in Central Africa with estimated area of 28,000km^2. It comprises two parts: a Continental Region (Río Muni), including several small offshore islands like Corisco, Elobey Grande and Elobey Chico; and an insular region containing Annobón Island and Bioko Island. The discovery of large

deposits of oil and gas in the 1990s transformed Equatorial Guinea into one of Africa's fastest-growing economies and one of the main destinations of foreign investment on the continent. Equatorial Guinea's Gross Domestic Product (GDP) was 60 times larger in 2007 than in 1995. As of 2004 Equatorial Guinea became a large oil producer in Sub-Saharan Africa since the discovery of large oil reserves in 1996. Its oil production has risen to 360,000 barrels per day (57,000 m^3/d), up from 220,000 barrels per day (35,000 m^3/d) only two years earlier. Oil production peaked at an estimated 290,000 barrels/day in 2005 (Microsoft Encarta, 2009).

Equatorial Guinea had proved oil reserves of 1.755 billion barrels at the end of 2007 or 0.14 % of the world's reserves. A 2008 BP Statistical Energy Survey (Mbendi, 2011) states that Equatorial Guinea produced an average of 363.3 thousand barrels of crude oil per day in 2007, 0.46% of the world total and a change of 1.5 % compared to 2006.

The Government's Ministry of Mines and Hydrocarbons regulates the industry and is the licensing authority. Originally the state was represented in an operating company called Guinea-Espanola de Petreleos SA (GEPSA), a 50/50 joint venture between it and Spain's Hispanica de Petroleos (Hispanoil, now Repsol). GEPSA was subsequently dissolved and there is now no fully owned national oil company in Equatorial Guinea.

Petroleum licensing is governed by the 1981 Hydrocarbons Law, amended in 1998, and taxation is covered by the general tax provisions of 1986, amended in 1988, 1991 and 1997. Contracts governing the exploration and exploitation of hydrocarbons are based on the Model Petroleum Production Sharing Contract in 1998, revised and updated in 2006. This contract allows for an initial exploration term of 5 years followed by two terms of 3 and 2 years extendable on a yearly basis for up to a total of 8 years. Production sharing is based upon the contractor's pre-tax return and is negotiable. The contractors can propose other forms of sharing. The signature, commercial discovery and production bonuses are

negotiable. The production bonus and signature bonus are both recoverable. Annual surface rentals range between $1.00 per hectare for water depths less than 200 metres and $0.50 per hectare for water depths greater than 200m. It has a sliding scale royalty with 10% as minimum for the 1998 model and 13% as minimum for the 2006 model. Cost recovery is 60% and profit sharing also follows a sliding scale pattern based on cumulative production. Income tax is 25% for the 1998 model and 35% for the 2006 model. The PFS is ring fenced around the block for cost recovery and country for tax.

2.3.4 ANGOLA E&P STRUCTURE

Angola is Africa's third largest oil producer behind Nigeria and Libya and, in January 2007, became the 12th member of the Organization of Petroleum Exporting Countries (OPEC). Angola has a proven reserve of 12.2 billion barrels (OPEC, 2011) and a production capacity of 1.7 million (Wikipedia, 2011) BOPD and has joined the ranks of the major producers. Angola exports more than 90% of its crude oil primarily to China and the US. According to the 2008 BP Statistical Energy Survey (Mbendi, 2011), Angola produced an average of 1723 thousand barrels of crude oil per day in 2007, 2.15% of the world total and a change of 20.7 % compared to 2006. Angola is a key player in Africa's oil industry as both a major producer and exporter. Offshore Angola is recognised as a world-class area for oil exploration and production. The majority of the country's crude oil is produced offshore in Block Zero, located in the northern Cabinda province. Crude reserves also are located onshore around the city of Soyo, offshore in the Kwanza Basin north of Luanda, and offshore of the northern coast. Significant discoveries have been made in Blocks 14, 15, 17 and 18 since the mid 1990s.

Sonangol is the government agency (established in 1976) that manages all fuel production and distribution in Angola. Angola's PSC allows for an initial exploration period of three years and extension to a maximum of three additional years. For deepwater, its initial

exploration period is four years and a two years addition. The production period is twenty (20) from date of discovery. It has no royalty scheme in the 1990 and 2004 PSCs. Surface rental is $300/km^2. There is a Domestic Market Obligation (DMO) of up to 40% of production and cost recovery is 50% with 40% uplift on development costs. Profit oil is shared based on average production rate (Meraks, 2010.).

2.3.5 GABON E&P STRUCTURE

Gabon is sub-Saharan Africa's fourth largest oil producer whilst holding the third largest oil reserves in the region. The country is almost wholly dependent on oil revenues to fund its economy. Exports of crude oil account for approximately 60% of the government's budget and more than 40% of GDP. Natural gas is a relatively unexploited natural resource in Gabon. According to the 2008 BP Statistical Energy Survey, Gabon had proved oil reserves of 1.995 billion barrels at the end of 2007 (0.16 % of the world's reserves). For the same period, Gabon produced an average of 230 thousand barrels of crude oil per day, 0.29% of the world total and a change of -2.1 % compared to 2006.

Gabon's largest oil field is the Shell operated Rabi-Kounga oilfield, with estimated reserves of 440 million barrels and production of 150,000 BOPD which accounts for 40% of national output. The second largest field is the Gamba-Ivinga field, also operated by Shell with production rates of 10,000 to 15,000 BOPD.

The state oil company is Société Nationale Petrolière Gabonaise (SNPG) responsible for overseeing the oil and gas operation. All ownership of oil and gas is vested in the State. It is the only titleholder of mining rights. The Mining Code was established by Law No 15/62 (1962), Decree No 981/PR (1970) and modified under Ordinance 45/73 (1973). The new taxation system is governed by Law No 14/74. Oil exploration and production licences are acquired by means of Exploration and Production Sharing Contracts (EPSC). Law No 14/82

passed in January 1983 established the EPSC which replaces the Concession Agreement. Gabon has a new PSC (1997) whose terms can be summarised as follows (Meraks, 2010):

i. The exploration phase can comprise either two periods of five years, or three periods comprising an initial five years followed by two 2-year terms. This is based on the location of the block and the work programme.

ii. The exploitation phase comprises an initial 10 year period followed by a second and third period of 5 years each.

iii. There is a 10% minimum state participation and 5% minimum Royalty payment (as a function of production)

iv. In terms of tax and payments, the state pays income tax on behalf of contractor and cost oil is limited to 50%. If development costs have not been recovered after five years of production, this could be raised to 75% at the company's request.

2.3.6 COTE D'IVOIRE (IVORY COAST) E&P STRUCTURE

The West African state of Ivory Coast is known more as an oil refining country rather than oil producing one. While it does not have the prolific offshore oil fields of Nigeria, it does possess a modest upstream oil industry. Oil producing fields are Lion and Panthere (condensates). Offshore oil was discovered in 1977, with production starting three years later. The bulk of the country's oil and gas wells (86%), are situated in shallow marine areas (Wikipedia, 2011), and with another 7% located in deep offshore wells. Only 7% of the country's oil and gas wells are onshore. Estimates by the Oil and Gas Journal have placed the country's proven petroleum reserves at 100 million barrels (16,000,000 m^3), as at 1st January, 2005. Production for 2004 was estimated at 35,541 barrels per day (5,650.6 m^3/d), with crude oil accounting for 35,000 barrels per day (5,600 m^3/d).

However, recent finds and new production at several offshore fields and blocks may push the nation's proven reserves and output total higher. For example, the Espoir field, which

began producing in early 2002, is estimated to contain recoverable reserves of 93 million barrels (14,800,000 m^3) of oil and 180 billion cubic feet (5.1×10^9 m^3) of gas. Also, Block CI-40, which is jointly operated by Canadian Natural Resources, Svenska Petroleum and the state oil corporation, Société Nationale d'Opérations Pétrolières de la Côte d'Ivoire (Petroci), and which lies 5 miles (8.0 km) to the south of the Espoir field, is estimated to have recoverable oil reserves of 200 million barrels (32,000,000 m^3). Block CI-112, located off Côte d'Ivoire's western coast, is estimated by Vanco Energy Company to contain 2.7 billion barrels (430,000,000 m^3) of oil in the block's San Pedro ridge and in other deposits (Wikipedia, 2011). Although natural gas was initially discovered in Côte d'Ivoire in the 1980s, it has only been recently developed as of January 1, 2005; the country is estimated to have natural gas reserves of 1 trillion ft^3. In 2003, natural gas output and domestic consumption were each estimated at 46 billion ft^3.

The national oil company, Petroci, was established in 1975. Petroci was restructured in 1998 and four new entities were created: Petroci Holding, a fully state-owned company that is responsible for the state's portfolio management in the oil sector and the three subsidiaries; Petroci Exploration-Production, responsible for upstream hydrocarbon activities; Petroci-Gaz, responsible for development of the gas sector; and Petroci Industries-Services, responsible for all other related services (BP, 2011). Up to 49% interest in the three subsidiaries is available to private sector investors. Petroci's role currently includes the development and maintenance of the main database on Cote d'Ivoire's oil assets, and the assumption of minority participation - generally between 5% and 15% - in the offshore ventures operated by international companies. The 1996 PSC for profit sharing is either based on R-Factor or jumping scale percentage on daily production. There is no royalty and signature bonus. Training fee and production bonus are negotiable. Cost recovery is 40% and

10% of contractor's oil at 75% of market price is used for DMO. Cost recovery, profit oil and tax are ring fenced (Meraks, 2010).

2.3.7 CAMEROON E&P STRUCTURE

The Republic of Cameroon, lies on the eastern border of oil-rich Nigeria. The country has gas reserves, estimated at 110 billion cubic metres that are still unexploited. The upstream oil industry is an important part of Cameroon's economy. Cameroon produced an average of 82 thousand barrels of crude oil per day in 2007, 0.1% of the world total and a change of -5.7 % compared to 2006. Reserves are located offshore in the Rio del Rey Basin of the Niger Delta, offshore and onshore in the Douala/Kribi-Camp basins on Cameroon's western coast, and onshore in the Logone-Birni basin in the northern part of the country (BP, 2011).

The Ministry of Mines and Energy regulates the industry, through its national oil company, Societe Nationale des Hydrocarbures (SNH). SNH reports directly to the president and is responsible for promoting the development of the country's hydrocarbon resources, and management of the state's interests in any discoveries of oil and gas resources. Petroleum exploration, development and production activities in Cameroon are at present governed by the mining law No 64-LF/3 of 1964 and the fiscal law no 78/14 of 1978. Cameroon's petroleum contract has been subject to a number of improvements in 1990, 1991, 1995, and 1998 to make it more attractive to investors (Mbendi, 2011). All hydrocarbon rights are vested on the State and the State reserves the right to acquire an interest in all or part of the petroleum operations. New petroleum legislation was passed in December 1999. In terms of this law, licenses are issued in the form of either a concession contract or a production sharing contract, and operators may choose which option they prefer.

The exploration phase is made up of an initial period of three years (which in the case of Special Petroleum Operations Zone can be extended to five years) and is renewable for two periods of two years. The exploration may not exceed 7 years or 9 years in the case of Special

Petroleum Operation Zones. The exploitation phase is 25 years for oil and 35 years for gas and may be renewed once, on application, for a maximum of 10 years. The petroleum contract may provide for a signature or a production bonus. The improved terms allow for exemption from custom duties during exploration and reduced rates for the first five years of exploitation. The operator has the right to a dollar accounting system and to remit profits and retain abroad proceeds from sales.

2.3.8 CHAD E&P STRUCTURE

According to the 2008 BP Statistical Energy Survey, Chad had proved oil reserves of 0.9 billion barrels at the end of 2007 (0.07 % of the world's reserves). Chad thus has the potential to be a significant energy producer with a viable upstream industry. In 2007 Chad produced an average of 143.5 thousand barrels of crude oil per day, 0.19% of the world total and a change of -6.2 % compared to 2006. Oil exploration began in the 1970's and several early discoveries were made in both the Lake Chad Basin and the Doba Basin in southern Chad by a consortium comprising Chevron, Conoco, ExxonMobil and Shell. Chad is not known to possess any natural gas reserves. Due to its lack of reserves and infrastructure, Chad has no plans to develop a gas industry at the present time.

The industry is regulated by the Ministry of Mines, Energy and Oil (Ministère des Mines, de l'Energie et du Pétrole) (MMEP). Chad’s R/T 1999 (Meraks, 2010) allows for a 5% royalty for gas products and 12.5% for oil products with a 50% tax rate. There is no production bonus but signature bonus is negotiable. The exploration period is made up of an initial 5 years period, followed by two 3-year period. Production period is for 25 years. There is no ring fencing.

2.3.9 LIBERIA E&P STRUCTURE

Liberia does not have a well-developed upstream oil industry. No viable oil and gas discoveries have been made and there is therefore no production or field development.

Hydrocarbon exploration started in the late 1960s with Frontier, Chevron and Union Carbide being active. Before exploration was interrupted in 1972, four wells were drilled and abandoned as dry. No oil and gas discoveries have been made and there is therefore no production or field development in Liberia. In mid 1999, Australian companies, Daytona Energy Corporation and Fusion Oil and Gas signed a joint venture agreement for the exploration of offshore Block A. Fusion, having taken over as operator from Daytona, has completed an initial review of Block A and is seeking to convert the Technical Cooperation Agreement (TCA) into a Production Sharing Contract (PSC). It is also seeking to extend its lease area (BP, 2011).

The National Oil Company of Liberia (NOCAL) is the government agency responsible for overseeing oil and gas activities. Some of NOCALs' function is to organize, conduct, arrange, and supervise all relevant research and exploration for liquid and gaseous hydrocarbons in Liberia, and to delineate, establish, and issue licenses for particular areas, fields, and block, as the case may be, on such terms and conditions as shall be deemed appropriate, subject to the approval of the Board of Directors and final ratification by the President. In the 2009 PSC, there is provision for signature bonus, college fee, and hydrocarbon development fund that are negotiable. There are also provisions for the payment of training fee, social and welfare fund, and rural energy fund (Meraks, 2010). Royalty rate for gas is 12% flat while oil has 12% for offshore and 15% for onshore fields. Cost recovery is 70% and profit sharing is determined by production rate using sliding scale.

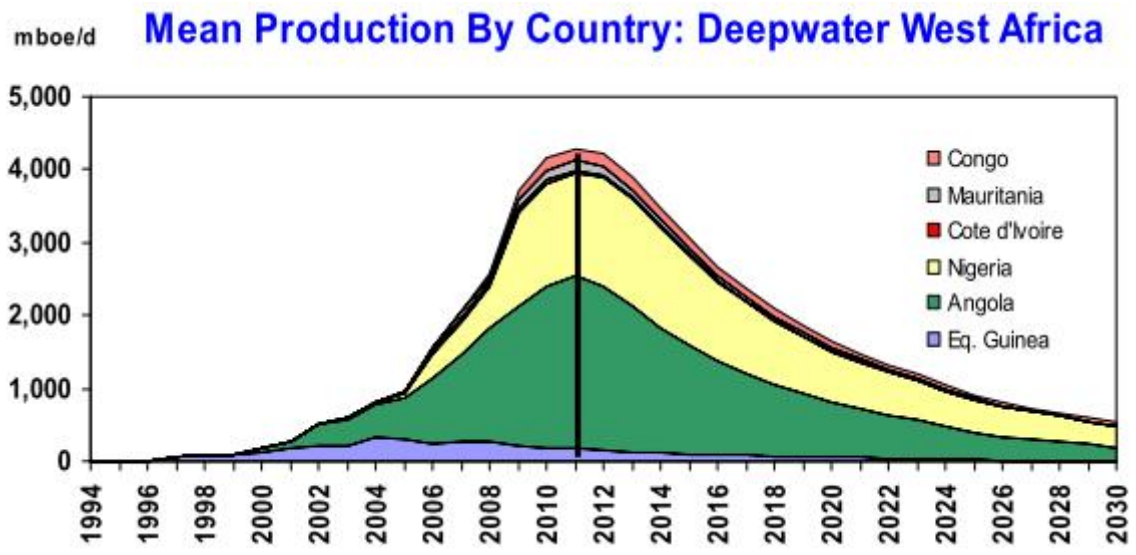


Figure 2.3: Mean production by country (www.pfcenergy.com)

2.3.10 SENEGAL E&P STRUCTURE

Senegal has a limited upstream oil industry, although it is becoming increasingly important to the Senegalese economy. Petrosen is actively promoting onshore and offshore acreage where, since 1998, major permits in the form of production sharing contracts have been awarded.

The oil industry in Senegal is regulated by the Ministry of Energy, Mines and Industries and its national oil company is Petrosen. Hydrocarbon exploration and production in Senegal is governed by Law N0. 98-05 enacted on January 5, 1998. No signature bonus is paid, but training fee is negotiable. Royalty follows a sliding scale of average production rate with liquid hydrocarbon onshore ranging from 2 – 10% while offshore peaks at 8%. Tax rate is 35%, and additional profit tax is applied based on R-Factor. There is ring fencing around contract area for additional profit tax but none for income tax (Meraks, 2010).

2.3.11 SIERRA LEONE E&P STRUCTURE

The Sierra Leone oil industry is regulated by the Department of Trade, Industry and State Enterprises. Sierra Leone has no known petroleum resources and therefore no upstream

oil industry (Mbendi, 2011). In August 2000, however, it was announced that the Ministry of Mineral Resources of Sierra Leone and TGS-NOPEC Geophysical Company were planning a joint project comprising a non-exclusive 2-D seismic programme of the Liberia Basin offshore Sierra Leone.

2.4 PETROLEUM RESERVES AND PRODUCTION FORECASTING

The starting point in any E&P business is project evaluation of the available petroleum resources which is the stock of oil deemed extractable in an undefined future, production capacity and forecasting. When the resources are presumed to be commercially recoverable under known technology and economic conditions, it becomes reserves. Reserves must be remaining, physically discovered and producible commercially and economically.

Reserves can be classified into proved and unproved reserves as depicted in figure 2.4 below. Proved reserves are quantities of petroleum that are reasonably certain to be commercially recoverable and are known with a high degree of uncertainty.

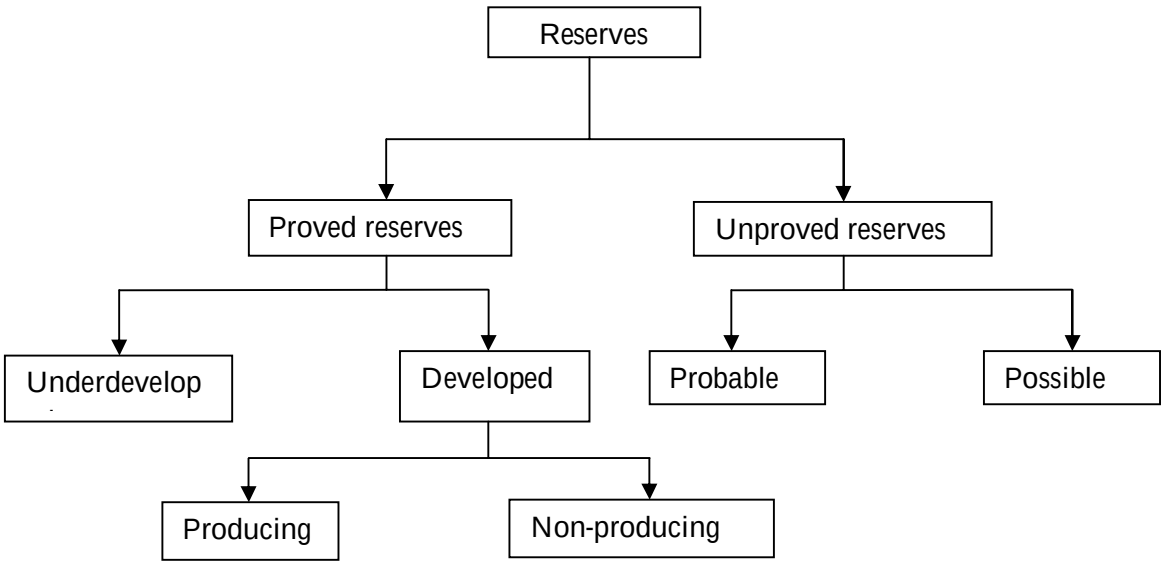


Figure 2.4: Classification of reserves.

According to Iledare (2011), it must have at least a probability of 90 percent that the actual recovery exceeds the estimated quantities of probabilistic methods used. They are either developed or undeveloped.

Developed proved reserves are reserves recoverable through existing wells and facilities. They are either producing or non-producing. Undeveloped proved reserves are reserves currently under undeveloped spacing, but with assumed high confidence of recovery when wells are drilled. Unproved reserves are less certain than proved reserves and can be divided into probable and possible reserves to reflect the degree of uncertainty. Probable reserves are unproved reserves that engineering and geological data suggests are more likely than not to be recoverable in commercial quantities.

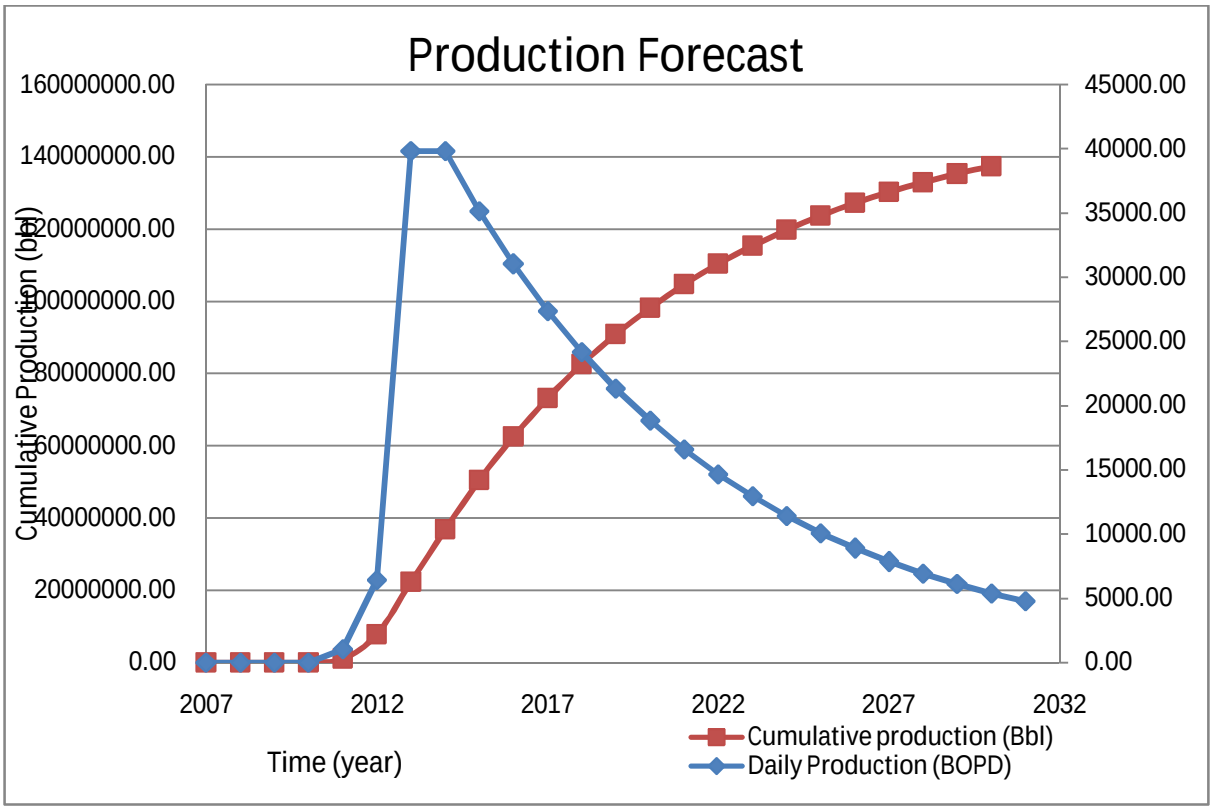


Figure 2.5: Typical production profile forecast.

2.4.1. ESTIMATING RESERVES

Reserves are those quantities of petroleum which are anticipated to be economically and commercially recovered from known accumulations from a given date forward. The degree of uncertainty depends on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data.

Methods of estimation can be deterministic or probabilistic (Iledare, 2011).

- Deterministic estimation method is when a single best estimate of reserves is made based on known geological, engineering, and economic data.
- Probabilistic estimation method is when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities.

Quantitatively,

$$Reserves = Ultimate\ recovery(UR) - cumulative\ production(N_p) \quad \ldots .2.1$$

$$UR = IOIP \times Recovery\ efficiency(E_R) = N \times E_R \quad \ldots 2.2$$

Five commonly used reservoir performance analysis and IOIP estimation techniques are (Mian 2002);

- Volumetric calculations
- Historical production and reservoir pressure performance analysis (Decline Curve Analysis)
- By analogy to similar reservoirs in the close vicinity of the area under evaluation
- Material balance equations
- Process and reservoir simulations (mathematical simulation).

2.4.1.1 VOLUMETRIC ESTIMATION

The total estimated volume of hydrocarbon accumulation known as Stock Tank Oil Initially in Place (STOIIP) can be calculated using

$$N = \frac{7758(1 - S_{wi})\emptyset hA}{B_{oi}} \quad \ldots .2.3$$

$$G = NR_{si} = \frac{7758(1 - S_{wi})\emptyset hA}{B_{gi}} \quad \ldots 2.4$$

Where;

B_{oi} = *initial oil formation volume factor* $\left(\frac{RB}{STB}\right)$, h = *formation thickness* (*feet*),

S_w = *water saturation* (*fraction*), A = *drainage area* (*acres*),

R_{si} = *initial solution gas oil ratio* $\left(\frac{scf}{stb}\right)$, $\emptyset$ = *porosity* (*fraction*),

G = *Initial gas in place for saturated oil reservoir*(*scf*), N = *STOIIP* (*STB*)

B_{gi} = *initial gas formation volume factor* $\left(\frac{RB}{SCF}\right)$,

The porosity and water saturation are obtained from well logs or core analysis or both. The formation thickness is estimated from resistivity logs or from geologic maps if the well is in a developed reservoir. The drainage area is estimated based on experience, type of reservoir producing mechanism, analogy to wells producing from similar horizons in the other areas, and from geologic maps. The oil formation volume factor is either determined in the laboratory from fluid analysis, or it is estimated from empirical correlations.

The STOIIP is multiplied by a recovery factor (E_r, *fraction*) to estimate the recoverable oil. The recovery factor is selected based on experience, reservoir drive mechanism, analogy, and rock and fluid properties.

2.4.1.2 RECOVERY EFFICIENCY

Recovery efficiency(E_R) is best estimated from production data on similar and/or offset reservoirs. According to Tiab (2010), in the absence of production data, American Petroleum Institute (API) correlation for primary recovery efficiency estimation can be used such as;

- ARP's correlation for solution gas drive sandstone reservoirs at $P \leq P_b$

$$E_R = 41.815\left[\frac{\emptyset(1-S_{wi})}{B_{ob}}\right]^{0.1611} \times \left[\frac{K}{\mu_{ob}}\right]^{0.0979} \times {S_w}^{0.3722} \times \left[\frac{P_b}{P_{ab}}\right]^{0.1741} \quad \text{... 2.5}$$

- ARP's correlation for natural water drive sandstone reservoirs

$$E_R = 54.898\left[\frac{\emptyset(1-S_{wi})}{B_{oi}}\right]^{0.0422} \times \left[\frac{K\mu_{wi}}{\mu_{oi}}\right]^{0.077} \times \left[\frac{1}{S_{wi}}\right]^{0.1903} \times \left[\frac{P_i}{P_{ab}}\right]^{-0.2159} \quad \text{... .2.6}$$

- Guthrie and Greenberger correlation for water drive sandstone reservoirs

$$E_R = 0.114 + 0.272 \log K + 0.256 S_w - 0.136 \log \mu_o - 1.538 \emptyset - 0.00035 h \quad \text{... 2.7}$$

The primary recovery factor, depending upon the type of reservoir drive, ranges from 12% to 30% (Mian, 2002).

2.4.1.3 DECLINE CURVE ANALYSIS

Decline curve analysis is used to determine future production and therefore ultimate recovery for wells/fields with some production history. Production decline analysis is a traditional means of identifying well production problems and predicting well performance and life based on real production data. It is a curve-fitting technique of past performances with higher accuracy for well/field with several months or years of production history (Mian, 2002). It is based on the following assumptions:

1. Sufficient past production performance is available in order to make a reasonable match of this performance and extrapolating its future performance.
2. The past production history is based on capacity (unrestricted) production with no changes in operational policy such as artificial lift, stimulation, etc. It is assumed the property will continue to be operated in the same manner in the future.

Decline curve analysis can be performed simply by finding a curve that approximates the past production history and extrapolating this curve into the future. A more rigorous procedure is to fit the past performance with a mathematical curve. Once the characteristics of this curve are known, they can be used to predict future performance.

Three rate-time decline curves as studied by Arps (1945) are discussed here:

1. Exponential decline
2. Hyperbolic decline
3. Harmonic decline

Arps (1945) relative decline rate equation is given by (Guo B. 2007)

$$\frac{1}{q}\frac{dq}{dt} = -aq^b \qquad \text{... 2.8}$$

Where a and b are empirical constants to be determined based on production data. When b = 0, the Arps equation degenerates to an exponential decline model, and b = 1 yields a harmonic model. When 0 < b < 1, equation 2.1 derives a hyperbolic decline model. The decline models are applicable to both oil and gas wells.

2.4.1.3.1 EXPONENTIAL DECLINE (Constant percentage decline) $(\boldsymbol{b = 0})$

Exponential decline technique, also known as constant percentage decline, has long been the favorite for petroleum engineers because it is easy and simple; it projects the most conservative estimates of UR of all the techniques available; and the underlying premise is that past factors affecting production in the past remain the same. The exponentially declining production plots as a straight line on semi-logarithmic graph paper (production on log scale and time on linear scale).

In its final form

$$q_f = q_i e^{-at} \qquad \text{... 2.9}$$

$$N_p = \frac{q_i(1 - e^{-at})}{a} \qquad \text{... .2.10}$$

$$a = -\frac{\ln\left(\frac{q_f}{q_i}\right)}{t} \qquad \text{... .2.11}$$

$$a = -\frac{\ln(1 - d)}{t} \qquad \text{... 2.12}$$

Where;

$q_i = initial\ production\ rate\ (bopd)$, $q_f = final\ production\ rate\ (bopd)$,

$N_p = cumulative\ production\ (stb)$, $t = time\ (years)$,

$a = nominal\ decline\ rate\ (fraction)$, $d = effective\ decline\ rate (fraction)$,

$b = hyperbolic\ exponent (fraction)$

2.4.1.3.2 HYPERBOLIC DECLINE ($0 < b < 1$)

The hyperbolic decline model is the more general model with the other two models being degenerations of the hyperbolic model. When plotted on a semi-logarithmic graph paper, the hyperbolic decline curve is a concave upward curve. As a result, the decline characteristics, a, is not a constant value but rather is the slope of the tangent to the rate-time curve at any point. The hyperbolic exponent, b, is constant with time (Mian 2002).

In its final form

$$q_f = q_i(1 + abt)^{-(\frac{1}{b})} \quad \text{....2.13}$$

$$N_p = \frac{q_i[1 - (1 + abt)^{-(\frac{b-1}{b})}]}{a(1 - b)} \quad \text{....2.14}$$

$$a = \frac{1}{bt}\left(\left(\frac{q_i}{q_f}\right)^b - 1\right)$$

$$= \frac{1}{bt}\left(\frac{d}{(1 - d)^b} - 1\right) \quad \text{....2.15}$$

2.4.1.3.3 HARMONIC DECLINE ($b = 1$)

Harmonic decline rate is a special case of hyperbolic decline with hyperbolic exponent b = 1. In this specific case, a plot of the inverse of the production rate versus time on a linear scale should also yield a straight line (Mian 2002). In its final form, harmonic equations used are

$$q_f = q_i(1 + at)^{-1} \quad \text{....2.16}$$

$$N_p = \frac{q_i}{a}\ln(1 + at) \quad \text{....2.17}$$

$$a = \frac{1}{t}\left(\frac{q_i}{q_f} - 1\right) = \frac{1}{t}\left(\frac{d}{1 - d}\right) \quad \text{....2.18}$$

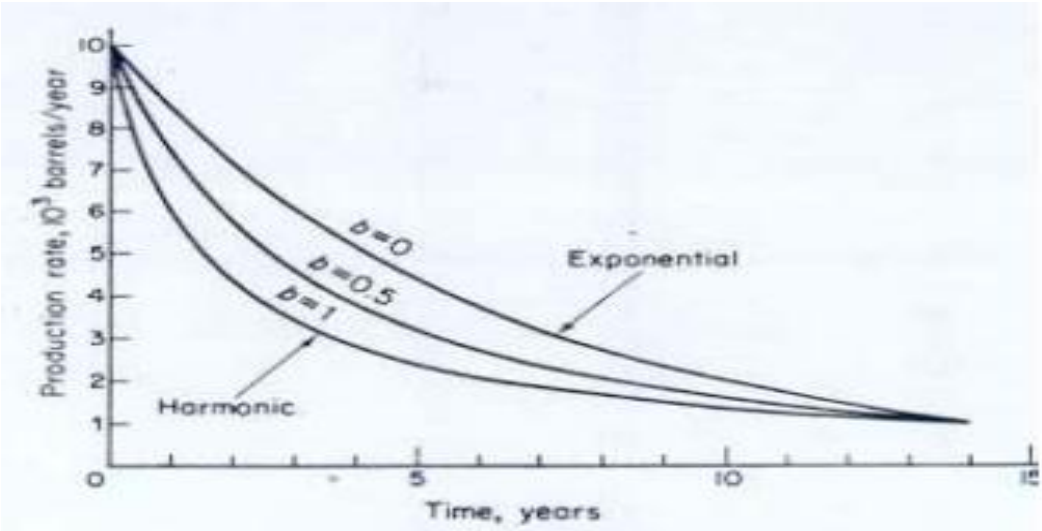


Figure 2.6: Hyperbolic decline curves (McCray A. W., 1975)

2.4.1.4 PRODUCTION FORECAST BY FIELD ANALOGY

This type of production forecasting entails using data analogy for wells drilled in a developed field to constitute the reservoir characteristics in the wells producing in the adjacent sections. For wildcats, the analogy can be used from other fields producing the same type of expected hydrocarbon accumulations. The analogy must be from the same type of reservoirs with approximately the same geological age, reservoir drive mechanism, and petrophysical properties. It can be used to determine average recovery factor, ultimate oil and/or gas reserves, and most likely production behaviors. The data used are the production, completion reports, well logs, fluid properties, structure maps, isopach maps, and isovolume maps. The more information is available, the better the analogy will be (Mian 2002).

2.4.1.5 MATERIAL BALANCE ESTIMATION

The concept of material balance estimation is based on the principle of the volumetric balance. It states that the cumulative withdrawal of reservoir fluid is equal to the combined effects of fluid expansion, pore volume compaction and water influx (Tiab, 2010). The generalized material balance equation assumes a tank model and can be written as

$$Initial\ volume = Volume\ removed + Volume\ remaining \quad \ldots 2.19$$

Material balance estimation can be used to:

i. Estimate initial hydrocarbon volumes in place
ii. Predict reservoir pressure
iii. Calculate water influx
iv. Predict future reservoir performance
v. Predict ultimate hydrocarbon recovery under various primary drive mechanisms.

In using the material balance equation, some basic data requirements include pressures, oil production data, gas production data, water production data, fluid properties, and rock properties. It does not necessarily require assumptions for areal extent and thickness. This method requires much information in its estimation which is not readily available such as pressures, and predictions are very sensitive to relative permeability.

