COMPARATIVE ANALYSIS OF NIGERIA PETROLEUM FISCAL SYSTEMS USING ROYALTY AND TAX OPTIMISATION MODELS TO DRIVE INVESTMENTS

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ABSTRACT

Declining Foreign Direct Investment (FDI) in Nigerian Oil and Gas Industry (NOGI) has been attributed to inappropriateness of the country's petroleum fiscal regimes and tax systems. Extant literature identified knowledge gap relating to the analytical measurement of the relationship between key fiscal terms and economic metrics, which provides understanding of the effects of the proposed Petroleum Industry Fiscal Bill (PIFB), 2012 on FDI. This study was designed to compare Nigeria's current and post PIFB fiscal regimes against selected world fiscal arrangements to determine if the proposed legislation, when enacted will improve competitiveness and FDI in the NOGI.

The study, adopted a quantitative research design, based on petroleum taxation theory used purposive sampling technique to select five fixed offshore crude production projects, labeled PRJI, PRJ2, PRJ3, PRJ4 and PRJ5; of an international oil company operating in Nigeria based on Joint Venture model with concession in shallow waters with less than 50 meters (m) depth and crude production uplifts of less than 40,000 barrel per day (kbd). The selected projects were used to develop Fiscal Terms Optimisation Model (FTOM) comprising - Discounted Cash Flow Rate (DCFR), Net Present Value (NPV), Profit-to-Investment Ratio (PIR), Maximum Cash Impairment (MCI), Actual Value Profit (AVP), and Payout that were combined with Global Competitive Index (GCI) from fifteen countries based on their competitiveness and global regional distribution to develop a meta-model that was used to determine Optimal Royalty and Tax Competitive Window (ORTCW) that predicts the relationship between the various economic metrics (DCFR, NPV, PIR, MCI, AVP, Payout) and fiscal terms that drive investment decisions.

The characteristics of the selected projects were (kbd, m) [PRJ1(26.1, 27.13); PRJ2(20.3, 28.04); PRJ3(36.4, 28.04); PRJ4(6.5, 27.43) and PRJ5(18.8, 42.67)]. The output FTOM data were DCFR(%)[(21.0 - 197.0);(13.0 - 492.0);(11.0 - 479.0);(35.0 - 346.0) and (21.0 -160.0)];

NPV(12%) in million dollars ($M)[(56.32 – 630.24);(3.44 -64.32); (2.20 - 47.24);(10.09 - 194.75) and (1.40 - 20.56)]; PIR [(2.4 – 10.7); (0.3 - 1.2); (0.2 - 1.1); (1.2 - 6.8) and (0.9 - 3.8)]; MCI($M) [([-34.9] – [-26.2]); ([-10.1] – [-2.8]); ([-10.1] – [-2.8]); ([-5.5] – [-4.2]) and ([-7.8] – [-3.7])]; AVP($M) [(925.1 - 4287.3); (57.7 - 101.8); (15.0 - 71.8); (79.2 - 465.2) and (8.4 - 35.7)]; PYT in years [(2.3 – 4.9); (1.2 - 3.3); (1.2 - 3.1); (2.2 - 3.1) and (1.5 - 2.0)]. There was a positive relationship between Royalty(R), Tax(T) and Profitability indices with correlation coefficients ranges: DCFR:R(0.65); DCFR:T(0.96); NPV12:R(0.63); NPV12:T(0.97); MCI:R(0.45); MCI:T(1.00); PIR:R(0.62); PIR:T(0.97); AVP:R(0.62); AVP:T(0.97); PYT:R(0.57) and PYT:T(0.90). The ORTCW showed that optimum royalty and tax rate for competitiveness were (0.15 - 0.20) and (0.28 - 0.55) respectively, while the current and post PIFB royalty and tax rate for the NOGI obtained were (0.19 – 0.31) and (0.80 – 0.85) respectively, this shows that Nigeria's current and post PIFB fiscal and tax rates were not competitive.

The current and proposed fiscal and tax regime of the Nigerian oil and gas sector are unlikely to drive investment, improve competitiveness and foreign direct investment in the sector and a review of the proposed Petroleum Industry Fiscal Bill is recommended.

Keywords: Petroleum Fiscal Systems, Foreign Direct Investment, competitive window
Word Count: 498

DEDICATION

This study is especially dedicated to my late mother, Mrs. FausatWahab. Even though her parents could not afford to send her to school, she cherished education so much that she sold the little she had and starved most of the time to ensure her kids lacked nothing. We felt rich even though we were poor. She prepared us for life by instilling tough mental strength very early in life that we actually believed we could touch the sky.

She would have shed tears of joy at the University of Ibadan graduation ceremony because she is a native of Ibadan town. A town where she could not obtain a primary education.

Sleep on mum, a woman of substance and builder of men. I now believe the sky is not even a limit anymore. Imagine a Ph.D. degree! Thank you for the confidence maami.

Obinrinrere, IyaElukumedemede. Sun re o.

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CERTIFICATION PAGE

I certify that this work was carried out by Mr. Wahab, Lukman in the Centre of Petroleum Engineering Energy Economics and Law, University of Ibadan

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ABBREVIATIONS

AGFA	Associated Gas Framework Agreement
AVP	Actual Value Profit
CAPEX	Capital Expenditure
CBN	Central Bank of Nigeria
CCSI	Colombia Center on Sustainable Investment
CIT	Companies Income Tax
CITA	Companies Income Tax Act
DCF	Discounted Cash Flow
DPBP	Discounted Payback Period
DPR	Department of Petroleum Resources
EMV	Expected Monetary Value
E&P	Exploration and Production
FIRS	Federal Inland Revenue Service
FDI	Foreign Direct Investments
GCI	Global Competitiveness Index
NHT	Nigerian Hydrocarbons Tax (NHT)
NNPC	Nigerian National Petroleum Corporation
NPV	Net Present Value
NPV10	Net Present Value at 10%
NPV12	Net Present Value at 12%
IRR	Internal Rate of Return
OGIC	Oil and Gas Implementation Committee
OPEC	Organization of Petroleum Exporting Countries
OPEX	Operating Expenditure
OPTS	Oil producers Trade Section
PBP	Payback Period
PI	Profitability Index
PIR	Profit to Investment Ratio
PIA	Petroleum Investment Allowance
PFS	Petroleum Fiscal System
PPT	Petroleum Profit Tax
PIB	Petroleum Industry Bill
PR	Profitability Ratio
PSC	Production Sharing Contracts
PV	Present Value
UNRISD	United Nations Research Institute for Social Development
VIR	Value Investment Ratio
VAT	Value Added Tax

CHAPTER ONE

INTRODUCTION

1.1 BACKGROUND OF THE STUDY

The discovery of oil in Nigeria in 1956 changed Nigeria's economy dramatically from agriculture to oil dependence (Atsegbua, 1999). In 1960, Agriculture and Oil's contributions to the National Gross Domestic Product (GDP) were 50% and 1% respectively (Ogunleye, 2008), and since then the contribution of Oil has increased considerably. From 1970 to 1980, the contribution of agriculture fell from 48% to 31% compared with the contribution of Oil from 7% to 22%. By early 2000, Oil had already contributed over 40% of GDP, over 70% of government revenues and over 90% of foreign exchange earnings, making the country heavily dependent on oil in the rankings of countries such as Mexico, Venezuela, Algeria, Indonesia and Norway (ESMAP, 2004).

The influence of Nigeria on the petroleum industry reaches beyond the boundaries of the nation; it is actually the largest petroleum industry on the African continent, accounting for about 10 percent of its economy as of 2016 (Wikipedia, 2018). Although petroleum remains dominant, it is actually a lower fraction of Nigeria's diversified economy with increasing government revenue and foreign exchange.

Host countries like Nigeria are required to enter into exploration and production agreements to exploit their hydrocarbon resources, as is usual in oil exploration and production upstream sector. Such agreements are sponsored by the Nigerian National Petroleum Corporation (NNPC) via several variants of contracts. The forms of contracts with major International Oil Companies (IOCs) are mainly two versions — Concessional Joint Venture (JV) and Production Sharing (PSC) agreements (Nwokeji, 2007).

The country's requirements, conditions, and intent are the main drivers for a nation's petroleum tax regime. Therefore, fiscal policies and systems typically vary from country to country depending on the specific circumstances of their short, medium and long-term goals. At the end of the day, the implementation of any specific petroleum agreement, whether concessional or contractual, is a fiscal decision on how to maximize government 'take' and guarantee acceptable revenue, which is the key focus of the theories of taxation and economic rent (Johnston, 1994). National oil companies are expected to develop tax systems to promote foreign investment, which will draw significant interest from IOCs. Many IOCs work internationally and have access to data from different tax regimes and can also model different parameters to assess each country's attractiveness scales. While some of the parameters may not be quantitative, non-analytical parameters can be transformed to analytical forms of benchmarking and comparative analysis to encourage benchmarking. The efficacy of any form of petroleum arrangement has a direct relationship to the attractiveness of the core tax systems and also a direct relationship to the design and implementation of the tax system (ESMAP, 2004).

Due to the competitive nature of this critical sector, developing an effective upstream oil and gas tax system is becoming increasingly difficult and specific objectives need to be taken into account. Typical multinational oil companies have constraints on available investment funds and invest in projects based on the highest rate of return or other profitability indices which can be bench marked globally. This selection process leads to a limited-budget global ranking of resources (Akinwale and Akinbami, 2016).

The intent of the petroleum taxation system must satisfy a joint interest of both national host country and international oils firms. Early on, the government of Nigeria had identified different focus areas and objectives in developing its petroleum tax systems – namely: rent share, front end and steady income, operational ease, and significant incentives for multinational oil companies (NEITI, 2005).

The foundations of Nigeria's petroleum fiscal regime were first set during the colonial period, when the British colonial administration issued two ordinances – the Petroleum Ordinance of 1889, and the Mineral Regulation (Oil) Ordinance of 1907 (Omorogbe Y., 1987). Although the 1907 Ordinance stipulated that oil exploration was restricted to British subjects and British controlled companies, the first concession agreement was granted to a German company in 1908. Exploration was terminated when World War One began in 1914, and no further exploration was undertaken in Nigeria until Shell D'Arcy Petroleum Development Company (the first predecessor of the modern Shell Petroleum Development Company of Nigeria) was awarded a concession grant in 1938. The concession issued to Shell was an oil exploration licence covering the entire mainland of Nigeria, which granted Shell an early monopoly on the exploration of oil. Shell made Nigeria's first commercial oil discovery in 1956 at Oloibiri Bayelsa State. Soon after this discovery, other oil companies, including Mobil and Texaco/Chevron, were granted concession licences to conduct onshore and offshore exploration. However Shell's early exploration monopoly placed it in the position to dominate oil production in Nigeria. Today, the company is responsible for 39% of oil production in Nigeria (Ghebremusse S.Z., 2014).

Nigeria's modern petroleum fiscal regime was established in 1969 with the passing of the Petroleum Act and the Petroleum (Drilling and Production) Regulations. Both pieces of legislation provide the legal framework for oil production in Nigeria. At its core is the vesting of petroleum in the state; Section 1(1) of the NPA stipulates: "The entire ownership and control of all petroleum in, under or upon any lands to which this section applies shall be vested in the State." The NPA grants companies incorporated in Nigeria the following rights: "(a) a licence, to be known as an oil exploration licence to explore for petroleum; (b) a licence, to be known as an oil prospecting licence to prospect for petroleum; and (c) a lease, to be known as an oil mining lease, to search for, win, work, carry away and dispose of petroleum."

For over four decades, the Nigeria petroleum sector sector has operated under dated and often misinterpreted laws such as the Petroleum Act of 1969, the Petroleum Profits Tax Act (PPTA) of 1959 and the Nigerian National Petroleum Corporation (NNPC) Act of 1977, among others. In December 2008, the Nigeria Petroleum Industry Bill (PIB) was conceptualized. The PIB was an all-encompassing piece of legislation into which was put a set of new provisions in respect of about sixteen pieces of existing legislation. It was meant to be a game changer aimed at significantly impacting the regulation and administration of Nigeria's oil and gas sector.

The PIB, which was first introduced to the National Assembly in 2008, has passed through several iterations and debates by successive law-making bodies since then. However, it has not been passed into law because of its size and the inability of various stakeholders to agree on all the fundamentals that the law was supposed to address. The bill has encountered many interpretations and has taken many forms since. Because of this bill's tremendous revolutionary nature, it is certainly the most common bill in the history of Nigeria.

Specifically, this bill would target Nigeria's highest national income contributor (i.e. revenue from oil and gas). The debate on this bill among all stakeholders is live and continuing and mostly intense in nature. Several support organizations have published variant proposals to explain their approaches with various stakeholders.

Over this time, the PIB priorities have remained consistent, namely – (1) creating a favorable business environment for oil and gas operations; (2) developing a sustainable fiscal framework that can drive more investment in the oil and gas sector with the government / host country coverage; (3) establishing effective and efficient regulatory bodies and; (4) Promoting transparency and consistency in the country's oil and gas resource management.

No matter how noble these goals may sound, to be attainable it must take into account the needs of the global oil companies. Hence, Nigeria in the league of the highest oil producing nations definitely require a competitive oil and gas fiscal structure capable of attracting interest from the very best multinational oil companies who have the technology and capabilities to explore these natural resources and also achieve the fundamental objectives for each this taxation arrangements were set up in the first place (UNRISD, 2007).

Since the initiation of the PIB, coincidentally, foreign direct investment (FDI) have experienced a decline (Reference figure 1.1 below), which suggests that there may be some correlation between the PIB and FDI while not discounting other factors or variables. Four factors have been identified as central to decision-making when planning to invest in oil and gas projects (1) Annual Cash Flow; (2) Profit Margin/Return on Investment; (3) Portfolio of Opportunities; (4) Shifts in Supply and Demand.

International and local oil companies under the auspices of Oil Producers Trade Section (OPTS) opposed the passage of the PIB in its current state (http://www.petroleumindustrybill.com). The OPTS stressed that the PIB fell short of addressing the challenges in the oil industry. The body stated that the Bill will significantly increase royalties and taxes making Nigeria one of the harshest fiscal regimes in the world, a situation that will culminate in the country, as an oil and gas producing region, becoming uncompetitive as projects will now become uneconomical. Given the enormous expenditure required to develop gas infrastructure, the body also opined that an incentive-based approach to domestic gas supply obligations will be required to jump start Nigeria's much needed gas revolution. OPTS reiterated supports for the objectives of the Bill and the reforms it seeks, however their believe is that the Bill as drafted will fail in delivering such objectives and will reduce the oil and gas industry contributions to the Nigerian economy.

This study adopted the last published version of the petroleum industry bill called' PIB 2012' for the purpose of this research. The PIB 2012 was submitted to the National Assembly on 18 July 2012. In line with the goals of the earlier versions, the PIB 2012 seeks to ensure management and the allocation of natural resources by Nigeria is done in a manner consistent with good governance, adding sustainability and transparency to its core principles. PIB 2012 was introduced to the National Assembly for deliberation and potentially final implementation of a short-term statute. With 32 parts and 5 schedules, this report is over 200 pages. Split into nine sections to cover upstream petroleum operations range. In the current forms, some existing laws will cease to exist and will subsume in the PIB 2012. Some of the existing laws that are eventually repealed are:

i. Associated Gas Re-injection Act CAP A25 Laws of the Federation of Nigeria, 2004

ii. Motor Spirits (Returns) Act, CAP M20 Laws of the Federation of Nigeria, 2004

iii Petroleum Act CAP 10, Laws of the Federation of Nigeria, 2004;('Petroleum Act')

iv Petroleum Products Pricing Regulatory Agency (Establishment) Act 2003;

v Petroleum Equalization Fund (Management Board, etc.) Act CAP 11 Laws of the Federation of Nigeria, 2004

vi Petroleum (Special) Trust Fund Act, CAP 14 Laws of the Federation of Nigeria, 2004; and

vii Petroleum Technology Development Fund Act CAP P15 Laws of the Federation of Nigeria, 2004;

viii Deep Offshore and Inland Basin Production Sharing Act, CAP D3 Laws of the Federation of Nigeria, 2004; except for sections 16 subsection (1) and (2)

ix Petroleum Profits Tax Act, CAP P13 Laws of the Federation of Nigeria, 2004.

1.2 STATEMENT OF THE PROBLEM

The PIB 2012 version is the end result of several years of industry transformation efforts that started with the creation of the Oil and Gas Implementation Committee (OGIC) during President Olusegun Obasanjo's regime (1999 to 2007). This committee produced a report and policy document that was eventually approved to become the PIB 2012 by the subsequent administration. The PIB 2012 version is the latest as at the time of conducting this study and will be adopted for analysis for the purpose of this report.

Nevertheless, it is important for the host country to find a balance between the quests for more 'take' in the short term and the longer term guarantee of revenue from multinational oil companies through taxation of petroleum resources. Hence the reason for this analysis. The problem statement may be summarized in four (4) parts;

(i) PIB 2012 will introduce higher tax and royalty rates. There are still limited appreciation of the impact of these fiscal changes on investment flow.

(ii) Modelling macroeconomic and micro/business aspects of competitiveness was identified as a challenge in methodology approaches utilized in previous studies

(iii) Nonexistence of an analytical model to compare Nigeria petroleum fiscal system to similar global fiscal system

(iv) An analytical relationship will aid the understanding/appreciation of the impact of tax and royalty rates on profitability indices

In order to attract the required amount of funding, technology and project management expertise to sustain and increase oil and gas production, Nigeria must maintain its competitiveness in the global context. Newly discovered resources (e.g., East Africa and shale gas), increase competition for international financing. Therefore, a good PIB should incorporate the following principles:

(i) Globally competitive fiscal terms that are stable and transparent;

(ii) Non-fiscal terms that promote investor confidence and are in line with global standards (e.g., dispute resolution, contract sanctity); and

(iii) An effective regulatory environment that ensures that projects, permits, license renewals and contracts are approved in an efficient and timely manner

Therefore, considering the strategic importance of IOCs in the Nigerian oil and gas industry coupled with the paucity of domestic technical know-how, lack of finance, and the extent of reliance of the Nigerian economy on oil revenue, it becomes necessary to evaluate the extent to which investment in the upstream oil and gas sector would be affected by the PIB-proposed fiscal terms.

1.3 RESEARCH QUESTIONS

Arising from the above, this research sets out to address the following main question:

1. How would the PIB 2012 proposed fiscal terms/design affect upstream investment in the Nigerian petroleum industry?
2. Examine impact of key fiscal parameters (Tax & Royalty) on investment decisions?
3. Comparative profitability of investments in Nigeria versus other global fiscal regimes?
4. Required key fiscal terms (royalty-tax rates) adjustments to maintain competitiveness?

The study therefore aims to explore in detail the impact of the PIB on investment in the Nigerian oil and gas industry's upstream market. As mentioned in the context to the report, IOCs also consider fiscal system design, in addition to the economic considerations of fiscal systems, before taking an international decision on exploration and investment in development. The petroleum fiscal system's economic and system development considerations include aspects of project cash flow; Net Present Value (NPV); Internal Rate of Return (IRR); fiscal neutrality; fiscal stability; fiscal flexibility; and taking.

1.4 RESEARCH OBJECTIVES

The study's objective is to critically examine whether the Nigerian petroleum tax system is properly structured and efficiently implemented to achieve the benefits that the country wants from its petroleum taxation arrangements. The specific objectives of the study are:

1. Assess fiscal attractiveness of Nigeria's current and post PIB 2012 upstream fiscal regimes, especially the analysis of the effect of royalty-tax rates

2. Present a new meta-modelling methodology approach that combines cash flow simulations from model field data into a regression model, using Global Competitiveness Index (GCI) normalize global systems

3. Derive an analytical relationship between key fiscal parameters (tax and royalty rates) and profitability indices

4. Develop an analytical model linked to similar global fiscal arrangements that can be used to drive oil and gas investment decisions

1.5 SCOPE OF THE STUDY

The study will utilize data from various IOCs projects in Nigeria to develop the base fiscal models. Sensitivity analysis will be conducted for similar global fiscal systems. Comparatively evaluating fiscal regimes of several major oil-producing countries is a daunting task given that risks in international comparisons of fiscal regimes concerning the oil and gas industry are abundant, among which "misinterpretation of individual fiscal regimes" might be the most dangerous. We therefore limit our study only to those regimes with similar concessions models for which the description is unambiguously provided on the Global Oil and Tax Guide websites (ey.com/oilandgas) and available free online, so that our interpretation of a given fiscal regime may be relatively easy to verify. The Global oil and gas tax guide summarizes the oil and gas corporate tax regimes in 87 countries and also provides a directory of EY oil and gas tax and legal contacts. The content is based on information current to 1 January 2017. With this limitation, our study covers only the following countries: Australia, Algeria, Australia, Brazil, Colombia, Ghana, Kazakhstan, Mozambique, Namibia, Netherlands, New Zealand, Peru, Romania, Russia and Trinidad. Each of these global fiscal systems will be conditioned to account for local factors that may influence results.

1.6 PLAN OF THE STUDY

Chapter one presents a brief account of issues relating to petroleum taxation and goes further to explain the reasons for undertaking this research. The aim, objectives and the significance of the study are also discussed in the chapter.

Chapter two presents a survey of relevant literatures on the subject matter highlighting the various methodologies that have been explored with attendant conclusions/recommendations for further research works. This chapter also discusses the theoretical framework followed by the reasons for the adoption of the theory as a framework into the design and implementation of petroleum tax regime.

Chapter three discusses the proposed research methodology and methods of the study. The economic analyses method involved cash flow modeling, project profitability and sensitivity analysis. An examination of the deterministic and probabilistic approach of economic analysis, Carlo simulation process and influential factors of project profitability was discussed in details.

Chapter four examine/discuss the results of the study. Starting with data analysis and uses various data presentations techniques to compare the results with various benchmarks from some of the previous studies mentioned in chapter two.

Chapter Five starts with a brief summary of the research encapsulating the reason and objectives of the research, followed by conclusions from findings.

CHAPTER TWO

LITERATURE REVIEW

2.0 INTRODUCTION

The suitability of Nigeria's oil and gas tax system has been constantly questioned by upstream petroleum players in Nigeria. An effective and efficient tax system that is properly designed provides confidence to external investors. The lack of sufficient investments by IOCs and the related impact on reserve growth are probably linked to the lack of clarity in the direction of fiscal terms over the years. Significant changes to these fiscal terms were expected from the PIB, but the timeline for passage remains unclear.

It is expected that the planned PIB reforms would affect the entire oil and gas sector, improving the revenue share of the national and immediate host communities. The slow pace of legislative convergence has prompted divestment in the oil sector over the past decade and recent investment decisions have been postponed or paced with signs that major international oil companies are now increasingly pursuing opportunities in neighboring African countries such as Ghana, Angola and Mozambique until such a time that this all important bill can see the light of day (ThisDay, 2012).

This chapter will opens with a review of the PIB fiscal challenges and further x-ray relevant studies that have attempted to tackle this issue of petroleum fiscal changes on investment using various methods. We will also review several aspects of fiscal regime analysis and modelling and conclude with a summary of fiscal systems of all the various countries selected for this global benchmarking.

2.1 FISCAL DEMANDS AND CHALLENGES OF PROPOSED PIB

With the uncertainties created by the inability to pass the PIB in a timely manner over the past decade, the Oil Producers Trade Section (OPTS), which is the industry representative body for the oil and gas producing companies in Nigeria, expressed concern about the intention of the federal government to change the laws governing the oil and gas industry, including harsh fiscal conditions. OPTS expressed this concern through a 129-page' Memorandum' on the Government's Evaluation of the proposed PIB submitted in 2009 to the PIB's' The House Joint Committee.' The major oil companies claim the proposed fiscal terms will affect their bottom line significantly and trigger uncertainties in their investments in the upstream sector. IOCs responded by stating that the proposed PIB will not achieve these aspirations; Nigerian oil and gas investments of about USD 100 billion through 2020 will not be viable with about 40% decrease in production, resulting in a sharp decrease in government revenue and considerable negative impact on job creation and the wider economy.

Key Industry concerns on proposed fiscal terms:

(i) The IOC JV partners is of the opinion that the Nigeria's JV oil fiscal regime is already one of the harshest in the world (July 18, 2013. IOCs feedback at the Joint Senate's Joint Committee on the PIB). Industry modeling shows that the PIB would result in government take increasing from 86% to 91% (excluding NNPC's profit share). The implication is that more than 30% of new JV oil developments would no longer be economically viable according to Wood Mackenzie report commissioned by OPTS).

(ii) The reduction in oil tax would be insignificant compared to the increase in royalties, addition of the new Petroleum Host Community Fund (PHCF) tax and loss of investment incentives. Complexity would also be increased by splitting one tax into two – Nigerian Hydrocarbon Tax (NHT) and Company Income Tax (CIT).

The PIB edition for 2012 incorporated higher royalties and increased government take. A normal 20 percent royalty is currently in effect for onshore activities and 18.5 per cent for opportunities in swamp / shallow waters (1-100 metres).

Rates built on a reducing sliding scale with water depth offshore fields up to 200 metres attracting 16.67 percent, 12.0 percent for 201-500 metres, 8.0 percent for 501-800 metres, 4.0 percent for 801-1,000 metres and 0 percent if depth exceeds 1,000 metres. Under PIB 2012 fiscal regulations, a progressive royalty linked to the rate of production and the price of oil is implemented to replace the existing royalty aligned with depth.

The existing royalties are also classified for oil and gas, based on an aggregate of royalties assessed for production rate and oil prices. Onshore operations below 2,000 barrels per day (b / d) receive 5 per cent royalty rate and rise to 25 per cent for production over 5,000 b / d. The shallow water areas attract 5 percent in production over 50,000 b / d and 25 percent in production over 50,000 b / d while Deepwater attracts 5 percent in production up to 25,000 b / d and 25 percent in production over 50,000 b / d. Price-based royalty ranges from 0 per cent to 25 per cent gradually starting at $70 bbl with such a price cap of $150. Therefore, in the instance of deep water fields and high oil prices, the Nigerian government would earn a fixed royalty of 50 percent. There is no question that this is a way for the government to extract windfall profits and raise government interest on attractive fields front end.

Major reforms for the Production Sharing Contracts (PSC) were made in government take. The cost recovery limit is set at 80 per cent of gross production and thus decreases the cost recovery of 100 per cent offered under the PSCs of 1993. In comparison to the 1993 PSCs, the terms of the PIB replace the benefit oil split on a sliding scale basis, which gives oil companies 80 per cent share of profit oil for the first 350 m barrels of output with decreasing share as cumulative production increases. The same applies to the 2005 PSCs using the R-Factor with a 70 per cent benefit oil split initial organisation share.

The two layers of tax introduced under the PIB, namely the Nigerian Hydrocarbons Tax (NHT) and Companies Income Tax (CIT) are applicable to both JV and PSC operations. NHT replaces the Petroleum Profit Tax (PPT) and is set at 50% for JV, 50% for gas and 30% for PSC while the CIT is introduced for all oil companies at the rate of 30% on net profits. A minimum of 10% withholding tax on dividends and education tax of 2% on revenue existing under the current fiscal regime is retained.

The PIB terms streamlined the NHT by abolishing the investment tax credits, investment tax allowances and the Petroleum Investment Allowance (PIA) uplift on capital expenditures for existing arrangements and replaced them with allowances for small oil fields and new gas finds. It further proposes to disallow interests expense/financing charges and imposes an 80% limit on expenses incurred outside Nigeria for tax deductibility while introducing benchmarking, verification and approval of all costs for tax deduction purposes. The cost benchmarking would be conducted by the regulatory institutions or the IOC and the verification and approval process conducted by the Federal Inland Revenue Service (FIRS).

2.2 IMPLICATIONS OF THE PIB 2012 FISCAL TERMS

The crux of opposition to the PIB is that it will create a harsh environment that would materially change the economics of the existing and new operations particularly in the Deepwater regions.