Basic assumptions used in the material balance equations are:

i. The reservoir is characterized by a constant temperature profile.
ii. The reservoir is homogenous rock with uniform porosity, permeability, and so on.
iii. Fluid recovery is independent of rate, number of wells, or location of wells.
iv. The reservoir is characterized with an average pressure throughout and constant fluid properties.

2.4.1.6 RESERVOIR SIMULATION METHOD

Petroleum reservoir simulation method is an approach whereby mathematical equations (a model) or computable procedure are employed to infer or gain insights into the behavior of the real reservoir (Ogbe, 2011). The model building (simulation) could be physical or mathematical models. With its history matching technique which is a process where certain variables (usually intermediate variables) are adjusted to get an agreement between the observed and calculated parameters, production forecasting can be easily made.

Basic assumptions of simulation are:

i. Simulation treats reservoir as a collection of individual blocks (cells), each has its own set of properties and can behave differently.

ii. Blocks are interdependent because of fluid continuity.

iii. Simulation does not have same limiting assumptions as conventional reservoir engineering.

Basic data requirements for each cell are permeability, porosity, thickness, elevation, initial saturation, initial pressure, and rock compressibility which could be sourced from well logs, core data, pressure transient tests, geological descriptions, seismic survey, and production data.

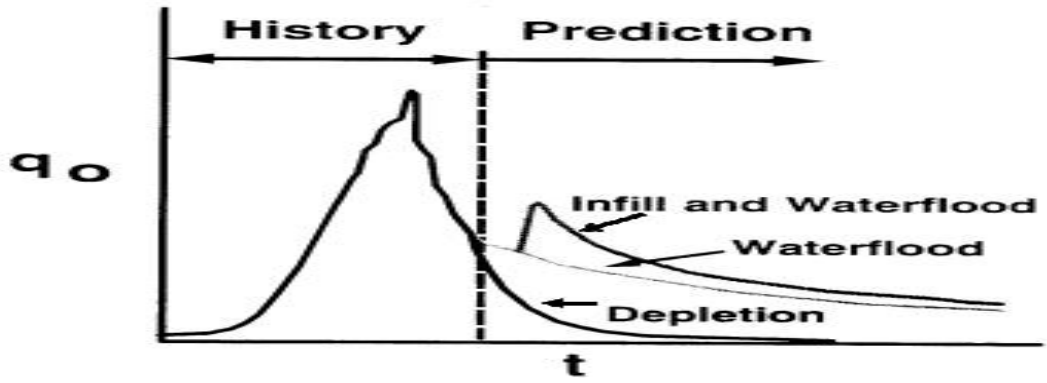


Figure 2.7: Simulation for evaluating field development plans (Ogbe, 2011)

Uses of reservoir simulation include:

i. To identify reservoir flow behaviour

ii. To describe complex reservoir flow processes in order to understand flow mechanisms.

iii. To design techniques to improve oil and gas recovery.

iv. To forecast future production performances.

2.5 PETROLEUM FISCAL SYSTEMS

Petroleum Fiscal Systems (PFS) describe, in general, the legislative, tax, contractual and fiscal elements underlying the exploration and production operations in a petroleum

province, region or country (Iledare, 2004). The purpose of the PFS is to determine equitably how costs are recovered and profits are shared between firms and the host governments. Its role also is to allocate the rights for development and operation of specific business within a country (Campbell, J., et al., 2001). Ownership of mineral rights could belong to individuals or state, but in the Gulf of Guinea (GOG) it is almost entirely in the national government (state). The federal petroleum law is the basis for all petroleum operations. Such laws often vest important discretionary powers on federal administrative or legislative bodies (Mian, 2002). The host government -- represented by either a national oil company, an oil ministry of the country, or both -- grants license or enters into contract with a contractor -- an international oil company (IOC), contractor group, or consortium of these -- for a given contract area.

As stated in section 2.2 above, the fiscal regime for oil and gas exploration and production is an important subject in industry game as it has attracted attention of many authors – for example, Van Meurs (1993), Johnston (1994), Johnston (2003), Dharmadji, T. (2002), Costa Lima G. A. (2010), Iledare (2008) and so on. This subject is important because it is one of the determinants of the attractiveness of exploration and production of oil and gas. As a result, international agreements vary considerably and the countries seldom follow same pattern.

The most common provisions and regulations in PFS have to do with the following according to Johnston D. (1994):

1. Type of permit, contract, or concession.
2. Size, shape, and geographic limits of area to be explored and developed.
3. Initial or primary term and extensions. If exploration efforts are successful, typical contract terms are for 20 to 30 years.
4. Fees and bonuses.
5. Relinquishment or surrender.

6. Selection and convertibility of acreage.
7. Assignment or transfer of acreage, lease, or concession
8. Royalty payments, sharing profits, and cost recovery
9. Tax obligations
10. Obligation to supply domestic markets first and building local refineries.
11. Employment and training of nationals
12. Equity participation by government and repatriation of capital by the contractor.

2.5.1 TYPES OF CONTRACT ARRANGEMENTS

There are two basic types of Petroleum Fiscal Systems (PFS):

1. Concessionary system, also referred to as Royalty/Tax system and
2. Contractual system.

The concessionary system allows private ownership of mineral resources, while in the contractual system; the state/government retains ownership of minerals.

The contractual systems are further reclassified into:

a. Production-Sharing contracts (PSC).
b. Service contracts

i. Pure service contracts
ii. Risk service contracts.

The primary difference is whether the fee is taken in cash (service) or in kind (PSC). The PSC is also referred to Production-Sharing Agreement (PSA). The difference between pure and risk service contracts is primarily based on whether the fees are based upon a flat fee (pure) or profit (risk). Some countries offer concessionary arrangements as well as service or production-sharing contracts. The bottom-line in either case is a financial issue (i.e., how costs are recovered, risks shared, and profits divided).

Table 2.1: Summary of risk and reward in fiscal regimes (Mian, 2002)

Contract Type	Contractor	Host Government
Concession	All risks/all reward	Reward is function of production and price
Production-Sharing Agreement	Exploration risk/Share in reward	Share in reward
Joint Venture	Share in risk and reward	Share in risk and reward
Pure Service Contract	No risk	All risk

In terms of a Production Sharing Contract (PSC) the state contracts for the services of a contractor (IOC) to explore for, and in the event of a discovery, to exploit hydrocarbons. The contractor is responsible for financing the petroleum operations. Hydrocarbon production is shared between the State and the contractor in accordance with the terms of the contract. The contractor will receive a share of production as reimbursement of its costs and as compensation in kind (cost oil), the remainder of the oil (profit oil) will be shared between state and contractor.

The risk and reward under each of the above contract types are summarized in Table 2.1 above and table 2.2 below shows fiscal system comparison.

Table 2.2: Fiscal system comparison (Johnston D. 2008)

	R/T System	PCSs	RSAs
Type of Projects	All types: Exploration, Development, EOR	All types: Exploration, Development, EOR	All types but often non-exploration
Ownership of Facilities	International Oil Company	Government NOC	Government NOC
Production Facilities Title Transfer	No transfer	"When landed" or upon commissioning	"When landed" or upon commissioning
IOC Ownership of Hydrocarbons (Lifting entitlement)	Gross production less royalty oil	Cost oil + profit oil	None may have preferential right to purchase
Repatriation of Service Company Equipment	Yes	Yes	Yes
IOC Lifting Entitlement (%)	Typically around 90%	Usually from 50-60%	None (by definition)
Hydrocarbon Title Transfer	At the wellhead	Delivery Point Fiscalization Point or Export Point	None
Financial Obligation	Contractor 100%	Contractor 100%	Contractor 100%
Government Participation	Yes | Not common	Yes | Common	Yes | Very Common
Cost Recovery Limit	No	Usually	Sometimes
Government Control	Low Typically	High	High
IOC Control	High	Low to Moderate	Low

2.6 WORLD ENERGY MARKET

According to the Oil and Gas in Africa report by ADB/AU (2009), the impact on the world economy and politics by the evolution of world energy market in the post-1970 has been profound. This is evidenced by the worldwide economic ripple effects caused by the volatility and occasional spectacular spikes in the prices of dominant global energy resources such as oil and gas. Other significant impact has been the fundamental changes in the structure, conduct, and performances of the oil and gas sectors – including considerable improvements in oil and gas technology, unprecedented consolidation among multinational oil companies, increasing global price transparency implicit in oil trade, new markets fundamentals, and environmental considerations.

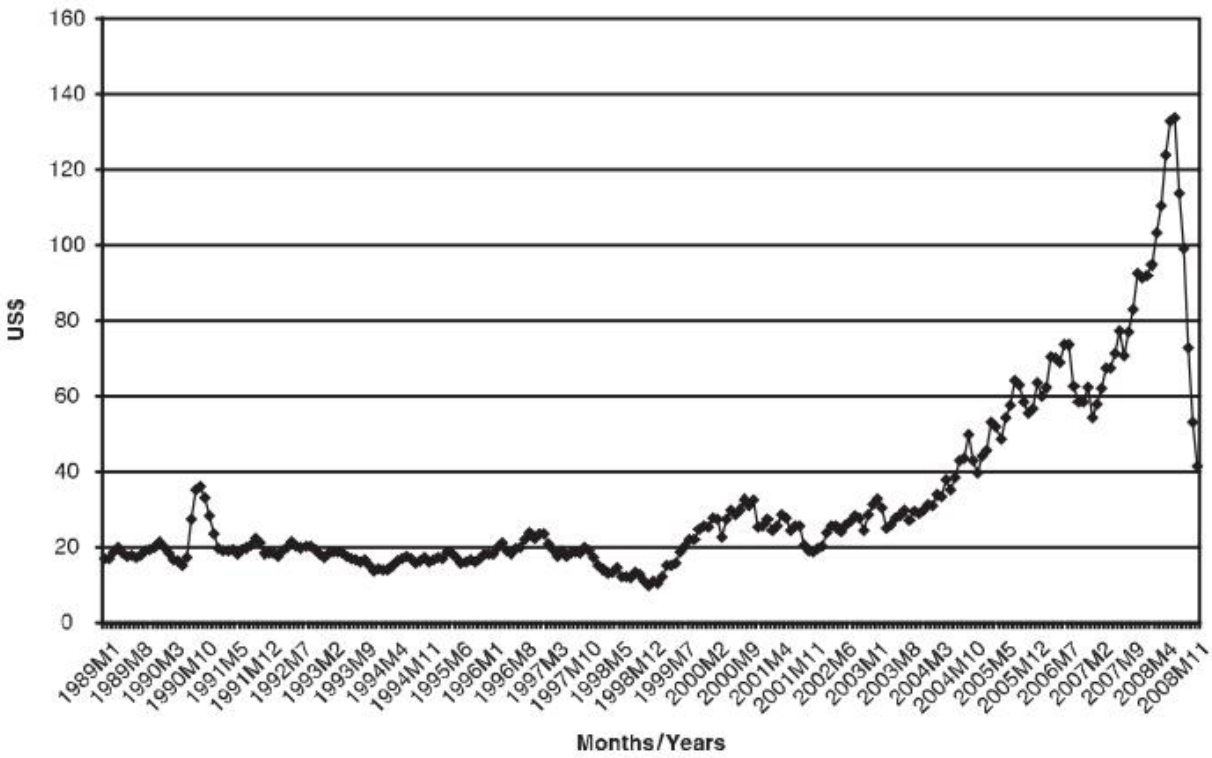


Figure 2.8: Crude oil spot price between 1989 and 2008 (IMF Commodity Prices Database, January 2009)

The high volatility of crude oil pricing is captured in figure 2.3 above from 1989 to 2008. As seen, there is huge uncertainty on crude oil pricing and this makes pricing a key factor in decision making in the oil and gas industry. Three primary market drivers are: demand from emerging countries (China and India in particular); production from OPEC countries; and inventory movement in major consuming countries (especially the United States). The profitability of any E&P venture and reserve estimation depends greatly on future pricing of crude oil.

2.7 SUMMARY

In this chapter, an overview of the role the Gulf of Guinea plays in meeting the world's energy demand was discussed. The comparative competitiveness of PFS in exploration and production activities around the globe was highlighted and an overview of

E&P activities in the GOG. A general description of E&P performances of countries in the GOG, their PFS and some of their instruments with their regulatory authorities were hinted. It was identified that as comparative PFS analysis of regions around the world exist, there is none for the GOG.

The importance of petroleum reserves and production forecasting in E&P project evaluation was iterated. Various methods of reserves estimation and production decline analysis were treated. The types of petroleum fiscal systems and their fiscal instruments were also discussed. The effect of unpredictable oil price on world energy market was also reviewed. It is seen that the profitability of any E&P investment and reserves estimation depends greatly on oil price.

CHAPTER THREE

3.0 METHODOLOGY

3.1 OVERVIEW

All economic evaluations involve a look into the future, but the evaluation engineer is required to take only a limited view. He must forecast only the return from investments in wells, plants, and pipelines (Stanley L. T., 1982). To do this, petroleum project evaluation engineer needs to know annual production rates, future operating costs and prices, taxes, inflation rate, cost of money, participation factors, reversionary interests, risk factors, and future investments required to keep the project going.

The methodologies necessary for petroleum project evaluation to determine its profitability or viability will be described in this chapter. It will entail description of required data, forecasting of production decline rate, cost treatment analysis, and petroleum fiscal systems applicable to the Gulf of Guinea (GOG) region. An economic model is formulated using Excel spreadsheet after the pattern presented by Iledare O. O. (2011) and Mian M. A. (2002).

Petroleum project evaluation viability still centers on the greatest assets of any E&P investment which is proved reserves. Establishing the quantity of proved reserves is the starting point of investment decision in oil and gas ventures. In this study, oilfield development technique used assumes huge oil reserve typical to GOG deepwater discoveries with good recovery factor. After the estimation of STOIIP and recovery factor from any of the methods discussed in section 2.4, a good estimate of proved reserves is known and a decision on the development plan is reached. The type of production decline pattern used in this research for analysis purposes is exponential decline pattern with linear build-up rate. The model has provision for non-linear build up rate with hyperbolic or harmonic decline

pattern. The maximum plateau rate attainable is tied to a percentage of the proved reserves. Attainable plateau rate is a function of percent reserves, facility size, or number of wells.

$$plateau\ rate = \min_i\{\%\ of\ reserves, facility\ size, \min rate \times wells\} \quad \ldots 3.1$$

Total plateau production is also tied to a proportion of proved reserves, as a result, time to end plateau production is estimated. From these estimations, decline factor is calculated from the remaining reserves after plateau period ends using constant percentage decline pattern. The total production life is then calculated by summing up all the periods in the development plan. For the purpose of comparative analysis of the fiscal systems in the GOG regions, the same technical cost treatment is used for all countries except depreciations, which is treated as specified in the fiscal instruments. Straight line depreciation (SLD) technique is adopted by the various governments in the GOG region, though the model has provisions for Double Declining Balance (DDB), Declining Balance (DB), and Sum of Year's digit Depreciation (SYD) methods. Subsequent to the establishment of annual production, annual gross revenue is projected by applying oil price.

Applying the fiscal terms, Production Sharing Contract (PSC) Economics before Corporate Income Tax (CITA) and after CITA is modelled to capture total yearly expenditure and the Net Revenue, contractor's and government take before CITA and after CITA. Depending on countries' fiscal instrument specifications, non-technical cost treatment of royalties, bonuses, rentals, and crypto taxes are imposed to front-end loaded government take. Afterwards, cost recovery economics is modelled for all PSCs with the relevant cost recovery limit (CRL) specifications applied before calculation of government take before CITA. Government and contractor takes after income tax is estimated after imposing the specified corporate income or petroleum profit tax in the PFS of each country.

Simulation analysis to account for uncertainty and risk in the deterministic result is performed and the probability of success of the venture to changes in reserves, peak

production rate, and development cost and crude oil prices using @Risk is also modelled. Objective functions to be analyzed are the Net Present Value (NPV), Government Take (GTake), Internal Rate of Return (IRR), Discounted Payout time/period (DPO), and Growth Rate of Return (GRR) using an assumed hurdle rate (discount rate) of 12.5%.

3.2 DATA REQUIREMENT

The generic data requirement for the usage of this economic model includes production data, technical cost data, fiscal systems, and oil price projection. Production data required for the field development plan of choice are estimated STOIIP, percentage recovery of STOIIP, initial production rate, build-up period, facility size, and percentage recovery of reserves to be produced at plateau. With this data, reserves, plateau rate, plateau period, production life, and decline rate are estimated by the model.

Technical costs required for the model include well costs, time to drill wells, number of anticipated wells to drill, exploration cost, geological and geophysical cost, operating cost, intangible drilling costs; field/facilities cost, and salvage value. In addition to these technical costs, the default PFS incorporated in the economic model gives opportunity for additional specification to model, design and contrast any fiscal system of choice. These data are depreciation type, depreciable item, depreciable years, investment tax allowance/credit, percentage of unrecoverable costs, and percentage of costs that are tangible and intangible.

The Petroleum Fiscal Systems (PFS) for the GOG region for this research are embedded as Fiscal Model Library (FML) in the model. The user can only select countries whose PFS is available in the FML. These countries are Angola; Cameroon; Chad; Cote D'Ivoire; Equatorial Guinea; Gabon; Ghana; Liberia; Mali; Niger; Nigeria; Senegal; and Sierra Leone. The corresponding PFS available in the FML are ANGOLA PSC (1990); ANGOLA PSC (2004); CAMEROON RENTE MINIERE (1995); CHAD R/T (1999); COTE D'IVOIRE PSC (1996); COTE D'IVOIRE PSC R-FACTOR (1996); EQUATORIAL

GUINEA PSC (1998); EQUATORIAL GUINEA PSC (2006); GABON PSC (1997); GHANA R/T (1997); LIBERIA PSC (2009); MALI R/T (1970); NIGER R/T (1992); NIGERIA JDZ PSC (2003); NIGERIA PSC (1993); NIGERIA PSC (2000); NIGERIA PSC (2005); NIGERIA PIB (2009 Proposed); NIGERIA R/T (2000); SENEGAL R/T (2000); and SIERRA LEONE RT (2001). But, Default PSC and R/T PFS are incorporated to allow users design and contrast fiscal systems. The basic fiscal instruments of PFS such as bonuses, rentals, royalties, royalty type (sliding, jumping, or incremental), CRL, crypto taxes, corporate tax, profit sharing, and so on are necessary data to be specified for the Default PFS.

Oil price projection data requires an initial estimated oil price in United States (US) dollar per barrel ($/bbl) and a capped price. The crude oil price could be real or nominal. If nominal, an escalation rate is specified to account for contemporary conditions. Other data necessary are lease acreage, model start year, and production delay period. Figure 3.1 below shows a guide to input parameters in the economic model.

3.3. GENERALIZED PRODUCTION PROFILE

The petroleum production development used in this study is based on three methods namely:

1. Field development plan with linear build up;
2. Field development plan with non-linear build up phase; and
3. Economic limit field development plan.

They all have a relationship between reserves and initial production. The plateau of the profile for the oil field development plans is a percentage of the reserves and optimum production capacity with economic limit. Production capacity is determined by the number of wells, equipment and facilities. Initial production rates affect the rate of production decline as well as the ultimate recovery.

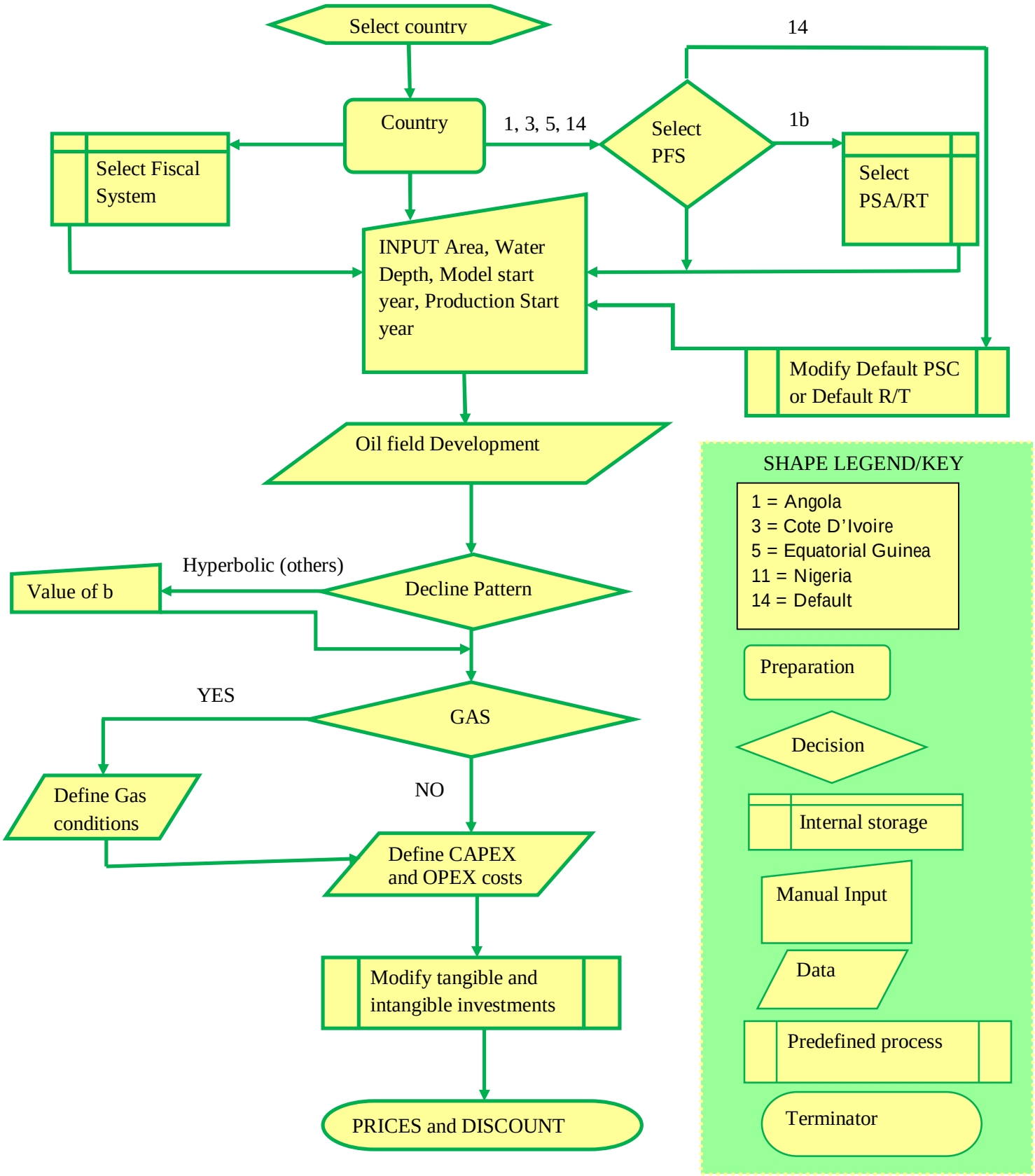


Figure 3.1: Input data flow chart

For the purpose of analysis in this research, field development plan with linear build-up and the conservative exponential (constant percentage) decline curve analysis was used for production forecasting, with the underlying premise that past factors affecting production in the past remain the same as depicted in figure 3.2.

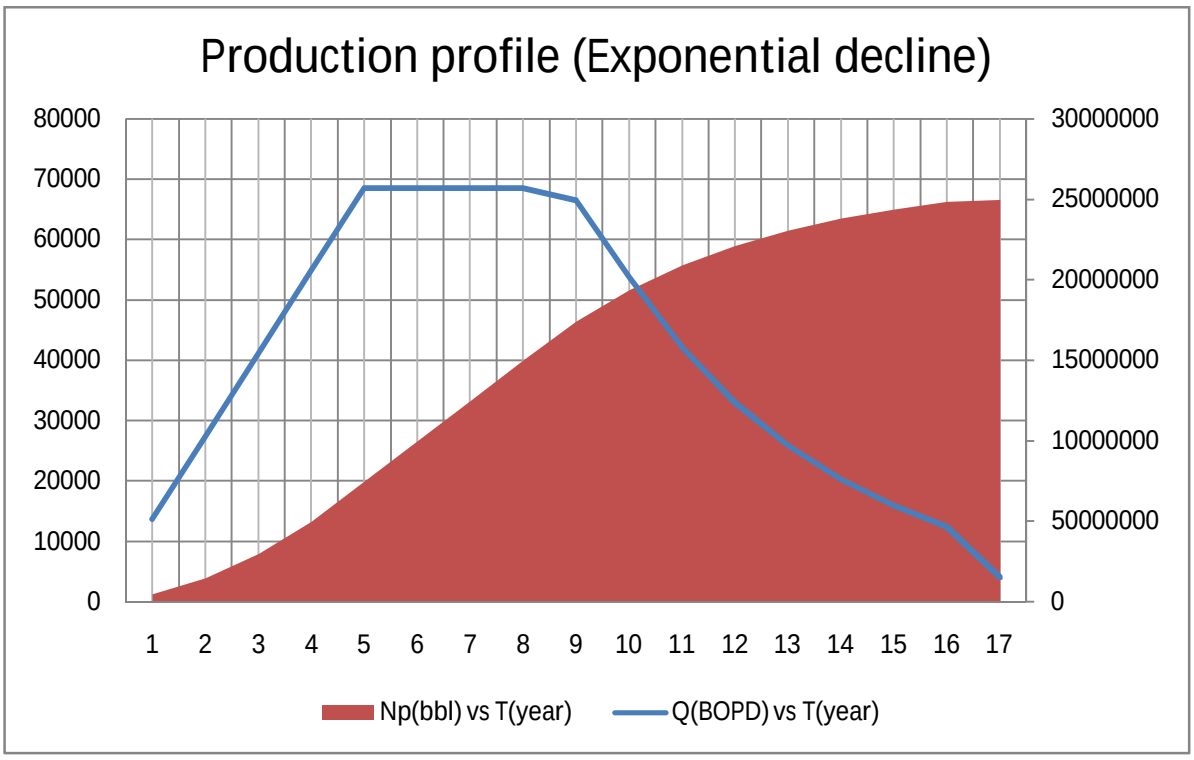


Figure 3.2: Exponential decline curve with cumulative production

3.3.1 FIELD DEVELOPMENT PLAN

Typical reservoir production phases in any field development plan include;

- Development build-up phase;
- Plateau phase; when production stays constant until nearly half of oil production has been produced. The period of stay depends on ultimate reserves
- Decline phase; which continues until production cost can no longer be covered. The producing lives depend on reservoir characteristics.

The essence of the development plan is to have good production capacity. The production capacity which is a measure of the sustainable flow of petroleum as a result of discovery,

investment, and infrastructure installed (Iledare, 2011) would have to generate enough revenue to compensate for the expenditures and be economical.

3.3.1.1 DEVELOPMENT BUILD-UP PHASE

This is the initial phase in every new field development plan. In this phase new wells were drilled, completed and production facilities installed. The well does not flow at its full potential at this early stage but gradually builds up to full potential. The process of build-up is a function of the initial production rate, peak/plateau production rate, build-up period and build-up rate.

The general Arps (1945) equations were used for the build-up as follows:

Exponential production build-up rate

$$q_b = q_i e^{-at} \quad \text{... 3.1}$$

$$a = -\frac{\ln\left(\frac{q_d}{q_p}\right)}{t} \quad \text{... 3.2}$$

Hyperbolic production build-up rate

$$q_b = q_i(1 + abt)^{-(\frac{1}{b})} \quad \text{... 3.3}$$

$$a = \frac{1}{bt}\left((\frac{q_p}{q_d})^b - 1\right) \quad \text{... 3.4}$$

Harmonic production build-up rate

$$q_b = q_i(1 + at)^{-1} \quad \text{... 3.5}$$

$$a = \frac{1}{t}\left(\frac{q_p}{q_d} - 1\right) \quad \text{... 3.6}$$

For the linear build-up production rate used, annual production was first calculated from equations 3.1, then

Table 3.1 ARPS BUILD-UP EQUATIONS

	Production rate, q_d	Cumulative production, N_p	Build-up rate, a
EXPONENTIAL	$q_p e^{-at}$	$\frac{q_p(1-e^{-at})}{a}$	$-\frac{\ln\left(\frac{q_d}{q_p}\right)}{t}$
HYPERBOLIC	$q_p(1+abt)^{-(\frac{1}{b})}$	$\frac{q_p[1-(1+abt)^{-(\frac{b-1}{b}}}{a(1-b)}$	$\frac{1}{bt}\left((\frac{q_p}{q_d})^b-1\right)$
HARMONIC	$q_p(1+at)^{-1}$	$\frac{q_p}{a}\ln(1+at)$	$\frac{1}{t}\left(\frac{q_p}{q_d}-1\right)$

The build-up rate production was calculates as

$$q_b = \frac{\min_i\{\%\ of\ reserves, facility\ size, \min rate \times wells\} \times number\ of\ years}{buildup\ period} \quad \ldots 3.7$$

Annual production, $N_a = 365 \times q_b$ for the linear build-up phase

Cumulative production, $N_p = \sum_{t=1}^{tb} N_{a,t}$ ... 3.8

Where $q_b = daily\ buildup\ production\ rate\ (bopd)$, $tb = buildup\ period\ (years)$

3.3.1.2 DEVELOPMENT PLATEAU PHASE

This is the next phase after the build-up phase. Plateau phase is characterized with constant reservoir pressure. At this phase the field is producing at its full potential and it is expected that all the facilities have been installed and most, if not all, wells drilled. Production operators tend to maintain this phase for as long as technical and economic feasibility permits. The plateau period is the period in which annual production is greatest and if price is favorable, much revenue is made to recover majority of the expenditures.

The general equation used for this phase was the same for exponential, hyperbolic, or harmonic cases;

Annual production, $N_a = 365 \times q_p$ ... 3.9

Cumulative production, $N_p = \sum_{t=1}^{tp} N_{a,t}$ ... 3.10

Where $q_p = daily\ plateau\ production\ rate\ (bopd)$, $tp = plateau\ period\ (years)$

3.3.1.3 DEVELOPMENT DECLINE PHASE

Decline phase is the last stage of every field development plan that leads to abandonment. It is the stage of development where reservoir pressure declines and may no longer support depletion, requiring external support such as artificial lift and various pressure maintenance techniques. The time to end production (abandonment) is determined by the economic limit of the project. Usually, this is when revenue generated no longer compensates for expenses and profit is not made. Technical, political, and social factors may also lead to abandonment.

In modeling the decline phase in this study, Arps (1954) equations were used for the three different production development plan presented in section 3.3. The equations are as presented below;

Exponential decline phase

$$q_d = q_p e^{-at} \quad \text{... 3.11}$$

$$N_p = \frac{q_p(1 - e^{-at})}{a} \quad \text{... 3.12}$$

$$a = -\frac{\ln(1 - d)}{t} \quad \text{... 3.13}$$

Hyperbolic decline phase

$$q_d = q_p(1 + abt)^{-(\frac{1}{b})} \quad \text{... 3.14}$$

$$N_p = \frac{q_p[1-(1+abt)^{-(\frac{b-1}{b})}]}{a(1-b)} \quad \text{... 3.15}$$

$$a = \frac{1}{bt}\left(\frac{d}{(1-d)^b} - 1\right) \quad \text{... 3.16}$$

Harmonic decline phase

$$q_d = q_p(1+at)^{-1} \quad \text{... 3.17}$$

$$N_p = \frac{q_p}{a}\ln(1+at) \quad \text{... 3.18}$$

$$a = \frac{1}{t}\left(\frac{d}{1-d}\right) \quad \text{... 3.19}$$

Table 3.2 ARPS DECLINE EQUATIONS

	Production rate, q_d	Cumulative production, N_p	Decline rate, a
EXPONENTIAL	$q_p e^{-at}$	$\frac{q_p(1-e^{-at})}{a}$	$-\frac{\ln(1-d)}{t}$
HYPERBOLIC	$q_p(1+abt)^{-(\frac{1}{b})}$	$\frac{q_p[1-(1+abt)^{-(\frac{b-1}{b})}]}{a(1-b)}$	$\frac{1}{bt}\left(\frac{d}{(1-d)^b} - 1\right)$
HARMONIC	$q_p(1+at)^{-1}$	$\frac{q_p}{a}\ln(1+at)$	$\frac{1}{t}\left(\frac{d}{1-d}\right)$

3.4 YEARLY TECHNICAL COST OUTLAY

Geological and Geophysical (G&G) exploration was simulated having time variations with adjustable intangible (65%) and tangible (35%) percentage ratio. Dry holes were treated as 100% intangible cost. Field development was also simulated with time variations representing platform fabrications and drillings commencing in consecutive years. Adjustable percentage ratio for tangible and intangible costs was also incorporated. Production/injection

well(s) has tangible investments of 30% and 70% intangible investments. Exploration/wildcat well(s) has 70% tangible investments and 30% intangible investments. Bonuses and leasehold costs and production platforms/facilities have 100% tangible investments, whereas additional operating cost and Intangible Drilling Cost (IDC) has 20% tangible investment and 80% intangible investments.

The cost outlay treatment in this economic model follows the pattern below;

a. G&G Exploration CAPEX
    - G&G
    - Wildcat/Exploration wells
    - Tangible G&G exploration
    - Intangible G&G exploration
b. Appraisal wells
    - Tangible Dry/Appraisal wells
    - Intangible appraisal CAPEX
c. Development CAPEX
    - Development wells
    - Facilities
    - Tangible development costs
    - Intangible development costs
d. Operating Expenditure
    - Field OPEX
    - IDC/Additional field OPEX
    - Tangible OPEX
    - Intangible OPEX
e. Total costs

- Total tangible CAPEX
- Total intangible CAPEX
- Total tangible cost
- Total intangible cost

Sections 3.2 to 3.4 above are the same for all the PFS modeled in this study.

3.5 CASH FLOW MODEL

Cash flow (CF) model is a model that shows flow of cash of an investment over a defined period of time. CF typically shows (1) cash receipts at the end of each year generated by the investment, (2) cash disbursements of all costs (initial and subsequent costs) per year required for the operations, and (3) total time span of the investment in years. Cash flow diagram shows that a capital investment is an amount paid to receive expected net cash inflows over the economic life of the investment (Mian, 2002).

For economic analysis, the cash flow model is preferred to other models like financial profit model and tax profit model, because it produces net cash flow and it places the timing of funds to and fro projects more accurately. Net cash flow (NCF) is simply revenue (cash received) less expenditure (cash spent) during a period usually one year and projected over the economic project life. Mathematically,

$$Net\ Cash\ Flow\ (NCF) = Receipts - Disbursements \quad \ldots 3.20$$

Subtracting the cash disbursements from the cash receipts will generate net negative or positive cash flow.

The economic model developed in this study for the different countries' PFS in the GOG region, considered the following cash flow items and treated them commonly as highlighted below.

3.5.1 CASH FLOW ITEMS

1. Gross Revenue: This is the product stream multiplied by the projected price of the product.

   $$GR = price \times marketed\ volume\ of\ hydrocarbon \quad \ldots 3.21$$

   Net revenue is share of marketed production multiplied by net price.

   $$Net\ Revenue = net\ price \times (1 - rate) \times production \quad \ldots 3.22$$

   Net price is prices received less any purchaser charges (rate).

2. Royalty is a fraction of gross profit. It is a paying homage.

   $$Royalty = royalty\ rate \times GR \quad \ldots 3.23$$

3. State and Local taxes: These are taxes other than income taxes levied on petroleum production. They are paid whether profits are made or not. These taxes for the GOG include National Hydrocarbon Tax (NHT), Niger Delta Development Corporation (NDDC) levy, Hydrocarbon Support Fund (HSF), training fees, social welfare fund, and education taxes.

4. Technical costs: These are CAPEX and OPEX.

   a. Capital Expenditures (CAPEX): It is also referred to as front-end costs. These are classified as investments – monies paid for assets that will generate benefits for more than one year. CAPEX can be classified as either tangible or intangible costs. Examples are cost of surface equipment, cost of drilling and developing a well, etc.