The PIB introduced a new taxation regime for the petroleum industry and, broadly speaking, is centered on two proposals. Firstly and most notably, the previous PPT will be replaced by the new NHT to be applied to profits from upstream petroleum operations. Secondly, the PIB extends the applicability of the existing Companies Income Tax (CITA) to profits emanating from upstream petroleum operations (where previously this tax applied only to downstream operations).

NHT will be payable on all profits of any company engaged in upstream petroleum operations at the following rates: 50 per cent for onshore and shallow water areas; and 20 per cent for frontier acreages and deep water areas.

In addition, the PIB will extend CITA to profits from upstream petroleum operations at a rate of 30 per cent. There are detailed provisions within the PIB concerning deductible allowances in the computation of both NHT and CITA, however it is appropriate to note here that NHT is not deductible for the purposes of calculating CITA and vice versa.

Finally, as mentioned above all upstream petroleum companies shall be required to contribute, on a monthly basis, 10 per cent of their net profit (defined as net profit less the Nigerian Hydrocarbon Tax and corporate income tax) to the PHCF. Table 1.2 below shows the summary of the impact of the proposed fiscal terms.

Table 2.2 below summarizes the effect of the fiscal terms suggested. The table contrasts the plans for fiscal terms of the PIB with current terms and shows the effect of the adjustments on sales, taxes and allowances.

Table 2.2: Changes in the PIB 2012 for Companies in a JV/PSC with NNPC

		Current terms	Proposed PIB terms		How would this impact an IOC[1]?
		Terrain or water depth based	*Production -based*	*Price-based*	
Royalties *(% of total revenues)*	PSC (oil)	Deepwater pay 0-12%	5 – 18.5%	0 – 21%	**PSC:** From 0% to 23.6%
	JV (oil)	0 – 20%	5 – 22%	0 – 21%	**JV Oil:** From 20% to 31%
	JV (gas)	5 or 7%	5 – 12.5%	0 – 21%	**JV Gas:** From 7% to 10%
		CIT or PPT	*CIT*	*NHT*	
Taxes *(% of taxable base or profit)*	PSC (oil)	50% PPT	30%	25%	**PSC:** From 50% to 55%
	JV (oil)	85% (65.75% new entrants)	30%	50%	**JV Oil:** From 85% to 80%
	JV (gas)	30% CIT	30%	50%	**JV Gas:** From 30% to 80%
Allowance *(deducted from tax base)*	PSC (oil)	*Investment allowance* 50% of capex credit or allowance	*Production allowance* US$ 5 per barrel produced		**PSC:** 50% of capex to US$5/boe
	JV	5%, 10%, 15% of capex allowance based on terrain	Oil: no allowance Gas: US$ 0.3/mmbtu		**JV Oil:** 5% of capex to US$0/boe **JV Gas:** 5% of capex to US$0.3/mmbtu
Cost deductibility *(from tax base)*		100% of costs incurred	80% of costs incurred (up to 20% foreign costs not tax deductible)		Up to 20% of costs incurred are not deductible from tax
Model PSC *(not in PIB)*		Sharing of profit **after** deducting cost and tax	Sharing of profit **before** deducting cost[2]		Comparable to additional 15-40% royalty over asset life

Combining all these changes, PIB is harsher than current terms and creates one of the world's harshest terms for both onshore (JV) and deepwater (PSC) projects

1 JV Oil (onshore): 100kbed; JV Gas (onshore): 600mmscfd; PSC Oil: 200kbd; Depth: 1000m; Price: $100/bbl; $1.8 / mmbtu
2 As shared by NNPC with industry September 3rd/14th 2012

2.3 RELEVANT STUDIES

A number of studies have been conducted over the past decade on models that can be used to optimise Nigeria Petroleum Fiscal Systems (Humphrey et al. 2017, Akinwale and Akinbami, 2016 etc.) and some other researched have specifically focused on comparative analysis of Nigeria's systems with other similar regional/global systems (Babajide 2014, and Adedayo 2014 etc.).

However, due to the initiation of the PIB in 2008, recent studies have been conducted to analyse the impact of the PIB (Saidu 2014, Adedayo 2014, Oyekunle 2011, Iledare 2010 etc.). Several other studies have also been conducted on the economic factors (Ayodele and Frimpong, 2003; Iledare, 2004; Adenikinju and Oderinde, 2009; Adamu, 2013) and the technological factors (Kaiser, 2010; Offia, 2011; Devold, 2013; Akinwale, 2015) affecting oil and gas field development across the globe and Nigeria in specific. The other relevant studies from 2004 to date are discussed below:

Ayodele and Frimpong (2003) proposed a new contractual arrangement for Nigeria marginal oil fields, specifically in sedimentary basins exploration areas. They improved existing arrangements by specifically assessing these unique petroleum fields. They conducted economic analyses to assess the feasibility of the contract terms. Their profitability analysis, cash flow modelling, sensitivity and risk modeling was done leveraging open data for Nigeria oil and gas operation. The result of their analysis showed that marginal oil field investment in Nigeria sedimentary basins are profitable and significantly viable. Their proposed agreement achieved favorable return on investment for all the parties involved. Their sensitivity analysis report further showed that if the combined cost of seismic survey and signature bonus is increased by ten percentage plus, the project becomes non-viable.

They also shown that, an oil price dip less than eighteen dollar (US) would necessitate project being re-evaluated because payback time will exceed field operation life span. An interpretation of their risk analysis result suggested that NPV increase would cause risk level to increase as well. Based on their observations, they presented optimal financing options for marginal oil fields development in Nigeria.

Cornelius (2004) examined Nigeria tax policies and governance structure and corresponding effect on profitability indices measured by multi-national oil companies operating within the nation's territorial waters. This researchers investigated connections between various contract types with the Nigerian government and the multi-national oil companies economic indicators vis a vis the various contract types. He also investigated the correlation between various fiscal tax variables and profitability indices by leveraging secondary data for the quantitative/statistical analysis. His conclusions reveals while fiscal tax systems has a very significant impact on profitability indices, other variables which may be less significant also impact economics of the multinational oil companies. He went further to high light possible variables that may alter project economics and drive for external investments into this critical sector.

Blake and Roberts (2006) conducted a comparison examination for five oil and gas fiscal regimes against oil price uncertainty. The following regimes were analysed: Alberta Canada tax and royalty system, Papua New Guinea (pre-2003) traditional Rate of Return system, the Sao Tome and Principe/Nigerian Joint Development Zone (SNJDZ) Production Sharing Contract, the Tanzanian Production Sharing Contract/Rate of Return hybrid system and the Trinidad and Tobago production sharing contract using Contingent claims analysis to evaluate the governments' tax claims under uncertainty and applied a numerical approach, using Monte Carlo simulation. They examined each system to obtain the after-tax revenue to each multi-national oil companies and also impact each of each system on the final valuations.

The output valuation ranking revealed that the Alberta Canada and PNG fiscal systems generated the best returns to multinational oil companies with the least fiscal distortion impact. The least ranked fiscal system is Tanzania system in all categories (bot valuation and distortion effect). The Sao Tome system was in the median range in all categories and slightly ahead of the Trinidad fiscal arrangement.

Mian (2010) explored various theoretical projects with multiple pricing assumptions for different fiscal arrangements. The end result analysis was based on the returns to the key stakeholders (i.e. Host Country and International Oil Companies). He reached a conclusion that with a clear objectives (i.e. reasonable take from both parties), fiscal arrangements can be simplified and not necessarily cumbrous. He studied various sub-elements of the fiscal arrangements and tried to balance the host government return against a reasonable/satisfactory return expectation from the contractor.

Iledare (2010) presented a detailed analysis of the 2009 petroleum industry bill and examined profitability indices impacts for selected deepwater projects. He analysed government take results based on the specific terms in this version of the bill. He utilized deterministic and probabilistic models for different scenarios with a resulting government take average of ninety percent. He summarized that the fiscal terms may need to be optimised and the terms should designed to freely reduce government take to encourage inward investment into this sector.

Wan and Zhu (2010) examined the effect of investment and cash flow sensitivity from a theoretical/empirical point of view. This analysis was used as a fiscal restraint and a means of verifying profitability of investments under various tax reforms. They wanted to confirm if this method of analysis is a valid way to check economic viability. They found out that VAT reforms will definitely necessitate the examination of cash flow models to determine the flow of investments.

Oyekunle (2011) examined the impact of the 2009 petroleum industry bill on a model built with deepwater parameters. This model can be used to understand the contractor point of view on impact of proposed tax reforms. The key aspect of the 2009 PIB was modelled deterministically. Scenarios of various investment options were modelled with corresponding cash flow profiles for both host country and contractors. He was able to establish relationship between the 2009 PIB fiscal parameters and profitability indices which were further sensitized. His sensitivity analysis was aimed at determining the variable with the maximum impact on key profitability indices that directly affect investment decisions. Royalty and Nigerian Hydrocarbon Tax were adjudged to provide the maximum impact on investment decisions. The analysis showed that the sliding scale approach to royalty rate in PIB 2009 has positive impact all scales of producers.

Adamu et al. (2013) conducted economic analysis on marginal fields development in Nigeria. Their analysis explored both determistic and probabilistic approaches to investment assessment. The simulated various marginal field scenarios and analysed the output profitability indices data. Monte Carlo simulation method was utilized to in assessing the uncertainties. They tested various fiscal regimes parameters and obtained various ranges of profitability indices and determined the most critical fiscal regimes parameters which the most impact on Net Present Value and Rate of Return. Their study identified tax rate and oil price as the most critical parameters.

Ackah (2014) conducted economic analysis on Ghana oil and gas fiscal system. He compared Ghana's system with neighboring African countries system to gauge its regional acceptability to investors. The comparative analysis involved both qualitative and quantitative methods. The combined discounted cash flow/government take indices was used to rank seven countries fiscal system and the Ghanaian's system ranked sixth.

While in terms of payback time (after tax), Ghanaian's system ranked second. In general, the study revealed that Ghanaians' system is relatively progressive compared to the neighboring African petroleum fiscal systems. However, study recommended further optimisation of the fiscal design in the areas of the royalty rates and cost recovery limits.

Adedayo (2014) research work compared Nigeria and Angola fiscal regimes. He examines common aspects like – Royalty rates, Signature bonus, National content, Contractor and Host Country take etc. He tested the progressiveness, Stability, Neutrality and Risk potentials for both countries fiscal regimes. He recommended a major overhaul of Nigeria proposed petroleum industry bill to further lower the dependency on oil returns. Specifically for Nigeria, this study recommended a redesign of the proposed taxation arrangements to enhance neutrality and flexibility rating.

Nor Aziah et al. (2014) developed a model for the analysis of proposed changes to Malaysian oil and gas fiscal system and its effect on foreign investment into the sector. Several marginal fields' data were modelled in their analysis. Key profitability indices (Net Present Value, Rate of Return, Payback period etc.) were generated for each scenario. They modelled the production sharing contract and risk service contracts over a 10-20 years period. They further sensitized price variants and multiple reserves scenarios. Their model clearly provided a direction to potential investors on what the impact of the fiscal terms changes will be on potential marginal fields' development in Malaysia. These model can also assist investors to benchmark other global investments with similar fiscal systems.

Babajide et al. (2014) developed a comparative fiscal system model for Nigeria, Malaysia and Indonesia. Their analysis was mainly qualitative in nature and for different fiscal terms, a 3-way bench marking was conducted. They relied mainly on available secondary data for their analysis. A case by case critique of each fiscal system for conducted with recommendations on how to relatively improve the investment attractiveness. The three systems were also bench marked internationally to provide investors with a global impact of the individual fiscal considerations.

Saidu and Mohammed (2014) conducted an assessment of the impact of Nigeria proposed fiscal policy change (PIB-2012) for Upstream Petroleum sector. They based their assessment on three main areas – Test for neutrality, flexibility and stability. They also evaluated profitability indices/cash flow analysis results like Net Present Value and Rate of Return. They demonstrated that the proposed PIB-2012 terms as-is may likely discourage investment into this crucial sector of the economy. Although the profitability indicators were positive, meaning the investments will still be produce reasonable return for Nigeria case but if tested globally may not be attractive to international investors. The proposed fiscal design was judged to be largely flexible and with an increase in return to host country when compared with existing fiscal terms. The study showed a negative values for neutrality and stability tests. The concerns about neutrality and stability may likely affect inflow of investment and generally affect investors' confidence. The study recommended a review of the PIB-2012 parameters to improve stability clauses and make the system more neutral to encourage investment.

Saidu (2014) conducted a comparative fiscal system assessment of four major oil producing countries – Nigeria, Malaysia, Guinea and Indonesia). He limited his analysis on the Production Sharing Contracts. He utilized publicly available data from other researchers for the analysis.

He bench marked the performance of Nigeria production sharing contracts against other similar global contracts. He was able to demonstrate that Nigeria contracts performed sub-optimally when compared to other similar arrangements. In order of countries with highest returns, Malaysia – Indonesia – Equatorial Guinea – Nigeria. He enumerated several socio economic factors that would have affected the outcome of his comparative analysis.

Sen (2014) conducted a study on India petroleum contracts arrangements using surrogate model method. This surrogate model method integrates cash flow models with regression analysis of the output data. His objective was to determine the effect of key fiscal parameters on profitability indices for host countries and contractors. He was able to identify the most critical fiscal parameters with the greatest influence, namely – Government Take, Oil Price and interest rate. He recommended notable policy fix i.e. – simple revenue formula to replace current r-factor approach.
His results depict royalty and tax rates are also key parameters that will significantly affect the fiscal system design but need to be considered with the broader host country objectives and revenue sharing expectations.

Echendu et al. (2015) conducted a fiscal system analysis of four African neighboring countries – Nigeria, Angola, Guinea and Gabon. These countries hold most the most reserves in the region, hence the selection for analysis. They utilized theoretical field data and made assumptions on cost data but vary the fiscal arrangements for each countries tom simulate the output effect of each arrangement. They examined the effect of the various government take, split arrangements and tax rates. They were able to demonstrate that these countries production sharing contract are closely competitive and risk/reward factor for deep offshore is balanced enough to encourage investment in deeper areas compared with investment in shallow waters.

Abdul Manaf et al. (2015) attempted to address the issue of measurement scale to determine fiscal systems effectiveness. They leveraged available secondary data of various scales of measurements put together by experts in the field. They integrated key fiscal parameters already established by other studies – Royalty and Tax rates to test attractiveness of fiscal systems. They conducted surveys that involved experts to validate their assumptions and assist with the interpretation of the measurement scale outputs and reliability tests. They also leveraged regression analysis and correlation tests. The outcome of the research produced a scale that was tested and validated by industry expert for the assessment of fiscal system performance. The steps were simple and can easily be adapted by other researchers. This is a giant step in developing a broader scale that can be adopted internationally for any fiscal system. However, local factors needs to be simulated for global acceptance.

Ogunleye (2015) studied the production sharing contracts key fiscal parameters and design. He limited his analysis to Nigeria production sharing contracts and the various types that have been executed to date. He was able to clearly identify the main differences in each contract types. He examined the 1999 Deep Offshore and Inland Basin Contracts Act and further examined the downsides in each contract variants. He concluded that in general, the production sharing contract is highly recommended for the Nigeria exploration scenario for both the host country and contractors point of view but a clear understanding of the upsides and downsides of each variant needs to be studied before adoption.

Akinwale (2016) examined the profitability of oil and gas investments in Nigeria with special focus on Indigenous oil operators. Their fiscal system modelling/analysis was focused on both economic and non-economic evaluation methods. They developed synthetic cash flow models with secondary data and ran Monte Carlo simulation scenarios.

Based on their analysis key fiscal parameters were sensitized and the most critical parameters identified are – Royalty rates, Tax rates and Oil price. These parameter had the most significant impact on the profitability variables like net present value. This study called for regular update to the key fiscal parameters to assess the invest feasibility based on current realities in both local and international market place and site specific geological conditions and prevailing government policies as at that time. Most of the fields assessed were transferred from major international oil companies based on future economic projections and risk estimations. This conditions needs to be properly by indigenous oil companies prior to Final Investment Decisions (FID).

Ogunsola and Falode (2017) examined the effect of oil price instability on marginal field investments using publicly available data for seven months interval. They integrated GARCH model and Johansen cointegration in their methodology. The Granger Causality tests results depict a strong correlation between oil price volatility and crude oil production. They also found out as crude oil price reduces, corresponding production data follows the same pattern. In summary, the lower the crude oil price, the less attractive marginal field investment become. This summary follows the law of demand and supply prediction.

Humphrey et al. (2017) examined the economic returns and investment viability for marginal fields within the south-south areas of Nigeria. They utilized the cashflow model with prevailing fiscal terms for the deterministic and probabilistic analysis. Their output economic indices (net present value, rate of return, payout period etc.) were extracted and modelled in crystal ball for the probabilistic analysis. They demonstrated that marginal field investment within the Niger Delta area of Nigeria is significantly profitable and will certainly achieve returns higher that the bench mark rate.

They also sensitize oil price and tax rates for optimal profit. The probabilistic modelling was useful in predicting variable parameters and providing investment a fairly accurate estimate of future profit/loss. Historical values of oil price and tax rates ranges were utilized for the probabilistic analysis. They concluded that even though marginal field's investments in this specific areas are viable, a reduction in key fiscal parameters – royalty and tax rates will further encourage investment in this security volatile region. They also suggested reduction in tax and capital allowance and loan rate burdens to further encourage investment and most especially local participation.

2.4 CONCEPTUAL AND THEORETICAL FRAMEWORK

Research methods can be broadly classified into two types – quantitative and qualitative methods. However, a new hybrid of qualitative and quantitative methods called mixed-method (Tashakkori and Teddlie, 1998). By definition, Quantitative research methods deals with measurable statistical activities and numbers data. This approach follows scientifically established methods with theoretical back up that has been proven over time for objective analysis. The key objective of this method is identify correlations between variables with a given boundary condition. According to (Carey, 1993), this method utilizes large amount of data points when compared with other methods to significantly establish reliable correlations. The large data base can be randomly selected to ensure even representation and sometimes well-structured questionnaires can also provide similar representation. Whichever selection methods that is utilized, the key idea is to confirm representation in a logical and sequential manner that can support the correlation postulations.

The Qualitative approach, on the contrary deals with nature in the natural setting. The goal here, is to fully understand the context in other to transfer the postulations to other scenarios. We are not expected to interfere with the prevailing conditions for our studies (Patton, 2001). We studied the occurrence of interest as-is and try to understand the 'why' and 'how' of the environmental impact. According to Shank (2002), this method is a systematic empirical probe to aid understanding. This approach studies socio-human challenges of specific scenarios from various views by allowing the natural setting to play out without any inhibitions. It employs graphical and complex analysis of the unfolding events. Some of the tactics used in the approach are – surveys, interviews, observations, case studies etc.

The hybrid combination of both Quantitative and Qualitative methods which is called Mixed-method by definition simply combines analytical/numeral analysis with real life scenario examinations.

2.4.1 EVOLUTION OF ECONOMIC METRICS

The word metrics refers to measurement. Businesspeople speak of performance metrics, and financial metrics, for instance. "Metrics" in each case reveal—measure—specific characteristics of data sets. Most people in business, even outside of finance or accounting have heard the term financial metrics. And, most are aware of examples such as return on investment or earnings per share. Not everyone understands the unique strengths and weaknesses of these metrics, however. And, not everyone appreciates their special data requirements. As a result, many businesspeople use financial metrics blindly, or in ways that signal misleading information.

Each financial metric conveys a unique message about a body of economic data. In that way, financial metrics are like descriptive statistics. The statistical average (arithmetic mean), for instance, reveals the "typical" value in a data set. Similarly, each financial metric reveals specific characteristics of the economic dataset. Usually, those characteristics are not readily apparent when merely reviewing the data. Cash flow investment metrics, for instance, measure investment performance by evaluating the series of cash inflows and outflows that follow from the investment. One of these metrics, the payback period, measures the time required for returns to cover costs. Potential investors can compare payback periods of different investments, to help decide which the better investment scenario is.

Prudent investors, however, will also analyze the same investment choices with other metrics besides payback period. Investors might, for instance, also use net present value (NPV), return on investment (ROI), and internal rate of return (IRR) to analyze the same investment choices. Each of these compares investment gains to investment costs in a different way and, as a result, each measures investment performance differently. And each metric also has its "blind spots"—insensitivities—to particular characteristics of the dataset. Consequently, decision-makers are always well advised *not* to base critical decisions on just one metric.

Most financial metrics in business belong to one of two families: Firstly, Cash Flow Metrics - Cash flow metrics help evaluate streams of cash flow events, such as investment outcomes or "business case" cash flow estimates. Familiar cash flow metrics include payback period, breakeven point, net present value (NPV), return on Investment (ROI), internal rate of return (IRR), and cumulative average growth rate (CAGR). Secondly, Financial Statement Metrics - Financial statement metrics, not surprisingly, are derived from financial statement figures. Business people use these metrics to evaluate a firm's financial position and financial performance. Well-known financial statement metrics include current ratio, inventory turns, the debt to equity ratio, and earnings per share.

Table 2.2 below shows all the critical economic metrics, indicating purposes and limitations of each metrics.

Table 2.2: Economic Metrics

	Metric	Definition	Purpose	Limitations
Efficiency	Discounted Cash Flow Return (DCFR)	Rate that discounts to zero the entire net cash flow generated by a project	▪ Single measure of return on investment ▪ Annual rated return on capital deployed ▪ Enables quick comparison of similar opportunities	▪ Potential multiple solutions ▪ Does not differentiate size/scale ▪ Fails to consider value of flexibility
Size/Scale	Net Present Value (NPV)	Present value of net cash flows discounted at assumed required rate of return	▪ Measure of value created from investment ▪ Differentiates opportunities size/scale ▪ Enables cash-flow de-levering	▪ Determining discount rate ▪ Fails to consider value of flexibility
Efficiency	NPV / I	Ratio of NPV generated per $ of capital invested	▪ Indicator of capital efficiency ▪ Normalized per $ invested to enable comparison across projects	▪ Organizational familiarity ▪ Quantification / Assumptions
Size/Scale	Actual Value Profit (AVP)	Total undiscounted net cash flow for a project	▪ Measure of total cash generated ▪ Demonstrates impact on future cash flows	▪ Ignores time value of money ▪ Fails to consider value of flexibility
Scale/Risk	Payout or Payback	Length of time required for capital spend to be recovered by cash generated from project	▪ Measure of time project capital is at risk ▪ Useful when comparing projects of similar size / risk	▪ Ignores time value of money ▪ Does not indicate value / profitability ▪ Fails to consider value of flexibility
Scale/Risk	Maximum Cash Impairment (MCI)	Largest negative value reached by cumulative net cash flow during life of project	▪ Measure of the maximum drain that the project is expected to impose on corporate cash flow ▪ For some projects may also indicate maximum risk exposure	▪ Ignores time value of money ▪ Does not indicate value / profitability ▪ Fails to consider value of flexibility

Source: Wikipedia January, 2019

2.4.2 Factors that are central to decision-making when planning to invest in oil and gas projects.

2.4.2.1 Annual Cash Flow

Oil and gas operators are constantly drilling and fracking for profitable sources of energy resources. Cash flow data from such public operators can help potential investors analyse the financial health of specific companies. Analysis of annual cash flow data from these energy companies regarding their activities can provide insights into their success and effectiveness in different well sites and geological plays. Investing in the energy sector entails receiving a profit share from each and every producing well that an investor has working interest.

2.4.2.2 Profit Margin/Return on Investment (ROI)

One of the most important factors to consider when investing in any commodity is the economic profit margin between the value and cost of the commodity. The return on your investment ultimately decides the overall profitability of that particular investment. Investors needs to first analyse the risk of the investment, which can be relative to the investor, and the potential for return.

2.4.2.3 Portfolio of Opportunities

Another factor that is central to energy investment decision-making is the number of other opportunities available to individual companies and the industry at large. Due to a limited amount of available space in targeted areas with known oil and gas reserves, choosing a company that has the necessary relationships to participate in these productive plays can be difficult.

2.4.2.4 Shifts in Supply and Demand

To generate investment in the oil and gas sector, it is important to factor in recent shifts in the supply and demand of oil and gas energy. A shift in supply and demand directly affects oil and gas prices all over the world. Investing at a time when supply and demand are near an equilibrium can yield higher returns down the line.

2.4.3 Key risks to consider before investing

2.4.3.1 Geological Risk

Definitive prediction of the presence of oil is definitely a bit unpredictable. Though technological advancements have made it easier for shale owners to detect oil and extract it with maximum efficiency, there's still a certain amount of risk with regard to accuracy.

2.4.3.2 Political Scenario

If there's a big change in the political scenario, it might affect the oil and gas industry. New governments often introduce changes in trade tariffs, taxes, and labor laws, which would impact oil investments. To avert such a scenario, you should invest with a firm that has a comprehensive understanding of the market and its potential volatilities.

2.4.3.3 Cybersecurity Issue

Any threat to the cybersecurity of an oil investment company could significantly impact operations and lead to undetected spills, downtimes or even shutdown of the operation.

2.4.3.4 Changing Oil Prices

There are always inherent risks during drilling/fracking while other unpredictable operational costs can impact the profitability and success rate of any project. A great way to reduce the risk involved is by diversifying the investment portfolio.

2.5 ECONOMIC RENT AS A THEORETICAL FRAMEWORK FOR THE DESIGN OF A PETROLEUM TAX SYSTEM

The concept of economic rent has, historically, underpinned the work of economists (Wessel, 1967) and is broadly divided into two versions; i) Ricardian rent and ii) Paretian rent (see Wessel, 1967). The Ricardian version has its origin traced through Marshal and Mill and then to Ricardo, whiles the Paretian version has its origin from the work of Pareto. Although definitional differences exist between the two versions, many writers do not recognize such difference and thus use them interchangeably, while those that see the dissimilarity adopt either of the definitions that suit their thinking (Wessel, 1967).

In spite of the differences that exist between the Ricardian and Paretian School of thoughts, as explained above, they are, however, united on the ground that economic rent affects land only. This position is strongly opposed by modern economists, who hold the view that ―all factors including land have alternatives. Therefore payment of rent should be attributed to all factors‖ (Jain and Ohri, 2009:308).

There are two basic reasons for this modern view on economic rent. These reason, Jain and Ohri (2009) noted, are: i) land has alternative uses and part of the rent paid for putting it into any one use would necessarily have to be paid to keep it in its present use, and ii) other factors of production (labour, capital, and enterprise) may also earn surpluses over and above what is necessary to keep them in their present use. It, thus, appears that all factors of production are alike: part of the payment for these factors of production is necessary to keep them from transferring to other jobs and the other part is a surplus over and above what is necessary to keep the factors in their present use. It is this surplus, which is not only peculiar to land, that is called economic rent in the view of the modernists.

2.5.1 The Meaning of Economic Rent

Economic rent, just like any other economic concept, has been variously defined. Tollison (1982) defines it as the excess return above normal levels that take place in competitive market. Dickson (1999), on the other hand, sees economic rent is: "The true value of the natural resource, the difference between the revenues generated from resource extraction and the costs of extraction. These costs include the costs of employing factors of production and their opportunity costs".

Economic rent, according to Banfi (2003), is defined as: "The surplus return above the value of the capital, labour and other factors of production employed to exploit the resource. It is the surplus revenue of the resource after accounting for the costs of capital and labour inputs". Similarly, Stiglitz (1996), describes economic rent as: Economic rent is the difference between the price that is actually paid and the price that would have to be paid in order for the good or service to be produced. Anyone who is in the position to receive economic rents is fortunate indeed, because these rents are unrelated to effort. Firms earn economic rent to the extent that they are more efficient than other firms. Consider a market in which all firms except one have the same average cost curve, and the market price corresponds to the minimum average cost of these firms. The remaining firm is super-efficient, so its average costs are far below those of the other firms. The company would have been willing to produce at a lower price, at its minimum average cost. What it receives in excess of what is required to induce it to enter the market are rents—returns on the firm‘s superior capabilities.

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Cordes (1995), on the other hand, describes economic rent in a different but consistent way as: The difference between existing market price for a commodity or input factor and its opportunity cost. Opportunity cost is the reservation price or minimum amount owners of the goods or service would be willing to accept. Thus, economic rent is a surplus, a financial return not required to motivate desired economic behaviour. Its existence implies predominantly distributional rather than resource allocation consequences.