      - Tangible costs were capitalized and depreciated for after tax calculation purposes.
      - Intangible costs were expensed through amortization for tax calculation purposes.

   b. Operating Expenses (OPEX): It is also referred to as Lease Operating Expenditure (LOE). These are direct costs associated with production or injection. They are

expenditures that benefits only the period in which they are made. Typical OPEX behavior patterns are variable costs – costs of raw materials – and fixed costs – management fees. Examples are well repairs and work-over costs, maintenance costs, etc.

5. Additional field OPEX: This is also known as overheads. Overhead represents a significant component of OPEX and is hidden costs of being in business. Additional field OPEX represents internal cost of accounting and making investment, it is estimated as a fixed yearly amount in this model.
6. Income taxes: Income taxes are some fraction of taxable income on annual or total life basis. It varies considerably from country to country in the GOG due to small business allowances, investments tax credits, adjustments for double taxation, and so on.
   - Taxable income is net revenue less fiscally permitted cost deductions. Fiscal allowable cost deductions include OPEX; royalty; depreciation; depletion allowance; expensed investments or amortized intangible capital investments; payments to government.

     $$Taxable\ income = Revenues - Royalties - Fiscal\ costs \quad \ldots 3.24$$

On annual cash flow for typical E&P venture Net Cash Flow (NCF) was modeled as:

$$NCF = Gross\ Revenue - Royalty - Net\ taxes - Operating\ expenses - Overheads - Capital\ investments - Bonuses - Rentals + Property\ sales\ price \quad \ldots 3.25$$

3.6 DEPRECIATION

Depreciation is the loss in the value of asset over the time it is being used (Mian, 2002). The purpose of fiscal depreciation expense is to spread investment costs over time, for income tax and financial report purposes. It is a method for capital recovery of the costs of

fixed assets over the estimated useful life of the asset according to the underlying rules set by tax legislation. Generally, all the PFS treated in this study adopted the SLN depreciation method but depreciable items were different from country to country as the case may be and depreciable years differ also.

Other depreciation methods incorporated in this economic model for the default PFS are;

- Straight line depreciation (SLN)
- Declining balance depreciation (DB)
- Double declining balance depreciation (DDB)
- Sum-of-the-years'-digits depreciation (DDB)

3.6.1. STRAIGHT LINE DEPRECIATION (SLN)

Straight line (SLN) depreciation is a method in which the depreciable cost is evenly distributed over the useful life of the asset.

$$SLN = \frac{Depreciable\ Cost - Salvage\ value}{useful\ years} \qquad \ldots 3.26$$

Salvage value is the estimated value of property at the end of its useful life.

3.6.1.1 DECLINING BALANCE DEPRECIATION (DB) AND DDB

Declining balance (DB) uses a fixed value of percentage applied to the book value (total value of asset less accumulated depreciation of previous years) of the asset year. Typical percentage values could be 125%, 150%, and 175%. If the percentage is 200%, it becomes double declining balance depreciation (DDB).

3.6.1.2 SUM-OF-THE-YEARS'-DIGITS DEPRECIATION (SYD)

Sum-of-the-Years'-Digits (SYD) method uses a declining depreciation charge each year by applying a declining charge to the total cost of asset (depreciation base) [10]. The declining charge is determined each year by dividing the remaining life of the asset by the sum of the years' digits.

$$SYD = \frac{Number\ of\ remaining\ years\ of\ life}{syd}(Depreciable\ Cost - Salvage\ value) \quad \text{... 3.27}$$

$$syd = \frac{n(n+1)}{2}, \quad n\ is\ the\ useful\ life\ of\ the\ asset \quad \text{... 3.28}$$

3.7 FRONT LOADED GOVERNMENT TAKE CASH FLOW

The economic model formulated for this study captures front loaded government take (FLGT) separately for the GOG region. The essence of FLGT is to determine equitably how costs are recovered and profits are shared between firms, the host governments, and mineral owners (Iledare, 2011). The host government usually tries to capture as much economic rents as possible through royalties, bonuses, surface rentals, crypto taxes, and taxes. Economic rent reflects the difference between the value of production and costs to extract it.

Economic rents extracted through royalties, bonuses, and crypto taxes basically made up the front loaded government take. Crypto taxes are indirect means by which government receives revenue through levies, imposition of duties and other financial obligations (Iledare, 2011) such as, NDDC contributions; institutional funds; training obligations; welfare developments; local content; and so on. Different PFS in the GOG has a mix of these crypto taxes specified in them.

Before the application of the FLGT components in the model, Domestic Market Obligations (DMO) is applied. Where specified, DMO provisions require E&P firms to sell a certain percentage of the contractor's pre-tax profit oil share to the host government, usually at a price lower than the market price.

Royalties and bonuses are forms of extraction that occur at the time of transfer of rights, which are not based on profits. In the GOG, some PFS have them specified, while some do not. Bonuses are made up of signature bonus, production bonuses, and discovery bonuses. Signature bonus is usually paid when lease is acquired and it is usually a single

lump payment. It may be determined through bidding, negotiation, or legislation. Discovery and production bonuses are paid during discovery and production periods. Production bonuses may be required when development begins, at start of production, and/or whenever certain predetermined levels of production are reached. Usually, when production bonuses are tied to production, it is usually jumping as explained below.

Table 3.3: Example production bonus specification

Production Bonus	Negotiable		
	Cum. Prod. Level (Mbbl)	Bonus (Mbbl)	
	1000	200	or Cash
	220000	1000	or Cash
	500000	1000	or Cash

Gross revenues formed the base of the royalty payment in this model. This rate base form of extraction is regressive as it is not tied to profits and it reflects risk aversion of the host government.

$$ROY_t = R(\varphi)(GR_t - ALLOW_t) \quad \ldots 3.29$$

Where the total allowance cost is denoted by $ALLOW_t$and the royalty rate $R(\varphi)$depends upon the location and time the tract was leased and the incentive schemes, if any, in effect. The royalty rate $R(\varphi)$, $0 \leq R(\varphi) \leq 1$, may be fixed or sliding scale may be employed. The terms of the royalty rate, like many other PSA factors, may be negotiable.

Three common types of royalties used in this model and as seen in the GOG PFS are:

1. Fixed percentage royalty
2. Fixed payment royalty, and
3. Sliding scales royalty
    i. Jumping scale
    ii. Incremental scale

Fixed percentage royalty was most widely used in GOG PFS. It is a type of royalty whereby a fixed percentage of the gross revenue is paid either in cash or in kind. Irrespective of oil price, this percentage is applied to gross revenue. Examples of countries that use fixed percentage royalty in the GOG region are Liberia, Ghana, Chad, Mali, Niger, and Sierra Leone. Fixed payment royalty is a type of royalty in which a fixed payment/amount is paid to mineral owner whether profit is made or not. It is no longer commonly used.

Sliding scale royalty tends to rectify the disadvantages of high fixed royalty. It was used to account for uncertainties in field size, oil price, average daily production, geology, economics or engineering, and so on. Sliding scale royalty scales were be tied to R-Factor, average daily production, cumulative production, oil price, and project economic measures as seen in the PFS. Sliding scale royalties could be jumping or incremental sliding scale. In jumping scale royalty, the value or percentage to be paid was dependent on the tranche (level) specified, while in incremental scale royalty, an effective value/percentage was calculated based on the tranche reached. Incremental sliding scale (Patterson W., 1979) could be linear scale or logarithmic scale.

To illustrate sliding scale methods used in this study, the following royalty specification tied to average daily oil production for deepwater field is used:

Table 3.4: Example sliding scale royalty

Average daily production, q_d (BOPD)	Royalty rate (%)
0 – 50 M	5
50 – 100 M	12.5
> 100 M	25

For an average daily production, $q_d = 75\ M\ BOPD$, the royalty rate would be

For jumping scale, the effective royalty rate would be 12.5% because the 75 MBOPD falls into the second tranche (level) which has the specification of 12.5% for average production between 50 – 100 MBOPD.

For Linear scale, the effective royalty rate is calculated as

$$Roy = 5\% + \frac{q_d - 50}{100 - 50}(12.5\% - 5\%) \quad \text{... 3.30}$$

$$Effective\ royalty\ paid = 8.75\%$$

For logarithmic sliding scale, the effective royalty rate is calculated as

$$Roy = \frac{(5\% \times 50) + (12.5\% \times (q_d - 50))}{q_d} \quad \text{... 3.31}$$

$$Effective\ royalty\ paid = 7.5\%$$

As part of FLGT in the GOG was surface rental payment. These rentals may be a lump sum payment, a constant payment per area, or payment that increases over time per area. It helps to provide government revenue from resource management and encourages voluntary release of leases or acreage. Other crypto taxes were also modelled. A summary of the crypto taxes, rentals, royalties and bonuses is attached in appendix A.

The final FLGT before tax is modelled as

$$FLGTB4T = Bonuses + Rentals + Royalty + Crypto\ taxes \quad \text{... 3.32}$$

3.8 COST RECOVERY TREATMENT

Cost recovery is a unique fiscal instrument present only in PSC. It was modeled only for PSCs and not for R/Ts in this study. It is a means through which investors can regain the expenditures incurred during exploration, development, and operations. The cost recovery scheme determines how the cost oil is computed. Many variations cost recovery exist, and in its most basic form as computed in this study are;

$$CR_t = U_t + CAPEX|I_t + OPEX_t + DEP_t + INT_t + INV_t + DECOM_t \quad \text{... 3.33}$$

$CR_t = Cost\ recovery\ in\ year\ t,$

$U_t = Cost\ recovery\ carried\ over\ from\ year\ t-1$,

$CAPEX|I_t = Intangible\ capital\ expenditures\ in\ year\ t$,

$DEP_t = Depreciation\ in\ year\ t$,

$INT_t = Interest\ on\ financing\ in\ year\ t$,

$DECOM_t = Decommissioning\ cost\ recovery\ fund\ appointment\ in\ year\ t$.

The amount of revenues the contractor can claim for cost recovery is normally bound by the so called "cost recovery ceiling/limit", and in some cases, a time limitation for full cost recovery may also be imposed. The only true distinction between concessionary R/T and PSC systems in terms of mechanics is the cost recovery limit (CRL) specification. Typically, 75% of PSCs have a CRL between 40 to 60%. In some GOG PSCs modelled the CRL is as high as 80% to 100%. Eligible cost recovery was modelled as

$$Total\ ECR = GovPyt + Depreciation + Expensed\ Cost + Abandonment\ costs \quad \ldots 3.34$$

Where

$$GovPyt = Total\ FLGTB4T - Royalty - Bonuses \quad \ldots 3.35$$

The recovery limit was modelled as

$$Recovery\ Limit = CRL \times (GR - Royalty) \quad \ldots 3.36$$

The costs to be recovered (Total ECR) can be carried forward to succeeding years indefinitely if unrecovered in any particular year.

Cost oil is constrained in value through a functional relation such as

$$CO_t = \min(CR_t, CR(\varphi)GR_t) \quad \ldots 3.37$$

Where the value of $CR(\varphi)$, $0 \leq CR(\varphi) \leq 1$, may be constant or based on a sliding scale.

The profit oil is the portion of production or revenue that the government shares with the contractor after royalties and cost oil is recovered from the gross revenue:

$$PO_t = GR_t - ROY_t - CO_t \quad \ldots 3.38$$

The profit oil was split between the contractor and government:

$$PO_t = PO|C_t + PO|G_t \quad \text{... 3.39}$$

Where,

$$PO|C_t = PO(\varphi)PO_t \quad \text{... 3.40}$$

$$PO|G_t = \left(1 - PO(\varphi)\right)PO_t \quad \text{... 3.41}$$

$$PO(\varphi) = Profit\ oil\ split,\ 0 \leq PO(\varphi) \leq 1$$

The contractor's share of profit oil is taxable. The profit oil split may vary with cumulative production or dependent on the project R-Factor.

After all costs (carried forward costs inclusive) are recovered, the excess cost remaining was added to the profit oil to make up the project total oil.

$$Project\ Total\ Oil = \left((1 - CRL) \times (GR - Royalty)\right) + Excess\ ECR \quad \text{... 3.42}$$

$$Total\ Profit\ Oil\ to\ Government$$

$$= (Project\ ECR - contractor's\ ECR)$$

$$+ (Project\ Profit\ oil - contractor's\ Profit\ oil) \quad \text{... 3.43}$$

3.9 BEFORE AND AFTER INCOME TAX CASH FLOW

Performing economic evaluations without accounting for tax effects is misleading. The interest payments on debt, depreciation, depletion, and amortization expenses do influence the value and timing of the taxable income and the resulting tax payments which is the actual cash flow. These items are known as tax-deductible items. Corporate taxes may not affect all investments to the same degree. For meaning analysis, project cash flows must always be expressed on an after-tax basis, as incorporating taxes in economic evaluation may reverse the decisions based on the before-tax cash flows.

In this study, the after-tax cash flow model was the main concern as it is the premise on which most decision criteria were applied, though the before-tax cash flow model preceding it captured some of the basic tax-deductible items. In most cases, the tax-deductible items are the same with little or no modifications. In the after-tax model of the

GOG, the tax laws vary considerably from country to country as expected due to some business allowance, investment tax credits, adjustment for double taxation, and so on. Tax rate also vary with time and is in the range of 25 to 50% for most countries in the deepwater GOG like Nigeria, Chad, Ghana, Equatorial Guinea PSC (1998), Liberia, Niger, Mali, Senegal, and Sierra Leone. It is worth noting, however, that in some countries like Gabon and Cote D'Ivoire, it is the state that pays the income tax and the IOC has zero tax rate.

3.9.1 ROYALTY/TAX ECONOMIC MODEL AND ITS COMPONENTS

Generally, the treatment of cash flow for R/T systems was governed by equation 3.44 as presented by Iledare (2011):

$$NCF_t = GR_t - ROY_t - CAPEX_t - OPEX_t - BONUS_t - TAX_t - OTHER_t \quad \text{... 3.44}$$

Where:

$NCF_t = After\ tax\ net\ cash\ flow\ in\ year\ t$ $\quad ROY_t = Total\ royalties\ paid\ in\ year\ t$;

$CAPEX_t = Total\ capital\ expenditure\ in\ year\ t$ $\quad GR_t = Gross\ revenue\ in\ year\ t$

$OPEX_t = Total\ operating\ expenditure\ in\ year\ t$ $\quad BONUS_t = Bonuses\ paid\ in\ year\ t$

$TAX_t = Total\ taxes\ paid\ in\ year\ t$ $\quad OTHER_t = Other\ costs\ paid\ in\ year\ t$

Using a typical GOG R/T system as illustration, before and after income tax calculation for Ghana R/T (1997) was treated as follows:

Before tax (BTAX) model;

$$Technical\ Costs\ Allowed\ (TCA) = Depreciated\ CAPEX + OPEX \quad \text{... 3.45}$$

OPEX cost was subjected to amount of foreign expenditure that is recoverable.

$Deductible\ payments\ to\ Government = FLGT\ without\ bonuses$

There was basically no stipulated tax other than income tax that could be charged. Therefore,

$$Host\ GTake\ before\ tax = Deductible\ payments\ to\ Government + bonus \quad \text{... 3.46}$$

$$Contractor\ take\ before\ tax = GR - TCA - Host\ GTake\ before\ tax \quad \text{... 3.47}$$

After tax (ATAX) model;

$Tax\ rate = 35\%$

$Additional\ Profit\ Tax\ (APT)\ as\ attached\ in\ appendix$

$TCA = Expensed + Depreciation\ costs$ ... 3.48

$Expensed\ costs = Total\ OPEX$

$Taxable\ Income\ (TI) = GR - TCA - GTake(without\ bonuses)$ ... 3.49

$Tax = TI \times Tax\ rate$ ... 3.50

Losses was carried forward indefinitely into subsequent years. IOCs do not pay the tax, but it was paid in lieu to host government by NOC.

APT was calculated based on contractor's real Rate of Return (ROR). State APT payments are deductible from contractor's NCF in determining State APT for 2nd, 3rd, 4th, and so on.

$Host\ GTake\ after\ tax = Host\ GTake(before\ tax) + Taxes + bonuses$ ... 3.51

$Contractor\ take = GR - TCA - Host\ GTake\ after\ tax$ ... 3.52

The R/T economic model for other countries with R/T does not necessary have the same instrument specified, but generally follows the same pattern. The uniqueness of each PFS is modelled such as Ghana's APT treatment.

3.9.2 PSC ECONOMIC MODEL AND ITS COMPONENTS

The net cash flow vector of an investment is the cash received less the cash spent during a given period, usually taken as one year, over the life of the project. The after tax net cash flow associated with any PSC field in this study, in year t generally took the form presented by Iledare (2011):

$NCF_t = GR_t - ROY_t - CAPEX_t - OPEX_t - BONUS_t - PO|G_t - TAX_t - OTHER_t$ ... 3.53

Where,

$PO|G_t = Government\ profit\ oil\ in\ year\ t$

$NCF(f) = (NCF_1, NCF_2, \ldots, NCF_k)$ ... 3.54

The gross revenues in year t due to the sale of hydrocarbons was defined as

$$GR_t = g_t^o P_t^o Q_t^o + g_t^g P_t^g Q_t^g \quad \text{... 3.55}$$

Where,

$g_t^o, g_t^g = conversion\ factor\ of\ oil\ (o), gas\ (g) in\ year\ t,$

$P_t^o, P_t^g = average\ oil, gas\ wellhead\ price\ in\ year\ t,$

$Q_t^o, Q_t^g = Total\ oil, gas\ production\ in\ year\ t,$

The conversion factor depends primarily on API gravity and the sulfur content of oil, and the amount of impurities, condensate, and hydrogen sulfide of natural gas. Conversion factors are both time and field dependent. The hydrocarbon price is based on a reference benchmark expressed as a time average over a given horizon.

Taxable income was determined as a percentage of the contractor profit oil and tax loss carry forward, if applicable. Tax rates are denoted by the value $T(\varphi)$, $0 \leq T(\varphi) \leq 1$, and may be fixed or based on a sliding scale:

$$TAX_t = \begin{cases} T(\varphi)(PO|C_t - CF_t), & PO|C_t - BONUS_t - CF_t > 0 \\ 0, & PO|C_t - BONUS_t - CF_t \leq 0, \end{cases} \quad \text{... 3.56}$$

Where, $CF_t\ represents\ the\ tax\ loss\ carry\ forward\ in\ year\ t.$

Annual Take Statistics: The division of profit between contractor and government determines the take.

The total profit in year t was determined as;

$$TP_t = GR_t - TC_t \quad \text{... 3.57}$$

The contractor and government take was computed as

$$CT_t = TP_t - BONUS_t - ROY_t - PO|G_t - TAX_t \quad \text{... 3.58}$$

$$GT_t = BONUS_t + ROY_t + PO|G_t + TAX_t \quad \text{... 3.59}$$

The contractor and government take in year t, expressed in percentage terms, are defined as

$$\tau_t^c = \frac{CT_t}{TP_t} \quad \text{... 3.60}$$

$$\tau_t^g = \frac{GT_t}{TP_t} \quad \text{... 3.61}$$

Using the Nigeria proposed 2009 PIB (IAT) modelled as illustration, PSC was modeled as Before tax (BTAX) model

$$NHT\ rate = 30\%\ for\ deepwater\ and\ 50\%\ for\ others$$

$$Technical\ Costs\ Allowed\ (TCA) = CAPEX + OPEX \quad \text{... 3.62}$$

CAPEX and OPEX costs were subjected to amount of foreign expenditure that is recoverable. Special production allowances as shown in table 3.5 were also made in computing NHT tax.

$$Deductible\ payments\ to\ Government = FLGT\ without\ bonuses + Total\ profit\ oil\ to\ Government \quad \text{... 3.63}$$

Therefore,

$$Host\ GTake\ before\ tax = Deductible\ payments\ to\ Government + bonuses + NHT \quad \text{... 3.64}$$

$$Contractor\ take\ before\ tax = GR - TCA - Host\ GTake \quad \text{... 3.65}$$

Table 3.5: Special production allowances for proposed 2009 PIB (IAT)

	Onshore			Capped at
Special Production Allowances	<= 10 MMBBL	$	30.00	30%
	<= 75 MMBBL	$	12.00	30%
	<= 1000 BCF	$	1.00	30%
	Shallow water			
	<= 20 MMBBL	$	30.00	30%
	<= 150 MMBBL	$	12.00	30%
	<= 2000 BCF	$	1.00	30%
	Deepwater			
	All	$	7.00	30%
	<= 3000 BCF	$	1.00	30%

After tax (ATAX) model:

$CITA\ rate = 30\%$

$Education\ tax\ rate = 2\%$

$TCA = CAPEX + OPEX$ 3.62

$CAPEX = Exploration + Intangible\ development + Depreciation\ costs$ ... 3.66

$Taxable\ Income\ (TI) = GR - TCA - GTake(without\ bonuses)$ ... 3.67

$CITA = TI \times CITA\ rate$ ... 3.68

$Education\ taxable\ income$

$= GR - TCA + CAPEX(after\ recovered\ costs)$

$- Gtake(without\ bonuses)$ ... 3.69

$Education\ tax = Education\ taxable\ income \times Education\ tax\ rate$ ... 3.70

Unrecovered costs were carried forward indefinitely.

$Host\ GTake\ after\ tax = Host\ GTake(before\ tax) + Taxes$ ... 3.71

$Contractor\ take = GR - TCA - Host\ GTake\ after\ tax$ ... 3.72

The PSC economic model for other countries with PSC does not necessary have the same instrument specified, but generally follows the same pattern. The uniqueness of each PFS was modelled such as Nigeria 2009 proposed PIB (IAT) special production allowances and surcharge education tax.

3.10 E&P ECONOMICS AND SYSTEM MEASURES

For capital budgeting and investment decision purposes in deepwater GOG regions, measures of investment worth criteria were modeled to aid in deterministic decision analysis and objective functions in stochastic analysis performed in this study.

The following measures of profitability were imposed,

- Government take (GTake)/Contractor's take (CTake)
- Internal Rate of Return (IRR)

- Net Present Value (NPV)
- Return on Investment (ROI)/Profit Investment Ratio (PIR)
- Payout Time (POT)
- Profitability Index (PI)
- Present Value Ratio (PVR)
- Effective Royalty Rate (ERR)/Access to Gross Revenue (AGR)
- Savings Index (SI)
- Gross Rate of Return (GRR)
- Discounted Net Cash Flow
- Front Loading Index

Discounted Take Statistics: The division of net cash flow (based on the agreed fiscal regime) between the contractor and the host government are called contractor take and government take, respectively. Take varies as a function of time over the life history of a field and is best computed on a discounted cumulative basis to account for the distribution of the cash flow and the distinct manner in which the contractor and government value money. The contractor and government take computed on a cumulative discounted basis in year x, x=1,…k, was

$$PV_x(\tau^c) = \frac{PV_x(CT)}{PV_x(CT) + PV_x(GT)} \qquad \text{... 3.73}$$

$$PV_x(\tau^g) = \frac{PV_x(GT)}{PV_x(CT) + PV_x(GT)} \qquad \text{... 3.74}$$

Where,

$$PV_x(CT) = \sum_{t=1}^{x} \frac{CT}{(1 + D^c)^{t-1}}$$

$$= present\ value\ of\ contractor\ take\ through\ year\ x \qquad \text{... 3.75}$$

$$PV_x(GT) = \sum_{t=1}^{x} \frac{GT}{(1 + D^c)^{t-1}}$$

$$= present\ value\ of\ government\ take\ through\ year\ x \qquad \ldots 3.76$$

$D^c = discount\ factor\ for\ contractor$

$D^g = discount\ factor\ for\ government$

Net Present Value (NPV): NPV or simply PV at the beginning of year t of cash flow vector NCF(f) was computed as;

$$NPV(f, F) = \sum_{t=1}^{k} \frac{NCF_t}{(1 + D)^t} \qquad \ldots 3.77$$

The present value or worth of a future dollar is the dollar that would be invested today at a specified interest rate to yield that dollar at that time in the future. In general, the net present value of a project is simply the sum of the present values of individual annual net cash flows over the life time of the project, assuming end of year cash receipts.

Internal Rate Of Return (IRR): IRR of cash flow vector NCF(f) was computed as;

$$IRR(f, F) = \{D | PV(f, F) = 0\} \qquad \ldots 3.78$$

IRR is defined as the discount rate at which the NPV of a series of cash receipts and disbursement reduces to zero. It is a profitability index that is independent of the size of cash flows.

$$NPV = \sum_{t=1}^{k} \frac{NCF_t}{(1 + IRR)^t} = 0 \qquad \ldots 3.79$$

Profitability Index (PI): A PI or investment efficiency ratio normalizes the value of the project relative to the total investment and is calculated as;

$$PI(f, F) = 1 + \frac{PV(f, F)}{PV(TC)} \qquad \ldots 3.80$$

PI is a dimensionless ratio of the PV of future operating project cash flow to PV of investment. Its interpretation as the amount of discounted profit per dollar invested permits its

use for ranking projects under limited fund availability. It is an effective measure of capital efficiency.

Effective Royalty Rate (ERR): ERR measures minimum share of revenues the government will get in any given period

$$ERR_t = PO|G_t + Royalty_t \quad \text{... 3.81}$$

$PO|G$ is government profit oil under the PSC systems

ERR or royalty is the compliment of contractor access to gross revenue (AGR)

The contractor access to gross revenue (AGR) is computed as

$$AGR_t = CO_t + NPO_t \quad \text{... 3.82}$$

NPO is after tax profit oil under the PSC systems

Return on Investment (ROI): ROI also called Profit Investment Ratio (PIR) is simply a measure of net cash flow attributable to the total investments for the project. It reflects total profit or return relative to value of investment and does not reflect time pattern of cash flow.

$$ROI = \frac{\sum NCF}{\sum(investments)} \quad \text{... 3.83}$$

Payout Time (POT): POT is the time at which the cumulative cash flow discounted or not becomes positive. It is the break-even point which is the time lapse from initial investment on E&P venture until recovery of investment. All revenues received after the payout period represents profits and new capital generated from the project.

Growth Rate of Return (GRR): GRR is also called equity rate of return or modified IRR. It resolves the shortcomings of multiple rates of return and reinvestment rate assumptions. It is computed as;

$$GRR = (PI)^{1/t}(1 + D) - 1 \quad \text{... 3.84}$$

Savings Index (SI): SI is a measure of incentives to lower technical costs (OPEX or CAPEX) or keep costs down. Only the profits-based fiscal elements affect this statistic.

Front-End Loading Index (FLI): FLI highlights the spread in the discounted and undiscounted takes. A value of FLI = 0 indicates an ideal condition in which there is no front-end loading at all. The higher the FLI becomes, the more front-end loaded the fiscal regime becomes. The fiscal regime with excessive front-end loading becomes less attractive for the contractor. The FLI is given by

$$FLI = \frac{Discounted\ Government\ take}{Undiscounted\ Government\ take} - 1 \qquad \ldots 3.85$$

3.11 SIMULATION AND SENSITIVITY ANALYSIS

Finally in this model, simulation and sensitivity analysis were performed on the measures of profitability discussed above using @RISK. Simulation analysis offers means to analyst to be able to describe risk and uncertainty in form of distributions for every possible value of any random variable. Simulation can be used to analyze any system or process and the costs of analysis are minimal. Simulation methods lend itself to sensitivity analysis.

Sensitivity analysis is the amount of uncertainty in a forecast caused by model assumption and model uncertainties. Sensitivity charts show the influence each assumption has on a particular forecast output.

3.11.1 Monte Carlo Simulation

Empirical solutions of complex probability models were obtained by applying the Monte Carlo method. A Monte Carlo (MC) method is a numerical technique that involves using uniformly distributed random numbers to estimate a model behavior over large number of runs and produce a series of deterministic calculations that represent the solution for a probability model. This numerical method reduces a stochastic model to a series of deterministic calculations.

In performing the Monte Carlo simulation in this study, the general algorithm applied follows that of Smith M. B. (1970), and was as follows:

1. Generate a random number uniformly distributed on the interval 0 to 1.

2. Compute a value for one of the stochastic variables in the model.
3. Repeat steps 1 and 2 until values have been obtained for all stochastic variables.
4. Perform the model calculation, retaining the results for statistical analysis.
5. Do steps 1 through 4 until a predetermined statistical requirement has been satisfied.
6. Summarize the solutions obtained in step 4 using conventional statistical methods.

It is necessary that the random number generated meet the statistical requisites – that is, that the series be both uniformly distributed and random.

A total of ten thousand (10000) iterations in one simulation were performed on seventeen (17) basic input variables and applied to six (6) measures of profitability indicator that have both time-value of money or not, serving as the objective functions. Lognormal distribution was assigned to STOIIP, normal distribution assigned to well rate, triangular distributions was imposed on all costs including crude oil price and development costs. A total of seventeen (17) different probability distribution functions were imposed ranging from normal, lognormal, to triangular distributions. The objective functions of interest were NPV, IRR, GTake, DPO, ROI, and GRR.

3.11.2 Sensitivity Analysis

Sensitivity analysis was simultaneously performed by @RISK on all variables of interest. The usual approach to any sensitivity analysis is to hold all other aspects of the model constant and vary each other parameters to determine the influence of these changes on optimal decisions. It provides information on what may happen if forecast assumptions are varied one by one. The input parameters in forecast calculations are varied around a base value (deterministic value was used as base value). The purpose is to judge the impact of variations in variables on the base case value of profitability.

CHAPTER FOUR

4.0 ESTIMATED DETERMINISTIC RESULT

The deterministic results for the economic model developed in chapter 3 are presented in this chapter for thirteen (13) countries with twenty (20) different PFS in the GOG region. Understanding the bias among petroleum economists in subscribing to the same methodology and/or terminology in modern analysis of fiscal systems (Wright J. D., 2001), this study analyzes the fiscal system of the different countries in the Gulf of Guinea region using the following decision metrics,

- Government take (GTake)/Contractor's take (CTake)
- Internal Rate of Return (IRR)
- Net Present Value (NPV)
- Return on Investment (ROI)/Profit Investment Ratio (PIR)
- Payout Time (DPO)
- Profitability Index (PI)
- Present Value Ratio (PVR)
- Effective Royalty Rate (ERR)/Access to Gross Revenue (AGR)
- Savings Index (SI)
- Gross Rate of Return (GRR)
- Discounted Net Cash Flow
- Front Loading Index

The above profitability indicators allow various practitioners the opportunity to make decision from suitable criteria of preference. In the ensuing discussion, fiscal systems would be grouped into PSC fiscal systems and R/T fiscal systems. Analyses and comparisons would then be done on these bases and finally combined to make any inference of choice.

It is worthy to mention here that the discussion below does not intend to cast aspersion on any fiscal system(s) nor categorically classify any system(s) as best among the rest. It is of the intent to be used as a guide in making investment decision in the GOG region, bearing in mind that some other factors such as politics, environment, proven reserves, and other latent factors affect the final result in investment in any country.

4.1 Model assumptions

1. An assumed bonus of $20m was used for all fiscal regimes with specifications of negotiable signature, discovery, and prospectivity bonuses specified.
2. Training fee and Surface rental specification of Liberia was imposed on fiscal regimes with training and surface rentals specification that are negotiable.
3. A default area size of 100km^2 is used for all PFS model.
4. An abandonment cost of 1% of depreciated costs is assumed for all fiscal regimes.
5. A salvage value of $20m is also used.
6. Prevailing oil price of $70/bbl and capped at $180/bbl is imposed.
7. An escalation of 2% is imposed on the pricing for nominal real money.
8. An assumed discount rate of 12.5% is used for all discounting purposes in the model.
9. The same exploration and production phases are imposed on all PFS for comparison purposes.
10. Government participation is ignored in the economic model as a result of a 2003 World Bank study, which argues thus: "Government take as a result of equity participation by government is really a government equity return, directly paid for by government, rather than a form of government take (Johnston D., 2010)……"
11. Exploration costs assume two dry holes and one wildcat well drilled.

12. Reserve estimation using decline curve analysis are only estimates, it does not necessarily mean that estimates of remaining reserves will become closer to truth as more production data becomes value.
13. Modeling is done in years rather than in days or months.
14. The timing of future investments in this model is at the beginning of the year regardless of the problem statement. This was guided by production forecast.
15. Cash generated from the sale of oil in a given year was assumed for discounting at the middle of the year (this assumption can actually have a less noticeable effect on the NPV with steeply declining wells and moderate discount rates unlike discounting at beginning or end of year).
16. Well count is relatively stable (for production forecast).
17. Production conditions and methods are largely unchanged over the producing life, and wellbore intervention and other remedial work can be classified solely as maintenance.
18. Assumptions of per unit cost of primary product ($/bbl for example) without the proper treatment of fixed cost or costs of producing secondary products, and
19. Cost is assumed to remain as predicted and fails to evaluate changes to costs due to the introduction of new recovery mechanisms.

4.2 FIELD DEVELOPMENT INPUT

In the field development plan using exponential decline, the basic input variables are summarized in table 4.1. With the assumptions made in the input variable as seen in table 4.1, the estimated reserves calculated is 250 MMBBL as a result of the 25% recovery of STOIIP assumed. Based on the methodology described in section 3.3.1, the estimated plateau rate is 68.49 MBOPD.

Table 4.1: Oil field development input and calculated results

Input Variables				Calculated values		
STOIIP	1000.00	MMBBL		Reserves	250.00	MMBBL
Recovery	25.0	%		Max plateau rate	68.49	MBOPD
Time to plateau	4.00	Years		Plateau rate	68.49	MBOPD
Well rate	10.00	MBOPD		Build up production	50.00	MMBBL
Wells to drill	15			Plateau production	112.50	MMBBL
Minimum rate	10.00	MBOPD		Plateau ends at	8.50	Years
Discount factor	12.50	%		Decline factor	0.2440	Fraction
Average Well cost	10.00	$MM		Production life	16.39	Years
Facility size	250.00	MBOPD				
Initial Oil Price	70.00	$/bbl				
Final Oil Price	180.00	$/bbl				
Plateau ends at	65.0	% of reserves				
Plateau rate is	10.0	% of reserves annually				

This plateau rate is reached after 4 years of starting production. The build-up period as stated earlier in chapter 3 is linear with an instantaneous rate of 10000 BOPD. The plateau period is estimated to last for 4.5 years ending after 8.5 years of production. At this time, it is estimated that a total of 50 MMBBL of oil would have been produced during the 4 years of build-up and 112.5 MMBBL of oil produced during the 4.5 years of maintaining constant rate. As a result of the cumulative production after 8.5 years, the decline factor is calculated using the remaining reserves of 87.5 MMBBL. A decline rate of 0.244 is calculated in this case. The total time it will take to economically and technically produce the 250 MMBBL estimated is about 17 years. The results obtain from this development plan form part of the base case input in this economic model analysis.

4.3 BASE CASE MODEL

To perform the analysis in this work, the base case model assumed here is displayed in table 4.2 below. As stated in chapter three, the same production profile of the oil field development plan with linear build up was used for the comparison purpose of the analysis.

Table 4.2: Base case input data

Deepwater Depth	800 - 1000m	Meters		Decline rate	21.65%	Effective
Production Period	17.00	Years		Initial Oil Price	$ 70.00	
Exploration period	5	Years		Unit Technical Cost	7.82	$/bbl
Discount rate	12.50%			Unit CAPEX	6.02	$/bbl
Reserves	250	MMBBL		Unit OPEX	1.79	$/bbl
Peak prod rate	68493	BOPD		Escalation	2%	

The conservative exponential decline method is used in the typical production profile shown below.