From a public policy viewpoint all rents could be taxed without altering current decisions on production and consumption. Resource owners would still earn acceptable or needed returns on their investment so output would remain the same.

Consumption levels would not change because under competitive conditions producers cannot shift the tax burden to raising prices. As a result, economic rent could be redefined as the magnitude of returns which could be taxed away without causing the pattern of resource use to be altered.

Economic rent is, therefore, extra revenue earn by investors. It is a bonus (Raja (1999) which even if taxed away can still allow companies to realise a rate of return acceptable on their investment. As a result, many scholars, including Rowland and Hann (1987), are of the view that economic rent constitutes a justifiable base for petroleum taxation.

2.5.2 Economic Rent Theory as a Theoretical Framework for the Design of Petroleum Tax System

The theory of economic rent is one of the several theories that are applicable to taxing of petroleum resources. This section discusses the reasons why the economic rent theory is adopted in this research as a theoretical framework for the design and implementation of petroleum taxation.

First and foremost, the reason that informed the decision to adopt the economic rent theory as a framework is that taxes levied on economic rent will not act as a disincentive on firms to undertake any activity since rent is not a requirement for the continuation or initiation of business operations (Nakhle, 2008).

Attraction of as much foreign investment as possible into the petroleum sector is arguably a requirement for the achievement of the main objective of ensuring that a fair share of the petroleum resources accrue to the host government without jeopardising the interest of the investors.

Second, a tax regime that has been designed to capture economic rent tends to increase government take when economic rent increases, and reduces government take when economic rent decreases (Nakhle, 2008). This is consistent with the principles of a flexible tax regime which provides the government with an adequate share of economic rent under varying conditions (Tordo, 2007). As markets and project conditions change over time, Tordo (2007) further asserts that flexible tax regimes become stable and this limits the need for renegotiation of contracts.

Finally, most taxes distort the economy and diminish efficiency. For example, an income tax on labour has the effect of shifting the supply curve of labour downward. This results in the society consuming less output relative to when such tax is not levied. Taxing economic rent, on the other hand, does not affect the availability of labour, capital, and other factors of production, and thus, free of such distortions (Otto, 2006). In other words, by shifting taxes off labour, capital, and other factors of production and on to economic rent, growth and employment would be stimulated and many distortions in the economy would be avoided.

2.5.3 Other Theories that could be applied as Framework for Petroleum Taxation

There are other theories, apart from the economic rent theory adopted for this study, which could be applied as a framework in the design of petroleum taxation. Two of these theories, namely; Principal-Agent theory and the Transaction Costs theory, as identified applicable by Osmundsen (1998) are discussed in the following subsections.

In this chapter, a review of the literature on the concept of economic rent covering the meaning, types, and its applicability in the petroleum industry was made. It was found that economic rent, as a concept, is suitable for application in the petroleum industry and particularly for the design of petroleum taxation as it does not act as a disincentive to investment. Similarly, a review of literature on other possible theories that could be applied in the design of a petroleum tax system revealed, among others, that the agency theory and transaction cost theory are also appropriate. A discussion of these theories together with the reasons for not using them in this study was presented above.

2.5.4 The Life Cycle of a Petroleum Project

The stages of a typical oil and gas project can be described as follows:

Licensing: In most cases the host government grants a license (lease, or block area) or enters into a contractual arrangement with an oil company or group of oil companies to explore for and develop a field without transferring the ownership of the mineral resources.

Exploration: After acquiring the rights, the oil company carries out geological and geophysical surveys such as seismic surveys and core borings. The data so acquired are processed and interpreted and, if a play appears promising, exploratory drilling is carried out. Depending on the location of the well a drilling rig, drill ship, semisubmersible, jack-up, or floating vessel will be used.

Appraisal: If hydrocarbons are discovered, further delineation wells are drilled to establish the amount of recoverable oil, production mechanism, and structure type. Development planning and feasibility studies are performed, and the preliminary development plan is used to estimate the development costs.

Figure 2.3 below provides a graphic representation of the project cycle.

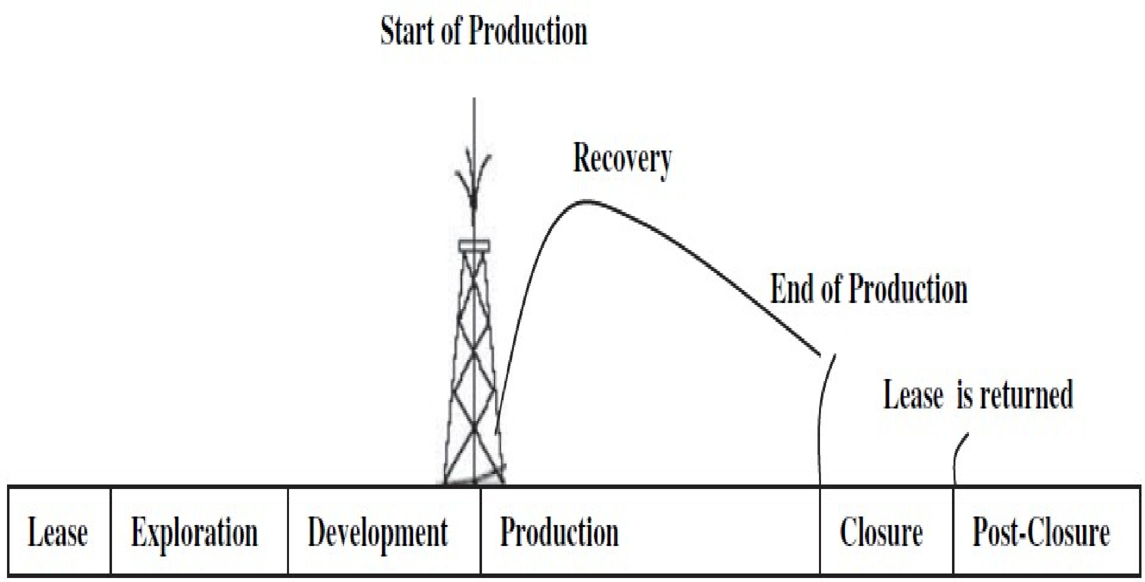


Figure 2.3: The Project Life Cycle (Source: World Bank Working Paper No. 123)

The risk profile of the project changes during its life cycle. Risks can be grouped under three main categories: geological, financial, and political. In general terms, while geological risk begins to diminish after a discovery, the political and financial risks intensify. One of the reasons for this is that the bargaining power and relative strength of the investors' and the host government's positions shift during the cycle of petroleum exploration and development. By the time production commences, capital investment is a sunk cost, and facilities installed in foreign countries represent a source of vulnerability to the investor.

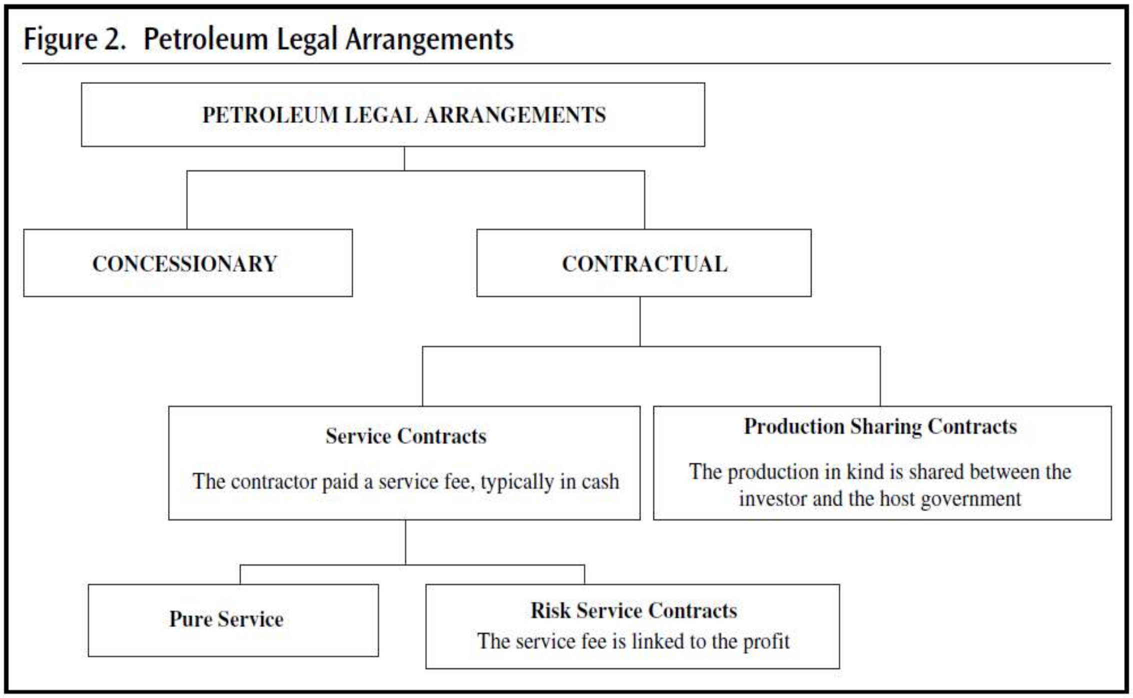
Although many of the variables that affect the profitability of a petroleum project are beyond the control of both the host government and the investing companies, the host government can take actions to minimize uncertainty. Options include providing potential investors with access to existing geological and geophysical data; strengthening macroeconomic and fiscal stability; improving transparency and the rule of law; promoting contract stability; and signing/ratifying relevant international conventions.

Project uncertainty correlates directly with the cost of the investment: reducing uncertainty results in a reduction of the cost of capital, which in turn increases the rent potentially available for taxation. Risk management is a key feature of the oil industry. Companies hedge against risk by investing in a diverse portfolio of projects and by involving multiple partners. Countries may not have the same ability to diversify their investments. Hence they hedge against risk by establishing flexible fiscal systems and transferring part of the risk to oil companies.

2.6 LEGAL ARRANGEMENTS IN THE PETROLEUM INDUSTRY

Many political actors are involved in the design of a legally recognised legal framework for oil and gas exploration, development and production. The petroleum industry law designed at the parliament outlines law principles, however there are provisions not affected by law principles which have to be regulated like – Technical specifications, Administrative procedures and fees etc. The host government will use contract / concession structures to assign rights (exploration / development / production) to hydrocarbon acreage areas. They can use the current hydrocarbon frame and write a powerful new one from the start.

There are different types of legal framework that specifically address all countries and contractors ' rights and obligations. And they can be generally divided into-concessional and contract schemes (see Figures 2.7 and 2.8 below).



Source: Adapted from Johnston (1994b).

Figure 2.7: Petroleum Legal Arrangements (Source: Johnston, 1994)

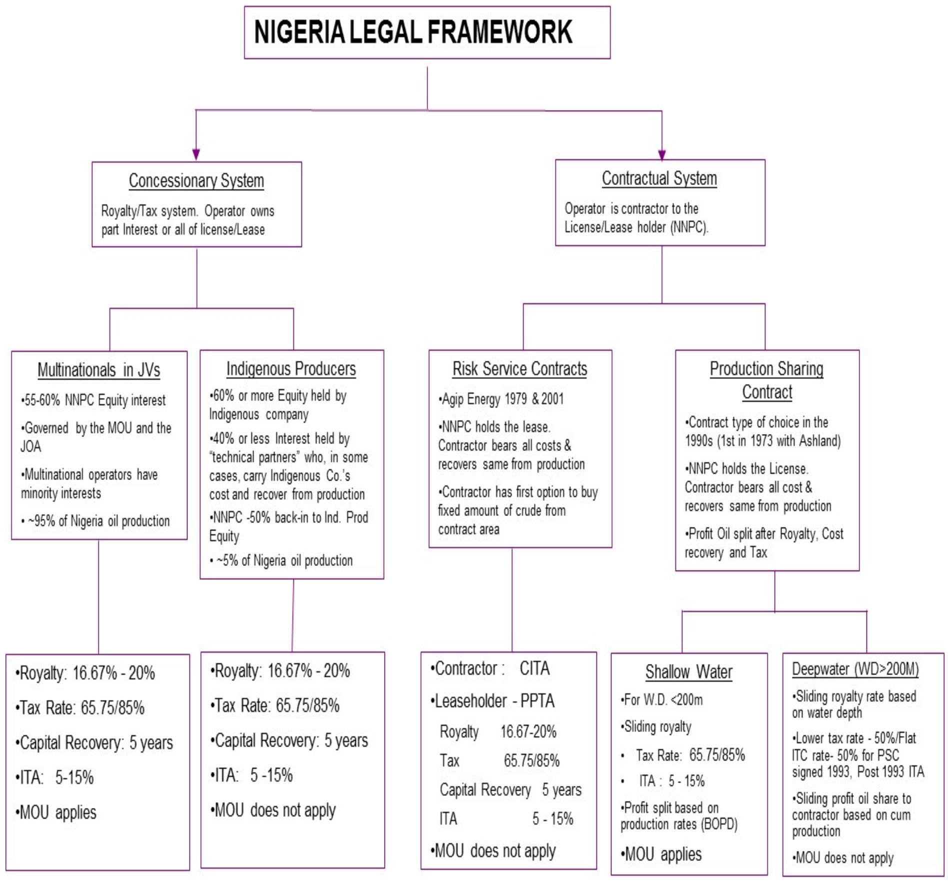


Figure 2.8: Nigerian Fiscal Terms (Author's summary)

The contractors are expected to bear all the risks associated with the business venture, i.e. discovery, development and production phases, for the broad categories of tax systems described above i.e. concessionary and contractual systems. And it is also expected that the contractor will be fully compensated for the risk to be taken. The more that the contractor must spend, the lower the percentage of the lease that goes to the host government as they take little of no risk in the project.

The main dissimilarity between concessionary and contractual systems is the resource ownership structure / arrangement:

i. Concession System: Hydrocarbon title is transferred from host countries to investorscontractors at the reservoir borehole. The host country will demand taxes and royalties for the resource usage. After the contract termination/expiration window, surface equipment and physical fixtures title will then revert back to host countries. The investor/contractor is expected to make provision for abandonment cost and sometime execute the abandonment process before departing the project sites.

ii. Contractual System: In contrast to the concession system, title of resource and all the physical fixtures are not transferred to investors, but continue to reside with the host government. However at the delivery point, the investor/contractor acquires ownership of production output alone. Title and possession of equipment and installation permanently attached to the ground and/or planned for hydrocarbon exploration and production is usually immediately transferred to the government. Therefore, if unique clauses are included in the contract (or the relevant legislation), the state (or the national oil company, "NOC") is usually legally responsible for the abandonment.

The key features of concessionary and contractual systems are summarized in Table 2.4 below.

Table 2.4: Concessionary Systems and Productions Sharing Contracts (Source: Johnston, 1994)

	Concessionary Systems	Production Sharing Contracts
Ownership of nation's mineral resources	Held by sovereign state	Held by sovereign state
Title transfer point	At the wellhead	At the export point
Company entitlement	Gross production less royalty	Cost oil/gas + profit oil/gas
Entitlement percentage	Typically 90%	Typically 50–60%
Ownership of facilities	Held by company	Held by the state
Management and control	Typically less government control	More direct government control and participation
Government participation (carried working interest)	Less likely	More likely
Ring fencing	Less likely	More likely

2.7 PETROLEUM FISCAL SYSTEM

The petroleum fiscal framework describes a set of agreements / laws that an oil and gas producing country uses to handle its future revenue / benefits arising from its natural resource exploration and development. The frameworks stipulate how contractually various parties can participate and the clauses in these contracts are legally binding across several boundaries. Most investment companies usually collaborate to share risks and rewards.

Usually, petroleum reserves are considered natural resources and draw mineral rights to the host country. The concept of land mineral rights in America is different, local landowners are legally entitled to land mineral rights, but internationally all mineral rights belong to the host country, not landowners.

Many countries align their fiscal system with oil and gas licensing systems. The main purpose of the licensing rounds is to transfer mineral rights to other legal entities other than the host country for the sole purpose of developing these mineral resources commercially. Both parties have a shared interest in benefiting from this right transfer and sharing in one way or the other, because in some situations the rights are not completely transferred or shared with the host countries.

The object of joining this agreement is different from nation to nation on the basis of their individual circumstances, which means that the petroleum tax systems are special. Nonetheless, broadly speaking, we can combine similar systems to explore in subsequent chapters based on some apparent common characteristics.

On the other hand, these systems are relatively easy to administer and may prove reasonably efficient in sharing the rent between the contractor and the government when project uncertainty is low, especially if used in conjunction with price indices

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R-Factor and RoR-based fiscal systems lower the project specific risk by introducing flexibility in the fiscal package to suit the profitability of the particular project. Because of their flexibility, these types of arrangement are more likely to encourage the development of marginal fields, or of complex projects with a long lead time for implementation. In addition, the use of R-factor and RoR-based systems normally lowers the break-even price of a project. This in turn makes these projects more attractive to the contractors and less risky as candidates for project financing.

The choice of trigger rates and thresholds is a key issue for all fiscal systems. It is quite unlikely that a particular set of triggers or thresholds would be able to optimise the government take under all possible scenarios. In order to define relevant thresholds and triggers, the host government would need to make reasonable assumptions about the size and profile of a typical project, as well as to determine the typical variability in key project parameters.

This would allow it to determine a representative distribution of R-factors, or RoRs, or other parameters chosen as thresholds and triggers, and to set appropriate floors and ceilings for such thresholds and triggers. The efficiency and neutrality of the fiscal system largely depends on how closely triggers and thresholds relate to the profitability of the underlying projects.

In general terms, wide thresholds may not efficiently capture the project rent, and steep trigger rates may have distortive effects on investment decisions.

The issue of government participation (the back-in option) in oil and gas exploration and production activities deserves special consideration. Nearly half of the countries around the world allow some form of participation through the NOC, the oil minister, or other government entity. Countries that use PSCs are more likely to use government participation as means of rent extraction. Governments that allow participation may or may not reimburse exploration costs to the contractor. Those who do not, normally allow the contractor to recover expenses (its share and the "carried") with a limited or unlimited carry forward.

From a purely financial standpoint, this has implications for the contractor's NPV and IRR.
In some cases, the carry may result in an implied borrowing rate for the government that is higher than its marginal borrowing rate. Un-recovered expenses affect the calculation of R-Factor and RoR, which in turn may affect the level of government revenue when profit oil split/taxes are determined on these bases. Therefore, when a carried interest is involved, the decision to exercise the back-in option, and the consequent use of public resources, needs to be evaluated in light of the overall macroeconomic objectives and resource allocation priorities of the government.

Even when a flexible petroleum fiscal regime is established, the host government would still need to regularly assess its performance and to adjust the relevant parameters as needed so that the fiscal regime applicable to future projects reflects changes in market conditions, government policy, and geological and country risks. Finally host governments would need to periodically re-assess the impact of their petroleum fiscal system on the overall macroeconomic framework to ensure it encourages the efficient and effective use of resources.

2.8 FISCAL SYSTEMS' MEASURES AND ECONOMIC INDICATORS

To evaluate a fiscal system, governments and oil companies use different measures; Oil companies aim to optimise their portfolio of assets. They use economic measures to compare investment opportunities worldwide and to assess their relative risk-reward profile. During the economic life of an asset, oil companies monitor the revenue generated by it to verify that they have covered the capital investment and expenditures and that the return on capital is consistent with the risk associated with the particular asset and with the strategic objectives of the corporation.

Host governments are interested in evaluating whether a fiscal system responds to its intended objectives. To do so, at a project level host governments use economic and system measures to assess whether the benefits—financial and social—derived from the project are consistent with its risk level and with the objectives of the government's sector policy. At a country level host governments monitor the impact of the revenue flow generated by the oil sector as a whole on the key macro-economic indicators (mainly inflation, GDP growth, balance of payments).

Economic and fiscal systems measures are project-specific quantities that vary with numerous system parameters unique to the project (including, but not limited to, the size and quality of discoveries, the development and operational plan of the operator, the cost structure; the financing costs, discounts or premia for the particular crude oil stream), as well as non-project specific variables (such as crude oil prices, inflation, currency exchange rates, local and global economic conditions, and regulatory changes). Hydrocarbon price, development cost, technological improvements, demand-supply relations, country risk, and the corporate strategy, all impact investment planning. Hence the accurate computation of the economic and fiscal system measures associated with a field largely depends on the reliability of the assumptions.

In effect, only at the end of a field's economic life, when all revenue, cost, royalty and tax data are known, can the profitability and the division of profits between the host government and the investors be reliably determined. In practice, due to their commercial sensitivity, cash flow and cost data are very rarely made public.

Various economic indicators are used to assess the performance of a project. The most common are the net present value of the project's cash flow (NPV), the internal rate of return (IRR), and the profitability ratio (PR). The NPV provides an evaluation of the project's net worth to the investor in absolute terms, while the IRR and the PR are relative measures used to rank projects for capital budgeting. Economic values are not intended to be interpreted on a standalone basis, but should be used in conjunction with other system measures and decision parameters. A combination of indicators is usually necessary to adequately evaluate a contract's economic performance.

One indicator frequently referred to in sector literature is the division of profits between companies and government (the "take"). The take is a fiscal statistic as opposed to an economic measure. Because the take does not provide a direct indication of the economic performance of a field, it generally matters more to the host government than to the oil companies.

The take is often a negotiated quantity that depends upon the strength, knowledge, experience, and bargaining position of the oil company and host government, the perception of the risk associated with the field development at the time the contract was written, and the availability of opportunities worldwide.

Unlike economic measures, which are generally well-established, general confusion surrounds the application and interpretation of take. In this paper, the government take is defined as the government's percentage of pre-tax project net cash flow adjusted to take into account any form of government participation. The government take can be calculated in discounted or undiscounted value.

The take statistics for a given country offer a first frame of reference to assess whether or not the fiscal terms applicable to a contract under negotiation are in line with those that already exist in that country (Johnston 2003), or as benchmark to determine the competitiveness of a country's fiscal terms. However, comparing the take of different projects and/or different countries is a very difficult and often misleading exercise because:

Calculating the take at project level requires: (i) ex-ante, the ability to forecast the expected cash flow for the project. As noted above, estimating the cash flow of a prospective project is highly uncertain, and even under the best conditions, is based on incomplete and often unobservable information; (ii) ex-post, the availability of information that is normally proprietary and not publicly known; The same limitations apply to the calculation of the take at country level. In addition, in a given country numerous vintages of contracts are normally in force at any one time; countries typically use more than one arrangement; and contracts are often renegotiated as political and economic conditions change, or as better information becomes available.

In industry statistics the government take is usually determined on the basis of theoretical price and cost assumptions. As noted above, the actual government take can be quite different from the theoretical average.

The take is inconsistent with the economic measures mentioned above, since it is frequently calculated and reported on an undiscounted basis. There can be a significant difference in the level of take depending on the manner in which the cash flow elements are discounted. For example the discounted take is normally much higher than the undiscounted one for regressive front-loaded systems.

As the government take is made up of different elements, more or less regressive, the risk-profile, hence the attractiveness to investors, of two fiscal regimes that present the same percentage government take can be dramatically different. The government take does not capture the spillover effects of oil and gas projects on the economy at large.

Using economic measures like the profitability index or the return on investment is also difficult as each government and each company has a unique risk-reward profile, and hence uses a specific discount rate. This of course provides the scope for negotiating contract and fiscal terms.

2.9 Key Elements of Successful Petroleum Legal Frameworks

Government authority

Ownership of natural resources; powers granted to government officers; enforcement; penalties and fines; the authority to negotiate contracts; the taxing authority, and approvals authorities.

Access to the acreage

Qualifications for authorization to explore, develop, produce and process; areas closed to mineral activities; areas subject to special controls or conditions; right of ingress and egress; resolution of conflicting land disputes; and the relation between surface and subsurface right holders.

Exploration and production rights and obligations

Extent of the exploration and production area; duration of the term for exploration and production rights; renewal of exploration and production rights; unitization; cancellation or termination of a right; area relinquishment; minimum work programs; security of tenure; reporting; transferability of rights and mortgageability; surface fees.

Protection of the environment

Environmental impact assessment; environmental impact mitigation; social or community impact; monitoring and reporting; abandonment liability; reclamation; and environment sureties.

Fiscal Terms

State participation; royalties; production sharing rate and base; custom duties; income tax rate and base; special petroleum taxes; other levies and taxes; gas production incentives and other incentives; ring fencing; and stability clauses.

2.10 Quantitative points of comparison for petroleum fiscal systems

The primary quantitative comparator is the "government take" which may be defined as the total government percentage gain of oil profits. The achievable take should depend on:

(a) The stability of the political regime (and thus the perceived risk for operators).

(b) The stage of development of the economy and central government structures –generally speaking, a developed economy should be capable of devising, implementing and, importantly, enforcing a fiscal system resulting in a high tax take.

(c) The accessibility of the deposits. This was the major disadvantage faced by the UK as no large scale offshore exploration had taken place before in such a hostile offshore environment.

2.11 Commonly used elements of petroleum fiscal systems

Petroleum fiscal systems consist of one or more of the following:

Joint Venture

Under a joint venture (JV) arrangement the government both contributes capital and shares directly in profits. These arrangements do not preclude the levying of royalty and taxes on the joint venture companies. They are often known as "concessionary" JV systems, where the JV company is granted a concession to explore and produce.

Nigeria operates the Joint Venture (OPL/OML) License, given to a corporate entity having more than one shareholder. For every JV in Nigeria, the government through NNPC is a shareholder. The Nigerian JVs are governed by the Joint Operating Agreement (JOA) which the Department of Petroleum Resources (DPR) issues on behalf of the Ministry of Petroleum Resources. About 95% of Nigeria's current oil production is carried out by such JVs. JVs are not now used by the UK government.

The Production Sharing Contract (PSC) is another type of licence for oil and gas exploration and production used to exploit the hydrocarbon resources in Nigeria and most OPEC countries. Under PSC licence, the government has equity in the company but shares in the volume of oil or gas won (produced) by the licence holder. The government's share of production volume after deduction of exploration and production cost (estimated in terms of value of production volume) escalates as production volume increases. The principal difference between a JV arrangement and a PSC licence is that oil companies fund the operations 100% under a PSC licence and it is therefore a no-risk option for the government.

Under the PSC arrangement, the "cost oil" is a key fiscal component. Costs are expressed in terms of barrels of oil which may be retained by the production company as reimbursement of its costs. If the actual costs of the production company are higher, then this element is regressive. This is because the production company is not allowed to deduct all its costs in computing the profit to be subject to taxes, and then used as a basis for computing the share of profits due to the "freeriding" government equity partner.

Cost oil limits need careful consideration. If they are set too low they act as a disincentive to exploit reserves. If, on the other hand, there is no limit at all on "cost oil recovery" then this provides a strong fiscal incentive to contractors. This was the basis of Nigeria's first PSC arrangement where strong incentives were needed, but as international confidence in the arrangements grew, subsequent Nigerian PSC arrangements have generally incorporated cost recovery limits. Such limits are valuable to a developing country where there is usually a grave imbalance in the accounting capabilities of the IOC and the government officials monitoring the arrangements.

Royalty/Tax

Under a pure royalty/tax system the state does not take a physical share of the oil and does not contribute to or underwrite the costs of exploration and exploitation. Royalties are due on quantities extracted and tax is due on the profits of the IOC. A system consisting solely of royalty and taxes is known as a concessionary system.

2.12 Choosing the appropriate system

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Systems can consist of a mix of the elements described above. Ideally, countries should design and adopt fiscal regimes that best suit their purposes at particular points in time according to the prevailing global and/or regional industry conditions which capture economic rent in an efficient manner.

Where there is need to attract international oil companies IOC the systems adopted are usually progressive. Politically stable countries with established and accessible oil reserves may be in a better position to enforce a more regressive petroleum fiscal system. PSCs are attractive at the exploratory stages, especially where government funds are scarce, as the state is not required to fund the risky exploration. However, when reserves are proven, governments may prefer to enter into JV arrangements to secure state ownership of part of the oil reserves.

If oil revenues are flowing freely then a government may consider it has the necessary funds to enter into JV arrangements. When a country is experiencing an oil boom risks may not be weighed up so stringently nor contracts examined in fine detail in the rush to acquire state ownership of the oil riches. NNPC officials consider this was the case in Nigeria in the early 1970s.

The level of sophistication of the relevant government agencies and the tax authority is crucial in the selection of an appropriate petroleum fiscal system. A developing country may find its government officials are no match for the highly trained personnel of the IOC, whose figures they must audit. Such a country may lack the infrastructure to administer and enforce a royalty/tax system.

2.13 Significance of the petroleum contract fiscal terms evaluation

All the operations for transnational petroleum cooperation are subject to the constraints of petroleum cooperation contract terms from the resource country, international petroleum contract is the link between international oil companies (IOCs) and petroleum resource country, which regulates the rights and duties of the parties with legal effect. It is the legal basis on which IOCs carry out exploration and development activities, investment and production operation, it also is a criterion of petroleum production income allocation between the IOC and the resource country.

Most resource countries have their own standard petroleum contracts specifically for oil and gas exploration and development in their countries. Integrating oil resources and investment environment in the resource countries, a series of relatively mature and fixed petroleum contract modes are typically formulated with relatively stable specific provisions.

2.14 Purpose and meaning of fiscal terms evaluation

As world market of oil and gas exploration and development is very competitive, Nigerian companies, when participating in international competition, should pay special attention to fiscal terms of petroleum contract, in addition to the geological conditions of the investment objectives, exploration success ratio, the scale of oil and gas fields, degree of exploration and development, infrastructure and political stability.

Fiscal terms of petroleum contracts are primary non-resource factors IOCs should consider when they want to enter a country, its attractiveness has essential influence on the feasibility of project and economic benefits of IOCs, and it is an important indicator to judge a country's oil investment environment. It is a required course for the oil companies that want to participate in the overseas market to study different countries' fiscal terms, analyse and compare fiscal terms of different investment objective countries.

Assessment and comparison of fiscal terms of different contracts in different countries can not only help Nigerian oil companies in selecting investment areas, but also impel oil companies to fully understand the international oil and gas exploration and development market and adjust its business strategy according to their own conditions, so as to achieve greater operational efficiency and ensure keeping and increasing the value of assets.

2.15 Evaluation method of the petroleum contracts'fiscal terms

In the international oil and gas cooperation, a variety of modes of cooperation have been formed, which are restricted by the national oil legislation, international relations, the status of the oil industry and stage of development, and are closely related to the national situation and legislation.

Specific terms of contracts may vary in different countries, however, in view of asset transfer, the fundamental difference is whether the resources ownership has been transferred to IOCs, and when and how it is transferred. In view of risk bearing, the difference is who bears the major risks caused by geological, commercial and political uncertainties. However, from fiscal point of view, there is no essential difference between various petroleum contracts, all petroleum contracts are the executed and performed based on the following four steps: First, investment to produce; Second, allocation of royalties or similar expenses attributable to the host country; Third, cost recovery, tax deduction and compensation for IOCs; Fourth, profit split (profit oil split or tax). All problems can be attributed to who provide the fund and how to allocate revenue and profit, so the difference between contract types can be ignored when evaluating the attractiveness of the fiscal terms.

Presently, there is no widely accepted, commonly used method to evaluate and compare different types of contracts in different countries. Attractiveness of fiscal terms of a country does not depend on the type of fiscal regime or the specific provision or its value, but on the combined effect of the fiscal terms. Therefore, to evaluate the attractiveness of fiscal terms, and compare between different contracts, we must choose indicator that can reflect the combined effect of the fiscal terms, and the indicator should have the following qualifications: First, it must be comprehensive, can reflect the income allocation ratio between the host nation and IOCs under the combined effects of the fiscal terms; Second, it should take impact of the allocation order into consideration, because of time value of money, time sequence of allocation obtained by different parties will affect the final benefit.

2.16 Principal terms of the international petroleum contracts

Generally, International petroleum contract includes three parts: operating provisions, fiscal terms and legal provisions, specific terms of each part vary with type of petroleum contracts, but objects they regulate and their role are mainly the same. Operating provisions generally include work duties, expenditure obligation, contract duration, contract area, right of withdrawal or abandonment, ownership of the equipment, commercial discovery judgment and announcement and other terms. Fiscal terms usually include terms such as host nation equity and manner, ring-fence of the revenue and cost, pricing mechanisms, cost recovery upper limit, cost recovery order, definition and distribution of profit oil, the proportion of the royalties, corporate income tax ratio, depreciation and depletion, bonus and its recovery, product pricing and sales methods, losses carry-over, rent, duties, pipeline construction and its cost, domestic market obligations, training fees, and other fees. Legal provisions are made up of insurance, security, transfer, HSE, force majeure, contract commencement and termination, applicable law, dispute resolution, contract language and working language and other items.

Fiscal terms of international petroleum contract adjust the petroleum profit allocation between the IOC and host country, determine the income distribution ratio of all parties, which are contract terms with distinctive petroleum feature and the core of the contract. They comprehensively reflect the nation's motive of attracting investment, controlling national resources, using national resources effectively and pursuing profit, and they also reflect the IOCs' desire of obtaining return with the risk correspondingly.

2.17 Modelling Global Competitiveness Factors

This research would use GCR, which is an annual report released by the World Economic Forum, to make our economic model more practical, particularly when benchmarking the fiscal structure of different global systems. Based on the Global Competitiveness Index, produced by Xavier Sala-i-Martin and Elsa V. Artadi, the Global Competitiveness Report has ranked countries since 2004. The macroeconomic ranks were previously based on the Economic Development Index of Jeffrey Sachs and the microeconomic ranks are based on the Business Competitiveness Index of Michael Porter. The Global Competitiveness Index combines the competitiveness dimensions of macroeconomics and micro / business into a single index.

The study "assesses countries ' ability to provide their people with high levels of productivity, which in turn depends on how competitive a country uses available resources. Thus, the Global Competitiveness Index evaluates the collection of structures, policies, and variables that set the current and medium-term sustainable levels of economic prosperity.

The report contains twelve competition pillars. These are: (1) institutions; (2) sufficient infrastructure; (3) secure macroeconomic framework; (4) good health and primary education; (5) higher education and training; (6) efficient markets in goods; (7) productive labor markets; (8) developed financial markets, (9) ability to take advantage of existing technology, (10) domestic and international market size, (11) producing new and different products using the most sophisticated manufacturing processes, and last but not least (12) creativity.

Therefore, the competitiveness effect of each pillar varies across countries, depending on their economic development stages. Therefore, pillars are given different weights in calculating the GCI, based on the nation's per capita income. The weights used in recent years are the values that best explain growth. For example, in variable and efficiency-driven economies, the complexity and innovation factors contribute 10 percent to the final score, but in innovation-driven economies they contribute 30 percent. During transitional phases, intermediate values are used for economies.

The annual reports of the Global Competitiveness Index are somewhat similar to the ' Ease of Doing Business Index ' and the ' Indices of Economic Freedom, ' which also look at factors (but not as many as the GCR) impacting economic growth.

While figure 2.5 shows the selected countries with similar concessionary fiscal regimes based on Colombia Center on Sustainable Investment (CCSI) 2013 report. CCSI has compiled a database of all fiscal reforms since the 1990′s until 2013, for all oil-rich countries with legislated fiscal terms or model contracts, identifying whether the fiscal reforms led to the introduction of progressive fiscal instruments.

Based on the published GCI score and ranking, we generated a composite score (0-1 range) for each of the selected countries. Table 2.3 and Figure 2.6 shows that calculated composite scores that feeds into the 'Calculations' panel.

The Global Competitiveness Index 2017–2018 Rankings

Covering 137 economies, the Global Competitiveness Index 2017–2018 measures national competitiveness—defined as the set of institutions, policies and factors that determine the level of productivity.

Rank	Economy	Score[1]	Prev.[2]	Trend[3]
1	Switzerland	5.86	1	
2	United States	5.85	3	
3	Singapore	5.71	2	
4	Netherlands	5.66	4	
5	Germany	5.65	5	
6	Hong Kong SAR	5.53	9	
7	Sweden	5.52	6	
8	United Kingdom	5.51	7	
9	Japan	5.49	8	
10	Finland	5.49	10	
11	Norway	5.40	11	
12	Denmark	5.39	12	
13	New Zealand	5.37	13	
14	Canada	5.35	15	
15	Taiwan, China	5.33	14	
16	Israel	5.31	24	
17	United Arab Emirates	5.30	16	
18	Austria	5.25	19	
19	Luxembourg	5.23	20	
20	Belgium	5.23	17	
21	Australia	5.19	22	
22	France	5.18	21	
23	Malaysia	5.17	25	
24	Ireland	5.16	23	
25	Qatar	5.11	18	
26	Korea, Rep.	5.07	26	
27	China	5.00	28	
28	Iceland	4.99	27	
29	Estonia	4.85	30	
30	Saudi Arabia	4.83	29	
31	Czech Republic	4.77	31	
32	Thailand	4.72	34	
33	Chile	4.71	33	
34	Spain	4.70	32	
35	Azerbaijan	4.69	37	
36	Indonesia	4.68	41	
37	Malta	4.65	40	
38	Russian Federation	4.64	43	
39	Poland	4.59	36	
40	India	4.59	39	
41	Lithuania	4.58	35	
42	Portugal	4.57	46	
43	Italy	4.54	44	
44	Bahrain	4.54	48	
45	Mauritius	4.52	45	
46	Brunei Darussalam	4.52	58	
47	Costa Rica	4.50	54	
48	Slovenia	4.48	56	
49	Bulgaria	4.46	50	
50	Panama	4.44	42	
51	Mexico	4.44	51	
52	Kuwait	4.43	38	
53	Turkey	4.42	55	
54	Latvia	4.40	49	
55	Viet Nam	4.36	60	
56	Philippines	4.35	57	
57	Kazakhstan	4.35	53	
58	Rwanda	4.35	52	
59	Slovak Republic	4.33	65	
60	Hungary	4.33	69	
61	South Africa	4.32	47	
62	Oman	4.31	66	
63	Botswana	4.30	64	
64	Cyprus	4.30	83	
65	Jordan	4.30	63	
66	Colombia	4.29	61	
67	Georgia	4.28	59	
68	Romania	4.28	62	
69	Iran, Islamic Rep.	4.27	76	
70	Jamaica	4.25	75	
71	Morocco	4.24	70	
72	Peru	4.22	67	
73	Armenia	4.19	79	
74	Croatia	4.19	74	
75	Albania	4.18	80	
76	Uruguay	4.15	73	
77	Montenegro	4.15	82	
78	Serbia	4.14	90	
79	Tajikistan	4.14	77	
80	Brazil	4.14	81	
81	Ukraine	4.11	85	
82	Bhutan	4.10	97	
83	Trinidad and Tobago	4.09	94	
84	Guatemala	4.08	78	
85	Sri Lanka	4.08	71	
86	Algeria	4.07	87	
87	Greece	4.02	86	
88	Nepal	4.02	98	
89	Moldova	3.99	100	
90	Namibia	3.99	84	
91	Kenya	3.98	96	
92	Argentina	3.95	104	
93	Nicaragua	3.95	103	
94	Cambodia	3.93	89	
95	Tunisia	3.93	95	
96	Honduras	3.92	88	
97	Ecuador	3.91	91	
98	Lao PDR	3.91	93	
99	Bangladesh	3.91	106	
100	Egypt	3.90	115	
101	Mongolia	3.90	102	
102	Kyrgyz Republic	3.90	111	
103	Bosnia and Herzegovina	3.87	107	
104	Dominican Republic	3.87	92	
105	Lebanon	3.84	101	
106	Senegal	3.81	112	
107	Seychelles	3.80	n/a	
108	Ethiopia	3.78	109	
109	El Salvador	3.77	105	
110	Cape Verde	3.76	110	
111	Ghana	3.72	114	
112	Paraguay	3.71	117	
113	Tanzania	3.71	116	
114	Uganda	3.70	113	
115	Pakistan	3.67	122	
116	Cameroon	3.65	119	
117	Gambia, The	3.61	123	
118	Zambia	3.52	118	
119	Guinea	3.47	n/a	
120	Benin	3.47	124	
121	Madagascar	3.40	128	
122	Swaziland	3.35	n/a	
123	Mali	3.33	125	
124	Zimbabwe	3.32	126	
125	Nigeria	3.30	127	
126	Congo, Democratic Rep.	3.27	129	
127	Venezuela	3.23	130	
128	Haiti	3.22	n/a	
129	Burundi	3.21	135	
130	Sierra Leone	3.20	132	
131	Lesotho	3.20	120	
132	Malawi	3.11	134	
133	Mauritania	3.09	137	
134	Liberia	3.08	131	
135	Chad	2.99	136	
136	Mozambique	2.89	133	
137	Yemen	2.87	138	

East Asia and Pacific · Eurasia · Europe and North America · Latin America and the Caribbean · Middle East and North Africa · South Asia · Sub-Saharan Africa

Note: The Global Competitiveness Index captures the determinants of long-term growth. Recent developments are reflected only in-so-far as they have an impact on data measuring these determinants. Results should be interpreted in this context.

1 Scale ranges from 1 to 7.

2 2016-2017 rank out of 138 economies.

3 Evolution in percentile rank since 2007 or earliest edition available.

The Global Competitiveness Report 2017–2018 | ix

Figure 2.3: GCI 2017-2018 Rankings

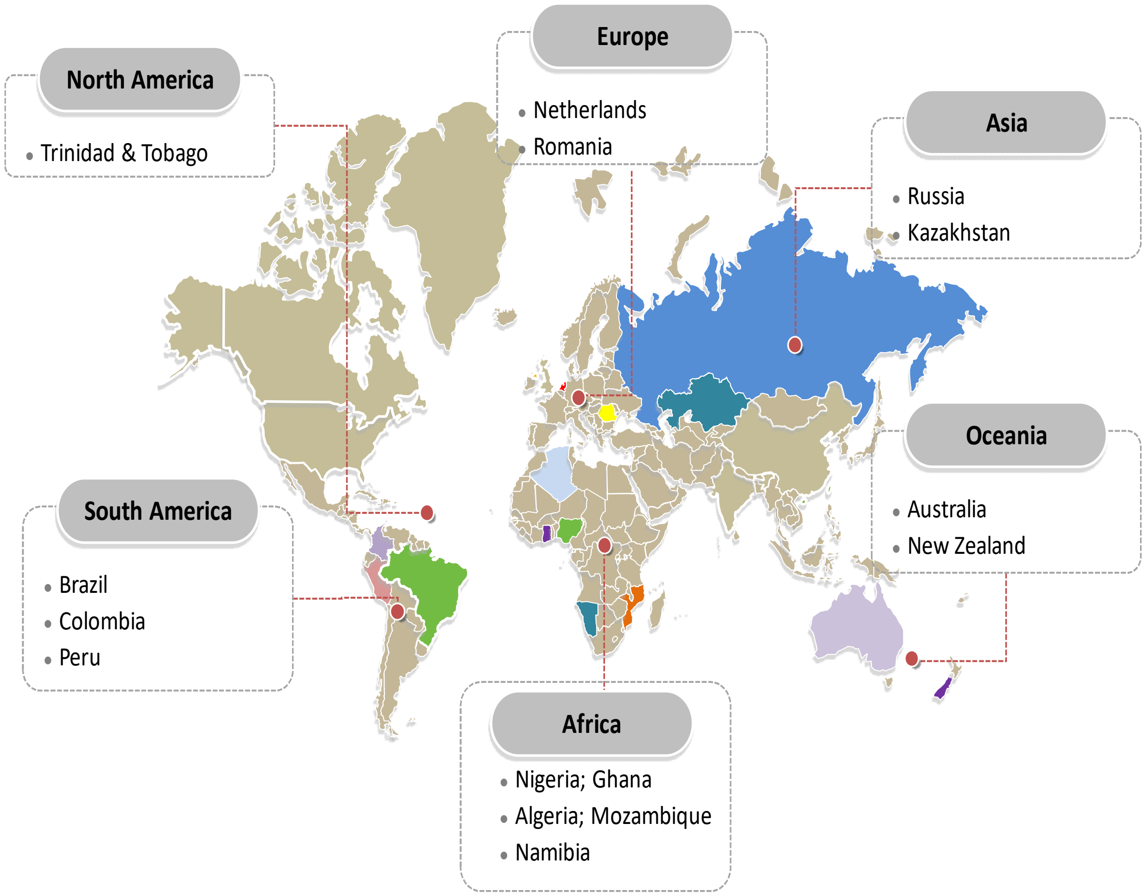

Figure 2.5: Selected Countries with similar concessionary fiscal regimes (Source: CCSI Jan 2013 Report)

Table 2.3: GCI Composite Score (Source: Author)

	GCI (2017-2018)		Composite Score
Countries	Score (out of 7)	Rank (out of 137)	CS = (((S/7)+((138 -R)/137)))*0.5
Nigeria	3.3	125	0.28
Ghana	3.72	111	0.36
Algeria	4.07	86	0.48
Mozambique	2.89	136	0.21
Namibia	3.99	90	0.46
Kazakhstan	4.35	57	0.61
Russia	4.64	38	0.70
Australia	5.19	21	0.80
New Zealand	5.37	13	0.84
Netherlands	5.66	4	0.89
Romania	4.28	68	0.56
Trinidad and Tobago	4.09	83	0.49
Brazil	4.14	80	0.51
Colombia	4.29	66	0.57
Peru	4.22	72	0.54
New Zealand	5.37	13	0.84

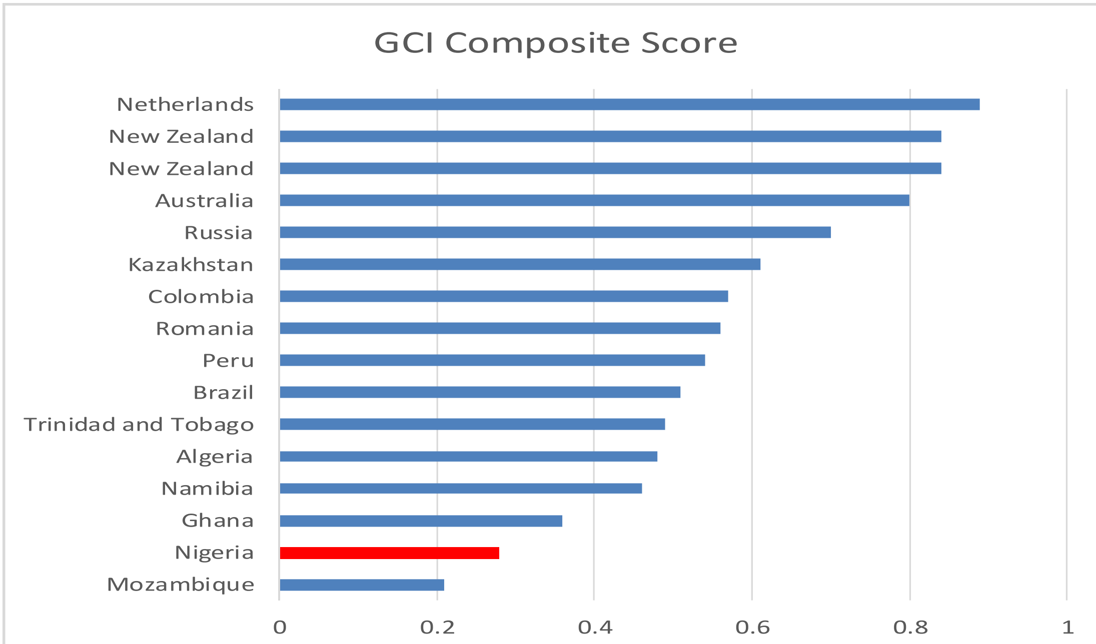

Figure 2.6: GCI Composite Score (Source: Author)

2.18 NIGERIA PETROLEUM LEGISLATION HISTORY

The history of oil laws can be divided into three phases:

(i) Pre-Colonial, under the British Colony, giving authority to the "Crown" for issuance of licenses and taxation under the Minerals Ordinance Act of 1914;

(ii) Nigeria Post-Independence (1960-1971), whereby only taxes are paid by petroleum companies;

(iii) After joining the Organization of Petroleum Exporting Countries (OPEC) in 1971, which provided the enabling atmosphere for greater government participation, taking equity in petroleum resources and operations, and as a prelude to the establishment of an Inspectorate Unit in the then Ministry of Mines and Power, as well as the promulgation of rules and regulations for the Ministry of Mines and Power.

This authority was expanded by the 1977 law creating a commercial entity, the Nigerian National Corporation (NNPC), together with the Inspectorate Division, renamed the Department of Petroleum Resources (DPR) in 1991 under the Ministry's office. Since then, mostly on the basis of need, the petroleum industry has implemented most ad-hoc laws without explicitly checking compliance with existing legislation.

The subsisting primary legislation that governed Oil & Gas in Nigeria are:

The Petroleum Act,which entered into force on November 27, 1969, was substantially amended. From it, subordinate laws (Regulations) and other similar international treaties exist. Accordingly, Nigeria's petroleum sector has approximately 70 main laws and 30 regulations.

The following regulations, amongst others are subsidiary to the Petroleum Act:

(i) Mineral Oils (Safety) Regulations, Statutory Instrument 1963 No. 45;

(i) Petroleum (Drilling and Production) Regulations, Statutory Instrument 1969 No. 69;
(ii) Crude Oil(Transportation and Shipment) Regulations, Statutory Instrument 1984 No. 1984;
(iii) The Oil Pipelines Act 1956;
(iv) The Oil Terminal Dues Act 1969;
(v) The Associated Gas Re-injection Act 1979
(vi) the Associated Gas Re-injection (and Flaring of Gas) Regulations 1979 (as amended)

The PPT Act, which entered into force on January 1, 1958, was revised several times. The main purpose was to provide for the evaluation and taxation of the income of companies involved in the development and production of Nigerian petroleum.

Some of the amendments include;
(i) The Deep Offshore and Inland Basin Production Sharing Contracts Act 1999 No. 9 (as amended);
(ii) Similar provisions under the 1986, 1991 and 2000 Memorandum of Understanding (MOU) NOT enforced but put in place and introduced by tax authorities;
B. It can be said that the separation or distinction between the fiscal structure of crude oil and natural gas started with the introduction of incentive terms under the 1991 Associated Gas Framework Agreement (AGFA). As a policy and in context, the terms promulgated under AGFA sought to further distinguish between Associated Gas (AG) and Non-Associated Gas (NAG). The existing legislations and fiscal incentives pertaining to gas are those of:
(i) The Nigerian Liquefied Natural Gas Act No 39, 1990;
(ii) The Finance (Miscellaneous Taxation Provisions) Act No. 18, 1998 (Amendment to PPT Act);

i.

(iii) The Finance (Miscellaneous Taxation Provisions) Act No. 19, 1998 (Amendment to the Petroleum Profits Tax Act)

2.18.1 The Nigeria Petroleum Industry Reforms

In acknowledgement of the oil and gas industry's significant contribution to the Nigerian economy, the actual and potential losses arising from the sector's continued mismanagement, the Federal Government of Nigeria (FGN) launched a systematic sector reform process that commenced in 2000.

The goal of the legislation was to create a revised Nigeria Oil and Gas Policy and a legislative framework (Petroleum Industry Act) to facilitate the implementation of sector priorities with a focus on a comprehensive overhaul of the Nigerian petroleum industry, reshaping upstream, downstream and natural gas operating systems, redefining main sector roles and responsibilities, increasing efficiency, accountability and transparency (Governance), licensing and land management, compliance with global standards and, last but not least, improving oil and gas tax codes.

While the issues at stake are complex, their resolution can be expected to have significant implications for capital flows, business development, and revenue from government. The overarching aim of the National Oil and Gas Policy was to "maximize the nation's net economic benefit from oil and gas wealth and improve people's social and economic development while meeting the nation's fuel needs at a reasonable price, doing everything in an environmentally acceptable manner."Enhancing the net economic benefit would include adjustments through effective fiscal regimes, sustained competition in the sector, execution of business growth, active local content policy, and enhanced direct links between the oil sector and other Nigerian economies.

2.18.2 The Nigeria PIB

The Nigeria PIB has been around in one form or another since its first release in 2008. Although further efforts were made to pass the 2012 edition of the PIB during the 7th National Assembly, it was sadly unsuccessful, similar to attempts at previous parliamentary sessions.

Continuous confusion and delay in passing the law have hampered development, leaving the country's future in doubt and limiting Nigeria the unique opportunity as the pioneer in oil and gas in sub-Saharan Africa. In general, the main goals remain relatively the same, expanding the industry's reach to:

(1) Enhance exploration and exploitation of petroleum resources;

(2) Significantly increase domestic gas supplies especially for power generation and industrial development;

(3) Create a peaceful business environment that enables petroleum operations;

(4) Establish a fiscal framework that is flexible, stable, progressive and competitively attractive;

(5) Create a commercially viable National Oil Company;

(6) Deregulate downstream petroleum business;

(7) Create efficient regulatory entity;

(8) Engender transparency and accountability;

(9) Promote active Nigerian Content and make Nigeria the hub of the western African petroleum province, and

(10) Promote and protect Health Safety and Environment.

In addition to quality problems with previous versions, one of the main limitations to adoption was the PIB's fake branding as a single legal instrument.Therefore, although this 2015 attempt involves improved content quality work, the bill has been broken into logically smaller pieces for submission to the 8th National Assembly, a complete break from all previous efforts.This helps the pieces to be viewed quickly and moved one after the other. And where improvements are needed in the future, the particular piece can be considered separately instead of opening up the entire Act for scrutiny.

Accordingly, the following pieces of legislation will be considered for the Nigeria PIB.

(1) Petroleum Industry (Governance & Institutional Reforms) Bill

(2) Petroleum Industry (Upstream Petroleum Administration Reforms) Bill

(3) Petroleum Industry (Downstream Petroleum Administration Reforms) Bill

(4) Petroleum Industry (Fiscal Framework & Reforms) Bill

(5) Petroleum Industry (Revenue Management Reforms) Bill.

The PETROLEUM INDUSTRY BILL 2012 is a 223 page document with 362 sections and 5 schedules. The Bill is divided into 9 parts, which propose to cover the entire spectrum of the oil and gas industry. This part of the blog seeks to summarise the Bill along its 9 parts.

Part I – Objectives

Part II – Institutions

Part III – Upstream Petroleum

Part IV – Downstream Licensing

Part V – Downstream Petroleum

Part VI – Indigenous Petroleum Companies

Part VII – Health, Safety & Environment

Part VIII – Provisions on Taxation in the Petroleum Industry

Part IX – Repeals, Transitional & Savings Provisions

Part I comprises of 4 sections, which provide the general principles governing the Bill. Section 1 lays out a number of objectives, which include:

(i) Creation of a conducive business environment for petroleum operations;

(ii) Establishment of a progressive fiscal framework that encourages further investment in the petroleum industry while optimising revenues accruing to the Government;

(iii) Creation of efficient and effective regulatory agencies; and

(iv) Promotion of transparency and openness in the administration of the petroleum resources of Nigeria.

Section 2 emphasises the principles laid out in section 44(3) of the Nigerian Constitution, which vests property and control of all petroleum in Nigeria including the Continental Shelf and Exclusive Economic Zone, in the Federal Government. Part I is rounded out by binding all agencies and companies created under the Bill to the provisions of the Nigerian Extractive Industries Transparency Initiative Act in carrying out their responsibilities.