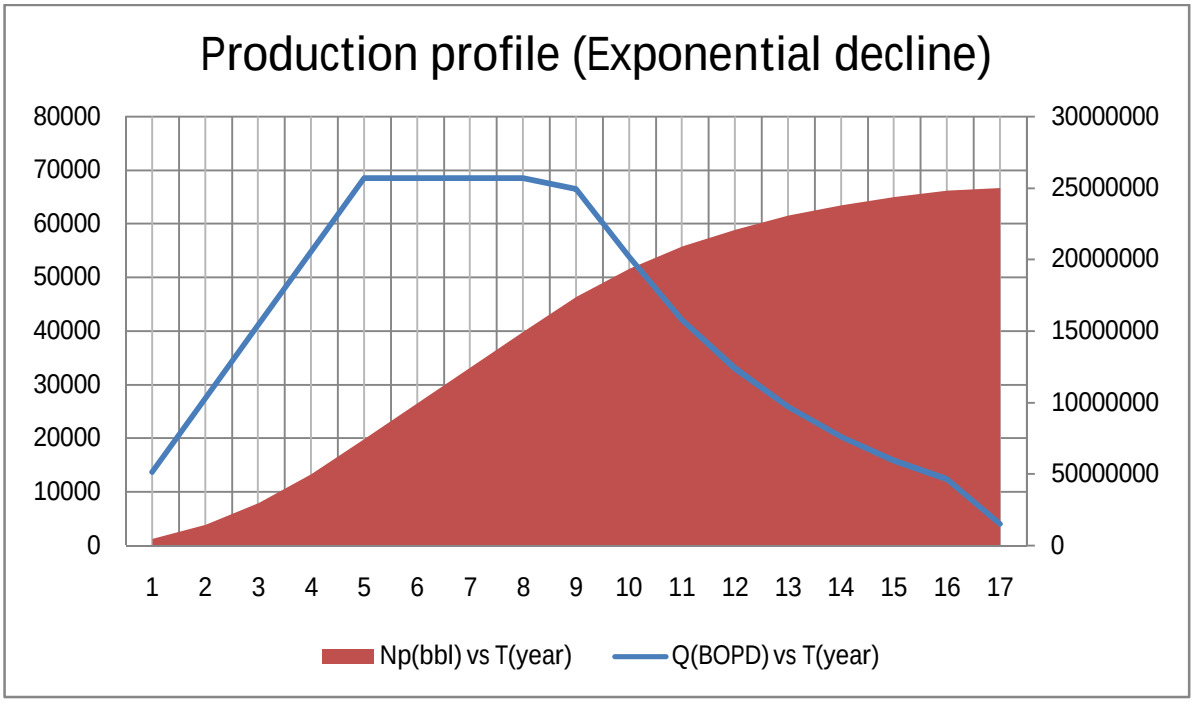


Figure 4.1: Linear exponential decline production profile with cumulative production

The same technical cost outlay is imposed for all fiscal terms discussed here with the unit CAPEX cost per barrel being $6.02 and unit OPEX cost per barrel being $1.79. A production delay of 5 years to accommodate for exploration and geological and geophysical works including facilities installation is imposed here as the base case. An initial oil price of $70 per barrel is used which is what is contemporary with an escalation of 2% but capped at $180 per barrel. The technical cost used in this model is attached in appendix A.

4.4 DECISION ANALYSIS GUIDE OF GOG FISCAL SYSTEMS BY PFS

In Analyzing the economic viability or otherwise of a venture common economic indicators often used in the industry are Net Present Value (NPV), Internal Rate of Return (IRR), Profitability Index (PI), Payout Period (DPO), the Contractor and Government take, Growth Rate of Return (GRR) and Present Value Ratio (PVR) together with decision rules. Ranking of a venture based on these indicators depends on the investors' investment preferences.

Table 4.3 Capital Budgeting Decision Rules (Iledare O. 2011)

Profitability Measure	Accept If @ r*	Reject If @ r*
NPV	>0	< 0
IRR	> r*	< r*
PI	> 1	< 1
DPO	≤ Desired	≥ Desired
PVR	>0	<0
GRR	>r*	<r*
FLI	~ 0	~ 1

Where r* = discount rate or opportunity cost of capital

As a result a country might be more attractive to an investor than the others. Each investor chooses its own Hurdle Rate (HR), a desired Payout Period (DPO) i.e. a bench mark is set to analyze each venture. The table 4.3 below gives a guide in decision making and appendix B summarizes the deterministic result of the model.

In no order, this comparative economic analysis compares the following GOG region PFS obtained from Merak (2010) documentation on fiscal regimes, except the ANGOLA PSC (1990), ANGOLA PSC (2004), and EQUATORIAL GUINEA PSC (2006) which was obtained from the internet through Google.

1. ANGOLA PSC (1990)

2. ANGOLA PSC (2004)
3. CAMEROON Rente Miniere (1995)
4. CHAD R/T (1999)
5. COTE D'IVOIRE PSC (1996)
6. COTE D'IVOIRE PSC R-Factor (1996)
7. EQUATORIAL GUINEA PSC (1998)
8. EQUATORIAL GUINEA PSC (2006)
9. GABON PSC (1997)
10. GHANA R/T (1997)
11. LIBERIA PSC (2009)
12. MALI R/T (1970)
13. NIGER R/T (1992)
14. NIGERIA JDZ PSC (2003)
15. NIGERIA PSC (1993)
16. NIGERIA PSC (2000)
17. NIGERIA PSC (2005)
18. NIGERIA R/T (2000)
19. SENEGAL R/T (2000)
20. SIERRA LEONE RT (2001)

Though the model also incorporated the proposed NIGERIA PIB (2009 IAT) redraft, it will not form part of this comparative analysis because it has not been passed into law.

The following performance analysis for the different PFS modeled is based on the deterministic result attached in appendix B.

4.4.1 PERFORMANCE OF ANGOLA PSC (1990)

Utilizing the capital budgeting decision rules presented in table 4.3 and result attached in appendix B, the NPV is greater than zero **(NPV > 0)** signifying value will be added to the company. The Internal Rate of Return **(IRR)** calculated is greater than the assumed r* (opportunity cost of capital). From appendix B, the contractor's IRR of 30% is greater than the assumed discount rate of 12.5%. This means that under this fiscal regime the investment is efficient and profitable as the interest earned from the investment is high. The Profitability

Index of 1.75 is greater than one **(PI > 1),** this implies more money is made than invested on the project. Hence the capital is effective. With a PVR of 0.75 greater than zero **(PVR > 0)** the investment is profitable. The GRR of 15.41% is greater than the assumed discount rate of 12.5% **(GRR > r*)** meaning the investment is yielding. The fiscal regime's ERR of 30.29% is greater than the world's average ERR of 20%. Investment under this fiscal regime is profitable. The ERR compliments the AGR, the AGR of 69.71% measures the maximum share of gross revenue the government has access to. The saving Index of 22.21% signifies that 22cents on every dollar is saved, which might not discourage gold plating. Percentage profit of 20.14% is going to the contractor in this fiscal regime. The higher the contractor's take the more result the contractor gets from the agreement. Depending on the IOC or contractor, a desired Payout Period is chosen. At this time, the venture is expected to start yielding profits. In this fiscal regime the DPO is 8.12 years.

4.4.2 PERFORMANCE OF ANGOLA PSC (2004) PSA

From appendix B, the NPV for this venture is $791 million which is greater than zero **(NPV > 0)** and means the company is making profits because value is been added. The contractor's IRR of 35% is greater than the assumed discounted rate of 12.50% (IRR > 12.50%). This means the investment is doing well and there is yield for every dollar invested under the fiscal regime. The higher the IRR the more profitable the venture is for the investor. A Profitability Index **(PI)** of 1.85 which is greater than 1 **(PI > 1)** was achieved meaning profit is made from the investment. The PVR is greater than zero **(PVR > 0)**; a value of 0.85 was obtained. This means value is been added to the company. The GRR is greater than the assumed discounted rate of 12.50% **(GRR > r*)** signifying the investment is doing well. An ERR of 30.29% greater than the world's average of 20.00% is obtained. This value is approximately equal to 30% the value for PSC systems. Therefore, there will be no zero field development thresholds. The ERR compliments the AGR, the AGR of 69.71% measures the

maximum share or gross revenue the government have access to. The saving Index of 22% signifies that 22cents on every dollar is saved. Percentage profit of 21% is going to the contractor in this fiscal regime. At this time, the venture is expected to start yielding profits. In this fiscal regime the DPO is 8.21 years.

4.4.3 PERFORMANCE OF CAMEROON RENTE MINIERE (1995)

The value of owning the venture at the moment in time is $1.2 billion as seen in appendix B. This NPV is greater than zero **(NPV>0)** which adds value to the company. The IRR calculated is greater than the assumed r* (opportunity cost of capital). In this fiscal regime the contractor's IRR of 34% is greater than the assumed discount rate of 12.5% meaning investment is efficient and profitable as the interest earned from the investment is high. The Profitability Index of 2.28 is greater than one **(PI > 1),** hence the capital is effective on every dollar invested. With a PVR of 1.28 greater than zero **(PVR > 0)** the investment is profitable. The GRR of 16.79% is greater than the assumed discount rate of 12.5% **(GRR > r*)** meaning the investment is yielding. The fiscal regime's ERR of 28.81% is greater than the world's average ERR of 20%. Investment under this fiscal regime is profitable. The ERR compliments the AGR, the AGR of 71% measures the maximum share of gross revenue the government has access to**.** The saving Index of 42.50% is quite high signifying that about 42cents on every dollar is saved. Percentage profit of 28.86% is going to the contractor in this fiscal regime. In this fiscal regime the DPO is 9.46 years.

4.4.4 PERFORMANCE OF CHAD R/T (1999)

$1.6 billion is the NPV achieved in this fiscal system which is greater than zero **(NPV > 0)** as shown in appendix B**.** This means the company is making profits because value is being added. The contractor's IRR of 31.5% is greater than the assumed discounted rate of 12.50% (IRR > 12.50%) meaning investment is doing well and there is yield for every dollar invested under this fiscal regime. The higher the IRR the more profitable the venture is for

the contractor or IOC. A Profitability Index **(PI)** of 2.76 which is greater than 1 **(PI > 1)** was got meaning profit is made from the investment. The PVR is greater than zero **(PVR > 0)**; a value of 1.76 was achieved. The GRR of 17.80% is greater than the assumed discounted rate of 12.50% **(GRR > r*)** signifying the investment is doing well. An ERR of 12.50% less than the world's average of 20.00% is obtained. This value is greater than 10% the ERR value for world R/T systems. Therefore, there will be no zero field development thresholds. The AGR of 87.50% measures the maximum share of gross revenue government has access to. The saving Index of 50.00% signifies that 50cents on every dollar will be saved. Percentage profit of 41% is going to the contractor in this fiscal regime. At this time, the venture is expected to start yielding profits after 9.49 years.

4.4.5 PERFORMANCE OF COTE D'IVOIRE PSC (1996)

A value of $240 million was obtained as the NPV under this fiscal regime which is greater than zero **(NPV > 0)**. This represents the value of owning the venture at the moment in time. Appendix B also shows IRR of 17% which is the measure of the efficiency of the investment, which is greater than the assumed discounted rate of 12.50%. The PI of 1.26 is greater than 1 **(PI > 1),** though slightly greater than one the investment is still profitable. The higher the PI the more profitable is the investment. A PVR of 0.24 is obtained which is greater than zero **(PVR > 0).** A GRR of 13.7% was obtained, which is slightly greater than the assumed discounted rate of 12.50%. ERR of 52.42% which is greater than world's average of 20% and well above the 30% approximate ERR value for PSC systems was obtained. The AGR of 47.58% measures the maximum share of gross revenue the government has access to. A Saving Index of 22.27% was achieved, meaning 22cents is saved on every dollar invested. The contractor takes 12.40% as profit from this fiscal regime and the DPO from this fiscal regime is 7.74 years signifying how early in years the investment will break even, just after 2.74 years of production after 5 years production delay.

4.4.6 PERFORMANCE OF COTE D'IVOIRE PSC R-FACTOR (1996)

Appendix B shows NPV of $1.2 billion which is greater than zero **(NPV>0)** signifying value added to the company is obtained. The Internal Rate of Return **(IRR)** calculated is greater than the assumed r*. In this PFS the contractor's IRR is 29% which is greater than the assumed discount rate of 12.5%. This means that under this fiscal regime the investment is efficient and profitable as the interest earned from the investment is high. The Profitability Index of 2.32 is greater than one **(PI > 1),** implying more money is made than invested on the project hence, the capital is effective. On every dollar invested a discounted profit of 2.32 is made. With a PVR of 1.32 greater than zero **(PVR > 0)** the investment is profitable. The GRR of 16.9% is greater than the assumed discount rate of 12.5% **(GRR > r*)** meaning the investment is yielding. The fiscal regime's ERR of 39.87% is greater than the world's average ERR of 20% and also greater than 30% ERR value associated with PSC systems. Investment under this fiscal regime is profitable. The AGR of 60.13% measures the maximum share of gross revenue the government has access to. The saving Index of 36.82% signifies about 37cents on every dollar is saved. Percentage profit of 33.28% is going to the contractor in this fiscal regime and the DPO from this fiscal regime is 7.74 years signifying how early in years the investment will break even, just after 2.74 years of production after 5 years production delay.

4.4.7 PERFORMANCE OF EQUATORIAL GUINEA PSC (1998)

NPV of $2.45 billion was obtained which is greater than zero **(NPV> 0).** This means the company is making profits because value is being added. The contractor's IRR of 45.9% is well above the assumed discounted rate of 12.50% (IRR > 12.50%). This means the investment is doing well and there is yield on every dollar invested under the fiscal regime. A PI of 3.65 which is greater than 1 **(PI > 1)** is obtained meaning profit is made from the investment. The PVR is greater than zero **(PVR > 0)**; a value of 2.65 was achieved. This

means value is being added to the company. The GRR of 19.32% is greater than the assumed discounted rate of 12.50% **(GRR > r*)** signifying the investment is doing well. An ERR of 16.02% which is less than the world's average of 20.00% is obtained. This value is equally less than the 30% the ERR value for PSC systems. The ERR compliments the AGR, the AGR of 83.98% measures the maximum share of gross revenue the contractor has access to. The saving Index of 60% signifies that 60cents on every dollar is saved and this will greatly discourage gold plating. Percentage profit of 53.08% is going to the contractor in this fiscal regime. DPO is 8.12 years.

4.4.8 PERFORMANCE OF EQUATORIAL GUINEA PSC (2006)

A value of $1.92 billion is obtained as the NPV under this fiscal regime as seen in appendix B which is greater than zero **(NPV > 0)**. $1.92 billion represents the value of owning the venture at the moment in time. IRR of 39.44% is a measure of the efficiency of the investment, which is greater than the assumed discounted rate of 12.50%. This shows that the investment is efficient and profitable in this fiscal regime. The PI of 3.07 is greater than 1 **(PI > 1),** meaning the investment is quite profitable. The higher the PI the more profitable is the investment. A PVR of 2.07 is obtained which is greater than zero **(PVR > 0).** A GRR of 18.4% was derived, which is greater than the assumed discounted rate of 12.50%. The ERR 18.06% is approximately equal to the world's average of 20% but less than the 30% approximate ERR value for PSC systems. The AGR of 81.94% measures the maximum share of gross revenue the government has access to. A savings index of 52% is obtained, meaning 52cents is saved on every dollar invested which will discourage gold plating. The contractor takes 43.22% as profit from this fiscal regime which is high. The DPO from this fiscal regime is 7.72 years; this signifies the numbers of years when the investment will start yielding profits after investment cost have been recovered.

4.4.9 PERFORMANCE OF GABON PSC (1997)

In appendix B the NPV for this venture is $762 million which is greater than zero **(NPV> 0)** and means the company is making profits because value is being added. The contractor's IRR of 24.3% is greater than the assumed discounted rate of 12.50% (IRR > 12.50%). This means the investment is doing well and there is yield for every dollar invested under the fiscal regime. The higher the IRR the more profitable the venture is for the contractor or IOC. A Profitability Index **(PI)** of 1.82 which is greater than 1 **(PI > 1)** is got meaning profit is made from the investment. The PVR is greater than zero **(PVR > 0)**; a value of 0.82 was achieved. This means value is being added to the company. The GRR is greater than the assumed discounted rate of 12.50% **(GRR > r*)** signifying the investment is doing well. A value of 15.6% was obtained. An ERR of 41.38% greater than the world's average of 20.00% is obtained. This value is also greater than 30% the value for world's average PSC systems. Therefore, there would not be zero field development thresholds. The AGR of 58.62% measures the maximum share or gross revenue the government has access to. The saving index of 29.82% signifies that 29cents on every dollar is saved. A percentage profit of 23.64% is going to the contractor in this fiscal regime. Depending on the IOC or contractor, a desired Payout Period is chosen. At this time, the venture is expected to start yielding profits after 7.85 years.

4.4.10 PERFORMANCE OF GHANA R/T (1997)

Appendix B shows that the NPV is greater than zero **(NPV>0)** signifying value will be added to the company. The value $1.8 billion means the value of owning the venture at the moment in time. The Internal Rate of Return **(IRR)** calculated is greater than the assumed r*. In this PFS, the contractor's IRR of 49.49% is greater than the assumed discount rate of 12.5%. This means that under this fiscal regime the investment is efficient and profitable as the interest earned from the investment is high. The Profitability Index of 2.93 is greater than

one **(PI > 1),** this implies more money is made than invested on the project. Hence the capital is effective; on every dollar invested a discounted profit of 2.93 is made. With a PVR of 1.93 greater than zero **(PVR > 0)** the investment is profitable. The GRR of 18.13% is greater than the assumed discount rate of 12.5% **(GRR > r*)** meaning the investment is yielding. The fiscal regime's ERR of 10.47% is approximately equal to 10% which is the approximate value of ERR for R/T systems. The AGR of 89.53% measures the maximum share of gross revenue the government has access to**.** The savings index of 49.15% is quite high signifying that 49cents on every dollar is saved. A contractor take of 39.1% is obtained signifying the profit the contractor receives from the agreement. A DPO of 8.54 is obtained in this fiscal regime.

4.4.11 PERFORMANCE OF LIBERIA PSC (2009)

NPV greater than zero **(NPV>0)** signifying value being added to the company is obtained in this fiscal regime as shown in appendix B. The value $1.72 billion means the value of owning the venture at the moment in time. The Internal Rate of Return **(IRR)** calculated is greater than the assumed r*. In this PFS, the contractor's IRR of 51.04% is greater than the assumed discount rate of 12.5% meaning, under this fiscal regime the investment is efficient and profitable as the interest earned from the investment is high. The Profitability Index of 2.86 is greater than one **(PI > 1),** this implies more money is made than invested on the project. Hence the capital is effective; on every dollar invested a discounted profit of 2.86 is made. With a PVR of 1.86 greater than zero **(PVR > 0)** the investment is profitable. The GRR of 18.00% is greater than the assumed discount rate of 12.5% **(GRR > r*)** meaning the investment is yielding. The fiscal regime's ERR of 22.50% is greater than the world's average ERR of 20%. The AGR of 77.50% measures the maximum share of gross revenue government has access to**.** The saving index of 42.25% is quite high signifying that 42cents on every dollar is saved. Percentage profit of 36.39% is going to the contractor

in this fiscal regime. The higher the contractor's take the more result the contractor gets from the agreement. In this fiscal regime the DPO is 8.37 years.

4.4.12 PERFORMANCE OF MALI R/T (1970)

Appendix B shows a value of $1.13 billion is obtained as the NPV under this fiscal regime which is greater than zero **(NPV > 0)**. $1.13 billion represents the value of owning the venture at the moment in time. IRR of 31.60% is a measure of the efficiency of the investment, which is greater than the assumed discounted rate of 12.50%. This shows that the investment is efficient and profitable in the current fiscal regime. The PI of 2.22 is greater than 1 **(PI > 1),** meaning the investment is quite profitable. The higher the PI the more profitable is the investment. A PVR of 1.22 is obtained which is greater than zero **(PVR > 0).** A GRR of 16.66% is obtained, which is greater than the assumed discounted rate of 12.50%. The ERR 12.50% is approximately equal to the 10% approximate ERR value for world's R/T systems. The AGR of 87.50% measures the maximum share or gross revenue the government has access to. A Saving Index of 50.00% is achieved, meaning 50cents is saved on every dollar invested. The contractor takes 40.37% as profit from this fiscal regime which is high. The DPO from this fiscal regime is 8.14 years; this signifies the numbers of years when the investment will start yielding profits after investment cost have been recovered.

4.4.13 PERFORMANCE OF NIGER R/T (1992)

NPV of $2.1 billion is achieved which is greater than zero **(NPV> 0)** meaning the IOC is making profits because value is being added. The contractor's IRR of 44.61% as seen in appendix B is well above the assumed discounted rate of 12.50% (IRR > 12.50%). This means the investment is doing well and there is yield on every dollar invested under the fiscal regime. The higher the IRR the more profitable the venture is for the contractor or IOC. A Profitability Index **(PI)** of 3.28 which is greater than 1 **(PI > 1)** is obtained meaning profit is made from the investment. The PVR value of 2.28 which is greater than zero **(PVR > 0)** is

obtained. The GRR of 18.73% is greater than the assumed discounted rate of 12.50% **(GRR > r*)** signifying the investment is doing well. The ERR 12.50% is approximately equal to the 10% approximate ERR value for world's R/T systems. The AGR of 87.50% measures the maximum share or gross revenue the government has access to. A Saving Index of 55.00% is got meaning 55cents is saved on every dollar invested. The contractor takes 47.38% as profit from this fiscal regime which is high. The DPO from this fiscal regime is 8.57 years; this signifies the numbers of years when the investment will start yielding profits after investment cost have been recovered.

4.4.14 PERFORMANCE OF NIGERIA JDZ PSC (2003)

From appendix B, the NPV is greater than zero **(NPV>0)** signifying value will be added to the company. The value $334 millions means the value of owning the project or venture at the moment in time. The Internal Rate of Return **(IRR)** calculated is greater than the assumed r*. In this fiscal regime the contractor's IRR of 20.27% is greater than the assumed discount rate of 12.5%. This means that under this fiscal regime the investment is efficient and profitable as the interest earned from the investment is high. The Profitability Index of 1.36 is greater than one **(PI > 1),** this implies more money is made than invested on the project. On every dollar invested a discounted profit of 1.36 is made. The PVR calculated is 0.36 under this fiscal regime. The GRR of 14.09% is greater than the assumed discount rate of 12.5% **(GRR > r*)** meaning the investment is yielding. The fiscal regime's ERR of 16.78% is less than the world's average ERR of 20% and less than 30% ERR value associated with PSC systems. The AGR of 83.22% measures the maximum share of gross revenue the government has access to. The savings index of 22.02% signifies about 22cents on every dollar invested is saved. Percentage profit of 11.87% is going to the contractor in this fiscal regime. Depending on the IOC or contractor, a desired payout period is chosen. At

this time, the venture is expected to start yielding profits. In this fiscal regime the DPO is 7.85 years.

4.4.15 PERFORMANCE OF NIGERIA PSC (1993)

The calculated NPV as shown in appendix B produced a value of $1.4 billion which is greater than zero **(NPV > 0),** therefore value is been added to the company. The Internal Rate of Return **(IRR)** calculated is greater than the assumed r* (opportunity cost of capital). In this PFS the contractor's IRR of 31.67% is greater than the assumed discount rate of 12.5%. This means that under this fiscal regime the investment is efficient and profitable as the interest earned from the investment is high. The Profitability Index of 2.51 is greater than one **(PI > 1),** this implies more money is made than invested on the project. Hence the capital is effective; on every dollar invested a discounted profit of 2.51 is made. With a PVR of 1.51 greater than zero **(PVR > 0)** the investment is profitable. The GRR of 17.31% is greater than the assumed discount rate of 12.5% **(GRR > r*)** meaning the investment is yielding. The fiscal regime's ERR of 17.9% is approximately the world's average of 20% but less than 30% associated with world's PSC systems. The AGR of 82.10% measures the maximum share of gross revenue the government has access to**.** The savings index of 39.20% is quite high signifying that 39cents on every dollar is saved. A contractor take of 35.82% is obtained signifying the profit the contractor receives from the agreement. A DPO of 7.99 is obtained in this fiscal regime.

4.4.16 PERFORMANCE OF NIGERIA PSC (2000)

A value of $1.16 billion is obtained as the NPV under this fiscal regime which is greater than zero **(NPV > 0)**. $1.16 billion represents the value of owning the venture at the moment in time. IRR of 28.9% is a measure of the investment's efficiency which is greater than the assumed discounted rate of 12.50%. This shows that the investment is efficient and profitable in the current fiscal regime. The PI of 2.26 is greater than 1 **(PI > 1),** meaning the

investment is quite profitable. The higher the PI the more profitable is the investment. A PVR of 1.26 is obtained which is greater than zero **(PVR > 0).** A GRR of 16.75% is achieved, which is greater than the assumed discounted rate of 12.50%. The fiscal regime's ERR of 22.25% is approximately world's average of 20% but less than the value of 30% associated with PSC systems. The AGR of 77.75% measures the maximum share of gross revenue the government has access to. A saving index of 34.30% is obtained meaning 34cents is saved on every dollar invested. The contractor takes 31.36% as profit from this fiscal regime. The DPO from this fiscal regime is 8.05 years; this signifies the numbers of years when the investment will start yielding profits after investment cost have been recovered.

4.4.17 PERFORMANCE OF NIGERIA PSC (2005)

NPV of $12.37 million is obtained which is greater than zero **(NPV> 0).** This means the company is making profits because value is been added. The contractor's IRR of 12.76% is very close to the assumed discounted rate of 12.50% (IRR > 12.50%). This means the investment is not doing too well and there is low yield on every dollar invested under this fiscal regime. The higher the IRR the more profitable the venture is for the contractor or IOC. A Profitability Index **(PI)** of 1.01 which is approximately 1 is got meaning profit is not being made from the investment. The GRR of 12.57% is approximately the assumed discounted rate of 12.50% signifying the investment is not doing well. The ERR obtained of 26.85% is greater than the world's average of 20% but less than the approximate value of 30% associated with PSC systems. A Saving Index of 33.95% is achieved, meaning 34cents is saved on every dollar invested. The contractor takes 8.37% as profit from this fiscal regime which is not high. The DPO from this fiscal regime is 8.41 years.

4.4.18 PERFORMANCE OF NIGERIA R/T (2000)

The NPV for this venture is $271 million which is greater than zero **(NPV> 0)** and means value is being added to the company. The contractor's IRR of 19.43% is greater than the assumed discounted rate of 12.50% (IRR > 12.50%). This means the investment is doing well and there is yield for every dollar invested under this fiscal regime. A Profitability Index **(PI)** of 1.29 is got which is greater than 1 **(PI > 1)**. The PVR is greater than zero **(PVR > 0)**; a value of 0.28 is obtained. The GRR is greater than the assumed discounted rate of 12.50% **(GRR > r*)** signifying the investment is doing well. ERR of 16.67% approximately equal to the world's average of 20.00% is obtained. This value is above the 10% value associated with world's R/T system. The ERR compliments the AGR, the AGR of 83.33% measures the maximum share or gross revenue the government has access to. The saving Index of 14.70% signifies 14cents on every dollar is saved. Percentage profit of 10.37% is going to the contractor in this fiscal regime. The higher the contractor's take the more result the contractor gets from the agreement. In this fiscal regime the DPO is 10.77 years.

4.4.19 PERFORMANCE OF SENEGAL R/T (2000)

The NPV value of $2.35 billion means the value of owning the venture at the moment in time is greater than zero **(NPV>0)**. The Internal Rate of Return **(IRR)** calculated is greater than the assumed r*. In this fiscal regime the contractor's IRR of 47.61% is greater than the assumed discount rate of 12.5%. This means that under this fiscal regime the investment is efficient and profitable as the interest earned from the investment is high. The Profitability Index of 3.55 is greater than one **(PI > 1),** implying more money is made than invested on the project. Hence the capital is effective; on every dollar invested a discounted profit of 3.54 is made. With a PVR of 2.54 greater than zero **(PVR > 0)** the investment is profitable. The GRR of 19.15% is greater than the assumed discount rate of 12.5% **(GRR > r*)** meaning the investment is yielding. The fiscal regime's ERR of 7.65% is less than 10% which is the

approximate value of ERR for world's R/T systems. The AGR of 92.35% measures the maximum share of gross revenue the government has access to**.** The saving Index of 58.50% is quite high signifying that 58cents on every dollar is saved. A contractor take of 52.78% is obtained signifying the profit the contractor receives from the agreement. A DPO of 8.56 years is obtained in this fiscal regime.

4.4.20 PERFORMANCE OF SIERRA LEONE R/T (2001)

NPV of $2.44 billion is achieved which is greater than zero **(NPV> 0)** meaning the company is making profits because value is been added. The contractor's IRR of 38.55% is well above the assumed discounted rate of 12.50% (IRR > 12.50%). This means the investment is doing well and there is yield on every dollar invested under the fiscal regime. The higher the IRR the more profitable the venture is for the investor. A Profitability Index **(PI)** of 3.63 which is greater than 1 **(PI > 1)** is obtained meaning profit is made from the investment. The PVR is greater than zero **(PVR > 0)**; a value of 2.63 is derived. This means value is being added to the company. The GRR of 19.29% is greater than the assumed discounted rate of 12.50% **(GRR > r*)** signifying the investment is doing well. The ERR of 6.50% is less than the 10% approximate ERR value for world's R/T systems. The AGR of 93.50% measures the maximum share of gross revenue the government has access to. A Saving Index of 63.00% was gotten, meaning 63cents is saved on every dollar invested. The contractor takes 57.03% as profit from this fiscal regime which is high. The higher the contractor's take the more result the contractor gets. The DPO from this fiscal regime is 8.43 years; this signifies the numbers of years when the investment will start yielding profits after investment costs have been recovered.

4.5 COMPARATIVE MEASURES OF INVESTMENT WORTH IN GOG REGION

The objective of the IOC is to maximize shareholders value, which depends on the ability of the IOC to maximize profit. The choice between two cash flow streams of equal risk is determined such that the project with highest profit and earlier returns is preferred. Thus, finding and producing petroleum is just a strategy of an E&P firm for the purpose of creating wealth through profit maximization.

Still using the profitability indicators mentioned in section 4.0 and the base case of section 4.3, comparative analysis of the different PFS summarized in section 4.4 will be done in this section. The effects of fiscal instruments in the PFS would be highlighted and reasons for variations would also be discussed in this section. The intent is not to cast aspersion on any fiscal system, but to serve as a guide in investment decisions in the GOG region.

4.5.1 GOVERNMENT TAKES (GTake) ANALYSIS

According to Daniel and David Johnston (2010), the four main means by which governments extract rent include (1) signature bonuses, (2) royalties, (3) profits-based mechanisms, and (4) government participation. But according to assumption number ten (10) in section 4.1 deduced from the 2003 World Bank survey, it can be concluded that government main rent extraction means that make up its take are;

a. Front loaded take
b. Profit oil, and
c. Taxes.

The front-end loaded take comprises mainly the signature bonuses and royalties mentioned by Johnston. The profit-based mechanism is the profit oil, while taxes make up the final portion. Table 4.4 below summarizes the undiscounted GTake and Government Net Cash Flow.

Table 4.4 below clearly points out the dynamics of fiscal systems and why economic models are actually needed to ascertain the effects of fiscal systems. As seen in the table, an increase in percentage government take does not necessarily mean a proportional increase in the net cash flow the government gets. It is actually a function of the intricacies embedded in the fiscal terms and their interpretation, methodology, and applications.

As can be seen in table 4.4 an undiscounted GTake of 79.86% for Angola PSC (1990) yielded a government net cash flow of $14.33 billion. With the Angola PSC (2004) fiscal terms, an undiscounted GTake of 79.28% is achieved which is a lower GTake compared to 1990, but the net cash flow to government increased to about $14.52 billion from $14.33 billion in 1990. Using GTake as only yardstick might be misleading to both government and investors. An investor might be scared with the high GTake statistics not knowing it really does not translate to a larger pie to the government as seen in Angola above, while the government might think they are actually improving their fiscal terms and achieving their objectives not knowing they are scaring investors and are earning less. A comparison of effects between Angola PSC (1990) and Gabon PSC (1997) shows a 3.5% change from Gabon's 76.36% to Angola's 79.86% GTake, but a 4.8% change from Angola's $14.3 billion to Gabon's $15 billion.

However, comparing Nigeria PSC (1993) and Nigeria PSC (2005) shows another interesting ideology which could culminate in designing fiscal systems. In 1993, GTake was 64.18% and NCF was $12.75 billion, and they rose to 91.63% and $27.3 billion in 2005. This is an increase of about 41% in GTake and 115% in NCF. This statistics compared to Nigeria proved reserves rising from a modest 0.184 billion barrels in 1958 to 25.93 billion barrels (NNPC, 2008) in 2000 gives a guide as to how to progressively design a fiscal system that would benefit the nation at large. The low GTake and NCF of 1993 led to much petroleum

activities in the nation and discovery of new reserves, and in 2005 the nation decides to reap what it has sown earlier in the increased proven reserves.

For the R/T fiscal systems, table 4.5 above summarizes the result. In table 4.5, it can be inferred that the same logical dynamism seen with the PSC systems of table 4.4 is also seen with R/T systems. Despite having a higher GTake of 59.55% for Mali R/T (1970) over Niger, Senegal, and Sierra Leone R/T systems, government NCF for Mali was still lowest.

Table 4.4: PSC undiscounted GTake, CTake and Govt. NCF with reserves estimate

KEY	COUNTRIES	Undiscounted GTake	Undiscounted CTake	GOVT NCF ($MM)	Proved Reserves (Bbbl)
1	ANGOLA PSC (1990)	79.86%	20.14%	$ 14,327.90	< 12.2
2	ANGOLA PSC (2004) PSA	79.28%	20.72%	$ 14,519.11	12.2
3	COTE D'IVOIRE PSC (1996)	87.60%	12.40%	$ 17,219.87	0.1
4	COTE D'IVOIRE PSC R-Factor (1996)	66.71%	33.29%	$ 13,114.08	0.1
5	EQUATORIAL GUINEA PSC (1998)	47.02%	52.98%	$ 9,523.39	1.78
6	EQUATORIAL GUINEA PSC (2006)	56.88%	43.12%	$ 11,501.76	1.78
7	GABON PSC (1997)	76.36%	23.64%	$ 15,011.08	2
8	LIBERIA PSC (2009)	63.61%	36.39%	$ 12,749.75	-
9	NIGERIA JDZ PSC (2003)	88.13%	11.87%	$ 17,479.84	37.2
10	NIGERIA PSC (1993)	64.18%	35.82%	$ 12,708.51	< 25.93
11	NIGERIA PSC (2000)	68.64%	31.36%	$ 13,590.13	25.93
12	NIGERIA PSC (2005)	91.63%	8.37%	$ 27,277.11	37.2

Table 4.5: R/T undiscounted GTake, CTake, and Govt. NCF

KEY	COUNTRIES	Undiscounted GTake	Undiscounted CTake	GOVT NCF ($MM)
1	CAMEROON Rente Miniere (1995)	71.12%	28.88%	$ 14,336.96
2	CHAD R/T (1999)	59.09%	40.91%	$ 12,178.70
3	GHANA R/T (1997)	60.90%	39.10%	$ 12,270.93
4	MALI R/T (1970)	59.63%	40.37%	$ 8,486.50
5	NIGER R/T (1992)	52.62%	47.38%	$ 10,606.21
6	NIGERIA R/T (2000)	89.63%	10.37%	$ 17,975.33
7	SENEGAL R/T (2000)	47.22%	52.78%	$ 9,517.94
8	SIERRA LEONE RT (2001)	42.97%	57.03%	$ 8,685.92

Beside the Mali variation, table 4.5 shows a consistency that indicates that GTake is directly proportional to NCF. Nigeria R/T (2000) has the highest GTake and corresponding NCF, followed by Cameroon, Ghana, Chad, Niger, Senegal, and Sierra Leone in that order.