Part II

Institutional reform was a key platform of the oil and gas reforms leading to the draft of the Bill. Part II provides for the institutions to be created, their functions, funding as well as the mode of appointment of senior officials. The post-PIB reform structure will look like this:

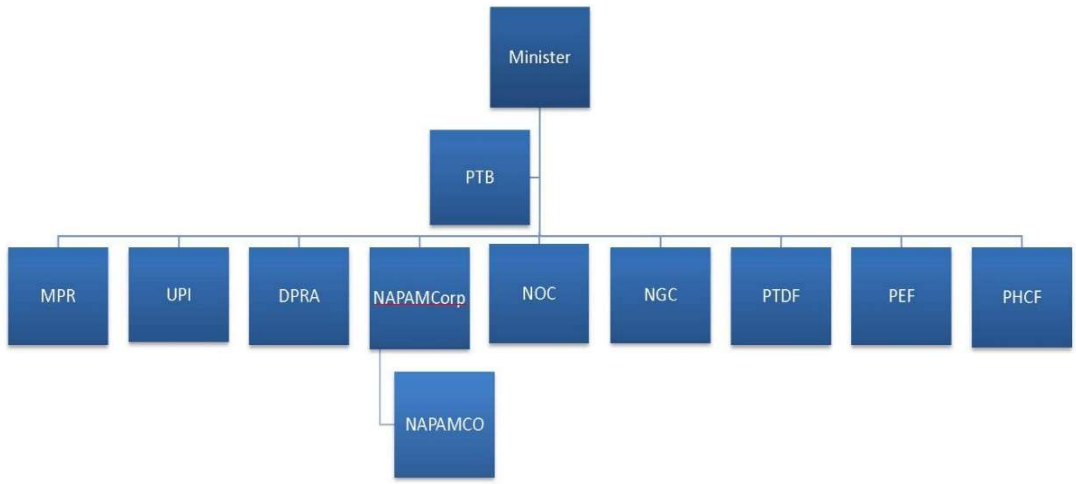

Figure 2.7: Post PIB reform structure (Source: petroleum industrybill.com) http://www.petroleumindustrybill.com/pib-summary/part-ii-institutions/#.XekZscKWzOQ

Glossary (refer to Figure 2.7 above)

PTB – Petroleum Technical Bureau

MPR – Ministry of Petroleum Resources

UPI – Upstream Petroleum Inspectorate

DPRA – Downstream Petroleum Regulatory Agency

PTDF – Petroleum Technology Development Fund

PEF – Petroleum Equalisation Fund

PHCF – Petroleum Host Communities Fund

NAPAMCorp – National Petroleum Assets Management Corporation

NAPAMCO – Nigerian Petroleum Assets Management Company Limited

NOC – National Oil Company

NGC – National Gas Company

2.19 Fiscal Systems Summary for selected countries

Algeria
Depending on the date on which the petroleum contract was signed, the Algerian fiscal regime applicable to the oil and gas upstream industry is governed by one of the following: • Law No. 86-14 dated 19 August 1986 • Law No. 05-07 dated 28 April 2005 (as amended by Ordinance No. 06-10 dated 19 July 2006 and Law No. 13-01 dated 20 February 2013) **Production based royalties (daily production)** Base of royalties is equal to the quantities of extracted hydrocarbons multiplied by the monthly average of the base prices; effective royalty rate is subject to negotiation between parties of contract, who set the rate in the contract but law sets minimum legal rates for each production bracket: Production Level; Minimum Rate for Zone A, B, C, and D respectively: 0 to 20,000 boe/day: 5.5%, 8.0%, 11.0%, 12.5% 20,001 to 50,000 boe/day: 10.5%, 13%, 16%, 20% 50,001 to 100,000 boe/day: 15.5%, 18%, 20%, 23% 100,001 boe/day: 12%, 14.5%, 17%, 20% **Production based tax on revenues (cumulative production)** Cumulative Production Value since beginning of exploitation; Tax Rate <70 BNs; 30% 30 BNs < Production < 385 BNs; [40/(385 - 70)] * [(PV - 70) + 30] >385 BNs; 70% **Additional Tax on Earnings** Assessment base of the additional tax on earnings consists of annual revenues minus deductions, depreciations, royalties, and operating expenses Rate: 30%; Reduced rate of 15% for re-invested earnings

Australia
1987: Petroleum Resources Rent Tax (PRRT) Petroleum Resources Rent Tax 1992: Petroleum (Onshore) Regulation No. 435 Royalty based on length of commercial production 2012: Petroleum Resource Rent Tax Petroleum Resource Rent Tax **Petroleum Resources Rent Tax** Tax rate: 40% on taxable profit Technical modifications (for example expansion to offshore projects): 1990, 2005, 2006, 2012 **Royalty based on length of commercial production** Based on value at the wellhead of production First 5 years: 0% 5 to 10 years: 6% to 10% (Increasing by 1% for each year) 10 years and greater: 10%
Brazil
The Brazilian fiscal regime that applies to the oil and gas industry consists of corporate income tax (CIT) and Government and third-party takes. Government and third-party takes vary depending on the type of contract. Government and third-party takes include: **Signature bonus** — a one-time amount (not less than the minimum price established by the ANP (the Brazilian National Agency of Petroleum, Natural Gas and Biofuels) paid by the winning bidder in the proposal for the CC or the PSC to explore and produce crude oil and natural gas. The minimum amount to be offered as signature bonus is set out in the bidding documents and may vary a lot depending on a field.

Royalty percentage — under the CC, it varies from 5% to 10% of the oil and gas production reference price. Under the PSC, it corresponds to 15% of the volume of produced oil.

Special participation percentage — applies only under the CC, as a percentage that varies from 10% to 40% for large production volumes, based on progressive tables relating to net production revenues adjusted for royalties, exploration investments, operating costs, depreciation and taxes.

Fee for occupation or retention of an area — the activities of exploration, development and production of oil and natural gas, carried out through concession contracts are subject to the payment of the area retention fee for the occupation/retention of the area. The collection of the area retention fee aims to discourage the retention of concessions without the purpose of exploration, and its value is set by the tender notice and the concession agreement. Such value is determined for each calendar year, based on the number of days of the contract and per square kilometer or fraction of the concession area (from BRL10 to BRL5,000 per km^2, depending on the phase and based on a progressive table).

Landlord cost percentage — under a CC, it varies from 0.5% to 1% of the oil and gas production reference price. Under a PSC, it applies only to onshore oilfields and corresponds to a percentage up to 1% of the value of the oil and gas production.

Income tax rate — 34%

Colombia

Fiscal regime that applies to the oil industry consists of a combination of corporate income tax (CIT) and royalty-based taxation.

Production based Sliding Scale Royalties

Monthly average daily production percentage

<= 5K BPD: 8%

>5K BPD - 125K BPD: 8 + (Production - 5K) * (0.10)

>125K BPD - 400K BPD: 20%

>400K BPD - 600K BPD: 20 + (Production - 400K) * (0.025)
>600K BPD: 25%

Income tax rate — CIT rate: 34% for FY 2017 and 33% from 2018
Income tax surcharge — 6% for 2017, 4% for 2018 and 0% from 2019

Ghana

The fiscal regime that applies to the petroleum industry consists of the combined use of four basic tax laws: the Income Tax Act1 (the ITA), Revenue Administration Act, 2016, Act 915 (the RAA), the Petroleum (Exploration and Production) Act, 2016, Act 919 (the E&PA), and the Petroleum Agreement (PA). The ITA and RAA repealed the Petroleum Income Tax Act, PNDCL 188 (PITA) and the Internal Revenue Act, 2000, Act 592 (as amended).

The principal aspects of the fiscal regime that are affecting the oil and gas industry are as follows:
Royalties — Royalty rates are not fixed. The PAs signed so far prescribe royalty rates ranging from 3% to 12.5% for gas and crude production.

Income tax rate — The income tax rate for upstream petroleum activities is 35%. For downstream petroleum activities, the applicable income tax rate is 25%.

Kazakhstan

Mineral extraction tax (MET) is a volume-based, royalty-type tax applicable to crude oil, gas condensate and natural gas. Rates escalate depending on volume. Different tables of rates apply, depending on what is produced and whether it is exported or sold domestically. The rates are applied to production valued at world prices for export sale.
Mineral Extraction Tax: replaces royalties

Volume of annual oil production (thousands of tons)	Rate
Up to 250	5%
Up to 500	7%
Up to 1000	8%
Up to 2000	9%
Up to 3000	10%

Netherlands
The fiscal regime that applies in the Netherlands to the petroleum industry consists of a combination of corporate income tax (CIT), a surface rental tax, a state profit share (SPS) levy and royalty-based taxation. The major elements of the fiscal regime are as follows: Royalties — 0% to 7% CIT — 25%; 20% applies to the first €200,000 of taxable income
New Zealand
New Zealand's fiscal regime applicable to the petroleum industry consists of a combination of corporate income tax (CIT) and royalty-based taxation. The main elements are: • Royalties — 0% to 20% • CIT rate — 28%
Nigeria
Companies carrying on petroleum operations are deemed to be in the upstream regime and taxed under the Petroleum Profits Tax Act (PPTA) 2004 (as amended). **Petroleum Profits Tax** [on chargeable profits] First Five years (new companies): 65.75% First Five years (existing companies): 85% Subsequent years (all companies): 85% **Royalty rates for Joint Venture:** Onshore Production: 20% Production in territorial waters less than 100m: 18.5% Offshore production beyond 100m: 16.67%
Nigeria Post -PIB 2012 (version)
Royalty rates: Production Based + Price Based JV Oil: 5-22% + 0-21% **Taxes:** CIT + NHT JV Oil: 30% + 50%

Peru
Oil and gas exploration and production (E&P) activities are conducted under license or service contracts granted by the Government of Peru. The Government guarantees that the tax law in effect on the agreement date will remain unchanged during the contract term. Royalties Royalties can be determined based on one of two methodologies: production scales (fixed percentage and variable percentage) or economic results (the R-factor calculation). The other main elements of the fiscal regime for oil and gas companies in Peru are as follows: • Corporate income tax (CIT) rate — 31.5% • Dividend tax — 5% **Production or R-factor based Royalties** Companies can choose between two methodologies (but once the licensing contract is signed, cannot change): a) Production Scale Level of Fiscalized Production (MBPCD); Royalty (%) Less than 5; 5% Between 5 and 100: 5-20% More than 100: 20% b) Based upon Economic Results R = Rf + Rv Rf: fixed royalty, set at 5% Rv: Variable royalty, defined as percentage FB: base R factor, established at 1.15 Variable royalty applied when Rt-1 >= 1.15 and when this belongs to the range 0% < Variable Royalty < 20% Xt-1: Last year revenue at moment of calculating the variable royalty Yt-1: Last year expense at moment of calculating variable royalty Rt-1: Ratio between revenues and expenses since the subscription of the contract til period t-1 (R - factor)

$Rv = [(Xt\text{-}1 - Yt\text{-}1)/Xt\text{-}1] * [1 - [1/(1 + (Rt\text{-}1 - FB)]] * 100$

Romania

The fiscal regime that applies in Romania to companies operating in the petroleum industry generally consists of corporate income tax (CIT), petroleum royalty and other oil-related taxes for special funds. In summary, the main elements are as follows:

CIT rate — 16%

Royalties — 3.5% to 13.5% on oil extraction, 10% on certain transportation/transit of oil and 3% on the underground storage of natural gas

Production based Royalties

[based on the value of gross production]

Crude oil/Condensate ('000s tons/quarter):

Below 10: 3.5% for fields which produce

Between 10 and 20: 5%

Between 20 and 100: 7%

Above 100: 13.5%

Russia

The fiscal regime that applies in Russia to the petroleum industry consists of a combination of royalties (called mineral extraction tax (MET)), corporate profits tax and export duty.

- Profits tax rate — 20%
- Royalties (MET):
  - Crude oil — RUB919 ($14.3) per tonne adjusted by coefficients
  - Natural gas — RUB35 ($0.6) per 1,000 cubic meters adjusted by coefficients
  - Gas condensate — RUB42 ($0.7) per tonne adjusted by coefficients
- Export duty:
  - Crude oil — 30% to 45% (linked to oil price)

Trinidad and Tobago

Companies engaged in upstream operations in Trinidad and Tobago (T&T) are subject to a special fiscal regime, principally governed by the Petroleum Taxes Act (PTA). In

summary, the following taxes, levies and imposts apply to companies engaged in the exploration and production of oil and gas:

- Petroleum profits tax (PPT) — 50% of taxable profits (petroleum operations in deepwater blocks: 35%)
- Unemployment levy (UL) — 5% of taxable profits
- Supplemental petroleum Tax (SPT) — The applicable rate of tax is based on the weighted average crude price and is applied to the gross income from the disposal of crude oil, less certain incentives (see section B); not applicable on gas sales
- Petroleum production levy (PPL) — Lower of 4% of income from crude oil for producers of more than 3,500 barrels of oil per day (BOPD) or proportionate share of local petroleum subsidy
- Royalties — Every exploration and production licensee must pay a royalty at a rate stipulated in the license on the net petroleum won and saved from the licensed area. Historically, applicable royalty rates have ranged from 10% to 15% for crude oil and US$0.015/mmcf for natural gas.

1.1 Fiscal Systems Summary for selected countries

Algeria

Depending on the date on which the petroleum contract was signed, the Algerian fiscal regime applicable to the oil and gas upstream industry is governed by one of the following:

- Law No. 86-14 dated 19 August 1986
- Law No. 05-07 dated 28 April 2005 (as amended by Ordinance No. 06-10 dated 19 July 2006 and Law No. 13-01 dated 20 February 2013)

Production based royalties (daily production)

Base of royalties is equal to the quantities of extracted hydrocarbons multiplied by the monthly average of the base prices; effective royalty rate is subject to negotiation between parties of contract, who set the rate in the contract but law sets minimum legal rates for each production bracket:

Production Level; Minimum Rate for Zone A, B, C, and D respectively:

0 to 20,000 boe/day: 5.5%, 8.0%, 11.0%, 12.5%

20,001 to 50,000 boe/day: 10.5%, 13%, 16%, 20%

50,001 to 100,000 boe/day: 15.5%, 18%, 20%, 23%

100,001 boe/day: 12%, 14.5%, 17%, 20%

Production based tax on revenues (cumulative production)

Cumulative Production Value since beginning of exploitation; Tax Rate

<70 BNs; 30%

30 BNs < Production < 385 BNs; [40/(385 - 70)] * [(PV - 70) + 30]

>385 BNs; 70%

Additional Tax on Earnings

Assessment base of the additional tax on earnings consists of annual revenues minus deductions, depreciations, royalties, and operating expenses

Rate: 30%; Reduced rate of 15% for re-invested earnings

Australia
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>125K BPD - 400K BPD: 20%

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>600K BPD: 25%

Income tax rate — CIT rate: 34% for FY 2017 and 33% from 2018
Income tax surcharge — 6% for 2017, 4% for 2018 and 0% from 2019

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Companies carrying on petroleum operations are deemed to be in the upstream regime and taxed under the Petroleum Profits Tax Act (PPTA) 2004 (as amended). **Petroleum Profits Tax** [on chargeable profits] First Five years (new companies): 65.75% First Five years (existing companies): 85% Subsequent years (all companies): 85% **Royalty rates for Joint Venture:** Onshore Production: 20% Production in territorial waters less than 100m: 18.5% Offshore production beyond 100m: 16.67%
Nigeria Post -PIB 2012 (version)
Royalty rates: Production Based + Price Based JV Oil: 5-22% + 0-21% **Taxes:** CIT + NHT JV Oil: 30% + 50%

Peru
Oil and gas exploration and production (E&P) activities are conducted under license or service contracts granted by the Government of Peru. The Government guarantees that the tax law in effect on the agreement date will remain unchanged during the contract term. Royalties Royalties can be determined based on one of two methodologies: production scales (fixed percentage and variable percentage) or economic results (the R-factor calculation). The other main elements of the fiscal regime for oil and gas companies in Peru are as follows: • Corporate income tax (CIT) rate — 31.5% • Dividend tax — 5% **Production or R-factor based Royalties** Companies can choose between two methodologies (but once the licensing contract is signed, cannot change): a) Production Scale Level of Fiscalized Production (MBPCD); Royalty (%) Less than 5; 5% Between 5 and 100: 5-20% More than 100: 20% b) Based upon Economic Results R = Rf + Rv Rf: fixed royalty, set at 5% Rv: Variable royalty, defined as percentage FB: base R factor, established at 1.15 Variable royalty applied when Rt-1 >= 1.15 and when this belongs to the range 0% < Variable Royalty < 20% Xt-1: Last year revenue at moment of calculating the variable royalty Yt-1: Last year expense at moment of calculating variable royalty Rt-1: Ratio between revenues and expenses since the subscription of the contract til period t-1 (R - factor)

Rv = [(Xt-1 - Yt-1)/Xt-1] * [1 - [1/(1 + (Rt-1 - FB)]] * 100
Romania
The fiscal regime that applies in Romania to companies operating in the petroleum industry generally consists of corporate income tax (CIT), petroleum royalty and other oil-related taxes for special funds. In summary, the main elements are as follows: CIT rate — 16% Royalties — 3.5% to 13.5% on oil extraction, 10% on certain transportation/transit of oil and 3% on the underground storage of natural gas Production based Royalties [based on the value of gross production] Crude oil/Condensate ('000s tons/quarter): Below 10: 3.5% for fields which produce Between 10 and 20: 5% Between 20 and 100: 7% Above 100: 13.5%
Russia

The fiscal regime that applies in Russia to the petroleum industry consists of a combination of royalties (called mineral extraction tax (MET)), corporate profits tax and export duty.
• Profits tax rate — 20%
• Royalties (MET):
    ○ Crude oil — RUB919 ($14.3) per tonne adjusted by coefficients
    ○ Natural gas — RUB35 ($0.6) per 1,000 cubic meters adjusted by coefficients
    ○ Gas condensate — RUB42 ($0.7) per tonne adjusted by coefficients
• Export duty:
    ○ Crude oil — 30% to 45% (linked to oil price)

Trinidad and Tobago
Companies engaged in upstream operations in Trinidad and Tobago (T&T) are subject to a special fiscal regime, principally governed by the Petroleum Taxes Act (PTA). In

summary, the following taxes, levies and imposts apply to companies engaged in the exploration and production of oil and gas:

- Petroleum profits tax (PPT) — 50% of taxable profits (petroleum operations in deepwater blocks: 35%)
- Unemployment levy (UL) — 5% of taxable profits
- Supplemental petroleum Tax (SPT) — The applicable rate of tax is based on the weighted average crude price and is applied to the gross income from the disposal of crude oil, less certain incentives (see section B); not applicable on gas sales
- Petroleum production levy (PPL) — Lower of 4% of income from crude oil for producers of more than 3,500 barrels of oil per day (BOPD) or proportionate share of local petroleum subsidy
- Royalties — Every exploration and production licensee must pay a royalty at a rate stipulated in the license on the net petroleum won and saved from the licensed area. Historically, applicable royalty rates have ranged from 10% to 15% for crude oil and US$0.015/mmcf for natural gas.

1.1 Fiscal Systems Summary for selected countries

Algeria
Depending on the date on which the petroleum contract was signed, the Algerian fiscal regime applicable to the oil and gas upstream industry is governed by one of the following: • Law No. 86-14 dated 19 August 1986 • Law No. 05-07 dated 28 April 2005 (as amended by Ordinance No. 06-10 dated 19 July 2006 and Law No. 13-01 dated 20 February 2013) **Production based royalties (daily production)** Base of royalties is equal to the quantities of extracted hydrocarbons multiplied by the monthly average of the base prices; effective royalty rate is subject to negotiation between parties of contract, who set the rate in the contract but law sets minimum legal rates for each production bracket: Production Level; Minimum Rate for Zone A, B, C, and D respectively: 0 to 20,000 boe/day: 5.5%, 8.0%, 11.0%, 12.5% 20,001 to 50,000 boe/day: 10.5%, 13%, 16%, 20% 50,001 to 100,000 boe/day: 15.5%, 18%, 20%, 23% 100,001 boe/day: 12%, 14.5%, 17%, 20% **Production based tax on revenues (cumulative production)** Cumulative Production Value since beginning of exploitation; Tax Rate <70 BNs; 30% 30 BNs < Production < 385 BNs; [40/(385 - 70)] * [(PV - 70) + 30] >385 BNs; 70% **Additional Tax on Earnings** Assessment base of the additional tax on earnings consists of annual revenues minus deductions, depreciations, royalties, and operating expenses Rate: 30%; Reduced rate of 15% for re-invested earnings

Australia
1987: Petroleum Resources Rent Tax (PRRT) Petroleum Resources Rent Tax 1992: Petroleum (Onshore) Regulation No. 435 Royalty based on length of commercial production 2012: Petroleum Resource Rent Tax Petroleum Resource Rent Tax **Petroleum Resources Rent Tax** Tax rate: 40% on taxable profit Technical modifications (for example expansion to offshore projects): 1990, 2005, 2006, 2012 **Royalty based on length of commercial production** Based on value at the wellhead of production First 5 years: 0% 5 to 10 years: 6% to 10% (Increasing by 1% for each year) 10 years and greater: 10%
Brazil
The Brazilian fiscal regime that applies to the oil and gas industry consists of corporate income tax (CIT) and Government and third-party takes. Government and third-party takes vary depending on the type of contract. Government and third-party takes include: **Signature bonus** — a one-time amount (not less than the minimum price established by the ANP (the Brazilian National Agency of Petroleum, Natural Gas and Biofuels) paid by the winning bidder in the proposal for the CC or the PSC to explore and produce crude oil and natural gas. The minimum amount to be offered as signature bonus is set out in the bidding documents and may vary a lot depending on a field.

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Royalty percentage — under the CC, it varies from 5% to 10% of the oil and gas production reference price. Under the PSC, it corresponds to 15% of the volume of produced oil.

Special participation percentage — applies only under the CC, as a percentage that varies from 10% to 40% for large production volumes, based on progressive tables relating to net production revenues adjusted for royalties, exploration investments, operating costs, depreciation and taxes.

Fee for occupation or retention of an area — the activities of exploration, development and production of oil and natural gas, carried out through concession contracts are subject to the payment of the area retention fee for the occupation/retention of the area. The collection of the area retention fee aims to discourage the retention of concessions without the purpose of exploration, and its value is set by the tender notice and the concession agreement. Such value is determined for each calendar year, based on the number of days of the contract and per square kilometer or fraction of the concession area (from BRL10 to BRL5,000 per km^2, depending on the phase and based on a progressive table).

Landlord cost percentage — under a CC, it varies from 0.5% to 1% of the oil and gas production reference price. Under a PSC, it applies only to onshore oilfields and corresponds to a percentage up to 1% of the value of the oil and gas production.

Income tax rate — 34%

Colombia

Fiscal regime that applies to the oil industry consists of a combination of corporate income tax (CIT) and royalty-based taxation.

Production based Sliding Scale Royalties
Monthly average daily production percentage
<= 5K BPD: 8%
>5K BPD - 125K BPD: 8 + (Production - 5K) * (0.10)
>125K BPD - 400K BPD: 20%

>400K BPD - 600K BPD: 20 + (Production - 400K) * (0.025)
>600K BPD: 25%

Income tax rate — CIT rate: 34% for FY 2017 and 33% from 2018
Income tax surcharge — 6% for 2017, 4% for 2018 and 0% from 2019

Ghana

The fiscal regime that applies to the petroleum industry consists of the combined use of four basic tax laws: the Income Tax Act1 (the ITA), Revenue Administration Act, 2016, Act 915 (the RAA), the Petroleum (Exploration and Production) Act, 2016, Act 919 (the E&PA), and the Petroleum Agreement (PA). The ITA and RAA repealed the Petroleum Income Tax Act, PNDCL 188 (PITA) and the Internal Revenue Act, 2000, Act 592 (as amended).

The principal aspects of the fiscal regime that are affecting the oil and gas industry are as follows:

Royalties — Royalty rates are not fixed. The PAs signed so far prescribe royalty rates ranging from 3% to 12.5% for gas and crude production.

Income tax rate — The income tax rate for upstream petroleum activities is 35%. For downstream petroleum activities, the applicable income tax rate is 25%.

Kazakhstan

Mineral extraction tax (MET) is a volume-based, royalty-type tax applicable to crude oil, gas condensate and natural gas. Rates escalate depending on volume. Different tables of rates apply, depending on what is produced and whether it is exported or sold domestically. The rates are applied to production valued at world prices for export sale.

Mineral Extraction Tax: replaces royalties

Volume of annual oil production (thousands of tons)	Rate
Up to 250	5%
Up to 500	7%
Up to 1000	8%
Up to 2000	9%
Up to 3000	10%

Netherlands
The fiscal regime that applies in the Netherlands to the petroleum industry consists of a combination of corporate income tax (CIT), a surface rental tax, a state profit share (SPS) levy and royalty-based taxation. The major elements of the fiscal regime are as follows: Royalties — 0% to 7% CIT — 25%; 20% applies to the first €200,000 of taxable income
New Zealand
New Zealand's fiscal regime applicable to the petroleum industry consists of a combination of corporate income tax (CIT) and royalty-based taxation. The main elements are: • Royalties — 0% to 20% • CIT rate — 28%
Nigeria
Companies carrying on petroleum operations are deemed to be in the upstream regime and taxed under the Petroleum Profits Tax Act (PPTA) 2004 (as amended). **Petroleum Profits Tax** [on chargeable profits] First Five years (new companies): 65.75% First Five years (existing companies): 85% Subsequent years (all companies): 85% **Royalty rates for Joint Venture:** Onshore Production: 20% Production in territorial waters less than 100m: 18.5% Offshore production beyond 100m: 16.67%
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CHAPTER THREE

METHODOLOGY

3.0 INTRODUCTION

This chapter describes the employed mixed-method conceptual/theoretical frameworks adopted for this study. Figure 3.0 below describes the various components of the Fiscal Terms Optimisation Model. The 'Case Manager' is a database of executed projects by various IOCs over the past decade. While the 'Input Values' panel represents all the economic model input parameters like capex, opex, price etc. The Calculation module generates cash flow data based on the various fiscal systems. The key output of the calculation panel are the 'Economic Metrics'.

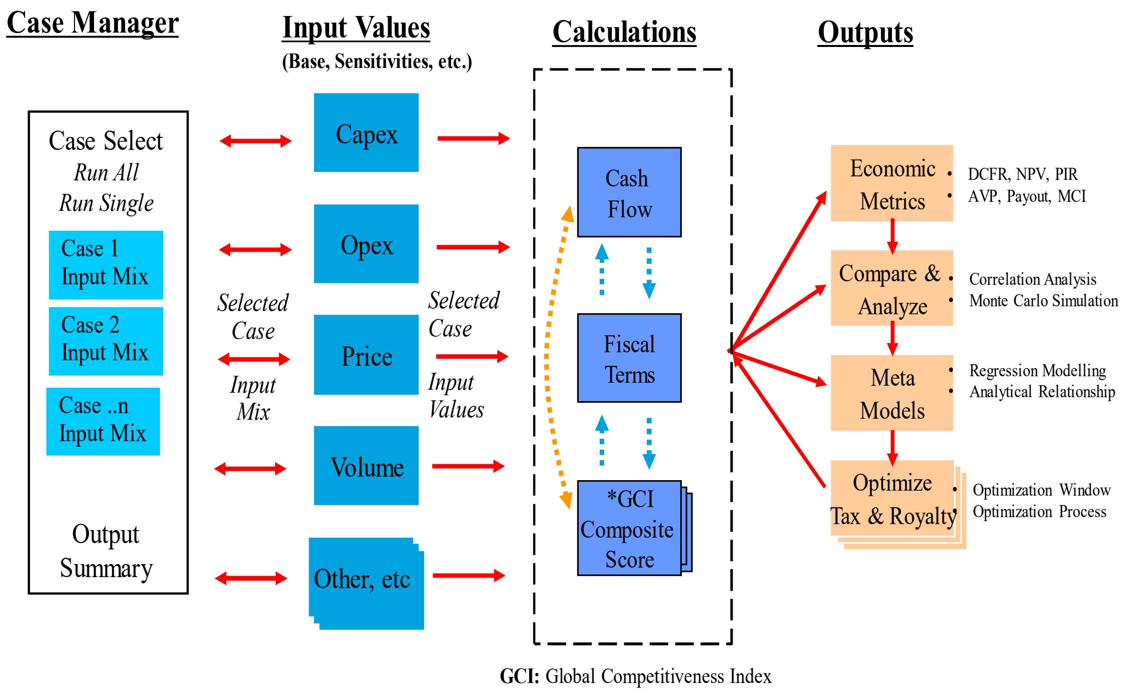


Figure 3.0: Fiscal Terms Optimisation Flow Chart (Source: Author)

1.3 THEORETICAL FRAMEWORK: CONCEPT OF RENT

Economic rent is defined as "the true value of natural resource which is the difference between the revenues generated from resource extraction and the costs of extraction" (Dickson 1999; Nakhle 2007). Most IOCs use cash flow models which are based on the concept of economic rent to evaluate petroleum resource projects. This is due to the model's simplicity as its equations can project cash flow for the whole project's lifespan and reveal the profitability of the project. Moreover, it is also defined as "the surplus return above the value of the capital, labor and other factors of production employed to exploit the resource. It is the surplus revenue of the resource after accounting for the costs of capital and labor inputs" (Banfi, 2005).

Significant economic rent can be generated from the exploitation and utilization of exhaustible natural resources, especially oil and gas resources which are exhaustible resources as well as a strategic commodity with no perfect substitute. This implies that the extraction of oil and gas can earn huge economic rent. Rowland and Hann (1987) asserted that "the economic worth of a license to produce oil from a tract may be measured by the present value of the flow of the future revenues from that tract's production less the present value of associated future costs, where the costs include monetary items such as equipment as well as non-monetary items such as exposure to risks. The difference between these two amounts, is the economic rent of that tract. It implies that the licensee enjoys more profits than those who induce the production of petroleum (pure profits)". Similarly, Raja (1999) argued that "taxes should be aimed at taxing positive net present value because the method discounts all future cash flows and incorporates all the relevant rewards to factors of production".

It can be argued that a positive net present value could be considered as economic rent representing the surplus over and above that which is necessary to induce investment. Therefore, in practical terms, it can be suggested that taxes should be aimed at taxing positive present values. When entering a project, IOC can calculate a return. Economic rent may thus be a bonus, a financial return not required to motivate desired economic behavior. This study agrees with simple and practical concept of economic rent by applying it in the discounted cash flow model used for the analysis to measure the attractiveness level of petroleum fiscal regimes. The economic rent is used in this study due to its simplicity and practical representation of revenue allocation between the host government and the IOC. In addition, oil and gas resources can naturally maximize the economic rent of a country through petroleum fiscal regimes.

CONCEPTUAL FRAMEWORK

The economic analyses implemented for this study involved cash flow analysis and an examination of the company's viability. A meta-model was used to explain the relationship between Fiscal Systems and Economic Metrics (DCFR, NPV, PIR). Meta-modelling, a relatively recent method of analysing fiscal systems, helps us to understand the relationships between variables and their relative effect through a realistic modeling approach (Kaiser and Pulsipher 2004).

Cash Flow Analysis

1.3.1 After-Tax Net Cash Flow Vector:

An investment's net cash flow factor is the money earned less cash spent over the life of the project over a given period, usually taken as one year. The net cash flow after tax associated with field f in year t is estimated as follows:

$$NCF_t = GR_t - ROY_t - CAPEX_t - OPEX_t - TAX_t ,$$

Where;

NCF_t = After-tax net cash flow in year t,

GR_t = Gross revenues in year t,

ROY_t = Total royalties paid in year t,

$CAPEX_t$ = Total capital expenditures in year t,

$OPEX_t$ = Total operating expenditures in year t,

TAX_t = Total taxes paid in year t.

The after-tax net cash flow vector associated with field f is denoted as

$$NCF(f) = (NCF_1, NCF_2, ..., NCF_k),$$

And is supposed to start in year one (t = 1) and go through field abandonment (or divestment) at t = k. The after-tax net cash flow function acts as the basic element in the take estimation and related economic measures.

1.3.2 Economic Returns Metrics Calculation

The next step is to measure three key economic outcome measures from the fiscal regime's application: PV, IRR (also known as DCFR), PI (also known as PIR).

For field f and fiscal regime denoted by F, the present value (PV(f, F)) and internal rate of return (IRR(f, F)) of the cash flow vector NCF(f) is computed as:

$$PV(f, \mathrm{F}) = \sum_{t=1}^{k} \frac{NCF_t}{(1+D)^{t-1}},$$

$$IRR(f, \mathrm{F}) = \{D \mid PV(f, \mathrm{F}) = 0\},$$

Where D is the rate (discount) equal to zero for the present value. A profitability index or investment efficiency ratio standardizes the project's value against the total investment and is calculated as:

$$PI(f, \mathrm{F}) = \frac{\mathrm{PV(f,F)}}{\mathrm{PV(TC)}}.$$

The present value provides an absolute estimate of the project's net value to the contractor, whereas the rate of return and the profitability ratio are comparable measures used to measure capital budgeting programs. Economic values are not intended to be interpreted on a stand-alone basis, but should be used in conjunction with other system measures and decision parameters. A mixture of metrics is typically necessary to properly assess a contract's economic performance.

The income distribution between the contractor and the government is referred to as "take." Take is a monetary metric as opposed to an economic calculation, and thus it is most applicable to the host government in general. Nevertheless, since taking does not provide a clear indicator of the economic performance of a sector, the contractor retains only secondary interest in its value. The total cost is specified in year t, TCt as:

$$TC_t = CAPEX_t + OPEX_t,$$

and the total profit is the difference between the gross revenues and total cost:

$$TP_t = GR_t - TC_t.$$

If the total profit in year t is written;

$$TP_t = CT_t + GT_t,$$

then the contractor and government take is computed as,

$$CT_t = TP_t - ROY_t - TAX_t = \text{Contractor take in year } t,$$

$$GT_t = ROY_t + TAX_t = \text{Government take in year } t.$$

1.3.2.1 Host nation take (GT)

GT is the most commonly used comprehensive indicator that reflects the attractiveness of contract. GT refers to the proportion of host nation's income to the total project revenue (DR) within the validity period of the contract. Host nation's income includes government take (GTG) and its state oil company's income (GTC). It puts the impacts of bonus, royalties, profit oil split, taxation of all levels, government equity participation and other factors into one indicator.

The larger GT is, the less attractive the contract is to the IOCs. At present, GT can be calculated through three ways: First, non-discounted cash flow method. At a certain level of oil price and output, without considering the time value of money, cash inflows and outflows of the contract period is simulated, appropriate deductions and allocations of the contract is made in accordance with the terms of the contract, and the proportion of host nation's income to the total project revenue within the validity period of the contract is just the non-discounted GT. The formula is:

$$GT = \frac{\sum_{t=1}^{n}(GTG_t + GTC_t)}{\sum_{t=1}^{n} DR_t} \times 100\%$$

Where: n—term of contract, a; GTGt—the host government take in the year t, \$; GTCt—income of Host country's NOC in the year t, \$; DRt—the total income in the year t, \$. Second, the discounted cash flow method, which is to calculate the discounted host nation take based on certain discount rate. At a certain level of oil price and output, cash inflow time of host nation during the contract period is simulated, and the present value of host nation's income during the entire life of oilfield is calculated as per a certain discount rate. The ratio of the above present value of host nation's income to that of the total project income is GTi. The formula is:

$$GT_i = \frac{\sum_{t=1}^{n}(GTG_t + GTC_t)(1+i)^{-t}}{\sum_{t=1}^{n} DR_t (1+i)^{-t}} \times 100\%$$

Where i refers to the discount rate. Third, fast and intuitive method. Forecast of cash flow needs abundant data, complex calculations and multidisciplinary collaboration, sometimes it is difficult to complete the calculation in a short time. Under fast and intuitive method, the total project income (I) is assumed as 100%, and calculation is made according to the order and the proportion of the contract. If the royalties, cost sharing ratio, profit-sharing ratio adopts a progressive sliding scale, then the average values of parameters in the project lifetime are used in calculating. Suppose the allocation order and ratio of a production sharing contract is: (1) the host nation obtains royalties (R), with proportion of the royalties (Rt) as 10%; (2) IOCs recover costs, with cost recovery upper limit (Rr) no higher than 35% of the total income with royalties deducted;(3) Allocation of profit oil, after the (1), (2) steps deductions, the remaining is portion of the profit oil (profit-sharing oil), from which the host nation take 55%(Er), IOCs get the remaining 45%;

(4) IOCs pay income tax (T) to the host nation, tax rate (Tr) is 25%. Taxable income is the income IOCs get from profit oil. The host nation's income mainly includes three parts: R, E and T. Then, GT can be calculated by the following formula:

$$GT = R + E + T$$

By using fast and intuitive method, we can quickly calculate the proportion of host nation's income to total income. It is a more simple method than cash flow simulation method, and its result is similar to that of non-discounted cash flow method.

GT calculated with the above three ways can reflect the attractiveness of contract to a certain extent, but all have an important flaw during comparison by different fiscal term combinations: it only reflects the total amount scale of the host nation's income, without considering the influence of different time sequences of income gaining by host nation on the benefit of IOCs and the attractiveness of the contract. We can find from the calculations that, there exists a huge gap between the discounted and non-discounted results. In the case of non-discounted, the proportion sum of host nation takes and IOC gets is 1, when calculated with a discount rate, the proportion of host nation takes may be greater than 1, this indicates that the project itself is in the red, the host nation gain income by imposing various taxes and fees, while the IOCs' income is negative. This indicates that the time sequence differences of income gaining by host nations will not only affect the actual benefit of host nation and IOCs, and even the project's profitability, but also on the attractiveness sequence of the fiscal terms. To make up the defect of this indicator and reflect the combination level of a contract's fiscal terms more realistically, based on the evaluation of the proportion of host nation get, front-loading index (FLI) of IOCs is used to reflect the impact of time sequence differences of host nation on the project and IOCs' profit.

1.3.2.2 Front-loading index

In the international petroleum cooperation, time sequence of incomes gaining by host nation is a major issue IOCs should consider, because delaying payment to the host nation means IOCs can recover costs early and quickly, and ultimately access to higher returns in a project. If the host nation obtains income based on the profits of the project, then there is no front-loading for the IOCs, discounted and non-discounted GT is the same. However, in most cases, the host nation doesn't get its income based on project profits, the presence of the following factors lead to the difference of host nation's proportion with discounted and non-discounted: First, early in the project operation, there exist signature bonus, finding bonus and host nation carried benefit, as well the business tax, VAT, import tax levied on the investment that may occur during the construction period. These expenditures occur before the profit making, and result in front-loading in the early stage; Second, in the production phase of the project, there are excise tax levies on the level of output, as well as royalties, production sharing ratio and bonus level determined by output and income, which may cause income of the host nation to grow faster than that of the project profit, and this can also constitute front-loading to IOCs.

The ratio of difference between non-discounted GT and the discounted GTi to GT is defined as IOCs' FLI. The smaller the FLI is, the less risk will IOCs face in the earlier stage, and the more attractive of contract items is to IOCs. Front-loading index can be calculated as:

$$FLI = \frac{GT - GT_i}{GT} \times 100\%$$

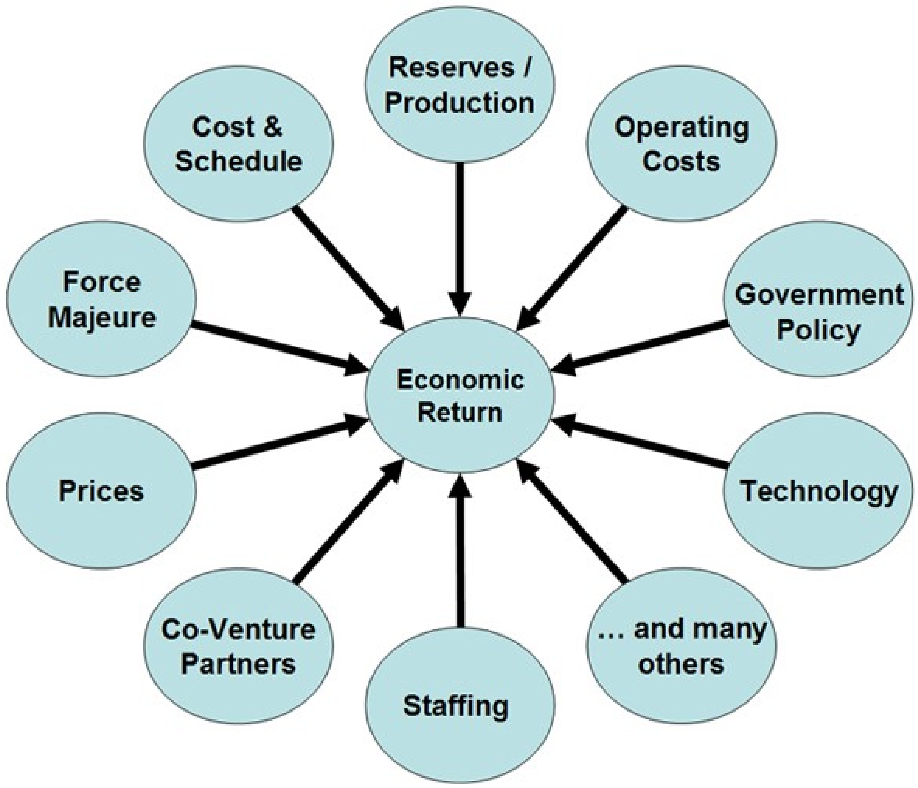


Figure 3.2: Economic Returns Factors

A system cash flow model has been built and the system parameters are sampled from the design space and evaluated using the cash flow model. Model results and system parameters are then analysed and from the produced data meta-models are created. The relations of fiscal structures, economic metrics and meta-models are defined in figure 3.2 above.

The summary of this approach is as follows:

(1) Identify the variable set ψ and define the design intervals $l_i \leq \psi \leq u_i$, $i=1\ldots n$, for each factor of interest, where the values of l_i and u_i are user-defined and account for a realistic range of the historic uncertainty (or expected variation) associated with each factor. Denote the design space as Ω

$\Omega = \{\psi = (\psi 1 \ldots \psi n) \mid li \leq \psi \leq ui, i=1\ldots n\}$.

(2) Sample the components parameters $\psi^* = (\psi 1^* \ldots \psi n^*)$ uniformly over the design space and compute the economic indicators $\{\varphi (f, F(\psi^*))\}$.

Based on the datasets $\{\psi^*\}$ and $\{\varphi (f, F(\psi^*))\}$ estimate for each measure φ the functional relation:

$$\varphi\big(f, F(\psi)\big) = \alpha_0 + \sum_{i=1}^{n} \alpha_i\,(\varphi)\psi_i$$

Where the coefficients α_i (φ) are determined through regression modelling.

1.4 A Functional Analytic Approach to System Measures

In the case of perfect information, the computation of the economic and system measures associated with a field will not depend on the individual performing the calculation. In reality, however, the computation of present value, rate of return, and take is strongly dependent on the level of system information available and the assumption set of the user.

To investigate the impact of a royalty/tax fiscal system for a specific field, it is necessary to calculate the after-tax cash flow under the fiscal system and to examine the factors that influence the economic performance of the field.

1.5 Elements of Fiscal Design

There are many applications of regression modeling to the design of efficient and flexible royalty/tax systems. The main elements of fiscal design are briefly highlighted:

1.5.1 Equivalent Fiscal Regimes:

There are many ways to extract economic rent, but none of the arrangements is inherently more profitable than any other, and all petroleum arrangements can be made fiscally equivalent. For field f and fiscal regime F(R,T) , the notion of equivalency is defined in terms of the system functional φ(f).

Definition. The fiscal regime $\mathrm{F}_{\varphi(f)}(R,T)$ is said to be $\varphi(f)$-equivalent to the fiscal regime $\mathrm{F}_{\varphi(f)}(R^*,T^*)$, $\mathrm{F}_{\varphi(f)}(R,T) \sim \mathrm{F}_{\varphi(f)}(R^*,T^*)$, if $\varphi(R,T) = \varphi(R^*,T^*)$. ■

The exact manner in which equivalency is maintained is determined by the functional relationship established for the field and the fiscal regime under consideration.

1.5.2 Feasibility Constraints:

For an operator to consider an investment opportunity feasible, certain minimum economic criteria must be satisfied. For example, if the fiscal regime of government is so constraining as to make development projects uneconomic, or if the fiscal marksmanship of a country is unrealistic and leaves production unprofitable, or if a contractor's expectation of return is unrealistically high, then the fiscal regime in the "eye" of the contractor would be considered infeasible since viable projects will either be abandoned prematurely or not developed.

The relationship of a fiscal system to operator constraints determines various "feasible" regions. A feasibility constraint is defined for a specific field and fiscal regime, and is determined by the functional φ(f) and the selection of a user-defined parameter $\varepsilon > 0$.

Definition. The (φ(f), ε)-constraint $_{(\phi(f),\varepsilon)}\Pi(R,T) = \{ (R,T) \mid \varphi(f) > \varepsilon\}$ for field f defines the set of fiscal parameters (R,T) that satisfy the design constraint $\varphi(f) > \varepsilon$.

Feasible Domain:

The collection of feasibility constraints and the logic operator "AND" defines the operator's "feasible" domain, the region that will simultaneously satisfy all the economic requirements of the operator.

Definition. The feasible domain of the operator, $\Sigma^O(R,T)$, is defined as the intersection of the set of all feasibility constraints, $\Pi_{(\varphi(f),\varepsilon)}$:

$$\Sigma^O(R,T) = \bigcap_{(\varphi(f),\varepsilon)} \Pi_{(\varphi(f),\varepsilon)} . \blacksquare$$

1.5.3 Progressive Fiscal Regimes:

The notion of "progressive" and "regressive" fiscal regimes are widely discussed in the trade press. Fiscal regimes that tax profitable projects heavily and marginal projects lightly are referred to as progressive, while fiscal regimes that taxes marginal fields heavily relative to profitable projects are called regressive.

A progressive regime is usually defined by the absence of royalties, bonuses, and other types of payment based on gross production, while emphasizing profit-based mechanisms such as taxation and sliding-scale terms. A progressive fiscal regime usually encourages the development of marginal prospects since the government take is at its lowest when oil company profitability is low; and as the profitability of a field increases, the government will extract more take.

A system cash flow model has been built and the system parameters are sampled from the design space and evaluated using the cash flow model. Model results and system parameters are then analysed and from the produced data meta-models are created. The relations of fiscal structures, economic metrics and meta-models are defined in figure 3.2 above.

The summary of this approach is as follows:

(1) Identify the variable set ψ and define the design intervals $l_i \leq \psi \leq u_i$, i=1…n, for each factor of interest, where the values of l_i and $u_i$are user-defined and account for a realistic range of the historic uncertainty (or expected variation) associated with each factor. Denote the design space as Ω

$\Omega = \{\psi = (\psi 1 \ldots \psi n) \mid li \leq \psi \leq ui, i=1 \ldots n\}$.

(2) Sample the components parameters $\psi^* = (\psi 1^* \ldots \psi n^*)$ uniformly over the design space and compute the economic indicators $\{\varphi (f, F(\psi^*))\}$.

Based on the datasets $\{\psi^*\}$ and $\{\varphi (f, F(\psi^*))\}$estimate for each measure φ the functional relation:

Two definitions of a progressive fiscal regime are provided. The first definition refers to the time history of one field, while the second definition refers to a collection of fields {f} evaluated at a point in time. The relationship between government take and rate of return is used to define the fiscal regime.

Definition 1: A fiscal regime F(R,T) is said to be progressive (regressive) with respect tothe field f if $\tau g (f , F)$ and IRR(f, F) are positively (negatively) correlated.

Definition 2: . A fiscal regime F(R,T) is said to be progressive (regressive) with respect tothe collection of fields {f} if $\tau g (f , F)$ is an increasing (decreasing) function of IRR(f, F);i.e., $\tau g (f , F) = \alpha + \beta$ IRR(f, F), where $\beta > 0$ ($\beta <0$).

1.6 Excel Regression Analysis Output:

Multiple R: This value ranges from zero to one, one being the perfect relationship while zero indicates no relationship at all. A median number between zero and one indicate an average relationship. It can also be described as the square root of 'r squared' which is to be defined in the next paragraph below.

R squared (r^2): A fifty percent r squared value means that fifty percent of the values fit the suggested model. Also known as a statistical measure characterizing the variance fraction for a dependent variable defined.

A system cash flow model has been built and the system parameters are sampled from the design space and evaluated using the cash flow model. Model results and system parameters are then analysed and from the produced data meta-models are created. The relations of fiscal structures, economic metrics and meta-models are defined in figure 3.2 above.

The summary of this approach is as follows:

(1) Identify the variable set ψ and define the design intervals $l_i \leq \psi \leq u_i$, i=1…n, for each factor of interest, where the values of l_i and u_i are user-defined and account for a realistic range of the historic uncertainty (or expected variation) associated with each factor. Denote the design space as Ω

$\Omega = \{\psi = (\psi 1 \dots \psi n) \mid li \leq \psi \leq ui, i=1 \dots n\}$.

(2) Sample the components parameters $\psi^* = (\psi 1^* \dots \psi n^*)$ uniformly over the design space and compute the economic indicators $\{\varphi (f, F(\psi^*))\}$.

Based on the datasets $\{\psi^*\}$ and $\{\varphi (f, F(\psi^*))\}$ estimate for each measure φ the functional relation:

1.7 Area of Study

Table 3.2 below lists the countries whose fiscal regimes will be tested/compared with the Nigeria Fiscal regimes (pre and post PIB 2012). This selection is based on the analysis of previous studies conducted by the Colombia Center on Sustainable Investment (2013) which detailed the fiscal structure of several hydrocarbon-rich countries with legislated fiscal terms or model contracts. The fiscal structures of these countries are similar and can easily be modelled for comparison.

Table 3.2: Selected Countries for Analysis (Source: Author)

Continents	Selected Countries
Africa	Nigeria, Ghana, Algeria, Mozambique, Namibia
Asia	Kazakhstan, Russia
Europe	Netherlands, Romania
North America	Trinidad and Tobago
Oceania	Australia, New Zealand
South America	Brazil, Colombia, Peru

CHAPTER FOUR
RESULTS & DISCUSSION

4.0 INTRODUCTION

Decisions on the design of an appropriate fiscal framework can be supported by an understanding of how its various components influence decision making and outcomes. To this end a simplified economic model of five petroleum projects was developed to illustrate the difficulties that a country would typically face in designing a suitable fiscal framework for the development of its hydrocarbon resources. In particular, simulations were conducted to show the effect on project economics of alternative fiscal terms and their relative responsiveness to changes in economic conditions.

Table 3.3 below shows the highlights of selected projects. Range of water depths: 27.13m – 42.67m with a project crude production uplift range of 6.5 kbd – 36.4 kbd. Work scope included front end engineering, topside fabrication/installation and drilling and completions. Most of the Nigeria Joint Venture projects are located within shallow water acreage (less than 50m water), hence the reason for selecting these projects are test cases for Concessionary models.

Treasurer's / Controller's normally define the discount rate "risk-free" to be used. For most multinational oil companies operating in Nigeria, the discount rates employed hovers around 10 to 12%. We have a country and customer "premium" that needs to be added to the "risk free" rate. "Risk-Free" meaning a country like the USA (Hurdle Rate). For this study, we tested discount rates of both 10% and 12% to understand the effect of the rate variations.

Table 3.3: Projects Summary

General Descriptions	– Topside installation project on fixed offshore platform to increase production. – Scope: Engineering Design (Structural, Process, Mechanical, Electrical & Instrumentation), Construction and Installation and well drilling.
Project 1	• Crude Production uplift: ~26.1 kbd (Gross)
	• Water Depth: 27.13m
Project 2	• Crude Production uplift: ~20.3 kbd (Gross)
	• Water Depth: 28.04m
Project 3	• Crude Production uplift: ~36.4 kbd (Gross)
	• Water Depth: 28.04m
Project 4	• Crude Production uplift: ~6.5 kbd (Gross)
	• Water Depth: 27.43m
Project 5	• Crude Production uplift: ~18.8 kbd (Gross)
	• Water Depth: 42.67m

4.1 RESULTS

Five fixed offshore crude production projects of an international oil company operating in Nigeria with crude production uplifts in thousand barrels per day (kbd) and water depth in metres (m) were selected and labeled – PRJ1, PRJ2, PRJ3, PRJ4 and PRJ5, and used to develop FTOM comprising – Discounted Cash Flow Rate (DCFR), Net Present Value (NPV), Profit-to-Investment Ratio (PIR), Maximum Cash Impairment (MCI), Actual Value Profit (AVP), and Payout (PYT) were combined with GCI from fifteen countries to develop a meta-model used to determine optimal and tax competitive window which predicts the relationship between the various economic metrics and fiscal terms that drive investment decisions.

4.1.1 Cash Flow Analysis Data

Cash flow data for five past projects were obtained from international companies operating in Nigeria. Table 4.1 below shows the cash flow economic metrics output by country for the five (5) sample projects. Table 4.1 displayed the key profitability indexes: DCFR/IRR, AVP, NPV @ 12% and 10%, MCI, PIR/PI and Payout. Table 4.1 also listed applicable royalty-tax rates for each of the selected sixteen (16) fiscal systems.

Companies summarize the thousands of figures associated with a project proposal into indicators of profitability that can be used to compare with alternative ways to invest. The economic metrics below summarize the quantitative aspect which is important in making the final investment decisions. The decision also considers factors that cannot be quantified; however, given that profit is the reason companies are in business, profit metrics depend largely in the judgment-making process.