4.5.2 DISCOUNTED CASH FLOW APPROACHES

Discounted cash flow profitability indicators are measures of investment worth that considers time value of money. These economic metrics include NPV, IRR, and GRR, discounted PI, and discounted payout period (DPO). Literally the Net Present Value (NPV) signifies the cost of owning a business venture at the moment in time. It is the value of a cash flow stream computed using a specified discount rate. It is the most popular petroleum evaluation criterion. Higher NPV denotes the value of an investment measured in today's dollar is higher. Often a venture with high NPV also has higher IRR but not in all cases as is noted from the fiscal systems. At one discount rate a venture might have a high NPV and IRR at other discount rates it might give a lower NPV. Some investments can even have multiple IRR. Therefore, it is advisable in measuring profitability of IRR to be used in conjunction with other economic indicators such as NPV and GRR.

The internal rate of return (IRR) means the interest rate earned from investment. It is the interest rate that makes the Net Present Value of the Net revenue equal to the Net Present Value of the investment. It incorporates the time value of money and tells the efficiency of a dollar invested. Higher IRR gives higher return on investment. Typically IRR should be compared with bank's interest rate. This is the guiding basis for the discount factor of 12.5% used in this economic model analysis. On the average the bank interest is around 12% for Nigeria and 10.52% for Ghana. In most cases, it is also noted that investment with higher NPV also has higher IRR and corresponding higher ROI, this is the general trend also observed in this case for both PSC and R/T fiscal systems.

For clarity and to avoid clumsiness in the charts plotted, the abscissa (x-axis) in the charts are numbered and the key to these numbers are shown in table 4.6a for PSCs and table 4.6b for R/Ts fiscal systems.

Table 4.6a: Key/Legend to PSCs abscissa for figures 4.2, 4.4, 4.6, and 4.8

KEY	PSC fiscal systems
1	ANGOLA PSC (1990)
2	ANGOLA PSC (2004) PSA
3	COTE D'IVOIRE PSC (1996)
4	COTE D'IVOIRE PSC R-Factor (1996)
5	EQUATORIAL GUINEA PSC (1998)
6	EQUATORIAL GUINEA PSC (2006)
7	GABON PSC (1997)
8	LIBERIA PSC (2009)
9	NIGERIA JDZ PSC (2003)
10	NIGERIA PSC (1993)
11	NIGERIA PSC (2000)
12	NIGERIA PSC (2005)

Table 4.6b: Key/Legend to R/Ts abscissa for figures 4.3, 4.5, 4.7, and 4.9

KEY	R/T fiscal systems
1	CAMEROON Rente Miniere (1995)
2	CHAD R/T (1999)
3	GHANA R/T (1997)
4	MALI R/T (1970)
5	NIGER R/T (1992)
6	NIGERIA R/T (2000)
7	SENEGAL R/T (2000)
8	SIERRA LEONE RT (2001)

The few deviations observed could be attributed to the treatment of costs in the fiscal regime. Liberia with an IRR of about 51% did not result to a higher NPV over Equatorial Guinea with IRR of about 46% because tangible development cost was depreciated straight line for 6 years in Equatorial Guinea (1998) whereas tangible fixed asset was depreciated over 15 years period straight line in Liberia.

Table 4.7: PSCs discounted cash flow economic metrics

KEY	COUNTRIES	IRR	GRR	NPV ($MM)	PI	DPO (years)
1	ANGOLA PSC (1990)	30.07%	15.41%	$ 697.24	1.75	8.12
2	ANGOLA PSC (2004) PSA	35.04%	15.70%	$ 790.97	1.85	8.21
3	COTE D'IVOIRE PSC (1996)	17.39%	13.69%	$ 240.83	1.26	7.74
4	COTE D'IVOIRE PSC R-Factor (1996)	29.11%	16.88%	$ 1,221.00	2.32	7.74
5	EQUATORIAL GUINEA PSC (1998)	45.88%	19.32%	$ 2,455.62	3.65	8.12
6	EQUATORIAL GUINEA PSC (2006)	39.44%	18.39%	$ 1,920.58	3.07	8.76
7	GABON PSC (1997)	24.26%	15.61%	$ 762.05	1.82	7.85
8	LIBERIA PSC (2009)	51.04%	18.00%	$ 1,721.47	2.86	8.37
9	NIGERIA JDZ PSC (2003)	20.27%	14.09%	$ 334.10	1.36	7.85
10	NIGERIA PSC (1993)	31.67%	17.31%	$ 1,399.40	2.51	7.99
11	NIGERIA PSC (2000)	28.90%	16.75%	$ 1,165.52	2.26	8.05
12	NIGERIA PSC (2005)	12.76%	12.57%	$ 12.37	1.01	8.41

Table 4.7 above summarizes economic metrics with time-value of money for PSCs. For Nigeria, the conventional scenario is seen as typically higher IRR is directly proportional to NPV. This is so because of similar cost treatment of 5 years straight line depreciation of tangible development costs. This is also seen between Angola PSC (1990) with IRR of about 30% and Angola PSC (2004) with IRR of about 35%.

The same analogy is observed from R/T fiscal systems summarized below in table 4.8. On the basis of NPV alone since it is the most common indicator used in the industry, the first ten fiscal regimes ranked highest in GOG region are Equatorial Guinea PSC (1998), Sierra Leone RT (2001), Senegal R/T (2000), Niger R/T (1992), Equatorial Guinea PSC (2006), Ghana R/T (1997), Liberia PSC (2009), Chad R/T (1999), Nigeria PSC (1993), and Cote D'Ivoire RF (1996). Comparing NPV of these countries with the discounted Payout Time (DPO), Equatorial Guinea's 1998 PSC fiscal regime with the highest NPV does not have the shortest DPO. On this basis, Equatorial Guinea PSC (1998) cannot be ranked the better fiscal regime, rather Cote D'Ivoire ranked 10th on the basis of NPV alone has the shortest DPO of 7.74 years.

Table 4.8: R/Ts discounted cash flow economic metrics

KEY	COUNTRIES	IRR	GRR	NPV	PI	DPO (years)
1	CAMEROON Rente Miniere (1995)	33.57%	16.79%	$ 1,183.28	2.28	9.46
2	CHAD R/T (1999)	31.46%	17.80%	$ 1,624.45	2.76	9.49
3	GHANA R/T (1997)	49.49%	18.13%	$ 1,786.96	2.93	8.54
4	MALI R/T (1970)	31.60%	16.66%	$ 1,130.19	2.22	8.14
5	NIGER R/T (1992)	44.61%	18.73%	$ 2,106.53	3.28	8.57
6	NIGERIA R/T (2000)	19.43%	13.82%	$ 271.04	1.29	10.77
7	SENEGAL R/T (2000)	47.61%	19.15%	$ 2,350.60	3.54	8.56
8	SIERRA LEONE RT (2001)	38.55%	19.29%	$ 2,436.22	3.63	8.43

However, on the basis of high NPV and DPO of the ten fiscal regimes, Nigeria's PSC (1993) performed well as it has the third lowest DPO of 7.99 years. The discounted Payout Period (DPO) answers the question of how long it will take to recover Exploration and Production investments. It is the length of time required to accumulate gross income that is equal to the gross investment. The lower the Payout Period the better the investment because a contractor can quickly break even and start making profits. All revenues received after the payback period represents profit and new capital generated from the project which could be reinvested. On the basis of DPO, Cote D'Ivoire fiscal system has the least DPO of 2.74 years after production starts and Nigeria R/T has the highest DPO of 5.77 years after production starts. On the average the GOG fiscal systems has an average of 3.5 years DPO after production starts, which is a very good indicator to investors. A venture with higher NPV might have a longer DPO or lower NPV with shorter DPO. Decisions on this basis vary from contractor to contractor.

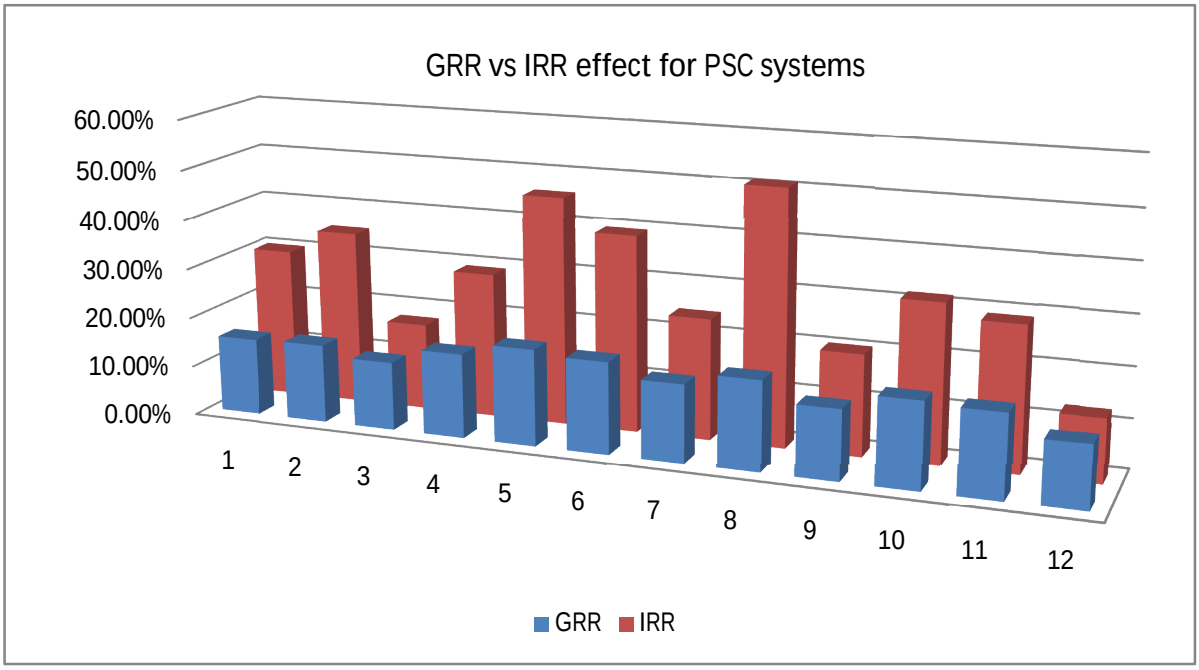


Figure 4.2: Comparison of GRR against IRR for PSCs

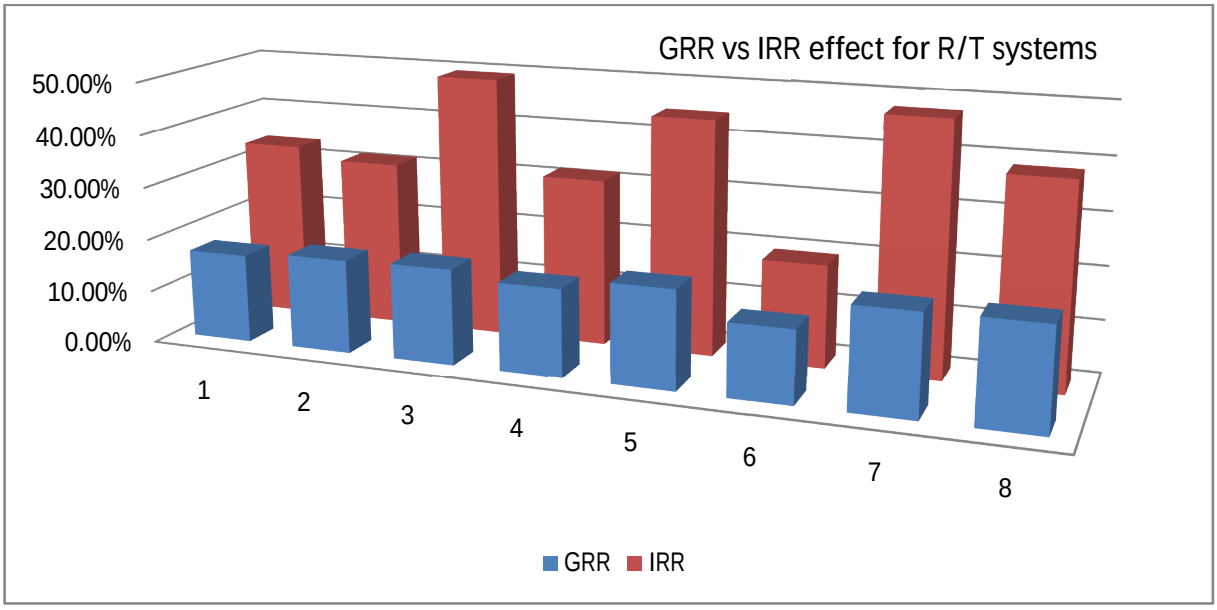


Figure 4.3: Comparison of GRR against IRR for R/Ts

The profitability of doing business in the Gulf of Guinea is further emphasized in figures 4.2 and 4.3 above showing the effect of GRR against IRR for both PSC and R/T systems. The interest rate that could be accrued in choosing to invest in banks rather than deepwater GOG could be seen as the GRR, and in all cases this rate is lower compared to IRR and they are all

greater than the discount rate of 12.5%. The Growth Rate of Return (GRR) corrects the short comings of IRR such as multiple internal rates of return.

4.5.3 MORE PROJECT ECONOMIC MEASURES

There are other petroleum project economic measures that could be used in decision analysis of choice in this economic model. These include PVR, ERR, SI, ROI, FLI, and DNCF. Some of these metrics ignore time-value of money in their approaches such as ROI criterion. Though these profitability indicators that ignore time value of money are relatively simple, their project performances cannot be weighted. Consequently, it is strongly advised that they are used with other economic measures that acknowledge time value of money in order to weigh the project performance and reflect the time pattern of cash flow. As a result, the ensuing analysis combines both in its comparison.

It is noteworthy to recall that tables 4.6a and 4.6b shows the key/legend to the numbers on the abscissa (x-axis) of all the charts in this section also to avoid clumsiness.

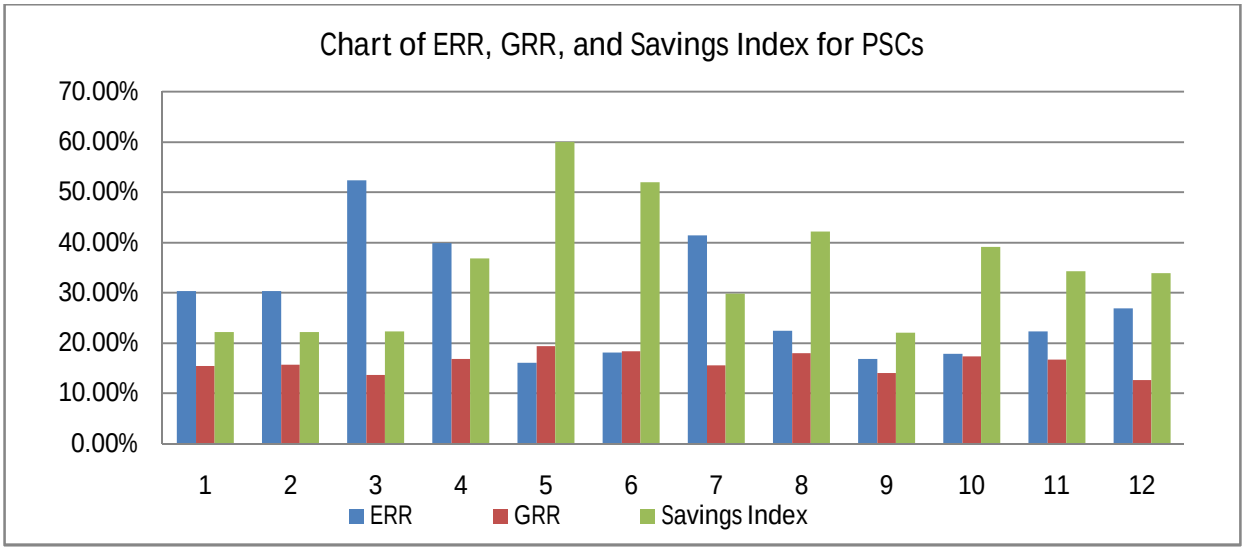


Figure 4.4: Chart of ERR, GRR, and Savings Index for PSCs

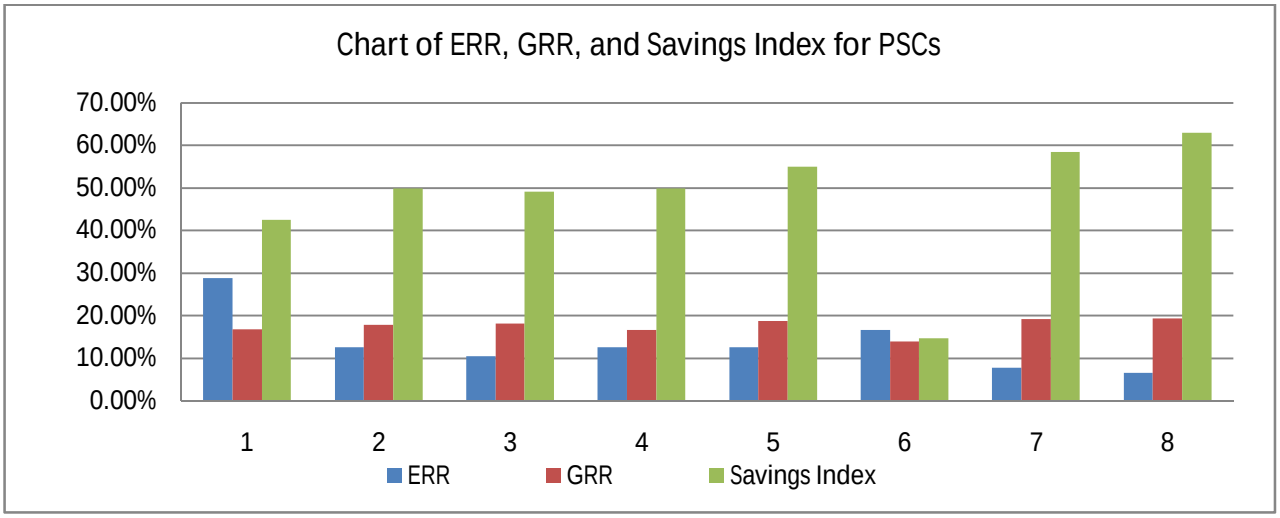


Figure 4.5: Chart of ERR, GRR, and Savings Index for R/Ts

Figures 4.4 and 4.5 show the effect of the measures built-in to help keep costs down in the region. Also shown is the average effective royalty rate for the region. In encouraging companies to keep costs down, the R/T systems have a high saving index of about 50% on the average, while the PSCs have an average of about 35%. The guaranteed share of revenue (ERR) compared to world average of 20% denotes that the Gulf of Guinea deepwater is competitive.

It can be deduced that fiscal systems that are not heavily front loaded like Angola PSCs, Cote D'Ivoire PSC, and Nigeria JDZ (2003) have very low savings index of about 20%. The GRR on the average is lower for the less front loaded systems as compared to the heavily loaded systems. This is also reflected in lower NPV for these systems. Conversely, fiscal systems with low FLGT ends up with high profit oil to government. This is seen with the PO/Govt. for countries in Angola PSCs, Cote D'Ivoire PSC, and Nigeria JDZ (2003) soaring above 60%.

4.6 IMPACT OF PRODUCTION START YEAR ON NPV, IRR, AND GOVT. NCF

The impact of starting production 2 and 4 years earlier and delaying production 2 and 5 years with respect to the base case on the fiscal systems of the GOG for NPV, and Govt. NCF are attached in appendices C-5 and C-6. Figures 4.6 and 4.7 show the impacts on IRR.

As seen from the charts, some of the fiscal systems are not profitable when production is delayed beyond the base case of 5 years. It is noteworthy to reiterate that tables 4.6a and 4.6b shows the key/legend to the numbers on the abscissa (x-axis) of all the charts in this section also to avoid clumsiness.

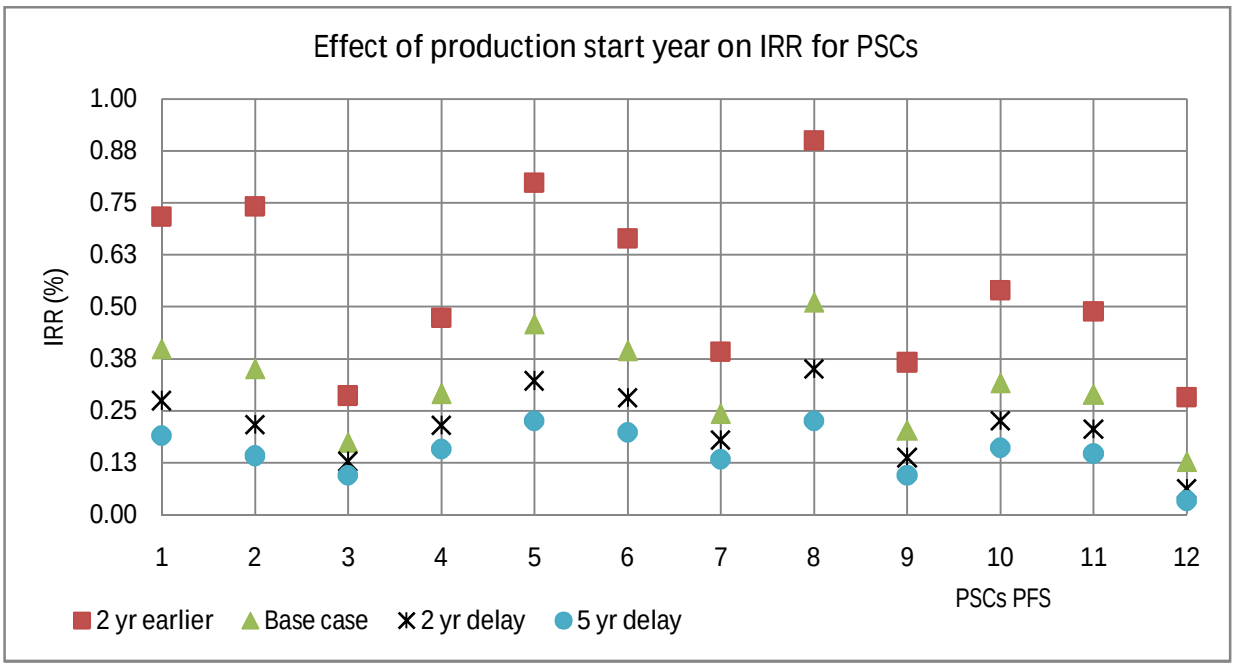


Figure 4.6: Effect of production start year on IRR for PSCs

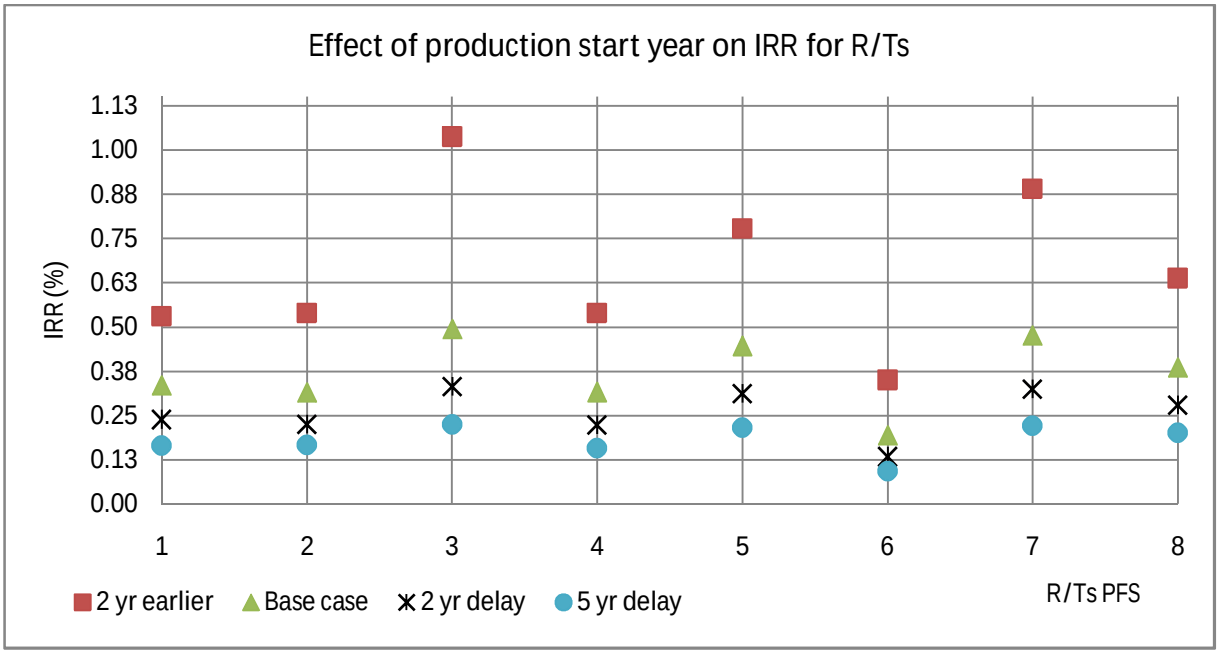
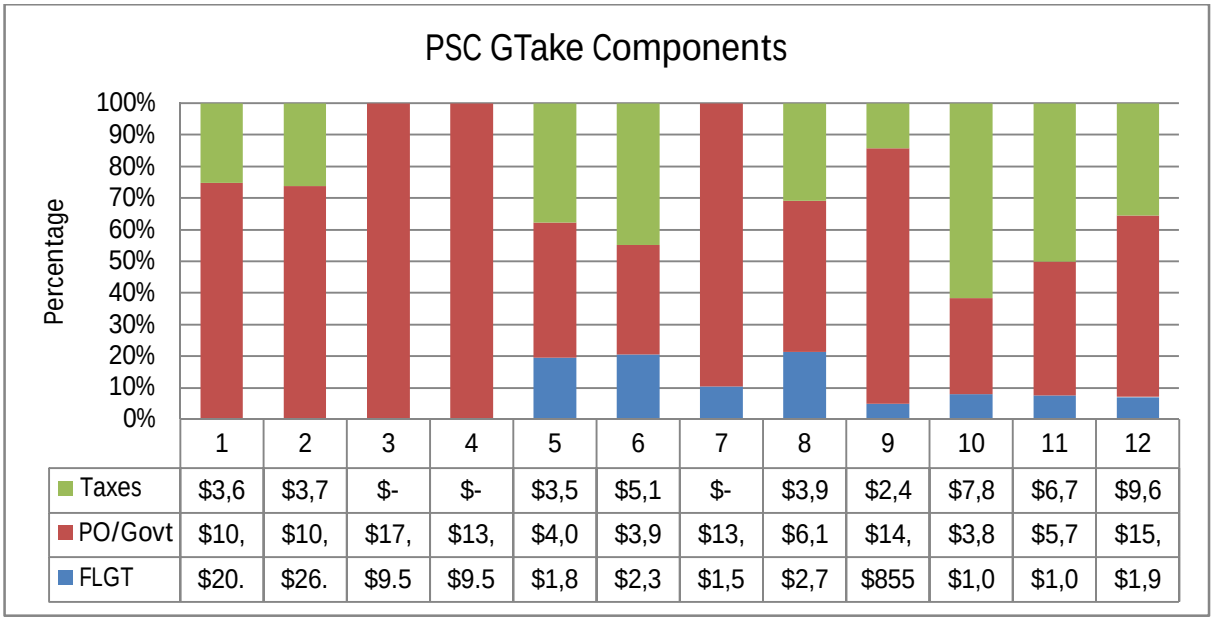


Figure 4.7: Effect of production start year on IRR for R/Ts

These fiscal systems are Nigeria PSC 2005, Nigeria JDZ 2003, Cote D'Ivoire PSC 1996, and Nigeria R/T 2000 as their IRR fell below the discount rate of 12.5%. Their NPVs were also affected as they fell below the zero dollar thresholds. It was observed that production start year did not affect GTake, SI, and ERR.

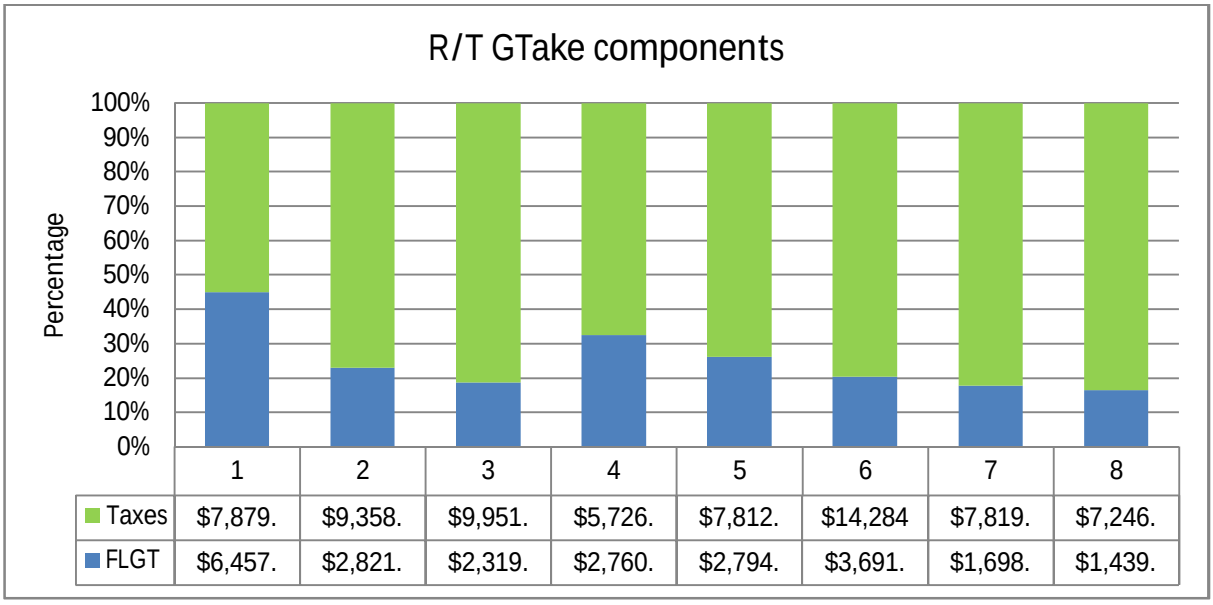
4.7 IMPACT OF FRONT LOADED GOVERNMENT TAKE (FLGT), FRONT-END LOADING INDEX (FLI) AND TAXATION

Figure 4.8 reflects the dynamism in structuring fiscal terms and their effects. Equatorial Guinea and Liberia have the highest contribution from front loaded government take of about 20% to its GTake but with the least government take of about 60%. This is because their FLIs are lower and close to zero. FLI for Equatorial Guinea is 0.0039 and Liberia is 0.0113. Cote D'Ivoire and Angola with no FLGT still has GTake statistics that are higher than 60%. This can be attributed to their higher FLIs of about 0.04 for Angola and 0.1 for Cote D'Ivoire.



	1	2	3	4	5	6	7	8	9	10	11	12
Taxes	$3,6	$3,7	$-	$-	$3,5	$5,1	$-	$3,9	$2,4	$7,8	$6,7	$9,6
PO/Govt	$10,	$10,	$17,	$13,	$4,0	$3,9	$13,	$6,1	$14,	$3,8	$5,7	$15,
FLGT	$20.	$26.	$9.5	$9.5	$1,8	$2,3	$1,5	$2,7	$855	$1,0	$1,0	$1,9

Figure 4.8: PSC undiscounted GTake showing taxes, PO/Govt. and FLGT (Please note in the table that a comma ','sign indicates a thousand divisors. Table 4.6a shows the key to abscissa)



	1	2	3	4	5	6	7	8
Taxes	$7,879.	$9,358.	$9,951.	$5,726.	$7,812.	$14,284	$7,819.	$7,246.
FLGT	$6,457.	$2,821.	$2,319.	$2,760.	$2,794.	$3,691.	$1,698.	$1,439.

Figure 4.9: R/T undiscounted GTake showing taxes and FLGT (Please note that Table 4.6b shows the key to countries on the abscissa)

Despite the 50% income tax on the average for most countries, their effects vary greatly on government take. The contribution from tax is highest in Nigeria PSC (1993) at about 62% and least in JDZ (2003) at about 15% contribution.

From the figure, it is conspicuous that profit oil contributes most to government take and therefore should be the key element in designing fiscal instruments. Though exempting taxation in their fiscal terms, Gabon and Cote D'Ivoire could still extract as much as $13 billion as NCF. This portrays the gimmicks of zero taxation system. In figure 4.9, taxation gave the highest contribution to GTake with a minimum of 55% for Cameroon and a maximum of 83% for Sierra Leone. Without the characteristic's profit oil of PSC, the R/T systems still achieved much economic rent. This confirmed that objectives of both government and investors could be achieved with any fiscal type; it only lies on the dynamics of the fiscal instruments embedded in fiscal terms.

CHAPTER FIVE

5.0 MODEL SIMULATION AND ANALYSIS

5.1 STOCHASTIC SIMULATION

The pertinent issue of high level risk and uncertainty associated with the extractive capital intensive industry which could make success rate to be relatively low is analyzed with the stochastic simulation done on the deterministic results obtained from the PFS of the GOG countries. This is analyzed explicitly in this chapter. This simulation analysis offers the investors means to be able to describe risk and uncertainty in the form of distributions for most possible value of any random variable in the GOG. For risk and decision analysis, the use of probabilistic models will help provide a better estimate of the expected value in decision making.

In the stochastic simulation for this economic model, @RISK is used. Risk analysis in @RISK is a quantitative method that seeks to determine the outcomes of a decision situation as a probability distribution. @RISK uses Monte Carlo simulation in its risk analysis to describe uncertain values and present results in the model.

Ten thousand (10000) iterations in one simulation were performed on seventeen (17) basic input variables and applied to six (6) measures of profitability indicator that have both time-value of money or not serving as the objective functions. A total of seventeen (17) different probability distribution functions were imposed ranging from normal, lognormal, to triangular distributions. Some of the basic distributions imposed on key parameters such as oil price, exploration and development well costs, discount rate, etc., are summarize in table 5.1 below. A summary of probability distribution imposed on the seventeen (17) input parameters to the simulation is attached in appendix D.

Table 5.1: Parameters distribution for stochastic analysis

Input Variables	*Stochastic Distribution*	*MIN*	*MEAN*	*MAX*
STOIIP (MMBBL)	Lognormal	502.27	599.98	2284.32
Recovery (%)	Normal	14.7	25	34.5
Exploration costs ($MM)	Triangular	13.51	15.17	16.99
Well rate (MBOPD)	Normal	6.03	10	13.79
Development costs ($MM)	Triangular	67.60	75	82.40
Discount factor (%)	Lognormal	10.04	11.25	33.19
Well cost ($MM)	Triangular	72.06	80	87.93
Initial Oil Price ($/BBL)	Triangular	30.46	66.67	99.67
Final Oil Price ($/BBL)	Triangular	100.54	140	179.44

Using the result from @RISK Monte Carlo simulation, the GOG PFS stochastic analysis will be done with the following objective functions with 10%, 50%, and 90% confidence levels consideration;

- NPV,
- IRR,
- GTake / CTake
- POT,
- ROI, and
- GRR.

5.2 MONTE CARLO SIMULATION ANALYSIS OF THE GULF OF GUINEA PFS

Analysis for the objective functions defined above would contain comparable information regarding the distributions of reserves. Since these basic reserves would be available for all exploration and production ventures, planning and budgeting can be approached by management (decision makers).

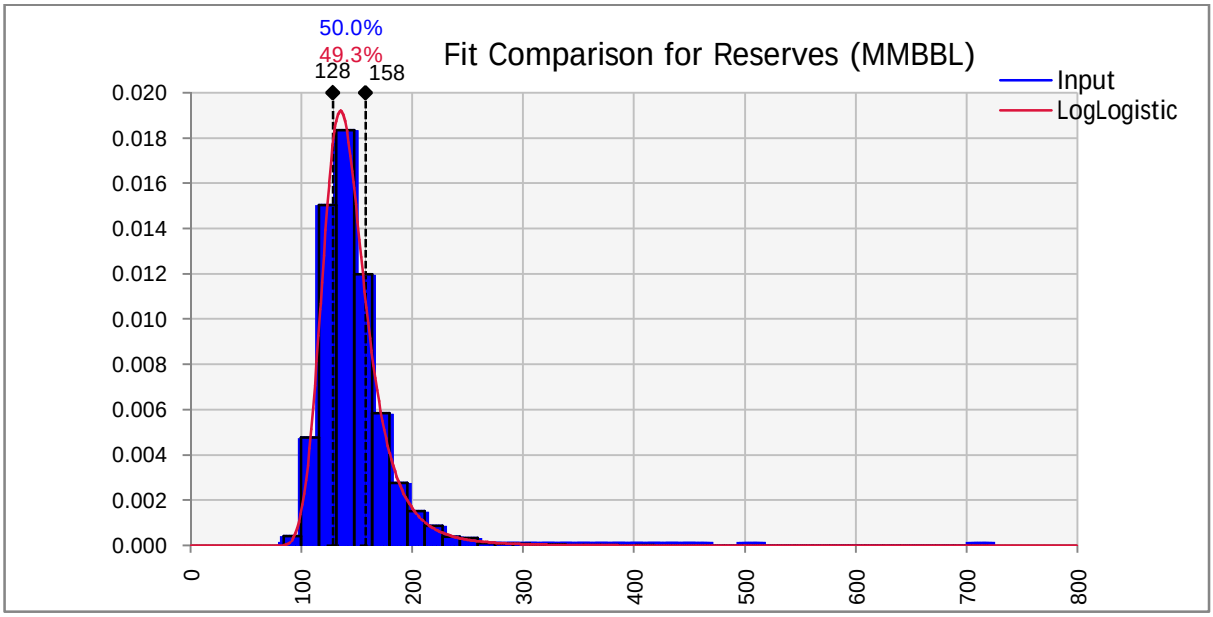


Figure 5.1 Probability of 50% certainty for Reserves

Probability statements can be inferred from figures 5.1 and 5.2 distributions that, there is a probability of 0.9 that prospect reserves will be less than 200 MMBBL and a complementary probability of 0.1 that prospect reserves will be more than 200 MMBBL. There is also a 50% chance of prospect reserves being between 128 and 158 MMBBL and a 90% probability that prospect reserves success would be between 111 and 200 MMBBL. The profitability indicators economic analyses done in the chapter is based on this estimated prospect reserves.

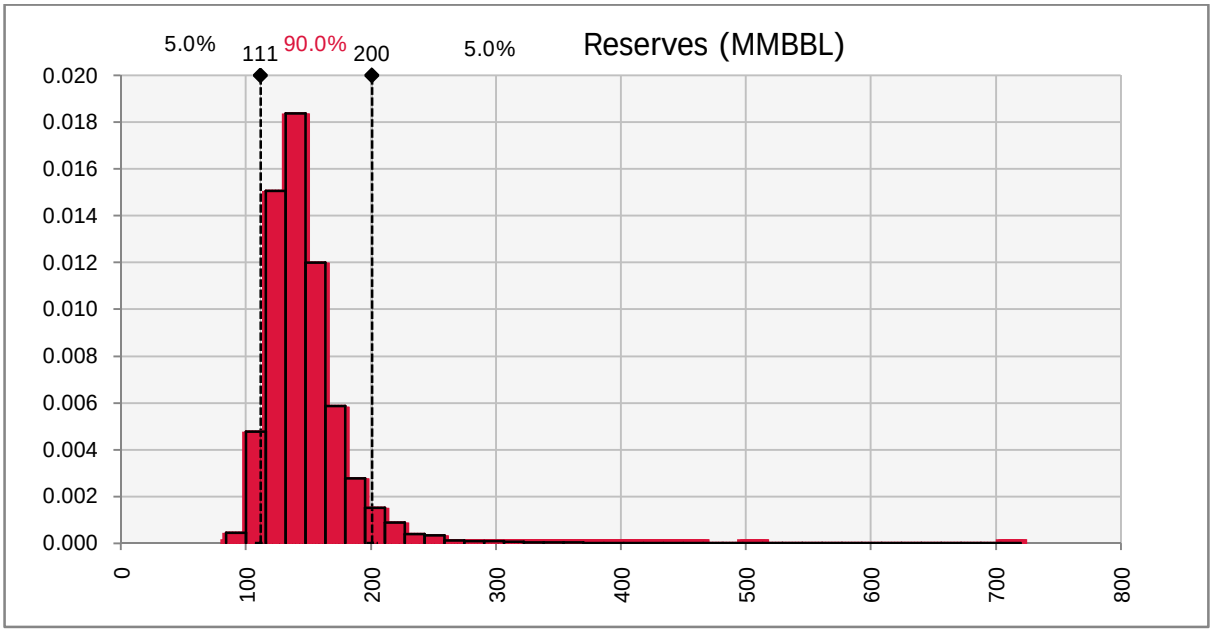


Figure 5.2 Probability of 90% certainty for Reserves

Table 5.2 summarizes P10, P50, and P90 (10%, 50%, and 90% respectively) chance probabilities for all the objective function defined. The GTake results obtained corroborate the deterministic result. The IRR results show that the GOG region PFS relative profitability of ventures having about the same project life and cash flow patterns is high. Most of the PFS has IRR > r* in all success ratio.

Government take is sufficiently high for all countries modeled as shown in table 5.2. On a P50 level, the average government take is about 65% indicating a 50/50% chance of having a government take lesser or greater than this value in deepwater Gulf of Guinea. On the average using P90, there is 90% chance the government take for countries in the Gulf of Guinea is going to be lesser than 67% and 10% probability of getting greater than 67% government take. The IRR derived from the simulation using a P10, P50, and P90 chances, is relatively greater than the assumed discounted rate of 12.5% for the PFS modeled. This indicates there will be returns on every dollar invested in the Gulf of Guinea. Despite performing 10,000 iterations IRR results shows profitability of the investment. The DPO indicates an average of 9 years. Meaning there is 90% chance of breaking even within a lesser period and 10% chance of the POP being greater. NPV as a profitability indicator shows that profit will be made on investments in the Gulf of Guinea under the existing fiscal regimes. P50 and P90 simulated results are greater than zero. On the average the P50 simulation result gave an NPV of $600 which is greater than zero. There exist a 50/50% chance of making lesser or greater than the quoted value in the Gulf of Guinea but greater than $0. Further indicating profitability of investment in the GOG is the GRR. The IRR of all the countries modeled is sufficiently/conveniently greater than the GRR, indicating there will be greater returns on investments if invested in the GOG. The P50 and P90 simulated results yielded a GRR greater than 12.5% for majority of the countries presented.

5.2.1 STOCHASTIC PERFORMANCE OF ANGOLA PSC (1990)

Stochastic modeling was performed on the profitability indicators, such that we obtain a range of possible average values that can occur instead of a single deterministic value. From the results generated and attached in appendix D and table 5.2, it is observed that there is 95% chance of making an NPV less than $765million and 5% chance of making an NPV greater than $765million. There is also a 95% chance of NPV greater than $28.63million to be generated. On the average NPV of $380.24million can be obtained and a maximum of $1.8 billion is achievable. In all the likelihood of obtaining positive NPV from this fiscal regime is high. Therefore, on this basis value will be added to the company. There is 90% certainty of obtaining an IRR between 12.22% and 28.03% and 50% certainty between 17.22% and 23.74% as seen in appendix D. An average IRR of 20.46% and a maximum of 41.81% is obtained. The GRR shows 90% certainty of being between 11.12% and 15.15%. There is 90% certainty that the government take will be between 74.27% and 78.26% and 50% certainty between 75.37% and 76.77%, a maximum of 85.38% is obtained. There is 90% certainty that the discounted POT will be between 8.35years and 11.75years and 50% certainty it will be between 8.9 years and 9.96 years. The ROI is between 0.002 and 0.440 with 90% certainty.

5.2.2 STOCHASTIC PERFORMANCE OF ANGOLA PSC (2004) PSA

Stochastic modeling produced the following results mostly with 50% and 90% certainty of occurrence in figure 5.3 and appendix D. There is 90% certainty of the NPV being between $131 million and $ 863 million and 50% certainty between $329 million and $625 million. There is a 10% chance of obtaining NPV greater than $766.20 million, 50% a chance of $476.23 million and 90% chance of NPV greater than $200 million. IRR is between 21.07% and 28.09% with 50% certainty of occurrence. There is 90% certainty that the GRR will be between 11.67% and 15.52%, 90% percentile of 14.30% and 10% percentile

of 12%. There is 90% certainty the Government take will be between 72.52% and 77.53% under this fiscal regime. Figure 5.4 shows 50% certainty exists for GTake to be between 74.12% and 75.89%.

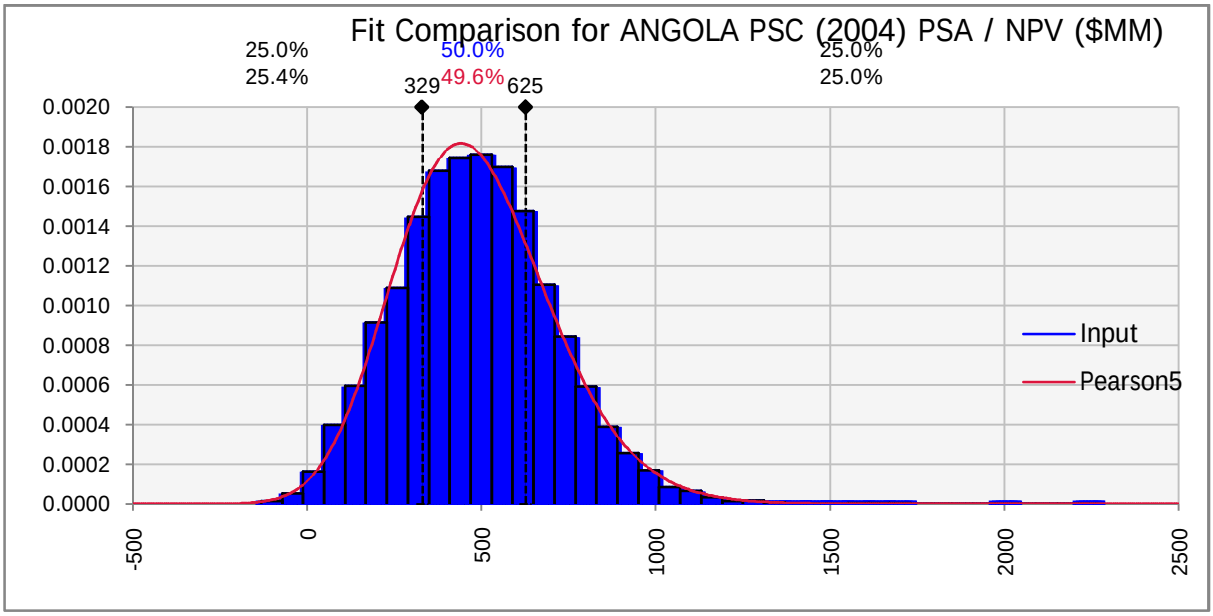


Figure 5.3: Angola PSC 2004 stochastic NPV

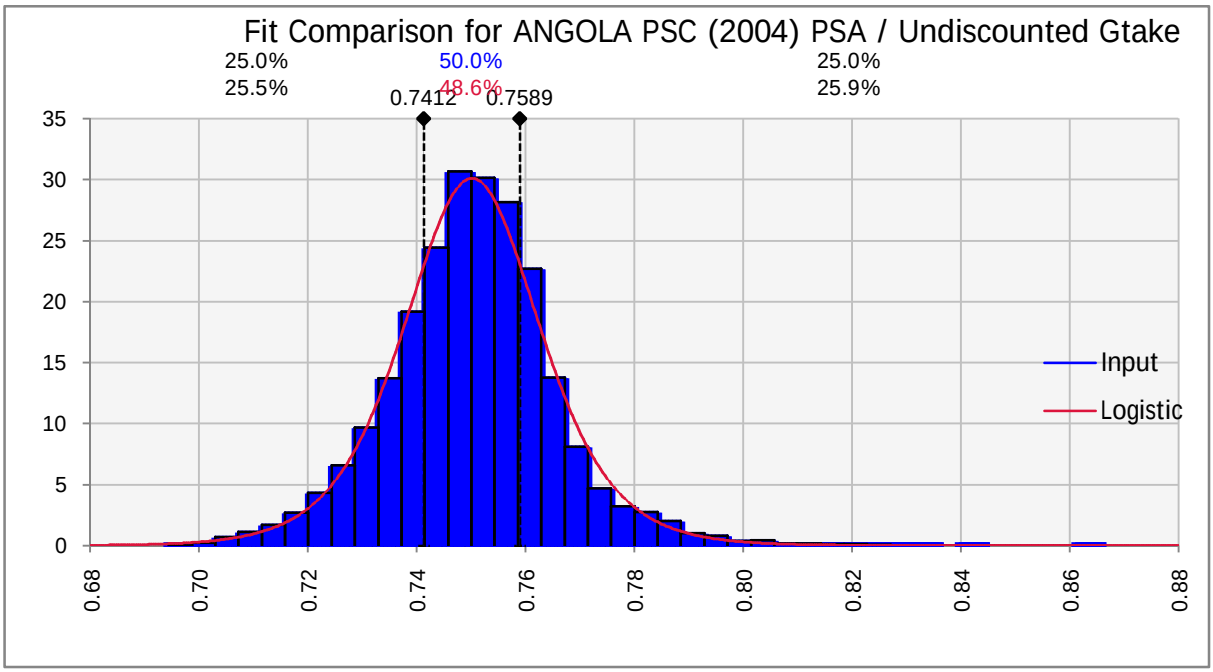


Figure 5.4 Angola PSC 2004 stochastic undiscounted GTake

An occurrence of between 8.48 years and 12.19 years with 90% certainty was obtained. 5% percentile of 8.48 years, 10% percentile of 8.76 and 90% percentile of 11.43 years was obtained for the DPO. The ROI with 50% certainty is between 0.19 and 0.36.

5.2.3 STOCHASTIC PERFORMANCE OF CAMEROON RENTE MINIERE R/T (1995)

From the stochastic modeling results generated in appendix D, it is observed that there is 5% chance of making an NPV greater than $1.14 billion and a 95% chance greater than $65 million i.e. 90% certainty of NPV occurrence within this range. On the average NPV of $557.21 million can be obtained. In all the likelihood of obtaining positive NPV from this fiscal regime is high. Therefore, on this basis value will be added to the company. There is 90% certainty of obtaining an IRR between 13.29% and 30.30% and 50% certainty it will be between 18.7% and 25.6%. An average IRR of 22.2% and a maximum of 47.97% is obtained. The GRR shows 90% certainty of being between 11.40% and 16%. There is 90% certainty that the government take will be between 71.39% and 74.62%, a maximum of 81.00% is obtained. There is 50% certainty that the DPO will be between 9.97 years and 11.85 years. The ROI is between 0.19 and 0.43 with 50% certainty.

5.2.4 STOCHASTIC PERFORMANCE OF CHAD R/T (1999)

From the stochastic modeling results generated in appendix D, it is observed that there is 95% chance of making NPV less than $1.6 billion and a 95% chance greater $42 million i.e. 90% certainty of NPV occurrence within this range. On the average NPV of $725.99 million can be obtained. There is also a 50% certainty of NPV being between $393 million and $991 million. In all the likelihood of obtaining positive NPV from this fiscal regime is high. Therefore, on this basis value will be added to the company. There is 50% certainty of obtaining an IRR between 17.3% and 23.7%. An average IRR of 20.54% and a maximum of 46.26% is obtained. The GRR shows 90% certainty of being between 11.40% and 16.78%

with 10% percentile of 12.01% and 90% percentile of 16.08%. There is 90% certainty that the government take will be between 59.67% and 66.75% and 50% certainty it will be between 60.63% and 63%, a maximum of 77.12% is obtained. There is 50% certainty that the POT will be between 10.38 years and 12.47 years. The ROI is between 0.030 and 0.898 with 90% certainty and 50% certainty it will be between 0.23 and 0.57.

5.2.5 STOCHASTIC PERFORMANCE OF COTE D'IVOIRE PSC (1996)

Under this fiscal regime the stochastic modeling yielded the following results from appendix D: It is observed that there is 50% certainty of making an NPV between $2 million and $247 million. On the average NPV of $41.65 million can be obtained. There is 90% certainty of obtaining an IRR between 6.95% and 16.40% and 50% certainty between 9.96% and 13.84%. An average IRR of 11.88% and a maximum of 26.36% is obtained. The GRR shows 90% certainty of being between 9.59% and 13.35% with 10% percentile of 9.97% and 90% percentile of 12.75%. There is 90% certainty that the government take will be between 81.1% and 86.7%, a maximum of 89.22% is obtained. There is 90% certainty that the discounted POT will be between 8 years and 10.9 years, on the average a POP of 9.2 years is obtained. The ROI is between 0 and 0.14 with 50% certainty.

5.2.6 STOCHASTIC PERFORMANCE OF COTE D'IVOIRE PSC R-FACTOR (1996)

Stochastic modeling produced in appendix D shows results with 50% and 90% certainty of occurrence for NPV. There is 90% certainty of the NPV being between $70 million and $1,264 million and 50% certainty between $474 million and $1.03 billion. A 5% chance of obtaining NPV greater than $1158.98 million, 50% chance greater than $689.45 million and 90% chance greater than $195.02 million exist. The IRR falls between 12.81% and 26.65% with 90% certainty of occurrence. There is 90% certainty that the GRR will be between 11.56% and 16.30%, 90% percentile of 15.69% and 10% percentile of 12.14%. There is 90% certainty the GTake will be between 60% and 65.41% under this fiscal regime.

An occurrence of between 8 years and 10.92 years with 90% certainty was obtained for POT. The ROI with 90% certainty is between 0.04 and 0.73.

5.2.7 STOCHASTIC PERFORMANCE OF EQUATORIAL GUINEA PSC (1998)

The stochastic modeling of this fiscal regime produced NPV between $443 million and $2.4 billion with 90% certainty and 50% certainty between $921 million and $1.7 billion as seen in appendix D. From table 5.2, there is a 10% chance of NPV greater than $2,127 million occurring, 50% chance greater than $1,300 million and 90% chance greater than $610 million occurring. The likelihood of obtaining positive NPV from this fiscal regime is high. Therefore, on this basis value will be added to the company. There is 90% certainty of getting a range of 20.4% and 42.0% for IRR, an average IRR of 31.43%. The GRR shows 90% certainty of being between 13.23% and 18.53% with 10% percentile of 13.83% and 90% percentile of 17.82% respectively. There is 90% certainty that the government take will be between 43.34% and 46.71%, a maximum of 58.56% is obtained. There is 50% certainty that the DPO will be between 8.94 years and 10 years, on the average a POP of 9.78 years is obtained. The ROI is between 0.26 and 1.4 with 90% certainty.

5.2.8 STOCHASTIC PERFORMANCE OF EQUATORIAL GUINEA PSC (2006)

The stochastic modeling performed on the profitability indicators figures 5.5 and 5.6, show the range of possible average values that can occur instead of a single deterministic value. From the results generated it is observed that there is 90% certainty that GTake will be between 55.37% and 61.24%. An average NPV of $961.34 million is achieved after the 10,000 simulation run with 10% chance of NPV greater than $1.6 billion and 90% chance of NPV greater than $339 million. There is 90% certainty of an NPV between $197 million and $1.87 billion and 50% certainty it will be between $598 million and $1.3 billion. In all the likelihood of obtaining positive NPV from this fiscal regime is high. There is 90% certainty of obtaining an IRR between 15.68% and 35.7% which is higher than the assumed 12.5%

used in the deterministic analysis. An average IRR of 25.94% is obtained. The GRR shows 90% certainty of being between 12.15% and 17.52%. There is 90% certainty that the POT will be between 9.1 years and 14.24 years. The ROI is between 0.35 and 0.73 with 50% certainty as seen in appendix D.

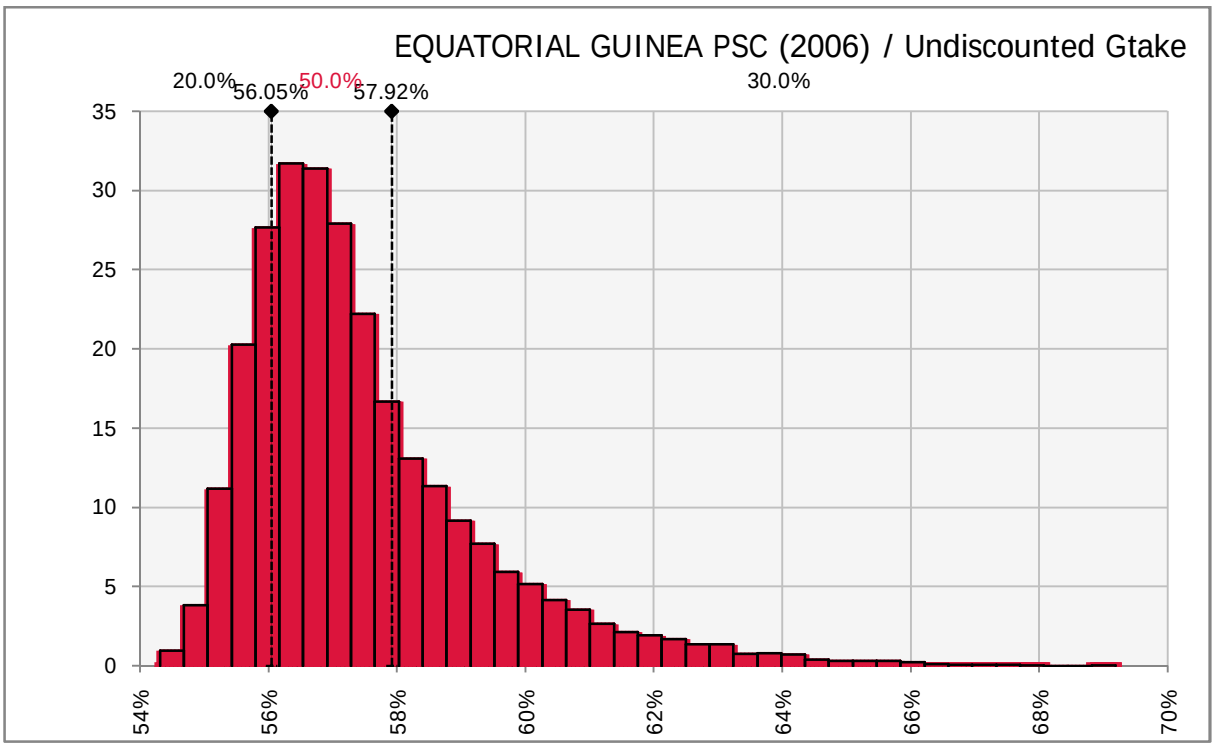


Figure 5.5 Equatorial Guinea PSC 2006 stochastic undiscounted GTake

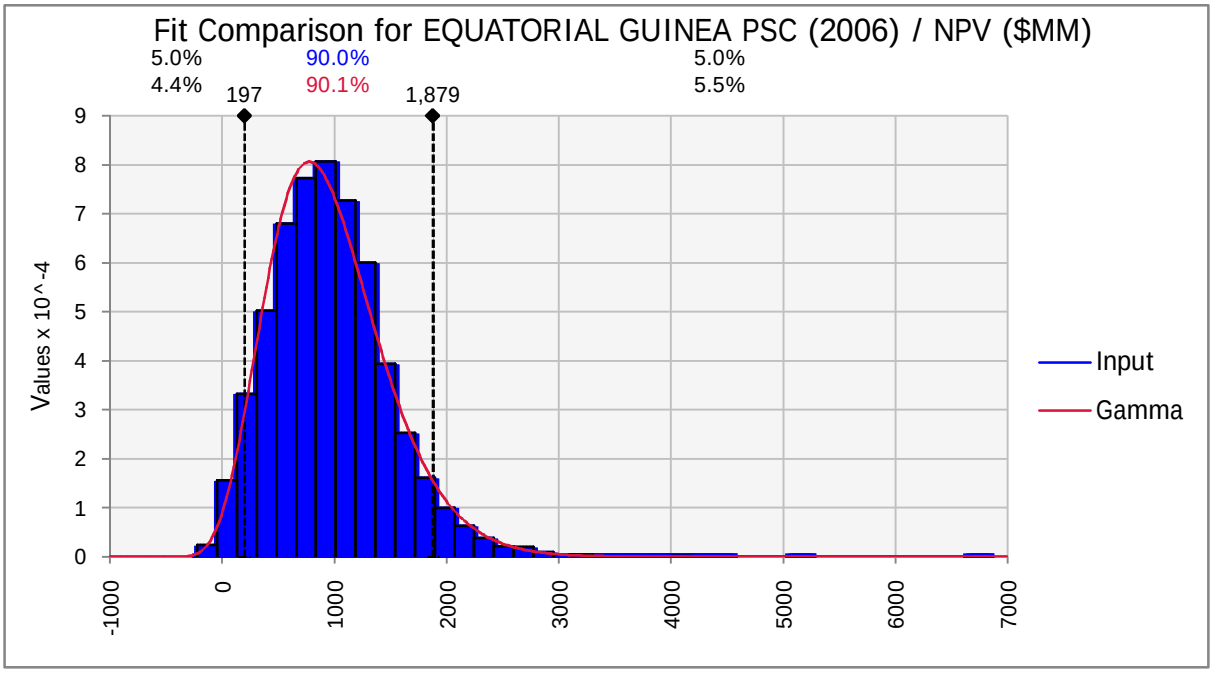


Figure 5.6 Equatorial Guinea PSC 2006 stochastic NPV

5.2.9 STOCHASTIC PERFORMANCE OF GABON PSC (1997)

From the results generated in appendix D and table 5.2, it is observed that there is 90% certainty that GTake will be between 71.27% and 74.78%. A 90% percentile of 73.93%, 50% percentile of 72.09%, and 10% percentile of 71.44% was achieved. An average NPV of $374.59 million is achieved after the 10,000 simulation run with 90% chance of NPV less than $744 million and 10% chance it will be less than $5.8 million. There is a 50% certainty that NPV will be between $172 million and $560 million. In all the likelihood of obtaining positive NPV from this fiscal regime is high. There is 50% certainty of obtaining an IRR between 14.14% and 19.42%. An average IRR of 16.77% is obtained. The GRR shows 90% certainty of being between 10.64% and 15.13% and 50% certainty it will be between 11.98% and 13.68%. There is 90% certainty that the POT will be between 8.1years and 11.15 years. The ROI is between 0.1 and 0.33 with 50% certainty.

5.2.10 STOCHASTIC PERFORMANCE OF GHANA R/T (1997)

From the results generated in the stochastic model and attached in appendix D and table 5.2, it is observed that there is 90% certainty that GTake will be between 53.3% and 60.43%. A 90% percentile of 59.63%, 50% percentile of 57.06%, and 10% percentile of 54.93% was achieved. An average NPV of $1 billion is achieved after the 10,000 simulation run with 10% chance of NPV greater than $1.57 billion and 10% chance of NPV less than $523.28 million. There is 50% certainty of an NPV between $744 million and $1.3 billion.

In all the likelihood of obtaining positive NPV from this fiscal regime is high. There is 90% certainty of obtaining an IRR between 22.3% and 45%. An average IRR of 33.9% is obtained. The GRR shows 90% certainty of being between 12.99% and 17.49%. There is 90% certainty that the POT will be between 8.76years and 12.68 years. The ROI is between 0.24 and 1.02 with 90% certainty.

5.2.11 STOCHASTIC PERFORMANCE OF LIBERIA PSC (2009)

The stochastic modeling performed on the profitability indicators showed the range of possible average values that can occur instead of a single deterministic value. From the results generated it is observed that there is 90% certainty that GTake will be between 63.75% and 65.76% and 50% certainty between 64% and 64.64% as seen in appendix D. An average NPV of $947 million is achieved after the 10,000 simulation run with 90% percentile of $1.4 billion and 10% percentile of $457.58 million. There is 90% certainty of an NPV between $346 million and $1.7 billion and 50% certainty between $661 million and $1.2 billion. In all the likelihood of obtaining positive NPV from this fiscal regime is high. There is 90% certainty of obtaining an IRR between 24.3% and 46.7%. An average IRR of 36.03% is obtained. The GRR shows 90% certainty of being between 12.71% and 17.3%. There is 90% certainty that the DPO will be between 8.65years and 12.45 years. The ROI is between 0.20 and 0.96 with 90% certainty.

5.2.12 STOCHASTIC PERFORMANCE OF MALI R/T (1970)

The stochastic modeling performed on the profitability indicators, showed the range of possible average values that can occur instead of a single deterministic value. From the results generated in appendix D, it is observed that there is 90% certainty that GTake will be between 59.82% and 62.68%. An average NPV of $498.93 million is achieved after the 10,000 simulation run with 90% percentile of $915.77 million and 10% percentile of $100.8 million. There is 90% certainty of an NPV between $10 million and $1 billion and 50% certainty it will be between $265 million and $686 million. In all the likelihood of obtaining positive NPV from this fiscal regime is high. There is 90% certainty of obtaining an IRR between 11.82% and 28.42%. An average IRR of 20.25% is obtained. The GRR shows 90% certainty of being between 11.12% and 15.82%. There is 90% certainty that the discounted

POT will be between 8.36 years and 12.17 years. The ROI is between 0.01 and 0.62 with 90% certainty.

5.2.13 STOCHASTIC PERFORMANCE OF NIGER R/T (1992)

From the results generated in the stochastic modeling attached in appendix D, it is observed that there is 90% certainty that GTake will be between 52.77% and 54.74%. A 90% percentile of 54.32%, 50% percentile of 53.37%, and 10% percentile of 52.88% was achieved. An average NPV of $88.27 million is achieved after the 10,000 simulation run with 90% percentile of $280.87 million. There is 90% certainty of making an NPV between $337 million and $2.04 billion and 50% certainty between $740 million and $1.4 billion. In all the likelihood of obtaining positive NPV from this fiscal regime is high. There is 90% certainty of obtaining an IRR between 19.5% and 40.5%. An average IRR of 30.30% is obtained. The GRR shows 90% certainty of being between 12.77% and 17.88%. There is 90% certainty that the POT will be between 8.82 years and 13.17 years. The ROI is between 0.20 and 1.17 with 90% certainty and 50% certainty between 0.43 and 0.82.

5.2.14 STOCHASTIC PERFORMANCE OF NIGERIA JDZ PSC (2003)

The stochastic modeling performed on the profitability indicators, showed the range of possible average values that can occur instead of a single deterministic value. From the results generated it is observed that there is 90% certainty that GTake will be between 83.72% and 87.21% and 50% certainty between 86% and 87% as seen in appendix D. An average NPV of $88.27 million is achieved after the 10,000 simulation run with 90% percentile of $280.87 million. There is a 50% certainty that NPV will be between $4 million and $206 million. In all the likelihood of obtaining positive NPV from this fiscal regime is moderate. There is 10% certainty of obtaining an IRR between 10.91% and 15.10%. An average IRR of 13.10% is obtained. The GRR shows 50% certainty of being between 10.9%

and 12.18%. There is 90% certainty that the discounted POT will be between 8.06 years and 11.2 years. The ROI is between 0 and 0.12 with 50% certainty.

5.2.15 STOCHASTIC PERFORMANCE OF NIGERIA PSC (1993)

The stochastic modeling performed on the profitability indicators, showed the range of possible average values that can occur instead of a single deterministic value. From the results generated it is observed that there is 90% certainty that GTake will be between 63.86% and 65.33%. Appendix D shows a 90% certainty of making an NPV between $16 million and $1.35 billion and 50% certainty between $280 million and $805 million is obtained. On the average NPV of $628 million can be obtained. In all the likelihood of obtaining positive NPV from this fiscal regime is high. Therefore, on this basis value will be added to the company. There is 50% certainty of obtaining an IRR between 16.9% and 23.5%. An average IRR of 25.81% is obtained. The GRR shows 50% certainty of being between 12.75% and 14.71%. There is 90% certainty that the discounted POT will be between 8.18 years and 11.6 years. The ROI is between 0.2 and 0.5 with 50% certainty.

5.2.16 STOCHASTIC PERFORMANCE OF NIGERIA PSC (2000)

The stochastic modeling performed on the profitability indicators showed the range of possible average values that can occur instead of a single deterministic value. From the results generated it is observed that there is 90% certainty that GTake will be between 68.44% and 71.33%. From figure 5.7, a 90% certainty of making an NPV between $135 million and $782 million and 50% certainty between $210 million and $682 million is obtained as seen in figure 5.8. On the average NPV of $470 million can be obtained. In all the likelihood of obtaining positive NPV from this fiscal regime is high. Therefore, on this basis value will be added to the company. There is 50% certainty of obtaining an IRR between 14.8% and 21.2%. An average IRR of 18.05% is obtained. Figure 5.8 shows GRR of 50% certainty being between 12.18% and 14.13% as seen in figure 5.7. There is 90% certainty that

DPO will be between 8.27 years and 11.86 years. The ROI is between 0.12 and 0.4 with 50% certainty.