Table 4.1: Cash Flow - Economic Metrics Output by Country

			Algeria	Australia	Brazil	Colombia	Ghana	Kazakhstan	Mozambique	Namibia	Netherlands	New Zealand	igeria Post-PI	Nigeria Pre-PI	Peru	Romania	Russia	Trinidad
	Royalty	%	20.0%	10.0%	10.0%	25.0%	12.5%	18.0%	10.0%	12.5%	7.0%	20.0%	31.0%	18.5%	20.0%	13.5%	16.0%	15.0%
	Tax Rate	%	38.0%	40.0%	34.0%	34.0%	35.0%	20.0%	32.0%	35.0%	25.0%	28.0%	80.0%	85.0%	28.0%	16.0%	20.0%	55.0%
Project 1	DCFR	%	178.5%	193.7%	203.2%	174.2%	197.1%	206.5%	206.2%	197.1%	221.9%	192.3%	78.6%	76.5%	192.3%	220.7%	210.6%	158.5%
	AVP	$M	2958.6	3277.8	3579.9	2909.4	3419.5	3851.6	3680.7	3419.5	4185.6	3394.5	978.8	925.1	3394.5	4287.3	3959.9	2369.9
	NPV 12	$M	667.9	745.9	815.7	654.0	777.6	874.2	839.0	777.6	957.3	768.0	211.6	201.1	768.0	977.3	900.3	534.5
	NPV 10	$M	824.8	919.5	1005.2	808.4	958.6	1077.9	1033.8	958.6	1178.5	947.8	264.7	251.5	947.8	1203.8	1109.7	660.6
	MCI	$M	-32.5	-32.2	-33.0	-33.0	-32.9	-34.9	-33.3	-32.9	-34.2	-33.8	-26.9	-26.2	-33.8	-35.4	-34.9	-30.2
	PIR	$/$	7.4	8.2	8.9	7.2	8.5	9.6	9.2	8.5	10.4	8.4	2.4	2.3	8.4	10.7	9.9	5.9
	Payout	Years	2.3	2.3	2.3	2.4	2.3	2.3	2.3	2.3	2.3	2.3	4.9	4.9	2.3	2.3	2.3	2.4
Project 2	DCFR	%	161.6%	279.8%	324.2%	129.6%	265.6%	234.8%	340.6%	265.6%	553.0%	185.0%	45.1%	64.5%	185.0%	359.4%	272.1%	153.8%
	AVP	$M	66.6	79.8	86.4	61.8	81.2	85.9	88.6	81.2	101.8	75.1	22.8	27.2	75.1	98.9	89.8	57.7
	NPV 12	$M	45.1	55.6	60.5	41.2	56.5	59.5	62.1	56.5	72.3	51.4	12.3	16.2	51.4	69.5	62.6	38.9
	NPV 10	$M	41.2	51.2	55.8	37.4	52.0	54.7	57.3	52.0	66.9	47.1	10.4	14.3	47.1	64.2	57.6	35.5
	MCI	$M	-6.7	-4.5	-4.2	-7.9	-4.8	-5.7	-4.0	-4.8	-2.8	-6.5	-10.1	-7.7	-6.5	-4.2	-5.1	-6.3
	PIR	$/$	0.8	0.9	1.0	0.7	0.9	1.0	1.0	0.9	1.2	0.9	0.3	0.3	0.9	1.2	1.0	0.7
	Payout	Years	2.0	1.5	1.4	2.2	1.5	1.6	1.4	1.5	1.2	1.8	3.3	2.8	1.8	1.3	1.5	2.0
Project 3	DCFR	%	153.1%	268.9%	312.9%	122.1%	255.3%	225.7%	329.2%	255.3%	538.7%	176.4%	38.5%	58.6%	176.4%	348.7%	262.4%	145.0%
	AVP	$M	46.5	56.2	60.8	43.0	57.1	60.1	62.4	57.1	71.8	52.5	15.0	19.0	52.5	69.5	63.0	40.5
	NPV 12	$M	32.7	40.7	44.3	29.6	41.3	43.3	45.5	41.3	53.1	37.2	7.9	11.5	37.2	50.8	45.6	28.2
	NPV 10	$M	30.1	37.8	41.2	27.1	38.3	40.1	42.3	38.3	49.6	34.4	6.6	10.1	34.4	47.3	42.4	26.0
	MCI	$M	-6.8	-4.6	-4.2	-7.9	-4.9	-5.8	-4.1	-4.9	-2.8	-6.5	-10.1	-7.7	-6.5	-4.2	-5.2	-6.3
	PIR	$/$	0.7	0.9	0.9	0.7	0.9	0.9	1.0	0.9	1.1	0.8	0.2	0.3	0.8	1.1	1.0	0.6
	Payout	Years	2.0	1.5	1.4	2.1	1.5	1.6	1.4	1.5	1.2	1.8	3.1	2.7	1.8	1.3	1.5	2.0
Project 4	DCFR	%	305.9%	336.6%	353.8%	296.4%	341.9%	357.0%	359.3%	341.9%	388.9%	330.7%	128.1%	124.8%	330.7%	384.4%	365.3%	271.5%
	AVP	$M	313.2	348.9	383.6	308.1	365.4	415.7	395.1	365.4	452.7	363.3	85.8	79.2	363.3	465.2	427.9	245.1
	NPV 12	$M	150.0	167.9	184.9	147.2	175.9	200.1	190.5	175.9	218.8	174.4	39.0	36.0	174.4	224.5	206.2	117.0
	NPV 10	$M	127.6	143.0	157.5	125.1	149.7	170.4	162.3	149.7	186.5	148.4	32.7	30.2	148.4	191.3	175.6	99.4
	MCI	$M	-5.1	-5.1	-5.2	-5.2	-5.2	-5.5	-5.2	-5.2	-5.4	-5.3	-4.3	-4.2	-5.3	-5.5	-5.5	-4.8
	PIR	$/$	4.6	5.1	5.6	4.5	5.4	6.1	5.8	5.4	6.7	5.3	1.3	1.2	5.3	6.8	6.3	3.6
	Payout	Years	2.3	2.2	2.2	2.3	2.2	2.2	2.2	2.2	2.2	2.2	3.1	3.2	2.2	2.2	2.2	2.3
Project 5	DCFR	%	138.9%	159.6%	165.1%	130.4%	158.4%	155.9%	166.8%	158.4%	179.9%	146.0%	75.3%	78.6%	146.0%	169.8%	160.9%	133.0%
	AVP	$M	24.5	27.8	30.2	23.7	28.7	31.8	31.0	28.7	35.4	27.9	8.6	8.4	27.9	35.7	32.8	20.1
	NPV 12	$M	15.7	18.0	19.6	15.2	18.6	20.6	20.2	18.6	23.1	18.0	5.1	5.0	18.0	23.2	21.3	12.8
	NPV 10	$M	14.2	16.2	17.7	13.6	16.8	18.6	18.2	16.8	20.9	16.3	4.4	4.4	16.3	21.0	19.3	11.5
	MCI	$M	-6.5	-6.4	-6.7	-6.8	-6.7	-7.6	-6.8	-6.7	-7.3	-7.1	-4.0	-3.7	-7.1	-7.8	-7.6	-5.5
	PIR	$/$	2.6	2.9	3.2	2.5	3.0	3.4	3.3	3.0	3.7	3.0	0.9	0.9	3.0	3.8	3.5	2.1
	Payout	Years	1.6	1.5	1.5	1.6	1.5	1.5	1.5	1.5	1.5	1.6	2.0	2.0	1.6	1.5	1.5	1.6

4.1.2 DCFR Data

Table 4.1 shows the DCFR values that were generated from the Cash Flow Analysis. While Figure 4.2 plots DCFR values for the sixteen (16) fiscal systems against the corresponding royalty-tax rates. The higher the DCFR of a venture, the more attractive it is to pursue. DCFR is standard for investments of different types and can therefore be used to rate various prospective projects on a fairly even basis. Perhaps the project with the highest DCFR would be considered the best and pursued first, assuming the investment costs are equal among the different projects. It is the corresponding interest rate that an investor is expected to earn.

Table 4.2: DCFR Data

Countries	DCFR Project 1 (X 100%)	DCFR Project 2 (X 100%)	DCFR Project 3 (X 100%)	DCFR Project 4 (X 100%)	DCFR Project 5 (X 100%)
Algeria	0.86	0.78	0.74	1.47	0.67
Australia	1.55	2.24	2.15	2.69	1.28
Brazil	1.04	1.65	1.60	1.80	0.84
Colombia	0.99	0.74	0.70	1.69	0.74
Ghana	0.71	0.96	0.92	1.23	0.57
Kazakhstan	1.26	1.43	1.38	2.18	0.95
Mozambique	0.43	0.72	0.69	0.75	0.35
Namibia	0.91	1.22	1.17	1.57	0.73
Netherlands	1.97	4.92	4.79	3.46	1.60
New Zealand	1.62	1.55	1.48	2.78	1.23
Nigeria Post-PIB	0.22	0.13	0.11	0.36	0.21
Nigeria Pre-PIB	0.21	0.18	0.16	0.35	0.22
Peru	1.04	1.00	0.95	1.79	0.79
Romania	1.24	2.01	1.95	2.15	0.95
Russia	1.47	1.90	1.84	2.56	1.13
Trinidad	0.78	0.75	0.71	1.33	0.65

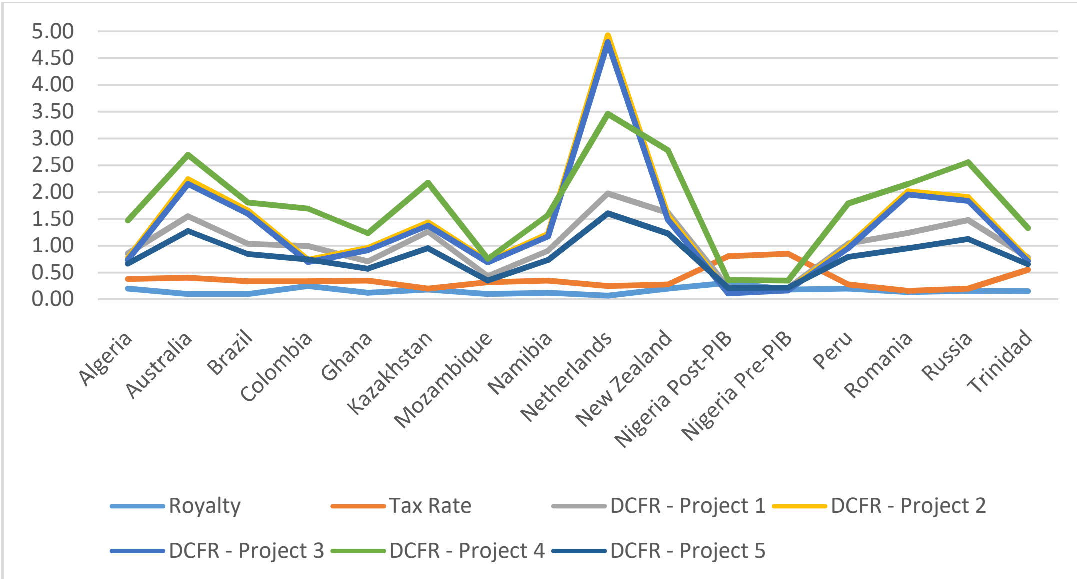


Figure 4.2: DCFR Plot

4.1.3 NPV Data

Table 4.3 and 4.4 shows the NPV data at 12% and 10% discount rate respectively. NPV transforms the potential cash flows of a company to a single equivalent value, taking into account the time value of money. In fact, it is the number of annual plan estimated cash flows that have been reduced to time zero. It is determined by discounting to a given effective date the cash flow stream at the discount rate of the company. Typical IOC discount rates in Nigeria are 12% and 10%, hence the need to produce data for both discount rates to check the effect of the price on production performance.

For capital budgeting, NPV is commonly used to assess that investments are likely to make the maximum profit. It is helpful to understand the scale and scope of the opportunity; to equate opportunities with different lifetimes; to determine the degree of extra gain (or loss) compared to the rate of discount. Figure 4.3 and 4.4 plots NPV values for the sixteen (16) fiscal systems against the corresponding royalty-tax rates.

Table 4.3: NPV12 Data

Countries	NPV 12 Project 1 ($M)	NPV 12 Project 2 ($M)	NPV 12 Project 3 ($M)	NPV 12 Project 4 ($M)	NPV 12 Project 5 ($M)
Algeria	320.59	21.66	15.68	72.01	7.55
Australia	596.71	44.47	32.53	134.34	14.37
Brazil	416.03	30.86	22.59	94.28	10.00
Colombia	372.80	23.48	16.87	83.93	8.64
Ghana	279.92	20.35	14.86	63.31	6.70
Kazakhstan	533.26	36.29	26.40	122.04	12.56
Mozambique	176.20	13.05	9.56	40.01	4.23
Namibia	357.68	26.00	18.99	80.90	8.56
Netherlands	851.98	64.32	47.24	194.75	20.56
New Zealand	645.11	43.16	31.28	146.53	15.15
Nigeria Post-PIB	59.24	3.44	2.20	10.93	1.42
Nigeria Pre-PIB	56.32	4.55	3.23	10.09	1.40
Peru	414.72	27.74	20.11	94.20	9.74
Romania	547.28	38.93	28.46	125.73	13.02
Russia	630.24	43.83	31.95	144.31	14.92
Trinidad	261.90	19.07	13.84	57.34	6.28

Table 4.4: NPV10 Data

Countries	NPV 10 Project 1 ($M)	NPV 10 Project 2 ($M)	NPV 10 Project 3 ($M)	NPV 10 Project 4 ($M)	NPV 10 Project 5 ($M)
Algeria	667.90	45.13	32.67	150.01	15.73
Australia	745.89	55.59	40.66	167.93	17.96
Brazil	815.74	60.51	44.29	184.87	19.61
Colombia	654.03	41.19	29.60	147.24	15.17
Ghana	777.56	56.52	41.28	175.87	18.61
Kazakhstan	874.20	59.49	43.27	200.07	20.59
Mozambique	839.03	62.15	45.50	190.51	20.16
Namibia	777.56	56.52	41.28	175.87	18.61
Netherlands	957.28	72.27	53.08	218.83	23.10
New Zealand	767.99	51.38	37.24	174.44	18.03
Nigeria Post-PIB	211.57	12.30	7.87	39.04	5.06
Nigeria Pre-PIB	201.13	16.23	11.52	36.04	4.99
Peru	767.99	51.38	37.24	174.44	18.03
Romania	977.29	69.52	50.83	224.51	23.25
Russia	900.34	62.61	45.65	206.15	21.31
Trinidad	534.49	38.91	28.24	117.03	12.82

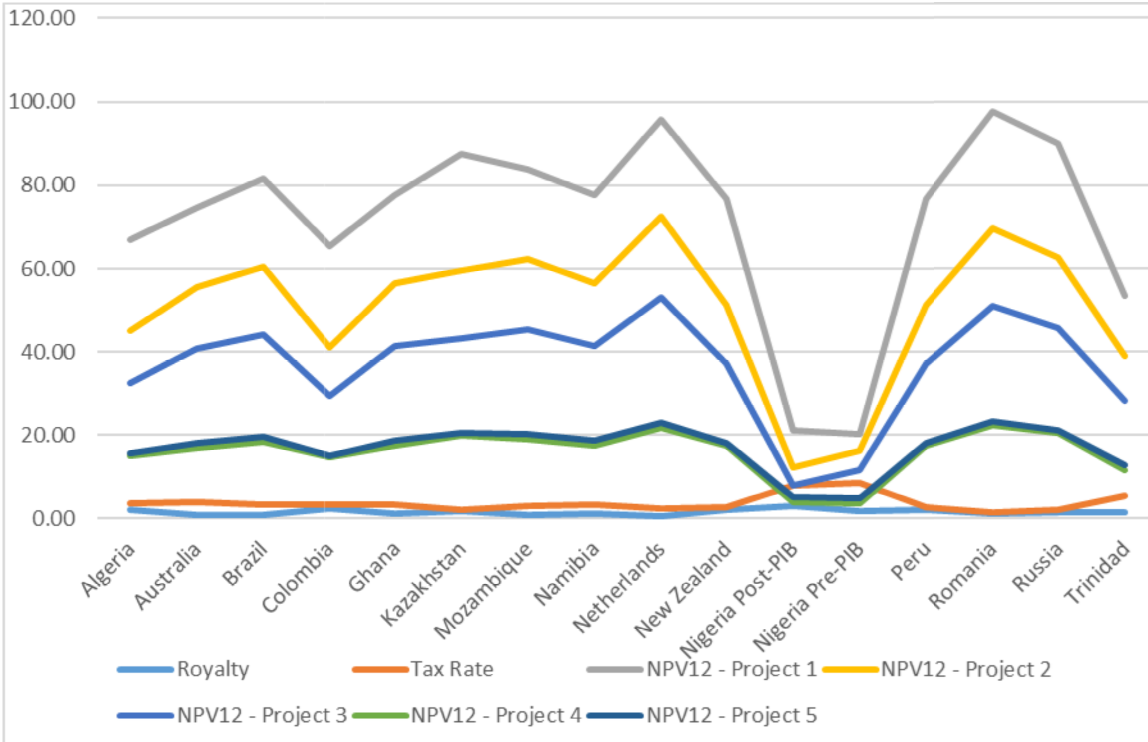


Figure 4.3: NPV 12 Plot

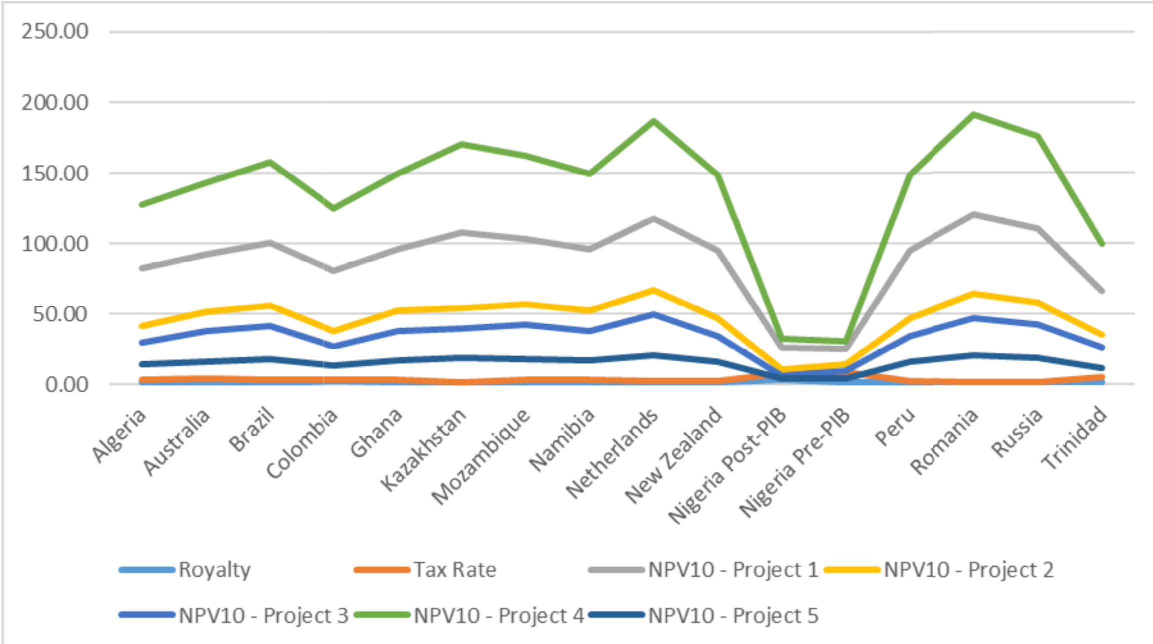


Figure 4.4: NPV 10 Plot

4.1.4 PIR Plot

Figure 4.5 shows the PIR Plot for the sixteen (16) fiscal systems against royalty-tax rates.

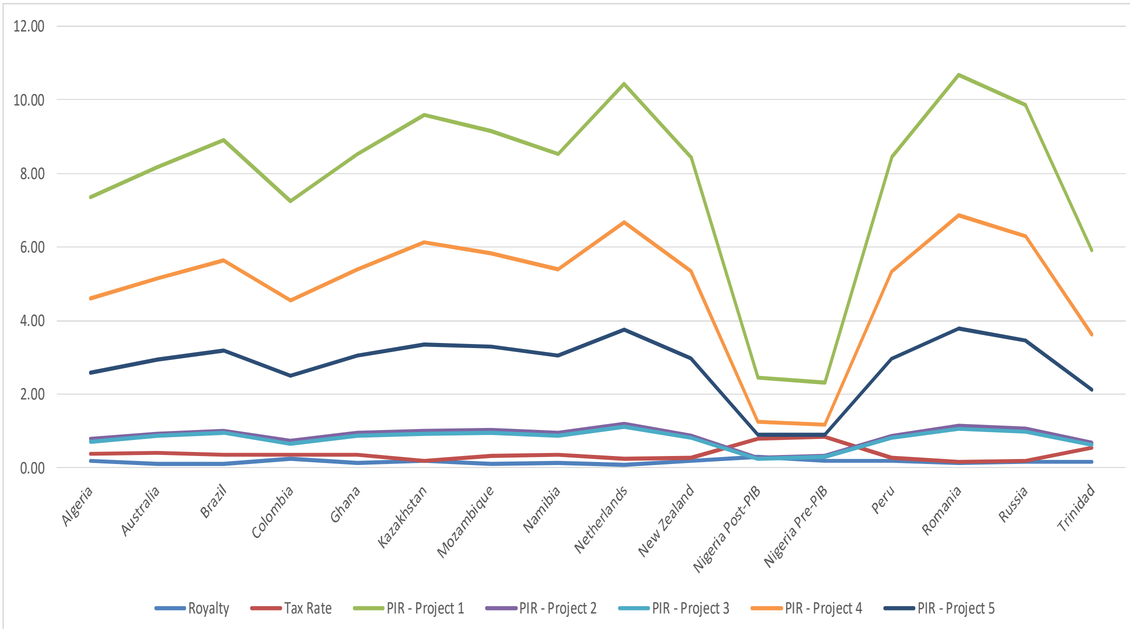


Figure 4.5: PIR Plot

4.1.5 Statistical Analysis – DCFR Correlation Analysis Results

Table 4.5: Correlation Analysis Results

Correlation Data	Royalty	Tax Rate	DCFR Project 1	DCFR Project 2	DCFR Project 3	DCFR Project 4	DCFR Project 5
DCFR - Project 1	0.6453	0.96287	1				
DCFR - Project 2	0.82721	0.66356	0.780283	1			
DCFR - Project 3	0.8263	0.66392	0.779956	0.999993	1		
DCFR - Project 4	0.65906	0.9584	0.999772	0.791805	0.791464	1	
DCFR - Project 5	0.7653	0.90115	0.983126	0.855366	0.854768	0.986571	1

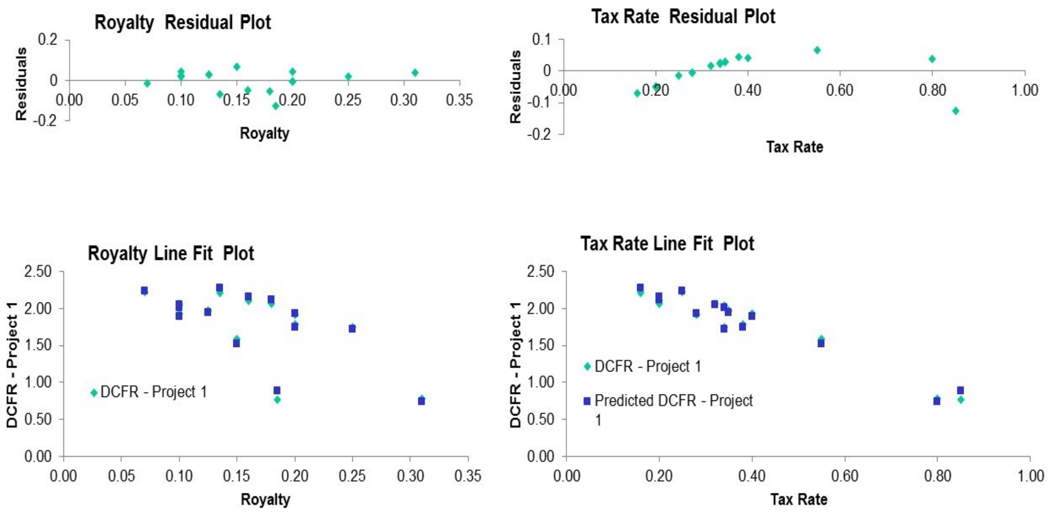
In statistics, the correlation coefficient r measures the strength and direction of a linear relationship between two variables on a scatterplot. The value of r is always between +1 and –1. To interpret its value, the closer to +1 or -1 indicate strong relationship. The range of values displayed in table 4.5 above indicates a strong relationship between Royalty-Tax and DCFR.

Table 4.6: Monte Carlo Analysis Results

							DCFR Random Values		
Countries	*DCFR - Project 1*	*Predicted DCFR - Project 1*	*Normal Value DCFR - Project 1*	*Average*	*Minimum*	*Maximum*	*1.5*	*1.75*	*2*
Algeria	1.78	1.741202547	1.633123704	1.741776361	0.49873699	3.30376	71.40%	49.20%	27.40%
Australia	1.94	1.894549822	1.909051306	1.895153802	0.63581865	3.428306	82.20%	63.00%	40.40%
Brazil	2.03	2.006612071	1.55988396	2.006983522	0.70421089	3.410326	88.20%	72.60%	50.60%
Colombia	1.74	1.720560034	1.333383664	1.720958466	0.42129785	3.285231	69.60%	47.20%	25.80%
Ghana	1.97	1.94025969	2.379678039	1.940229624	0.62807485	3.218297	84.60%	67.20%	44.60%
Kazakhstan	2.06	2.115529566	2.088372214	2.115851147	0.85913675	3.430921	92.40%	80.20%	60.60%
Mozambique	2.06	2.043966154	1.952117602	2.044386519	0.72991448	3.496454	89.80%	75.40%	54.20%
Namibia	1.97	1.94025969	1.725564879	1.939737233	0.29027284	3.383635	84.80%	67.20%	44.60%
Netherlands	2.22	2.231915852	1.838874369	2.232298794	0.82819108	3.723625	95.60%	86.80%	70.60%
New Zealand	1.92	1.927972962	2.133741439	1.927975132	0.52833862	3.405334	84.00%	66.20%	43.40%
Nigeria Post-PIB	0.79	0.746995308	0.643979144	0.746738768	-0.5821152	2.019634	4.00%	0.80%	0.20%
Nigeria Pre-PIB	0.77	0.891986797	0.381444324	0.892636531	-0.3500321	2.36807	7.80%	2.40%	0.40%
Peru	1.92	1.927972962	2.245181016	1.928198334	0.66572466	3.283103	84.00%	66.00%	43.40%
Romania	2.21	2.276053344	1.848153878	2.27584395	0.90645709	3.580312	96.40%	89.00%	74.00%
Russia	2.11	2.153669838	2.760422855	2.153810075	0.83200548	3.619337	93.60%	82.60%	64.00%
Trinidad	1.59	1.519043519	0.982208534	1.51901632	0.20510908	2.818113	51.80%	29.40%	13.00%
Standard Deviation	0.429381468								

The Monte Carlo method uses repeated random sampling to generate simulated data to use with a mathematical model. The results in Table 4.6 above shows that Nigeria pre and post PIB DCFR data are outside the competitive window.

4.1.6 DCFR Regression Analysis Results



Regression Statistics	
Multiple R	0.993206
R Square	0.986457
Adjusted R Square	0.984374
Standard Error	0.054747
Observations	16

ANOVA					
	df	SS	MS	F	Significance F
Regression	2	2.838228635	1.419114	473.4686	7.17882E-13
Residual	13	0.038964539	0.002997		
Total	15	2.877193174			

Figure 4.6: Regression Analysis Results

4.1.7 Derived Analytical Relationship to predict DCFR 'Competitive Window'

1. DCFR = 2.83233284176146 - 1.90701358119569 * Royalty - 1.86770415499038 * Tax
2. DCFR = 5.4193771444141 - 13.2746674168728 * Royalty - 2.33574497878783 * Tax
3. DCFR = 5.27320153523937 - 13.0353077306106 * Royalty - 2.30414404830835 * Tax
4. DCFR = 4.98913236262258 - 3.6922602935283 * Royalty - 3.32048857383424 * Tax
5. DCFR = 2.20256671711311 - 2.17312000588162 * Royalty - 1.0549564651166 * Tax

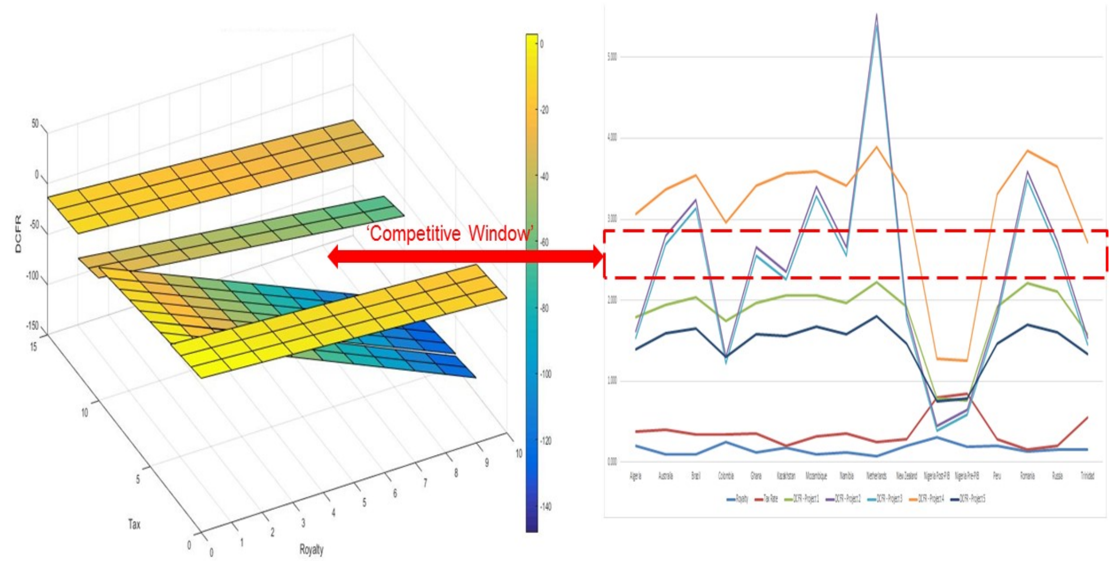


Figure 4.7: Derived Analytical Relationship

Interpreting the analytical relationship in Fig. 4.7. above:

The columns in Table 4.7 are:

1. Coefficient: Gives you the least squares estimate.
2. Standard Error: the least squares estimate of the standard error.
3. T Statistic: The T Statistic for the null hypothesis vs. the alternate hypothesis.
4. P Value: Gives you the p-value for the hypothesis test.
5. Lower 95%: The lower boundary for the confidence interval.
6. Upper 95%: The upper boundary for the confidence interval.