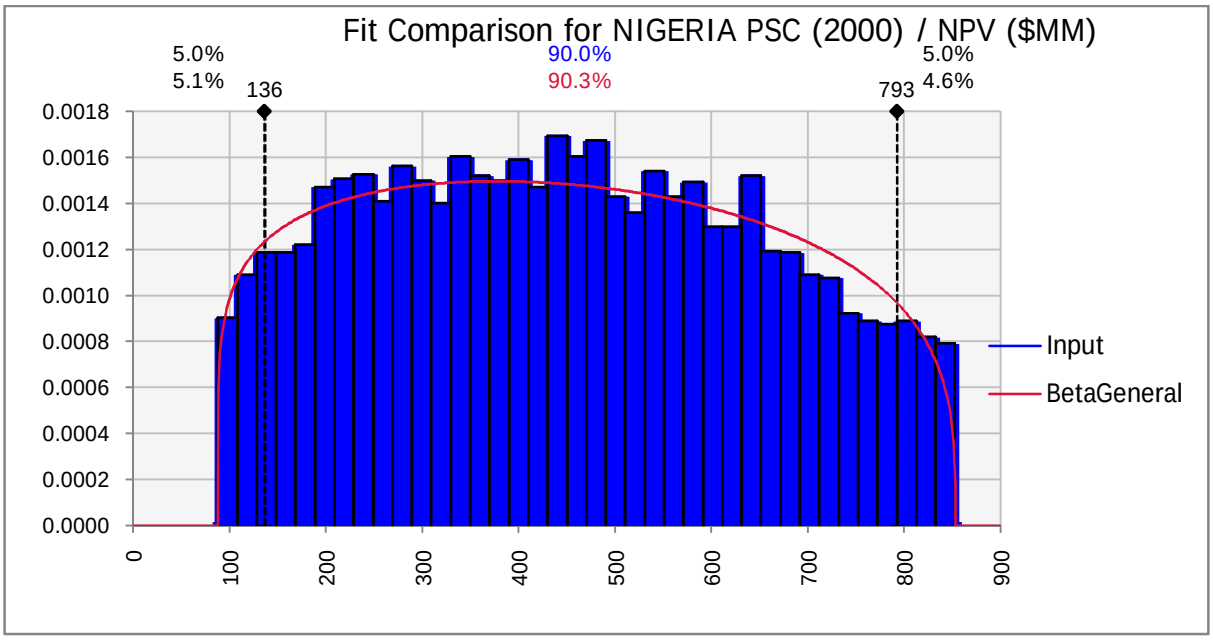


Figure 5.7 Nigeria PSC 2000 stochastic NPV with relative fitting of SD = 1

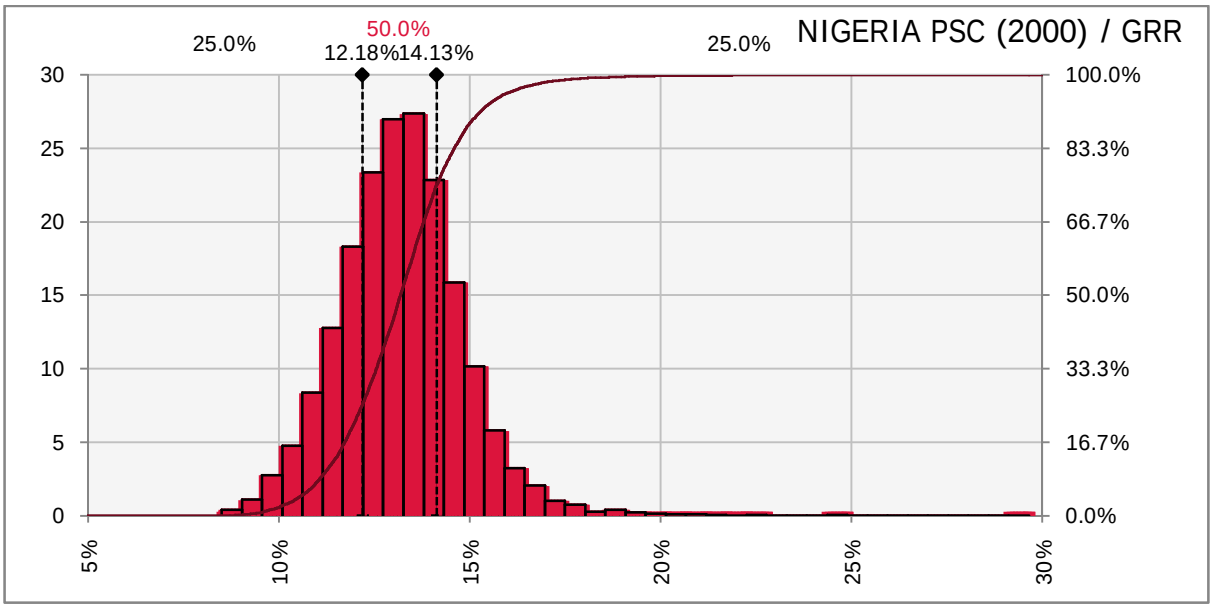


Figure 5.8 Nigeria PSC 2000 stochastic GRR with cumulative frequency distribution

5.2.17 STOCHASTIC PERFORMANCE OF NIGERIA R/T (2000)

Appendix D shows a summary of the results generated, it is observed that there is 90% certainty that GTake will be between 89.67% and 90.28%. A 50% certainty of making

an NPV between $3 million and $336 million is achieved. On the average NPV of $15.99 billion can be obtained. In all the likelihood of obtaining positive NPV from this fiscal regime is moderate. There is 50% certainty of obtaining an IRR between 9.08% and 13.62%. An average IRR of 11.45% is obtained. The GRR shows 50% certainty of being between 10.51% and 11.79%. There is 50% certainty that DPO will be between 10.94 years and 17.23 years. The ROI is between 0 and 0.18 with 50% certainty.

5.2.18 STOCHASTIC PERFORMANCE OF SENEGAL R/T (2000)

The stochastic modeling performed on the profitability indicators showed the range of possible average values that can occur instead of a single deterministic value as attached in appendix D. From the results generated it is observed that there is 90% certainty that GTake will be between 47.28% and 52.12%. A 90% certainty of making an NPV between $373 million and $2.3 billion and 50% certainty between $821 million and $1.57 billion is achieved. On the average NPV of $1.2 billion can be obtained. In all the likelihood of obtaining positive NPV from this fiscal regime is high. Therefore, on this basis value will be added to the company. There is 90% certainty of obtaining an IRR between 19.9% and 43.2%. An average IRR of 32.07% is obtained. The GRR shows 90% certainty of being between 12.86% and 18.27%. There is 50% certainty that DPO will be between 9.39 years and 10.81 years. The ROI is between 0.48 and 0.91 with 50% certainty.

5.2.19 STOCHASTIC PERFORMANCE OF SIERRA LEONE R/T (2001)

From the results generated in appendix D, it is observed that there is 90% certainty that GTake will be between 43.33% and 48.51%. A 90% certainty of making an NPV between $294 million and $2.35 billion and 50% certainty between $679 million and $1.49 billion is achieved. On the average NPV of $1.2 billion can be obtained. In all the likelihood of obtaining positive NPV from this fiscal regime is high. Therefore, on this basis value will be added to the company. There is 90% certainty of obtaining an IRR between 16.21% and

34.92%. An average IRR of 25.81% is obtained. The GRR shows 90% certainty of being between 12.61% and 18.30%. There is 90% certainty that the POT will be between 9.31 years and 10.64 years. The ROI is between 0.17 and 1.35 with 90% certainty and 50% certainty between 0.45 and 0.92.

Table 5.2: Stochastic Economic Metric Measures for Deepwater Gulf of Guinea

	GTake (%)			IRR (%			DPO (Years)			NPV ($MM)			GRR (%)			ROI (Fraction)		
PFS	P(10)	P(50)	P(90)	P(10)	P(50)	P(90)	P(10)	P(50)	P(90)	P(10)	P(50)	P(90)	P(10)	P(50)	P(90)	P(10)	P(50)	P(90)
ANGOLA PSC (1990)	74.71%	76.07%	77.52%	14.07%	20.63%	26.34%	8.60	9.48	10.98	$ 94.98	$ 372.74	$ 664.25	11.50%	12.86%	14.44%	0.06	0.22	0.38
ANGOLA PSC (2004) PSA	73.18%	75.04%	76.74%	17.71%	24.66%	30.87%	8.76	9.71	11.43	$ 200.09	$ 476.23	$ 766.20	12.00%	13.26%	14.80%	0.12	0.28	0.44
CAMEROON Rente Miniere (1995)	71.45%	72.09%	73.39%	15.57%	22.39%	28.46%	9.99	11.45	15.53	$ 156.29	$ 528.73	$ 972.01	11.86%	13.51%	15.30%	0.09	0.31	0.56
COTE D'IVOIRE PSC (1996)	82.00%	84.20%	86.03%	8.03%	11.98%	15.37%	8.22	9.08	10.35	N/A	$ 43.74	$ 244.85	9.97%	11.32%	12.75%	N/A	0.03	0.14
COTE D'IVOIRE PSC R-Factor (1996)	60.06%	60.09%	65.34%	14.57%	20.18%	25.33%	8.22	9.08	10.35	$ 195.02	$ 689.45	$ 1,158.98	12.14%	14.11%	15.69%	0.11	0.40	0.67
EQUATORIAL GUINEA PSC (1998)	43.62%	44.78%	46.22%	22.90%	31.48%	39.36%	8.63	9.56	11.18	$ 610.08	$ 1,300.57	$ 2,127.53	13.83%	15.87%	17.82%	0.36	0.76	1.22
EQUATORIAL GUINEA PSC (2006)	55.67%	57.01%	59.93%	18.03%	26.01%	33.27%	9.39	10.56	12.93	$ 339.84	$ 914.37	$ 1,609.93	12.76%	14.82%	16.79%	0.20	0.53	0.93
GABON PSC (1997)	71.44%	72.09%	73.93%	11.56%	16.90%	21.58%	8.34	9.22	10.58	$ 5.79	$ 363.25	$ 744.12	11.13%	12.86%	14.51%	N/A	0.21	0.43
GHANA R/T (1997)	54.93%	57.06%	59.63%	24.87%	34.04%	42.51%	8.98	9.92	11.79	$ 523.28	$ 1,018.83	$ 1,573.37	13.42%	15.08%	16.80%	0.31	0.59	0.90
LIBERIA PSC (2009)	63.86%	64.34%	65.32%	27.08%	36.21%	44.23%	8.95	9.90	11.69	$ 457.58	$ 907.87	$ 1,459.29	13.14%	14.77%	16.58%	0.27	0.53	0.84
NIGERIA JDZ PSC (2003)	84.53%	86.37%	87.10%	9.03%	13.00%	17.14%	8.26	9.16	10.55	N/A	$ 78.92	$ 280.87	10.36%	11.49%	13.01%	N/A	0.05	0.16
NIGERIA PSC (1993)	63.95%	64.30%	65.02%	13.78%	20.30%	26.49%	8.44	9.35	10.89	$ 132.60	$ 591.25	$ 1,147.29	11.81%	13.76%	15.69%	0.08	0.34	0.66
NIGERIA PSC (2000)	68.59%	69.28%	70.70%	11.84%	18.05%	23.93%	8.54	9.46	11.06	$ 23.54	$ 436.14	$ 936.95	11.24%	13.18%	15.10%	0.01	0.25	0.54
NIGERIA R/T (2000)	89.70%	89.85%	90.15%	7.05%	11.36%	15.77%	11.59	15.89	22.00	N/A	$ 8.13	$ 191.45	9.96%	11.10%	12.65%	N/A	N/A	0.11
SENEGAL R/T (2000)	47.41%	48.45%	51.11%	22.67%	32.15%	40.65%	9.10	10.16	12.37	$ 523.63	$ 1,176.13	$ 1,984.24	13.51%	15.56%	17.55%	0.31	0.68	1.14
SIERRA LEONE RT (2001)	43.62%	44.89%	47.41%	18.41%	25.86%	32.70%	9.02	10.00	12.01	$ 452.59	$ 1,154.62	$ 2,025.57	13.28%	15.50%	17.58%	0.27	0.67	1.16

CHAPTER SIX

6.0 CONCLUSIONS AND RECOMMENDATIONS

6.1 SUMMARY

In this study, the comparative competitiveness of PFS around the world is discussed. An overview of the important role the GOG region plays in meeting global energy demand is highlighted. Analyzing fiscal regimes serves to determine the possibility of investing in a hydrocarbon producing nation or not. The key challenge for harnessing oil and gas resources is making the right strategic choices and synchronizing their implementation in a context that supports fiscal prudence and minimizes macroeconomic distortion (ADB/AU, 2009). This study is therefore imperative for the GOG because it affects investments interest. The aim of the study is to develop a generic economic model that would be used to perform comparative economics analysis of PFS in the GOG region. The economic model accounts for risks and uncertainties using @RISK for its stochastic simulation for appropriate decision making at the outset of an E&P venture.

The economic model is formulated in an Excel spread sheet with @RISK add-in for stochastic modeling. The methodology adopted for the study involves:

- Data gathering to build economic model. These are
    - production data; in this study the same hypothetical data was used to forecast production
    - technical cost data; well costs, operating cost, number of anticipated wells to drill, exploration cost, geological and geophysical cost, intangible drilling costs
    - fiscal regimes of countries involved, and
    - Oil price forecast.
- Forecasting production field development plan

- Formulating yearly cost outlay plan for the venture
- Developing the cash flow model. This captures;
    - Front loaded government takes.
    - Cost recovery treatment for PSCs.
    - Before and after income tax cash flow.

Twelve different profitability indicators of choice such as NPV, IRR, GTake, DPO, PI, ERR, DNCF, SI, GRR, FLI, PVR, and ROI that acknowledge both time value of money or not are applied to analyze E&P contracts and tax regimes of thirteen countries (Angola, Cameroon, Chad, Cote D'Ivoire, Equatorial Guinea, Gabon, Ghana, Liberia, Mali, Niger, Nigeria, Senegal, and Sierra Leone) with twenty PFS in order to assess the relative merits of E&P investments. The same field size, proved reserved, production forecast, CAPEX, OPEX, and oil price were imposed on the different PFS for the purpose of analysis.

6.2 CONCLUSIONS

In this research, it can be concluded that:

- An automated economic model was successfully developed for deepwater E&P ventures using 20 PFS from 13 countries in the GOG region to be able to study the comparative competitiveness of these PFS in the GOG region.
- The economic model can also estimate peak production rate, reserves, production period, and decline factor based on few basic input parameters like STOIIP, percentage recovery, instantaneous production rate, and facility size.
- The economic model provides investors the opportunity of making decisions using twelve (12) different profitability indicators of choice such as NPV, IRR, GTake, DPO, PI, ERR, DNCF, SI, GRR, FLI, PVR, and ROI that acknowledges both time value of money or not.

- Stochastic simulation to account for uncertainties and risks was successfully incorporated in the model, making it unique from models in other regions.
- Deterministic and stochastic results showed that countries like Angola and Nigeria could afford to progress their GTake as a result of increased proved reserves, thus countries trying to emulate them must do so following the same yardsticks.
- The results obtained points out clearly that countries with proven reserves have high GTake as compared to countries with lower reserves. This can be linked to the facts that proved reserves actually reduce risks thus leading to high GTake fiscal systems.
- It can also be concluded that fiscal instruments factored into PFS should not necessarily be designed to reflect high GTake and discourage investors, as this does not literally translate to high NCF for the government.
- It is important to state here that generally on the average, investment in the Gulf of Guinea is highly profitable in terms of IRR as stochastic and deterministic results showed. This assertion is based on the facts that the IRR results are higher than bank's interest rate plus risk premium.
- On the average the GOG fiscal systems have an average of 3.5 years DPO after production starts, which is a very good indicator to investors.
- On the basis of NPV, the probability and frequency distribution shows that there is 50% certainty of making an NPV greater than $600 million.

6.3 RECOMMENDATIONS

The following recommendations are made for further study:

- The input for cost treatment should be refined to real cost data for exploration, development, and operating expenses rather than using hypothetical costs. This is required because cost treatment in the various PFS affect the overall measures of profitability.

- Using the incorporated default PFS, changes should be made to the various PFS in terms of changing the depreciation types, CRL, sliding scale types, the taxes, and so on to know the impacts and advice in designing new PFS.
- The impact of producing dry gas and proper monetization of gas sales should be incorporated in further analysis of this research.
- Development and operating costs could be tied to reserves in further study.
- This research could be extended to PFS of other countries in Africa at large.

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NOMENCLATURE

ATAX – After Income Tax

BBL – Barrel

BOPD – Barrels of Oil Per Day

BP – British Petroleum

BTAX – Before Income Tax

C/F – Cost Carried Forward

C/R – Cost Recovery

CAPEX – Capital Expenditure

CF – Cash flow

CITA – Corporate Income Tax

CRL – Cost Recovery Limit

CTake – Contractor Take

CUM. PROD. – Cumulative Production

DB – Declining Balance

DDB – Double Declining Balance

DEVT – Development Costs

DPO – Discounted Payout time/period

E&P – Exploration and Production

ECR – Excess Cost Recovery

ETAX – Education Tax

EXPL. – Exploration Costs

FLGT – Front Loaded Government Take

FML – Fiscal Model Library

FVF – Formation Volume Factor

G & G – Geological and Geophysical Costs

GDP – Gross Domestic Product

GOG – Gulf of Guinea

GRR – Growth Rate of Returns

GTake – Government Take

IAT – Inter-Agency Team

IDC – Intangible Drilling Costs

IOC – International Oil Companies

IRR – Internal Rate of Returns

ITA – Investment Tax Allowance

LOE – Lease Operating Expenditure

Mb/d – Million Barrels Per Day

Mb/d – Thousand Barrels Per Day

MMBBL – Million Barrels

NCF – Net Cash Flow

NDDC – Niger Delta Development Commission

NHT – Nigerian Hydrocarbon Tax

NNPC – Nigerian National Petroleum Corporation.

NOC – National Oil Company

NPV – Net Present Value

OECD – Organization for Economic Co-Operation and Development

OPEC – Organization of Petroleum Exporting Countries

OPEX – Operating Expenditure

PFS – Petroleum Fiscal System

PI – Profitability Index

PIB – Petroleum Industry Bill

PO – Profit Oil

POP – Payout Period

PPI – Producer Price Index

PPT – Petroleum Production Tax

PROD. RATE – Production Rate

PSC – Production Sharing Contract

PVR – Present Value Ratio

R/T – Royalty and Tax

STOIIP – Stock Tank Oil Initially in Place

SLD – Straight Line Depreciation

SPE – Society of Petroleum Engineers

STB – Stock Tank Barrel

STB/D – Stock Tank Barrel Per Day

SYD – Sum of Years Digit Depreciation

TC – Technical Cost

UR – Ultimate Recovery

APPENDIX A-1: Overview of fiscal instruments present in GOG region

	Royalty	Bonuses	Rental	Crypto	CRL	ITA/ITC	Tax rate
Angola PSC (1990)	None	Signature	Flat rate	None	50% and 40% uplift	None	In-lieu 50%
Angola PSC (2004)	None	Signature	Flat rate	None	50% and 40% uplift	Yes	PIT=50% PPT=20%
Cameroon RM (1995)	Sliding (R-Factor)	Signature, Production	Negotiable	HSF, Trg. Fee	None	None	57.5%
Cote D'Ivoire PSC (1996)	None	Production	None	Trg. Fee	40%	None	0%
Equatorial Guinea (1998)	Incremental sliding	Signature, Discovery, Production	Negotiable	Trg. Fee	60%	None	25%
Equatorial Guinea (2006)	Linear sliding	Signature, Discovery, Production	Negotiable	Trg. Fee,	60%	None	35%
Gabon PSC (1997)	Incremental sliding	Signature, Production	Negotiable	Trg. Fee, HSF	50%	None	0%
Ghana R/T (1997)	Fixed %	None	None	None	None	None	CIT=35%, APT

Liberia PSC (2009)	Fixed %	Signature, Production	Negotiable	SWF, Trg. Fee, HDF,	70%	None	35%
Nigeria JDZ (2003)	Linear sliding	Signature, Discovery, Production	Negotiable	None	80%	50%	50%
Nigeria PSC (1993)	Fixed %	Signature, Production	Negotiable	None	100%	50%	PPT=50%, Edu=2%
Nigeria PSC (2000)	Fixed %	Signature, Production	Negotiable	None	100%	50%	PPT=50%, Edu=2%, VAT=5%
Nigeria PSC (2005)	Fixed %	Signature, Prospectivity, Production	Negotiable	NDDC, ATF	80%	50%	PPT=50%, Edu=2%, VAT=5%
Senegal R/T (2000)	Incremental Sliding	None	Fixed rate	Trg. Fee	None	None	35%, sliding APT
Sierra Leone RT (2001)	Fixed %	None	Fixed rate	None	None	None	30%, VAT=12%

APPENDIX A-2: Technical Cost Outlay

	G&G Exploration CAPEX				Appr. Wells		Development CAPEX				TOTAL	TOTAL		OPEX					TOTAL	TOTAL	TC
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
2010	9.75	7	8.25	16.75	0	50	0	0	0	0	58.25	16.75	75	0	0	0	0	0	58.25	16.75	75
2011	9.75	42	23.25	51.75	0	50	0	75	0	75	73.25	126.75	200	0	0	0	0	0	73.25	126.75	200
2012	9.75	0	5.25	9.75	18	42	0	75	0	75	47.25	102.75	150	0	0	0	0	0	47.25	102.75	150
2013	0	0	0	0	18	42	0	75	0	75	42	93	135	0	0	0	0	0	42	93	135
2014	0	0	0	0	19.5	45.5	48	75	112	123	157.5	142.5	300	0	0	0	0	0	157.5	142.5	300
2015	0	0	0	0	19.5	45.5	48	0	112	48	157.5	67.5	225	0	0	0	0	0	157.5	67.5	225
2016	0	0	0	0	0	0	48	0	112	48	112	48	160	0	0	0	0	0	112	48	160
2017	0	0	0	0	0	0	22.5	0	52.5	22.5	52.5	22.5	75	0	0	0	0	0	52.5	22.5	75
2018	0	0	0	0	0	0	22.5	0	52.5	22.5	52.5	22.5	75	0	0	0	0	0	52.5	22.5	75
2019	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2021	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2022	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2023	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2024	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2025	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2031	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2033	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0.06	0.24	20.06	20.3	0.24	20.06	20.3

KEY TO APPENDIX A-2 HEADING.

A	Year Begin	L	Intangible CAPEX
B	Geological and Geophysical (G&G) cost	M	Tangible CAPEX
C	Wildcat/Exploratory wells cost	N	Total CAPEX
D	Intangible G&G Exploration CAPEX	O	Field OPEX
E	Tangible G&G Exploration CAPEX	P	IDC/Additional Field OPEX
F	Tangible Dry/Appraisal well cost	Q	Intangible OPEX
G	Intangible Appraisal CAPEX	R	Tangible OPEX
H	Development wells	S	Total OPEX
I	Facilities	T	Intangible costs
J	Intangible development CAPEX	U	Tangible costs
K	Tangible development CAPEX	V	Total cost

APPENDIX B: Deterministic PSCs and R/T results

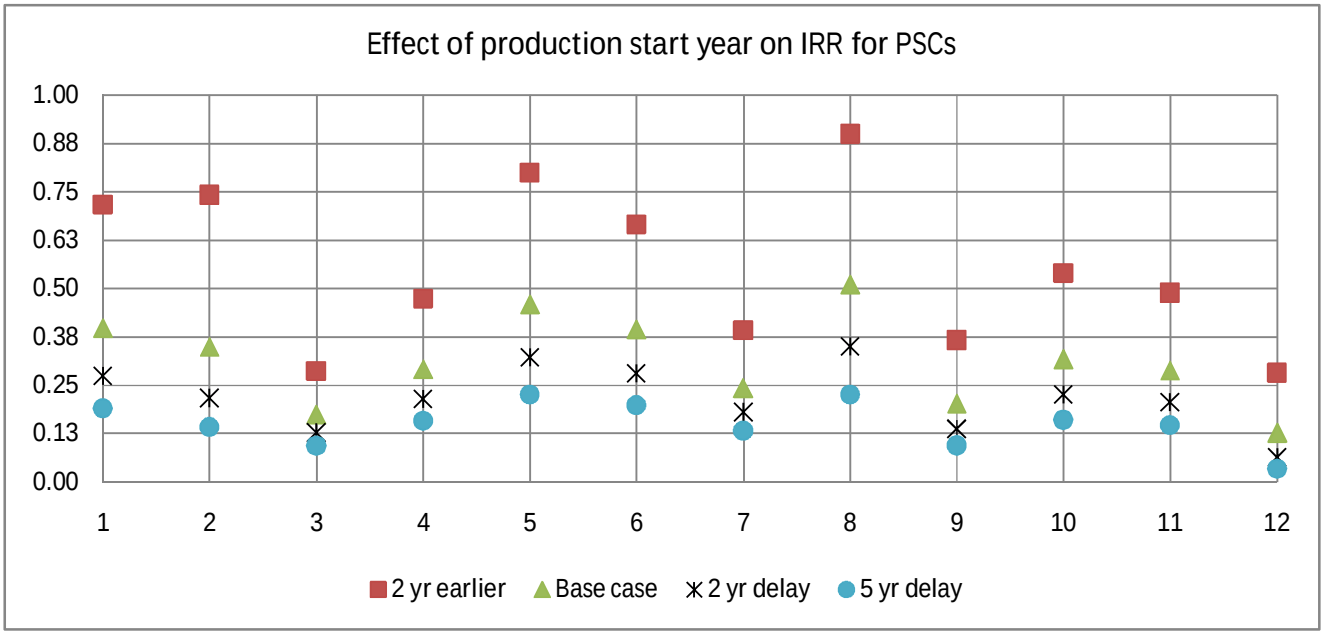
APPENDIX B-1: Summary of PSCs' DPO, ERR, PI, GRR, SI, and DNCF

KEY	COUNTRIES	DPO (years)	ERR	PI	GRR	Savings Index	Contr. DNCF
1	ANGOLA PSC (1990)	8.12	30.29%	2.66	17.62%	22.21%	$ 1,729.94
2	ANGOLA PSC (2004) PSA	8.21	30.29%	1.85	15.70%	22.21%	$ 889.84
3	COTE D'IVOIRE PSC (1996)	7.74	52.42%	1.26	13.69%	22.27%	$ 270.94
4	COTE D'IVOIRE PSC R-Factor (1996)	7.74	39.87%	2.32	16.88%	36.82%	$ 1,373.63
5	EQUATORIAL GUINEA PSC (1998)	8.12	16.02%	3.65	19.32%	60.01%	$ 2,762.57
6	EQUATORIAL GUINEA PSC (2006)	8.76	18.06%	3.07	18.39%	52.01%	$ 2,160.65
7	GABON PSC (1997)	7.85	41.38%	1.82	15.61%	29.82%	$ 857.31
8	LIBERIA PSC (2009)	8.37	22.50%	2.86	18.00%	42.25%	$ 1,936.65
9	NIGERIA JDZ PSC (2003)	7.85	16.78%	1.36	14.09%	22.12%	$ 375.86
10	NIGERIA PSC (1993)	7.99	17.90%	2.51	17.31%	39.20%	$ 1,574.33
11	NIGERIA PSC (2000)	8.05	22.25%	2.26	16.75%	34.30%	$ 1,311.21
12	NIGERIA PSC (2005)	8.41	26.85%	1.74	15.37%	33.95%	$ 771.80

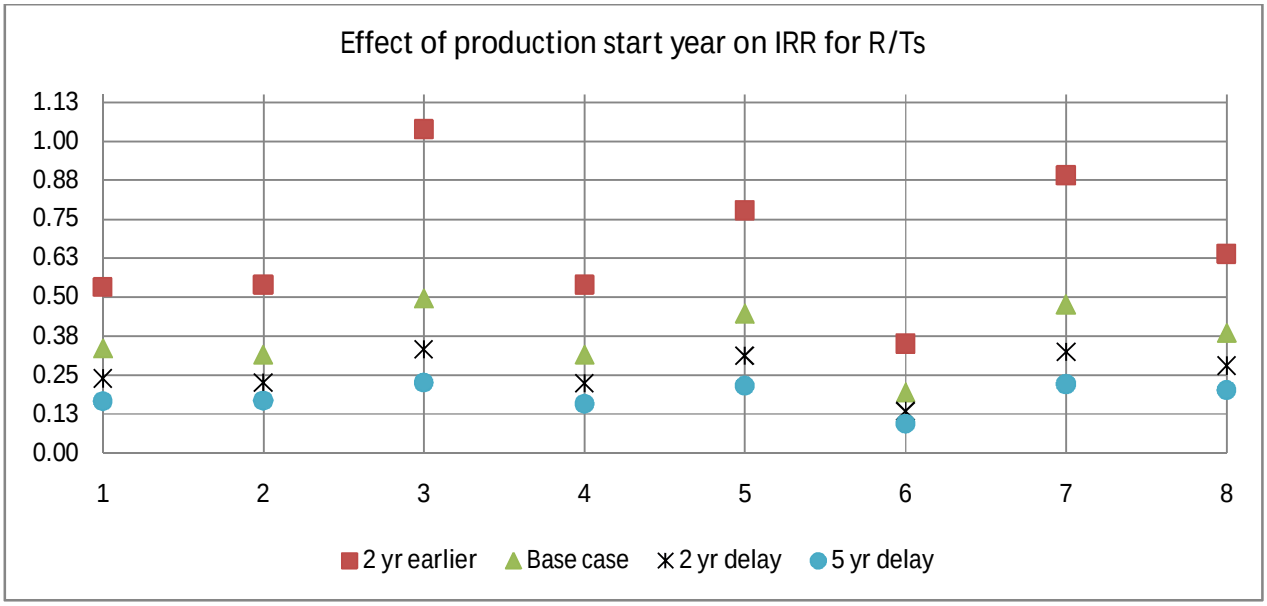
APPENDIX B-2: Summary of R/Ts' DPO, ERR, PI, GRR, SI, and DNCF

KEY	COUNTRIES	DPO (years)	ERR	PI	GRR	Savings Index	Contr. DNCF
1	CAMEROON Rente Miniere (1995)	9.46	28.81%	2.28	16.79%	42.50%	$ 1,331.18
2	CHAD R/T (1999)	9.49	12.50%	2.76	17.80%	50.00%	$ 1,827.50
3	GHANA R/T (1997)	8.54	10.47%	2.93	18.13%	49.15%	$ 2,010.33
4	MALI R/T (1970)	8.14	12.50%	2.22	16.66%	50.00%	$ 1,271.47
5	NIGER R/T (1992)	8.57	12.50%	3.28	18.73%	55.00%	$ 2,369.84
6	NIGERIA R/T (2000)	10.77	16.67%	1.29	13.82%	14.70%	$ 304.92
7	SENEGAL R/T (2000)	8.56	7.65%	3.54	19.15%	58.50%	$ 2,644.42
8	SIERRA LEONE RT (2001)	8.43	6.50%	3.63	19.29%	63.00%	$ 2,740.75

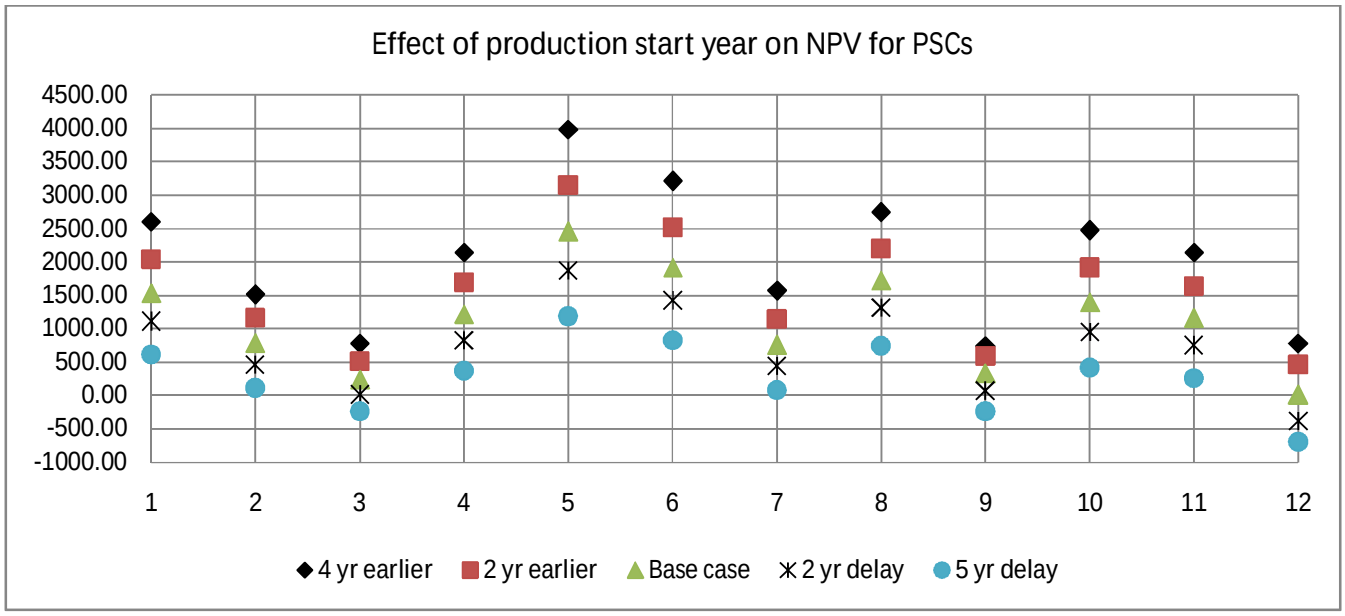
APPENDIX B-3: Effect of production start year on IRR for PSCs



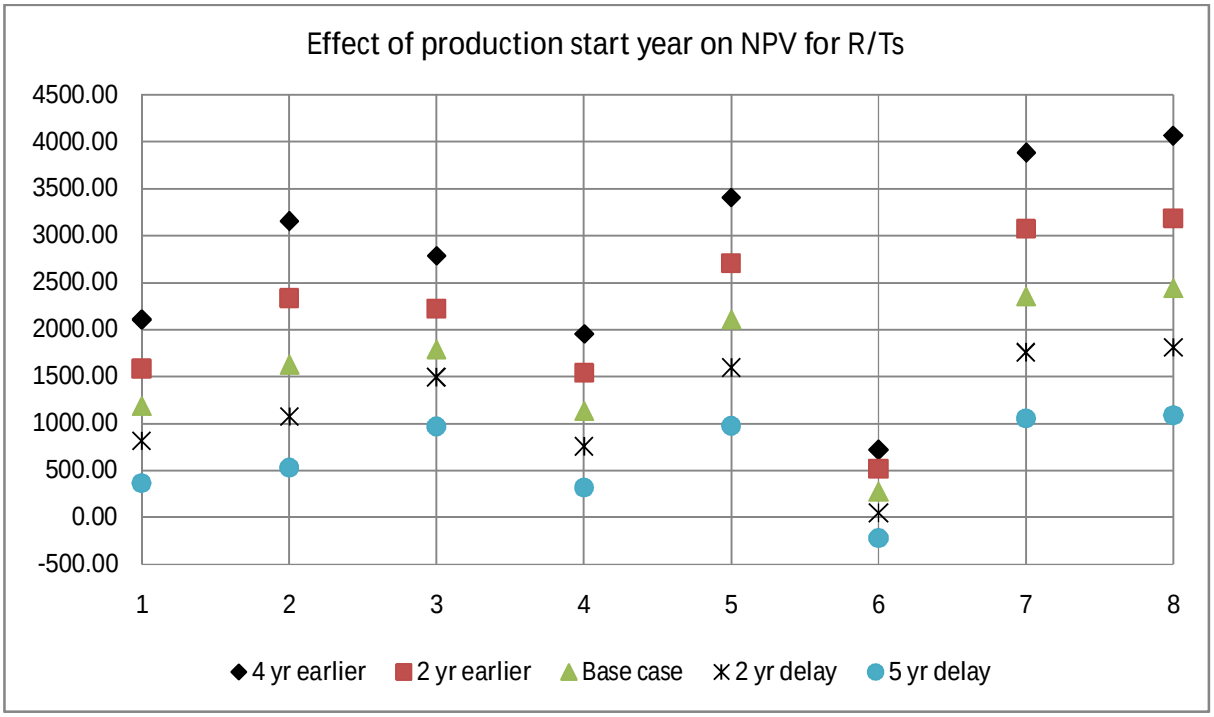
APPENDIX B-4: Effect of production start year on IRR for R/Ts



APPENDIX B-5: Effect of production start year on NPV for PSCs



APPENDIX B-6: Effect of production start year on NPV for R/Ts



APPENDIX C: Summary of deterministic economic indicator indices for the Gulf of Guinea region

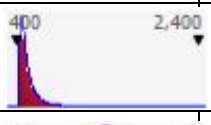
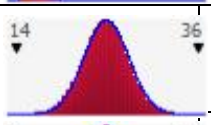
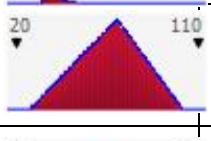
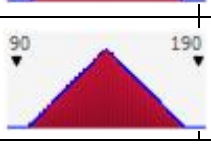
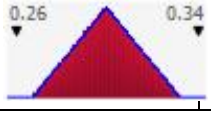
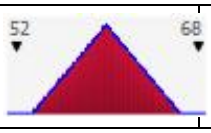
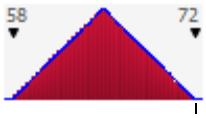
PFS	Undisc. GTake	Discounted GTake	Contractor's IRR	Payout (years)	Contractor's NPV ($MM)	ERR	Savings Index	PVR	PI	GRR	CONTR DNCF ($MM)	ROI/ PIR	FLI
ANGOLA PSC (1990)	79.86%	82.98%	30.07%	8.12	$ 697.24	30.29%	22.21%	0.75	1.75	15.41%	$ 784.40	0.40	0.04
ANGOLA PSC (2004) PSA	79.28%	81.43%	35.04%	8.21	$ 790.97	30.29%	22.21%	0.85	1.85	15.70%	$ 889.84	0.46	0.03
CAMEROON Rente Miniere (1995)	71.12%	74.47%	33.57%	9.46	$ 1,183.28	28.81%	42.50%	1.28	2.28	16.79%	$ 1,331.18	0.68	0.05
COTE D'IVOIRE PSC (1996)	87.60%	94.49%	17.39%	7.74	$ 240.83	52.42%	22.27%	0.26	1.26	13.69%	$ 270.94	0.14	0.08
COTE D'IVOIRE PSC R-Factor (1996)	66.71%	72.06%	29.11%	7.74	$ 1,221.00	39.87%	36.82%	1.32	2.32	16.88%	$ 1,373.63	0.70	0.08
EQUATORIAL GUINEA PSC (1998)	47.02%	47.21%	45.88%	8.12	$ 2,455.62	16.02%	60.01%	2.65	3.65	19.32%	$ 2,762.57	1.41	0.00
EQUATORIAL GUINEA PSC (2006)	56.88%	59.11%	39.44%	8.76	$ 1,920.58	18.06%	52.01%	2.07	3.07	18.39%	$ 2,160.65	1.11	0.04
GABON PSC (1997)	76.36%	82.56%	24.26%	7.85	$ 762.05	41.38%	29.82%	0.82	1.82	15.61%	$ 857.31	0.44	0.08
GHANA R/T (1997)	60.90%	61.71%	49.49%	8.54	$ 1,786.96	10.47%	49.15%	1.93	2.93	18.13%	$ 2,010.33	1.03	0.01
LIBERIA PSC (2009)	63.61%	64.33%	51.04%	8.37	$ 1,721.47	22.50%	42.25%	1.86	2.86	18.00%	$ 1,936.65	0.99	0.01
NIGERIA JDZ PSC (2003)	88.13%	92.39%	20.27%	7.85	$ 334.10	16.78%	22.12%	0.36	1.36	14.09%	$ 375.86	0.19	0.05
NIGERIA PIB (2009 Proposed)	73.00%	76.57%	29.93%	8.15	$ 1,060.11	9.52%	54.88%	1.15	2.15	16.47%	$ 1,192.62	0.61	0.05
NIGERIA PSC (1993)	64.18%	67.98%	31.67%	7.99	$ 1,399.40	17.90%	39.20%	1.51	2.51	17.31%	$ 1,574.33	0.81	0.06
NIGERIA PSC (2000)	68.64%	73.33%	28.90%	8.05	$ 1,165.52	22.25%	34.30%	1.26	2.26	16.75%	$ 1,311.21	0.67	0.07
NIGERIA PSC (2005)	91.63%	99.72%	12.76%	8.41	$ 12.37	26.85%	33.95%	0.01	1.01	12.57%	$ 771.80	0.39	0.09
NIGERIA R/T (2000)	89.63%	93.97%	19.43%	10.77	$ 271.04	16.67%	14.70%	0.29	1.29	13.82%	$ 304.92	0.16	0.05
SENEGAL R/T (2000)	47.22%	49.45%	47.61%	8.56	$ 2,350.60	7.65%	58.50%	2.54	3.54	19.15%	$ 2,644.42	1.35	0.05
SIERRA LEONE RT (2001)	42.97%	46.83%	38.55%	8.43	$ 2,436.22	6.50%	63.00%	2.63	3.63	19.29%	$ 2,740.75	1.40	0.09

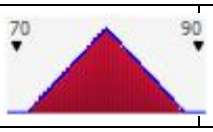
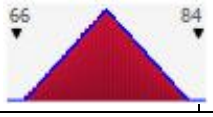
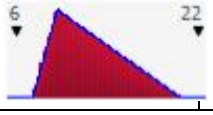
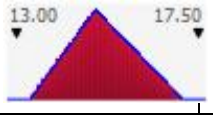
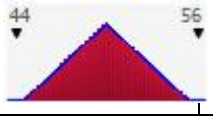
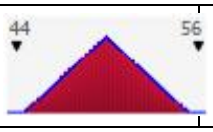
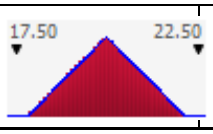
APPENDIX D-1: Summary of Stochastic input distribution

@RISK Input Results

Performed By: Joseph ECHENDU

Date: Thursday, November 17, 2011 12:05:56 AM

	Name	Worksheet	Cell	Graph	Min	Mean	Max	5%	95%	Errors
	STOIIP	INPUT	H3		502.27	599.98	2284.32	517.97	777.92	0
	% Recovery of STOIIP	INPUT	H4		14.7	25.0	34.5	20.9	29.1	0
	Min Well Rate (MBOPD)	INPUT	H6		6.03	10.00	13.79	8.35	11.64	0
	Discount Factor	INPUT	H9		10.04%	11.25%	33.19%	10.22 %	13.48%	0
	Initial Oil Price	INPUT	H12		30.46	66.67	99.67	41.83	89.75	0
	Final Oil Price	INPUT	H13		100.54	140.00	179.44	112.65	167.34	0
Category: Additional Operating Cost/IDC										
	Additional Operating Cost/IDC / Cost/year ($MM/yr)	INPUT	C48		$ 0.27	$ 0.30	$ 0.33	$ 0.28	$ 0.32	0
Category: Appraisal Well(s)										
	Appraisal Well(s) / Cost/Well ($MM/well)	INPUT	C39		$54.06	$60.00	$65.95	$55.90	$64.10	0
Category: Appraisal Well(s) (Optional)										
	Appraisal Well(s) (Optional) / Cost/Well ($MM/well)	INPUT	C40		$58.58	$65.00	$71.42	$60.55	$69.44	0

Category: Development Well(s)										
	Development Well(s) / Cost/Well ($MM/well)	INPUT	C41		$72.06	$80.00	$87.93	$74.53	$85.47	0
Category: Development Well(s) (Optional)										
	Development Well(s) (Optional) / Cost/Well ($MM/well)	INPUT	C42		$67.59	$75.00	$82.42	$69.87	$80.13	0
Category: Exploration Cost										
	Exploration Cost / Cost/year ($MM/yr)	INPUT	C45		$ 8.03	$12.67	$19.97	$ 9.09	$17.55	0
Category: Field/Facilities Cost										
	Field/Facilities Cost / Cost/year ($MM/yr)	INPUT	C49		$67.60	$75.00	$82.40	$69.87	$80.13	0
Category: G&G Cost										
	G&G Cost / Cost/year ($MM/yr)	INPUT	C46		$13.51	$15.17	$16.99	$14.01	$16.41	0
Category: TOTAL Dry hole(s)										
	TOTAL Dry hole(s) / Cost/Well ($MM/well)	INPUT	C43		$45.01	$50.00	$54.95	$46.58	$53.42	0
Category: Wildcat Well										
	Wildcat Well / Cost/Well ($MM/well)	INPUT	C38		$45.02	$50.00	$54.93	$46.58	$53.42	0
Category: Yearly Operating Cost										
	Yearly Operating Cost / Cost/year ($MM/yr)	INPUT	C47		$18.02	$20.00	$21.98	$18.63	$21.37	0

APPENDIX D-2: Summary of P50 and P90 certainty on GTake, IRR, DPO indices for the Gulf of Guinea region

	GTake (%)				IRR (%				DPO (Years)			
	P(50) Success		P(90) Success		P(50) Success		P(90) Success		P(50) Success		P(90) Success	
PFS	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
ANGOLA PSC (1990)	75.37%	76.77%	74.26%	78.26%	17.22%	23.74%	12.22%	28.03%	8.90	9.96	8.36	11.75
ANGOLA PSC (2004) PSA	74.12%	75.89%	72.52%	77.53%	21.07%	28.09%	15.78%	32.75%	9.08	10.25	8.48	12.29
CAMEROON Rente Miniere (1995)	71.77%	72.41%	71.38%	74.63%	18.70%	25.60%	13.30%	30.30%	9.97	11.85	9.14	16.24
CHAD R/T (1999)	60.63%	63.01%	59.67%	66.77%	17.30%	23.70%	12.40%	28.40%	10.38	12.47	9.18	17.18
COTE D'IVOIRE PSC (1996)	82.74%	84.94%	81.08%	86.70%	9.96%	13.84%	6.96%	16.36%	8.35	9.37	8.01	10.92
COTE D'IVOIRE PSC R-Factor (1996)	60.05%	60.75%	60.05%	65.42%	18.33%	24.49%	12.85%	26.72%	8.47	9.50	8.01	10.92
EQUATORIAL GUINEA PSC (1998)	44.14%	45.49%	43.34%	46.75%	27.10%	35.70%	20.50%	41.90%	8.94	10.07	8.37	11.95
EQUATORIAL GUINEA PSC (2006)	56.05%	57.92%	55.37%	61.24%	21.90%	29.90%	15.70%	35.70%	9.57	11.07	9.11	14.24
GABON PSC (1997)	71.65%	72.70%	71.27%	74.80%	14.14%	19.42%	10.10%	22.99%	8.60	9.66	8.11	11.20
GHANA R/T (1997)	56.20%	57.88%	53.28%	60.42%	29.30%	38.50%	22.30%	45.10%	9.16	10.36	8.75	12.75
LIBERIA PSC (2009)	64.00%	64.64%	63.75%	65.76%	31.60%	40.60%	24.40%	46.80%	9.24	10.49	8.66	12.52
MALI R/T (1970)	60.17%	61.09%	58.92%	62.69%	16.90%	23.50%	11.90%	28.50%	8.97	10.15	8.37	12.17
NIGER R/T (1992)	53.02%	53.67%	52.77%	54.74%	26.00%	34.50%	19.50%	40.60%	9.39	10.72	8.83	13.17
NIGERIA JDZ PSC (2003)	86.06%	87.04%	83.72%	87.22%	10.91%	15.10%	8.01%	18.57%	8.55	9.61	8.06	11.20
NIGERIA PSC (1993)	64.00%	64.46%	63.87%	65.33%	16.90%	23.60%	12.00%	28.50%	8.75	9.85	8.19	11.67
NIGERIA PSC (2000)	68.69%	69.58%	68.43%	71.33%	14.80%	21.20%	10.10%	25.90%	8.71	9.82	8.27	11.86
NIGERIA R/T (2000)	89.75%	89.95%	89.67%	90.29%	9.08%	13.62%	5.97%	17.17%	10.94	17.23	10.94	22.00
SENEGAL R/T (2000)	47.60%	49.02%	47.28%	52.12%	27.40%	36.90%	20.00%	43.30%	9.39	10.81	8.82	13.52
SIERRA LEONE RT (2001)	43.98%	45.69%	43.34%	48.47%	22.00%	29.50%	16.30%	35.00%	9.31	10.64	8.72	13.02

APPENDIX D-3: Summary of P50 and P90 certainty on NPV, GRR, ROI indices for the Gulf of Guinea region

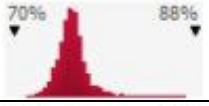
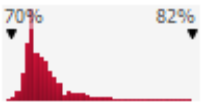
	NPV ($MM)				GRR (%)				ROI (Fraction)			
	P(50) Success		P(90) Success		P(50) Success		P(90) Success		P(50) Success		P(90) Success	
PFS	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
ANGOLA PSC (1990)	$ 225.00	$ 522.00	$ 23.00	$ 762.00	11.98%	13.42%	11.12%	15.15%	0.13	0.30	0.01	0.44
ANGOLA PSC (2004) PSA	$ 329.00	$ 625.00	$ 131.00	$ 863.00	12.44%	13.79%	11.66%	15.54%	0.19	0.36	0.08	0.50
CAMEROON Rente Miniere (1995)	$ 323.00	$ 743.00	$ 65.00	$ 1,143.00	12.64%	14.37%	11.40%	15.99%	0.19	0.43	0.04	0.66
CHAD R/T (1999)	$ 393.00	$ 991.00	$ 42.00	$ 1,561.00	13.01%	15.08%	11.41%	16.79%	0.23	0.57	0.03	0.90
COTE D'IVOIRE PSC (1996)	$ 2.00	$ 247.00	$ (231.00)	$ 304.00	10.65%	11.98%	9.60%	13.39%	0.00	0.14	(0.14)	0.18
COTE D'IVOIRE PSC R-Factor (1996)	$ 474.00	$ 1,027.00	$ 70.00	$ 1,264.00	13.10%	14.91%	11.57%	16.30%	0.25	0.56	0.04	0.73
EQUATORIAL GUINEA PSC (1998)	$ 921.00	$ 1,707.00	$ 443.00	$ 2,438.00	14.82%	16.86%	13.23%	18.52%	0.54	0.99	0.26	1.40
EQUATORIAL GUINEA PSC (2006)	$ 598.00	$ 1,257.00	$ 197.00	$ 1,879.00	13.76%	15.82%	12.15%	17.50%	0.35	0.73	0.12	1.08
GABON PSC (1997)	$ 172.00	$ 560.00	$ (84.00)	$ 869.00	11.98%	13.68%	10.64%	15.15%	0.10	0.33	(0.05)	0.50
GHANA R/T (1997)	$ 744.00	$ 1,299.00	$ 403.00	$ 1,775.00	14.22%	15.90%	12.99%	17.49%	0.44	0.76	0.24	1.02
LIBERIA PSC (2009)	$ 661.00	$ 1,178.00	$ 346.00	$ 1,671.00	13.92%	15.63%	12.70%	17.31%	0.39	0.68	0.20	0.96
MALI R/T (1970)	$ 265.00	$ 686.00	$ 10.00	$ 1,088.00	12.40%	14.17%	11.12%	15.79%	0.16	0.40	0.01	0.62
NIGER R/T (1992)	$ 740.00	$ 1,407.00	$ 337.00	$ 2,045.00	14.24%	16.18%	12.78%	17.84%	0.43	0.82	0.20	1.17
NIGERIA JDZ PSC (2003)	$ 4.00	$ 206.00	$ (153.00)	$ 356.00	10.90%	12.18%	10.05%	13.71%	0.00	0.12	(0.09)	0.20
NIGERIA PSC (1993)	$ 280.00	$ 805.00	$ 16.00	$ 1,358.00	12.75%	14.71%	11.25%	16.36%	0.20	0.50	0.01	0.78
NIGERIA PSC (2000)	$ 210.00	$ 682.00	$ 2.00	$ 1,572.00	12.18%	14.13%	10.67%	15.78%	0.12	0.40	0.00	0.91
NIGERIA R/T (2000)	$ 3.00	$ 336.00	N/A	$ 257.00	10.51%	11.79%	9.67%	13.37%	0.00	0.18	N/A	N/A
SENEGAL R/T (2000)	$ 821.00	$ 1,574.00	$ 360.00	$ 2,283.00	14.50%	16.56%	12.88%	18.23%	0.48	0.91	0.21	1.31
SIERRA LEONE RT (2001)	$ 679.00	$ 1,487.00	$ 281.00	$ 2,357.00	14.37%	16.55%	12.60%	18.29%	0.45	0.92	0.17	1.35

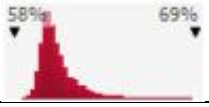
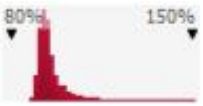
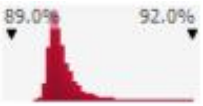
APPENDIX D-4: Summary of probability distributions on objective functions for the Gulf of Guinea region

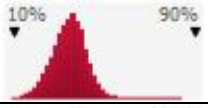
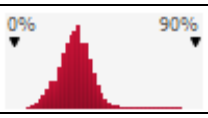
@RISK Output Results

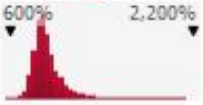
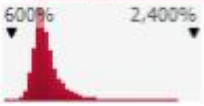
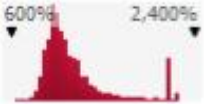
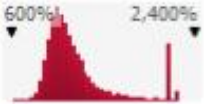
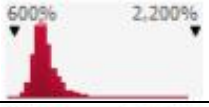
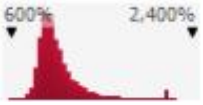
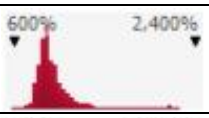
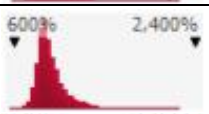
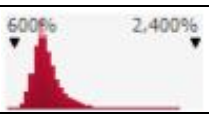
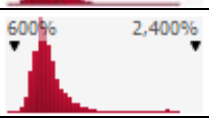
Performed By: Joseph ECHENDU

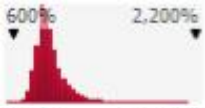
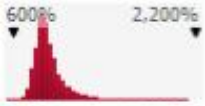
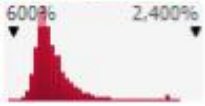
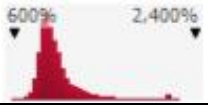
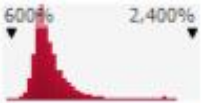
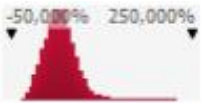
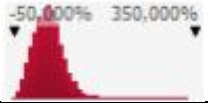
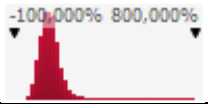
Date: Thursday, November 17, 2011 12:07:26 AM

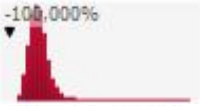
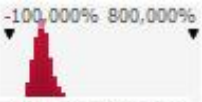
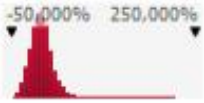
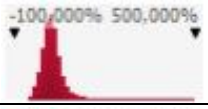
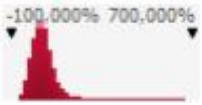
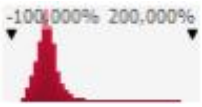
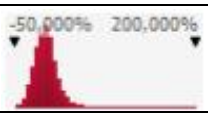
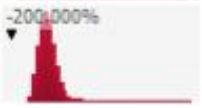
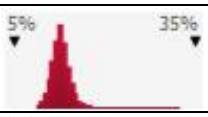
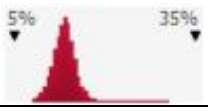
Name	Graph	Min	Mean	Max	5%	95%
Reserves		88.75	150.05	698.35	115.80	202.26
Max Plateau Rate		24.31	41.11	191.33	31.72	55.41
Reserve (MMBBL) / 800 - 1000m		84.03536	146.623	720.1044	111.4784	200.4445
ANGOLA PSC (1990) / Undiscounted Gtake		71.98%	76.13%	86.73%	74.26%	78.26%
ANGOLA PSC (2004) PSA / Undiscounted Gtake		69.44%	75.02%	86.56%	72.52%	77.53%
CAMEROON Rente Miniere (1995) / Undiscounted Gtake		70.34%	72.46%	81.28%	71.38%	74.63%
CHAD R/T (1999) / Undiscounted Gtake		57.03%	62.38%	76.54%	59.67%	66.77%
COTE D'IVOIRE PSC (1996) / Undiscounted Gtake		73.50%	83.83%	89.41%	81.08%	86.70%
COTE D'IVOIRE PSC R-Factor (1996) / Undiscounted Gtake		60.04%	60.89%	83.75%	60.05%	65.42%
EQUATORIAL GUINEA PSC (1998) / Undiscounted Gtake		42.36%	44.89%	60.64%	43.34%	46.75%
EQUATORIAL GUINEA PSC (2006) / Undiscounted Gtake		54.31%	57.48%	69.19%	55.37%	61.24%
GABON PSC (1997) / Undiscounted Gtake		70.26%	72.45%	81.57%	71.27%	74.80%

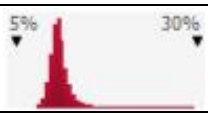
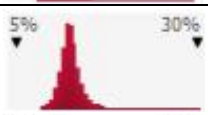
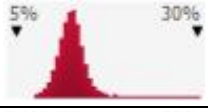
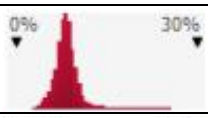
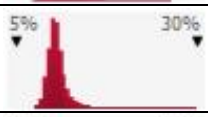
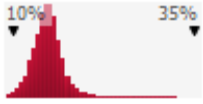
GHANA R/T (1997) / Undiscounted Gtake		50.16%	57.13%	61.67%	53.28%	60.42%
LIBERIA PSC (2009) / Undiscounted Gtake		63.23%	64.50%	73.15%	63.75%	65.76%
MALI R/T (1970) / Undiscounted Gtake		58.90%	60.87%	68.59%	59.82%	62.69%
NIGER R/T (1992) / Undiscounted Gtake		52.08%	53.51%	58.16%	52.77%	54.74%
NIGERIA JDZ PSC (2003) / Undiscounted Gtake		76.67%	86.06%	88.47%	83.72%	87.22%
NIGERIA PIB (2008 Proposed) / Undiscounted Gtake		69.50%	73.95%	78.79%	71.29%	76.87%
NIGERIA PIB (2009 Proposed) / Undiscounted Gtake		67.52%	72.36%	77.41%	69.23%	75.62%
NIGERIA PSC (1993) / Undiscounted Gtake		63.63%	64.41%	68.52%	63.87%	65.33%
NIGERIA PSC (2000) / Undiscounted Gtake		68.00%	69.50%	77.13%	68.43%	71.33%
NIGERIA PSC (2005) / Undiscounted Gtake		89.60%	96.88%	148.94%	92.34%	105.78%
NIGERIA R/T (2000) / Undiscounted Gtake		89.48%	89.90%	91.95%	89.67%	90.29%
SENEGAL R/T (2000) / Undiscounted Gtake		46.66%	48.80%	62.25%	47.28%	52.12%
SIERRA LEONE RT (2001) / Undiscounted Gtake		41.62%	45.26%	56.94%	43.34%	48.47%
ANGOLA PSC (1990) / Contractor's IRR		5.51%	20.46%	47.93%	12.22%	28.03%
ANGOLA PSC (2004) PSA / Contractor's IRR		8.59%	24.55%	56.49%	15.78%	32.75%
CAMEROON Rente Miniere (1995) / Contractor's IRR		5.58%	22.20%	59.71%	13.30%	30.34%
CHAD R/T (1999) / Contractor's IRR		5.67%	20.54%	58.31%	12.40%	28.43%

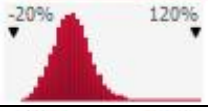
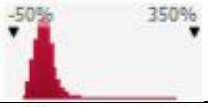
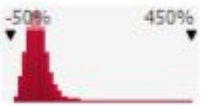
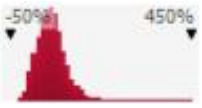
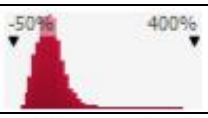
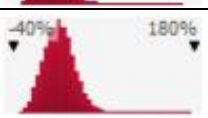
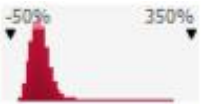
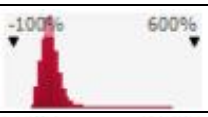
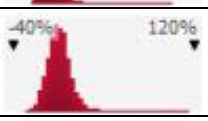
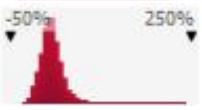
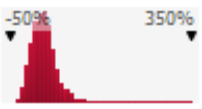
COTE D'IVOIRE PSC (1996) / Contractor's IRR		3.54%	11.89%	34.48%	6.96%	16.36%
COTE D'IVOIRE PSC R-Factor (1996) / Contractor's IRR		6.30%	20.53%	41.33%	12.85%	26.72%
EQUATORIAL GUINEA PSC (1998) / Contractor's IRR		11.83%	31.44%	77.64%	20.49%	41.94%
EQUATORIAL GUINEA PSC (2006) / Contractor's IRR		7.44%	25.94%	67.94%	15.74%	35.73%
GABON PSC (1997) / Contractor's IRR		5.04%	16.78%	42.79%	10.10%	22.99%
GHANA R/T (1997) / Contractor's IRR		12.42%	33.91%	87.20%	22.30%	45.09%
LIBERIA PSC (2009) / Contractor's IRR		12.26%	36.03%	82.27%	24.36%	46.80%
MALI R/T (1970) / Contractor's IRR		5.15%	20.25%	59.21%	11.87%	28.46%
NIGER R/T (1992) / Contractor's IRR		10.47%	30.29%	76.54%	19.49%	40.57%
NIGERIA JDZ PSC (2003) / Contractor's IRR		4.67%	13.10%	39.50%	8.01%	18.57%
NIGERIA PIB (2008 Proposed) / Contractor's IRR		5.53%	18.42%	53.05%	11.69%	25.09%
NIGERIA PIB (2009 Proposed) / Contractor's IRR		6.53%	19.33%	52.42%	12.63%	25.95%
NIGERIA PSC (1993) / Contractor's IRR		5.52%	20.31%	58.97%	11.97%	28.54%
NIGERIA PSC (2000) / Contractor's IRR		4.05%	18.06%	55.28%	10.12%	25.92%
NIGERIA PSC (2005) / Contractor's IRR		-4.38%	4.28%	31.74%	-1.20%	10.32%
NIGERIA R/T (2000) / Contractor's IRR		2.28%	11.46%	39.88%	5.97%	17.17%
SENEGAL R/T (2000) / Contractor's IRR		9.44%	32.07%	81.44%	19.96%	43.34%

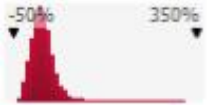
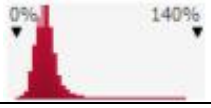
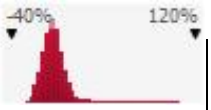
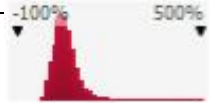
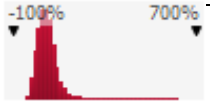
SIERRA LEONE RT (2001) / Contractor's IRR		8.28%	25.81%	68.71%	16.25%	35.00%
ANGOLA PSC (1990) / Payout (years)		6.26	9.69	21.00	8.36	11.75
ANGOLA PSC (2004) PSA / Payout (years)		6.28	9.96	22.00	8.48	12.29
CAMEROON Rente Miniere (1995) / Payout (years)		7.08	12.30	22.00	9.71	21.00
CHAD R/T (1999) / Payout (years)		7.00	12.60	22.00	9.79	21.00
COTE D'IVOIRE PSC (1996) / Payout (years)		6.11	9.20	21.00	8.01	10.92
COTE D'IVOIRE PSC R-Factor (1996) / Payout (years)		6.11	9.20	21.00	8.01	10.92
EQUATORIAL GUINEA PSC (1998) / Payout (years)		6.26	9.78	21.00	8.37	11.95
EQUATORIAL GUINEA PSC (2006) / Payout (years)		6.55	11.00	22.00	9.11	14.24
GABON PSC (1997) / Payout (years)		6.15	9.37	21.00	8.11	11.20
GHANA R/T (1997) / Payout (years)		6.55	10.26	22.00	8.75	12.75
LIBERIA PSC (2009) / Payout (years)		6.37	10.17	22.00	8.66	12.52
MALI R/T (1970) / Payout (years)		6.27	9.86	22.00	8.37	12.17
NIGER R/T (1992) / Payout (years)		6.52	10.45	22.00	8.83	13.17
NIGERIA JDZ PSC (2003) / Payout (years)		6.13	9.32	21.00	8.06	11.20
NIGERIA PIB (2008 Proposed) / Payout (years)		6.23	9.83	22.00	8.26	12.25
NIGERIA PIB (2009 Proposed) / Payout (years)		6.21	9.88	22.00	8.28	12.37

NIGERIA PSC (1993) / Payout (years)		6.20	9.56	21.00	8.19	11.67
NIGERIA PSC (2000) / Payout (years)		6.24	9.68	21.00	8.27	11.86
NIGERIA PSC (2005) / Payout (years)		6.40	10.37	22.00	8.64	13.30
NIGERIA R/T (2000) / Payout (years)		7.38	16.73	23.00	10.94	22.00
SENEGAL R/T (2000) / Payout (years)		6.50	10.54	22.00	8.82	13.52
SIERRA LEONE RT (2001) / Payout (years)		6.39	10.35	22.00	8.72	13.02
ANGOLA PSC (1990) / Contractor's NPV ($MM)		$ (220.21)	$ 380.15	$ 2,169.75	$ 22.87	$ 762.22
ANGOLA PSC (2004) PSA / Contractor's NPV ($MM)		$ (131.97)	$ 483.98	$ 2,272.43	$ 131.38	$ 862.79
CAMEROON Rente Miniere (1995) / Contractor's NPV ($MM)		$ (212.82)	$ 557.40	$ 5,793.00	$ 64.68	$ 1,143.08
CHAD R/T (1999) / Contractor's NPV ($MM)		$ (320.24)	$ 726.47	$ 8,336.02	$ 41.79	$ 1,561.27
COTE D'IVOIRE PSC (1996) / Contractor'sNPV ($MM)		$ (447.84)	$ 41.71	$ 1,770.30	$ (231.26)	$ 304.49
COTE D'IVOIRE PSC R-Factor (1996) / Contractor's NPV ($MM)		$ (333.84)	$ 691.77	$ 2,739.96	$ 69.69	$ 1,264.23
EQUATORIAL GUINEA PSC (1998) / Contractor's NPV ($MM)		$ (104.83)	$ 1,354.65	$ 8,361.19	$ 443.33	$ 2,438.50
EQUATORIAL GUINEA PSC (2006) / Contractor's NPV ($MM)		$ (218.97)	$ 961.64	$ 6,829.33	$ 196.89	$ 1,879.14
GABON PSC (1997) / Contractor's NPV ($MM)		$ (389.01)	$ 374.50	$ 3,238.53	$ (83.73)	$ 869.19
GHANA R/T (1997) / Contractor's NPV ($MM)		$ (45.90)	$ 1,045.53	$ 7,669.86	$ 402.86	$ 1,774.98

LIBERIA PSC (2009) / Contractor's NPV ($MM)		$ (14.60)	$ 947.41	$ 7,034.57	$ 345.52	$ 1,671.49
MALI R/T (1970) / Contractor's NPV ($MM)		$ (265.14)	$ 499.22	$ 5,733.37	$ 10.21	$ 1,087.57
NIGER R/T (1992) / Contractor's NPV ($MM)		$ (109.40)	$ 1,111.54	$ 9,509.13	$ 336.88	$ 2,045.49
NIGERIA JDZ PSC (2003) / Contractor's NPV ($MM)		$ (354.95)	$ 88.41	$ 2,109.70	$ (153.04)	$ 356.13
NIGERIA PIB (2008 Proposed) / Contractor's NPV ($MM)		$ (299.91)	$ 416.75	$ 4,793.42	$ 0.11	$ 898.71
NIGERIA PIB (2009 Proposed) / Contractor's NPV ($MM)		$ (275.24)	$ 470.23	$ 4,462.57	$ 46.93	$ 962.20
NIGERIA PSC (1993) / Contractor's NPV ($MM)		$ (331.90)	$ 629.16	$ 6,508.43	$ 16.08	$ 1,358.43
NIGERIA PSC (2000) / Contractor's NPV ($MM)		$ (390.28)	$ 470.47	$ 6,025.75	$ (81.15)	$ 1,125.73
NIGERIA PSC (2005) / Contractor's NPV ($MM)		$ (716.26)	$ (313.76)	$ 1,753.70	$ (557.23)	$ (41.79)
NIGERIA R/T (2000) / Contractor's NPV ($MM)		$ (354.36)	$ 16.07	$ 1,946.71	$ (201.92)	$ 257.07
SENEGAL R/T (2000) / Contractor's NPV ($MM)		$ (104.68)	$ 1,236.48	$ 9,368.36	$ 360.05	$ 2,282.56
SIERRA LEONE RT (2001) / Contractor's NPV ($MM)		$ (243.34)	$ 1,219.45	$ 11,488.61	$ 281.32	$ 2,357.49
ANGOLA PSC (1990) / GRR		9.54%	12.96%	31.77%	11.12%	15.15%
ANGOLA PSC (2004) PSA / GRR		10.26%	13.39%	32.62%	11.66%	15.54%
CAMEROON Rente Miniere (1995) / GRR		9.65%	13.59%	31.70%	11.40%	15.99%
CHAD R/T (1999) / GRR		9.19%	14.08%	30.23%	11.41%	16.79%
COTE D'IVOIRE PSC (1996) / GRR		7.88%	11.38%	27.93%	9.60%	13.39%

COTE D'IVOIRE PSC R-Factor (1996) / GRR		9.39%	14.03%	30.38%	11.57%	16.30%
EQUATORIAL GUINEA PSC (1998) / GRR		11.06%	15.88%	33.72%	13.23%	18.52%
EQUATORIAL GUINEA PSC (2006) / GRR		9.94%	14.83%	32.45%	12.15%	17.50%
GABON PSC (1997) / GRR		8.72%	12.88%	29.00%	10.64%	15.15%
GHANA R/T (1997) / GRR		11.13%	15.14%	33.88%	12.99%	17.49%
LIBERIA PSC (2009) / GRR		10.91%	14.86%	34.08%	12.70%	17.31%
MALI R/T (1970) / GRR		9.36%	13.36%	31.08%	11.12%	15.79%
NIGER R/T (1992) / GRR		10.75%	15.27%	33.45%	12.78%	17.84%
NIGERIA JDZ PSC (2003) / GRR		8.76%	11.64%	29.01%	10.05%	13.71%
NIGERIA PIB (2008 Proposed) / GRR		9.28%	13.07%	29.79%	11.10%	15.30%
NIGERIA PIB (2009 Proposed) / GRR		9.58%	13.28%	30.06%	11.35%	15.49%
NIGERIA PSC (1993) / GRR		9.10%	13.78%	30.51%	11.25%	16.36%
NIGERIA PSC (2000) / GRR		8.51%	13.20%	29.65%	10.67%	15.78%
NIGERIA PSC (2005) / GRR		3.91%	8.97%	25.29%	6.45%	11.48%
NIGERIA R/T (2000) / GRR		8.41%	11.26%	29.25%	9.67%	13.37%
SENEGAL R/T (2000) / GRR		10.54%	15.57%	33.85%	12.88%	18.23%
SIERRA LEONE RT (2001) / GRR		10.15%	15.49%	32.13%	12.60%	18.29%

ANGOLA PSC (1990) / ROI/PIR		-0.14	0.22	1.14	0.01	0.44
ANGOLA PSC (2004) PSA / ROI/PIR		-0.08	0.28	1.20	0.08	0.50
CAMEROON Rente Miniere (1995) / ROI/PIR		-0.13	0.32	3.05	0.04	0.65
CHAD R/T (1999) / ROI/PIR		-0.20	0.42	4.39	0.02	0.90
COTE D'IVOIRE PSC (1996) / ROI/PIR		-0.27	0.02	0.93	-0.13	0.17
COTE D'IVOIRE PSC R-Factor (1996) / ROI/PIR		-0.21	0.40	1.50	0.04	0.72
EQUATORIAL GUINEA PSC (1998) / ROI/PIR		-0.07	0.79	4.41	0.26	1.40
EQUATORIAL GUINEA PSC (2006) / ROI/PIR		-0.14	0.56	3.60	0.12	1.08
GABON PSC (1997) / ROI/PIR		-0.24	0.22	1.71	-0.05	0.50
GHANA R/T (1997) / ROI/PIR		-0.03	0.61	4.04	0.24	1.02
LIBERIA PSC (2009) / ROI/PIR		-0.01	0.55	3.71	0.20	0.96
MALI R/T (1970) / ROI/PIR		-0.17	0.29	3.02	0.01	0.62
NIGER R/T (1992) / ROI/PIR		-0.07	0.64	5.01	0.20	1.17
NIGERIA JDZ PSC (2003) / ROI/PIR		-0.22	0.05	1.11	-0.09	0.20
NIGERIA PIB (2008 Proposed) / ROI/PIR		-0.19	0.24	2.53	0.00	0.52
NIGERIA PIB (2009 Proposed) / ROI/PIR		-0.17	0.27	2.35	0.03	0.55
NIGERIA PSC (1993) / ROI/PIR		-0.21	0.36	3.43	0.01	0.78

NIGERIA PSC (2000) / ROI/PIR		-0.24	0.27	3.18	-0.05	0.65
NIGERIA PSC (2005) / ROI/PIR		0.06	0.27	1.28	0.17	0.40
NIGERIA R/T (2000) / ROI/PIR		-0.22	0.01	1.03	-0.12	0.15
SENEGAL R/T (2000) / ROI/PIR		-0.07	0.72	4.94	0.21	1.31
SIERRA LEONE RT (2001) / ROI/PIR		-0.15	0.71	6.05	0.17	1.35