Table 4.7: Regression Analysis Result

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2.832332842	0.040945057	69.17398712	4.4756E-18	2.743876424	2.920789259	2.743876424	2.920789259
Royalty	-1.907013581	0.252657672	-7.547815857	4.20319E-06	-2.452847296	-1.361179866	-2.452847296	-1.361179866
Tax Rate	-1.867704155	0.079842318	-23.39240908	5.21693E-12	-2.040192995	-1.695215315	-2.040192995	-1.695215315

The most useful part of the regression analysis is the generation of the linear equation: y = mx + b. i.e.

y = slope * x + intercept.

For the above table below, the equation would be approximately:

y = 2.83233284176146 -1.90701358119569 R -1.86770415499038 T.

Where R=Royalty Rate; T=Tax Rate

4.1.8 Tax and Royalties 'Competitive Window' Iteration Steps

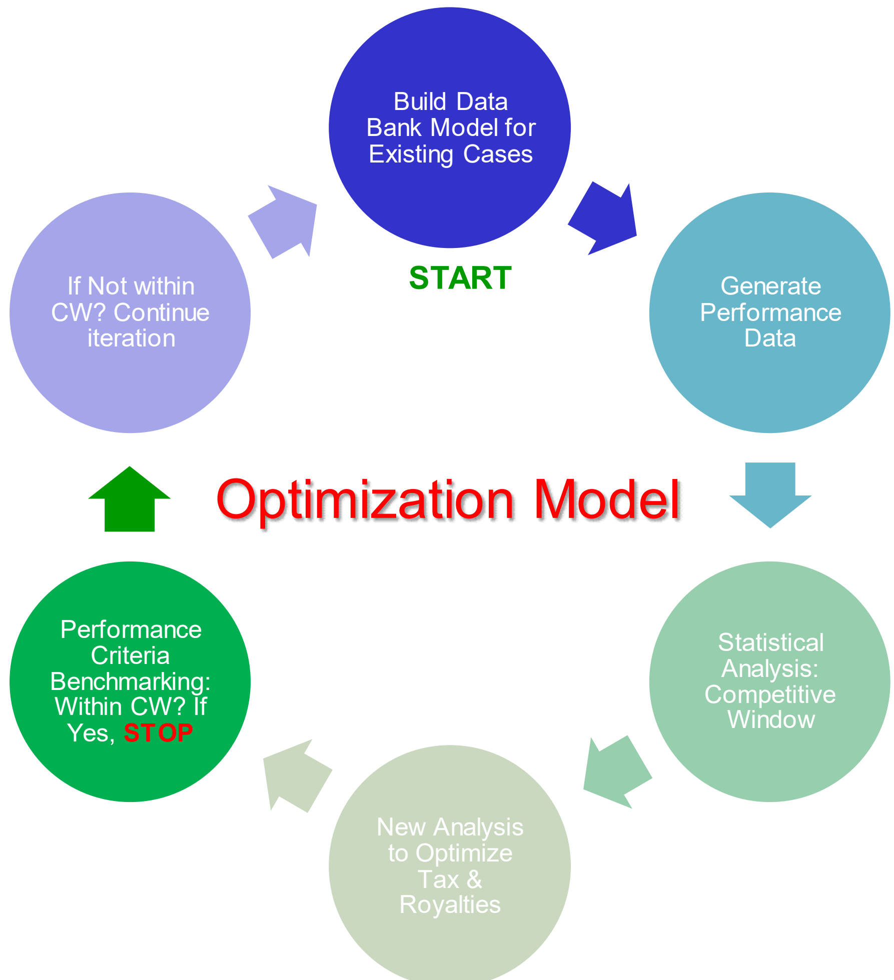


Figure 4.9:Optimisation Model

Figure 4.9 shows the required fiscal terms optimisation procedure. It involves several iterative steps from building the data bank, to data analysis and testing for competitiveness. To improve the result, we have to increase the data banks/fiscal regimes.

4.2 DISCUSSIONS

The output FTOM data for PRJ1 (26.1 kbd, 27.13m) were DCFR1 (21.0-197.0 %); NPV1 (12%) in million dollars ($M), (56.32 – 630.24); NPV1 (10%) (201.13 – 977.29); PIR1 (2.4 – 10.7); MCI1 ($M) ([-34.9] – [-26.2]); AVP1 ($M) (925.1-4287.3); PYT in years (2.3 – 4.9); PRJ2 (20.3 kbd, 28.04m) – DCFR2 (13.0 – 492.0%); NPV2 (12%) (3.44 – 64.32); NPV2 (10%) (12.30 – 72.27); PIR2 (0.3 – 1.2); MCI2 ([-10.1] – [-2.8]); AVP2 (57.7 – 101.8); PYT2 (1.2 – 3.3); PRJ3 (36.4 kbd, 28.04m) – DCFR3 (11.0 – 479.0%); NPV3 (12%) (2.20 – 47.24); NPV3 (10%) (7.87 – 50.83); PIR3 (0.2-1.1); MCI3 ([-10.1] – [-2.8]); AVP3 (15.0 – 71.8); PYT3 (1.2 -3.3); PRJ3 (36.4 kbd, 28.04m) – DCFR3 (11.0 – 479.0%); NPV3 (12%) (2.20 – 47.24); NPV3 (10%) (7.87 – 50.83); PIR3 (0.2 – 1.1); MCI3 ([-10.1] – [-2.8]); AVP3 (15.0 – 71.8); PYT3 (1.2 – 3.1); PRJ4 (6.5 kbd, 27.43m) – DCFR4 (35.0 – 346.0%); NPV4 (12%) (10.09 – 194.75); NPV4 (10%) (36.04 – 224.51); PIR4 (1.2 – 6.8); MCI4 ([-5.5] – [-4.2]); AVP4 (79.2 – 465.2); PYT4 (2.2 – 3.1); PRJ5 (18.8 kbd, 42.67m) – DCFR5 (21.0 – 160%); NPV5 (12%) (1.40 – 20.56); NPV5 (10%) (4.99 – 23.25); PIR5 (0.9 – 3.8); MCI5 ([-7.8] – [-3.7]); AVP5 (8.4 – 35.7); PYT5 (1.5 – 2.0).

The DCFR showed the efficiency indicator of how quickly investment returns both initial capital and a return (growth) on capital invested. Generally speaking, the higher a project's DCFR, the more desirable it is to undertake. DCFR is uniform for investments of varying types and, as such, DCFR can be used to rank multiple prospective projects on a relatively even basis. Assuming the costs of investment are equal among the various projects, the project with the highest DCFR would probably be considered the best and be undertaken first.

For all the five projects evaluated, a positive DCFR rate was established for each country under assessment. A relative comparison can then be computed to assess how significant the DFCR values are relative to project/country. You can think of the DCFR as the rate of growth a project is expected to generate.

While the actual rate of return that a given project ends up generating will often differ from its estimated DCFR, a project with a substantially higher DCFR value than other available options would still provide a much better chance of strong growth.

An investment that is expected to have a zero return is not a wise financial decision. With a return of zero, it would be better if the money were not invested at all. However, one measure of investment worth measures the cost of the investment in comparison to its expected future cash flows. NPV is a method used to assess the worth of an investment in comparison to the risk associated with the expected cash flows. For the five scenarios analysed, positive NPV were estimated. We noticed closely trending behavior for all other metrics – PIR; MCI, AVP, and PYT. Which provided the ground to model the trend and established direct correlation to key parameters of the fiscal systems that are specific to each country and may likely to contribute to the variations observed in the output panels of the FTOM. Several studies have identified royalty and tax rates as highly significant fiscal parameters with high impact to the FTOM results.

The optimal royalty and tax rates from the ORTCW that will indicate competitiveness were calculated as (0.15 – 0.2) and (0.28 – 0.55) respectively, compared with the current and post PIFB rate for the NOIGI obtained were (0.19 – 0.31) and (0.80 – 0.85) respectively, showing that our current and post PIFB fiscal and tax rates are not competitive.

CHAPTER FIVE

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

5.0 Introduction

The relationship between fiscal systems and economic return metrics although challenging, it is still possible to understand the interactions of the variables and their related influences by developing meta-models. Fig. 5.1 below shows the fiscal terms optimisation approach formulated for this study. A cash flow model of the system was constructed and parameters of the system are defined through specified design intervals (Plot 1-3, Fig. 5.1). The parameters of the system are sampled from the design space and evaluated with the cash flow model. The results of the model and the system parameters are then analysed and meta-models are developed from the generated data (Plot 4-6, Fig. 5.0).

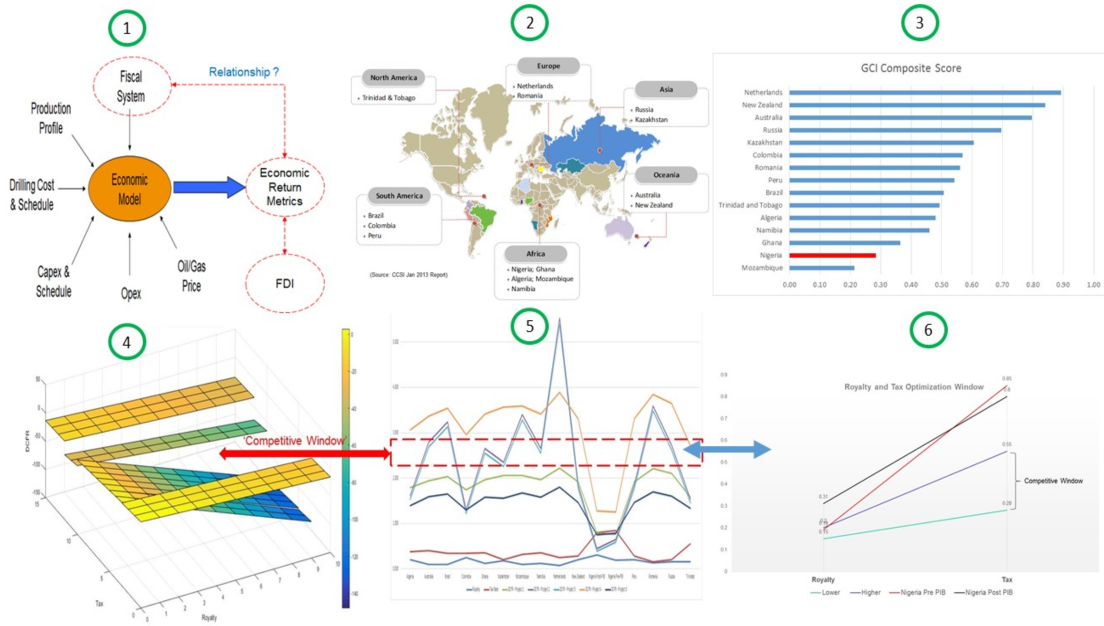


Figure 5.0: Tax and Royalty Optimisation Process (Author)

5.1 Summary

The study presented a new meta-modelling approach that integrates Global Competitiveness Index (GCI), combines cash flow simulations from model field data and regression models. The following countries with similar concession models were selected for this analysis based on previous studies (CCSI report, 2013) – Algeria, Australia, Brazil, Colombia, Ghana, Kazakhstan, Mozambique, Namibia, Netherlands, New Zealand, Nigeria, Peru, Romania, Russia and Trinidad. Plot 6 on Fig. 5.1 shows the tax and royalty rates optimisation window that can be used to predict competitive tax-royalty rates that can assist Nigeria policy makers, legislators, industry regulators and other stakeholders to better appreciate the implications of the proposed PIB 2012.

Tax and Royalty rates have been identified by several literatures as key factors with maximum impact on economic returns/profitability and can invariably influence FDI into the Nigeria Upstream Petroleum sector. We developed a 'Fiscal Terms Optimisation Process' which incorporated Sixteen (16) concession fiscal regimes against Nigeria pre and post PIB 2012 fiscal regimes. Key Economic Metrics were generated for several scenarios and analysed.

In order to make our economic model more realistic especially when bench marking fiscal system of various global systems, this study developed a GCI "Composite Score'. The Composite Score is based on the GCR annual report published by the World Economic Forum since 2004. We generated meta-models to describe the relationships with Economic Metrics and Royalty-Tax rates. IOCs operating in Nigeria can directly evaluate and compare various fiscal term combinations in the process of negotiation and select an appropriate strategy by tradeoffs between risk and reward. The meta-models described the linear relationship between the economic indicators and fiscal variables and can be conveniently used in negotiation. The meta-models show clearly the sensitivity of the economic indicators to the changes of fiscal terms and provide a valuation for parameter changes. With the meta-models (Fig 4.6), both IOC and Host Government can evaluate and compare combination strategies.

A petroleum tax system that is appropriately designed is also expected to attract to the host government an appropriate level of foreign direct investments. Designing fiscal arrangements that encourage a stable fiscal environment and efficient resource development maximises the magnitude of the revenues to be divided.

5.2 Findings

The ORTCW showed that optimum royalty and tax rate for competitiveness were (0.15 – 0.2) and (0.28 – 0.55) respectively, while the current and post PIFB rate for the NOIGI obtained were (0.19 – 0.31) and (0.80 – 0.85) respectively, showing that our current and post PIFB fiscal and tax rates are not competitive.

Based on the output results from Figure 5.2. We determined the competitive window (High and Low) for both Royalty and Tax rates. We superimposed the corresponding royalty-tax rates for both pre and post PIB 2012 terms. The result indicates the need to optimise Nigeria fiscal terms to maintain competitiveness.

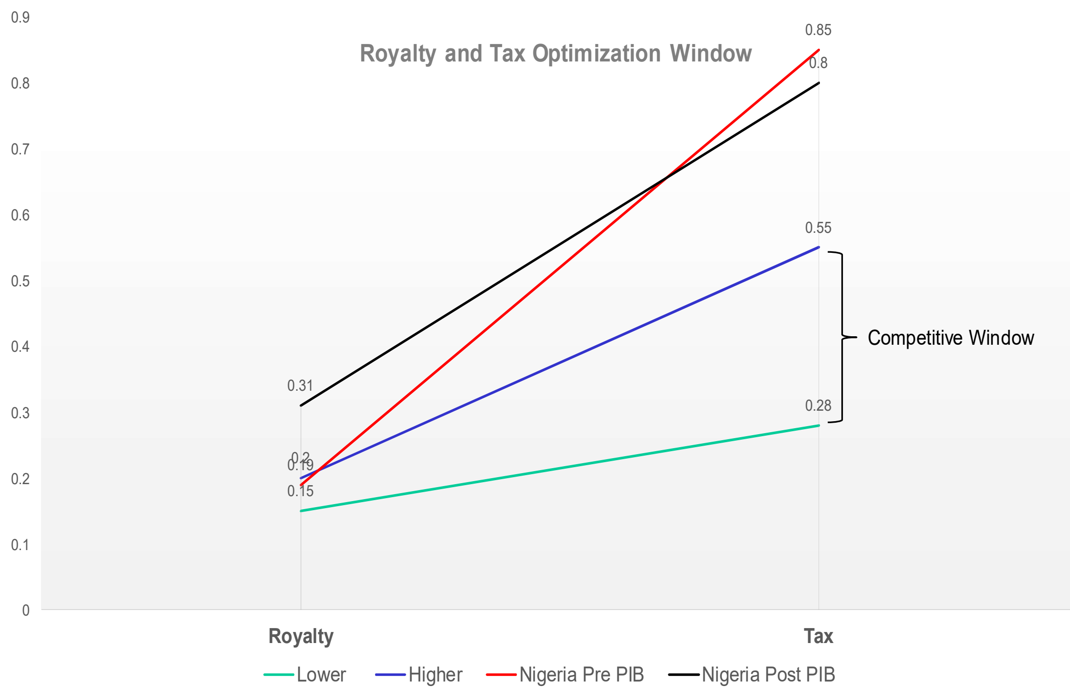


Figure 5.2: Fiscal Optimisation Window

5.3 Conclusions

With reference to the earlier stated study objectives: (1) Assess fiscal attractiveness of Nigeria's current and post PIB 2012 upstream fiscal regimes, especially the analysis of the effect of royalty-tax rates; (2) Present a new meta-modelling methodology approach that combines cash flow simulations from model field data into a regression model, using Global Competitiveness Index (GCI) normalize global systems; (3) Derive an analytical relationship between key fiscal parameters (tax and royalty rates) and profitability indices.

Based on the results presented in Figure 5.2

1. The study concluded from preliminary studies that there is a correlation between fiscal terms (tax and royalty) and various profitability indexes (DCFR, PIR, AVP, NPV, MCI & payout).
2. The global comparative analysis result also shows that Nigeria fiscal terms (pre & post PIB) are outside the competitive window and will invariably discourage foreign direct investments
3. The study presented an analytical relationship / model that can be used to optimise tax-royalty.

5.4 Recommendations

In evaluating options to encourage oil exploration and production activities, host governments should focus on measures that: (i) materially improve the economics and/or reduce the investment risk, (ii) involve low compliance and administration costs; (iii) address market deficiencies; (iv) minimize distortionary effects; and (v) are consistent with the country's macro-fiscal policy and with local development objectives.

Given the importance of oil and gas sector to the Nigerian economy, it has become imperative to design fiscal incentives that would encourage investment in the sector, in order to maximise its potential and government revenue. In addition to optimising royalty-tax rates, Nigeria Government need to optimise some of the current fiscal incentives. Nigerian government needs to strike a balance between the country's drive for increased oil revenue in the short term, and the long term guarantee of revenue from the major players in the industry through taxation.

Finally, this study established that current and proposed fiscal and tax regime of the Nigerian Oil and Gas sector is not likely to drive investment in the sector and recommends a review of the proposed petroleum industry fiscal bill.

5.5 Contribution to Knowledge

Several studies have extensively addressed a range of issues relating to the dynamics of petroleum fiscal systems and investment in different countries, including Nigeria. The following gaps were identified in existing literatures:

1. Specific studies on the effects of PIB 2012 on investment in the Nigerian petroleum sector are also not conclusive, especially the analysis of the effect of the key fiscal parameters i.e. Tax and Royalty rates. This research will add to existing body of knowledge regarding the effects of the key PIB-proposed fiscal terms on investment in the Nigerian upstream petroleum sector using a new analytical approach.
2. The study adopted methodology introduced by Sen A. (2014) which outlined the meta-modelling approach which combines cash flow simulations from model field data into a regression model to identify the impact of fiscal terms under the fiscal regime on economic measures representing returns to both firms and the government. There is currently no similar study that utilized this type of technique to optimise global fiscal systems to assess project viability in Nigeria with specific focus on PIB 2012 proposed terms.
3. Another gap in current literature is the non-existence of an analytical model to quantify competitiveness of Nigeria key fiscal terms with other competing countries with similar petroleum fiscal arrangements.
4. Several reviewed studies identified tax and royalty rates as major determinants on profitability indices, however they were unable to derive am analytical relationship between these key factors and the profitability indices.

The outcome of this research is to assist Nigeria policy makers, legislators, industry regulators and other stakeholders to better appreciate the implications of the proposed PIB key fiscal terms (Tax and Royalty) on investment in the upstream petroleum sector.

Second, Current/Prospective Investors can also use the proposed tax-royalty optimisation model to assess project viability. Study will assist IOCs operating in Nigeria to understand the significance of balancing their self-interest with that of the interests of Nigeria.

Third, such a model for the comparison of upstream petroleum fiscal structures is important, as national governments can estimate their petroleum sector's international competitiveness and private investors seeking to undertake profitable petroleum ventures have a guideline for comparison.

Finally, the economy of Nigeria largely depends on revenue from the sale of crude oil. As noted above, over 70% of government revenue comes from the sale of oil and there is no strong commitment on the part of the government to diversify its revenue base. Oil is and will remain vital to the economy for the foreseeable future. Thus, this study examines the appropriateness of the Nigerian petroleum tax system, should be of interest to the Nigerian government.

5.6 Suggestion for further research

Steps recommended to improve the results are: (1) Increase databank of model field data; (2) test more sophisticated optimisation tools like Hill Climbing, Simulated Annealing and Particle Swarm Optimisation algorithms to search the 3D space in order to test more than two variables (tax-royalty rates).

DCF method does not produce a complete figure of strategy which may add uncertainties. Real options provide a complete figure of strategy for the whole life time, therefore it delivers more flexibility in decision making process. DCF valuation is extremely sensitive to assumptions related to perpetual growth of discount rate.

Any minor tweaking here and there, and the DCF valuation will fluctuate wildly and the value so generated will be inaccurate.

Study results was based on shallow water (less than 200m depth) data as depicted in Table 3.7 and cannot used to evaluate deepwater (more than 200m depth). Further research can be conducted for deep water locations to broaden the scope of the models.

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APPENDIX A – SELECTED FISCAL SYSTEMS SUMMARY

Source:Global Oil and Tax Guide websites (ey.com/oilandgas)

Algeria
Depending on the date on which the petroleum contract was signed, the Algerian fiscal regime applicable to the oil and gas upstream industry is governed by one of the following: • Law No. 86-14 dated 19 August 1986 • Law No. 05-07 dated 28 April 2005 (as amended by Ordinance No. 06-10 dated 19 July 2006 and Law No. 13-01 dated 20 February 2013) **Production based royalties (daily production)** Base of royalties is equal to the quantities of extracted hydrocarbons multiplied by the monthly average of the base prices; effective royalty rate is subject to negotiation between parties of contract, who set the rate in the contract but law sets minimum legal rates for each production bracket: Production Level; Minimum Rate for Zone A, B, C, and D respectively: 0 to 20,000 boe/day: 5.5%, 8.0%, 11.0%, 12.5% 20,001 to 50,000 boe/day: 10.5%, 13%, 16%, 20% 50,001 to 100,000 boe/day: 15.5%, 18%, 20%, 23% 100,001 boe/day: 12%, 14.5%, 17%, 20% **Production based tax on revenues (cumulative production)** Cumulative Production Value since beginning of exploitation; Tax Rate <70 BNs; 30% 30 BNs < Production < 385 BNs; [40/(385 - 70)] * [(PV - 70) + 30] >385 BNs; 70% **Additional Tax on Earnings** Assessment base of the additional tax on earnings consists of annual revenues minus deductions, depreciations, royalties, and operating expenses Rate: 30%; Reduced rate of 15% for re-invested earnings

Australia
1987: Petroleum Resources Rent Tax (PRRT) Petroleum Resources Rent Tax 1992: Petroleum (Onshore) Regulation No. 435 Royalty based on length of commercial production 2012: Petroleum Resource Rent Tax Petroleum Resource Rent Tax **Petroleum Resources Rent Tax** Tax rate: 40% on taxable profit Technical modifications (for example expansion to offshore projects): 1990, 2005, 2006, 2012 **Royalty based on length of commercial production** Based on value at the wellhead of production First 5 years: 0% 5 to 10 years: 6% to 10% (Increasing by 1% for each year) 10 years and greater: 10%
Brazil
The Brazilian fiscal regime that applies to the oil and gas industry consists of corporate income tax (CIT) and Government and third-party takes. Government and third-party takes vary depending on the type of contract. Government and third-party takes include: **Signature bonus** — a one-time amount (not less than the minimum price established by the ANP (the Brazilian National Agency of Petroleum, Natural Gas and Biofuels) paid by the winning bidder in the proposal for the CC or the PSC to explore and produce crude oil and natural gas. The minimum amount to be offered as signature bonus is set out in the bidding documents and may vary a lot depending on a field.

Royalty percentage — under the CC, it varies from 5% to 10% of the oil and gas production reference price. Under the PSC, it corresponds to 15% of the volume of produced oil.

Special participation percentage — applies only under the CC, as a percentage that varies from 10% to 40% for large production volumes, based on progressive tables relating to net production revenues adjusted for royalties, exploration investments, operating costs, depreciation and taxes.

Fee for occupation or retention of an area — the activities of exploration, development and production of oil and natural gas, carried out through concession contracts are subject to the payment of the area retention fee for the occupation/retention of the area. The collection of the area retention fee aims to discourage the retention of concessions without the purpose of exploration, and its value is set by the tender notice and the concession agreement. Such value is determined for each calendar year, based on the number of days of the contract and per square kilometer or fraction of the concession area (from BRL10 to BRL5,000 per km^2, depending on the phase and based on a progressive table).

Landlord cost percentage — under a CC, it varies from 0.5% to 1% of the oil and gas production reference price. Under a PSC, it applies only to onshore oilfields and corresponds to a percentage up to 1% of the value of the oil and gas production.

Income tax rate — 34%

Colombia

Fiscal regime that applies to the oil industry consists of a combination of corporate income tax (CIT) and royalty-based taxation.

Production based Sliding Scale Royalties

Monthly average daily production percentage

<= 5K BPD: 8%

>5K BPD - 125K BPD: 8 + (Production - 5K) * (0.10)

>125K BPD - 400K BPD: 20%

>400K BPD - 600K BPD: 20 + (Production - 400K) * (0.025)

>600K BPD: 25%

Income tax rate — CIT rate: 34% for FY 2017 and 33% from 2018

Income tax surcharge — 6% for 2017, 4% for 2018 and 0% from 2019

Ghana

The fiscal regime that applies to the petroleum industry consists of the combined use of four basic tax laws: the Income Tax Act1 (the ITA), Revenue Administration Act, 2016, Act 915 (the RAA), the Petroleum (Exploration and Production) Act, 2016, Act 919 (the E&PA), and the Petroleum Agreement (PA). The ITA and RAA repealed the Petroleum Income Tax Act, PNDCL 188 (PITA) and the Internal Revenue Act, 2000, Act 592 (as amended).

The principal aspects of the fiscal regime that are affecting the oil and gas industry are as follows:

Royalties — Royalty rates are not fixed. The PAs signed so far prescribe royalty rates ranging from 3% to 12.5% for gas and crude production.

Income tax rate — The income tax rate for upstream petroleum activities is 35%. For downstream petroleum activities, the applicable income tax rate is 25%.

Kazakhstan

Mineral extraction tax (MET) is a volume-based, royalty-type tax applicable to crude oil, gas condensate and natural gas. Rates escalate depending on volume. Different tables of rates apply, depending on what is produced and whether it is exported or sold domestically. The rates are applied to production valued at world prices for export sale.

Mineral Extraction Tax: replaces royalties

Volume of annual oil production (thousands of tons)	Rate
Up to 250	5%
Up to 500	7%
Up to 1000	8%
Up to 2000	9%
Up to 3000	10%

Netherlands
The fiscal regime that applies in the Netherlands to the petroleum industry consists of a combination of corporate income tax (CIT), a surface rental tax, a state profit share (SPS) levy and royalty-based taxation. The major elements of the fiscal regime are as follows: Royalties — 0% to 7% CIT — 25%; 20% applies to the first €200,000 of taxable income
New Zealand
New Zealand's fiscal regime applicable to the petroleum industry consists of a combination of corporate income tax (CIT) and royalty-based taxation. The main elements are: • Royalties — 0% to 20% • CIT rate — 28%
Nigeria
Companies carrying on petroleum operations are deemed to be in the upstream regime and taxed under the Petroleum Profits Tax Act (PPTA) 2004 (as amended). **Petroleum Profits Tax** [on chargeable profits] First Five years (new companies): 65.75% First Five years (existing companies): 85% Subsequent years (all companies): 85% **Royalty rates for Joint Venture:** Onshore Production: 20% Production in territorial waters less than 100m: 18.5% Offshore production beyond 100m: 16.67%
Nigeria Post -PIB 2012 (version)
Royalty rates: Production Based + Price Based JV Oil: 5-22% + 0-21% **Taxes:** CIT + NHT JV Oil: 30% + 50%

Peru

Oil and gas exploration and production (E&P) activities are conducted under license or service contracts granted by the Government of Peru. The Government guarantees that the tax law in effect on the agreement date will remain unchanged during the contract term.

Royalties

Royalties can be determined based on one of two methodologies: production scales (fixed percentage and variable percentage) or economic results (the R-factor calculation).

The other main elements of the fiscal regime for oil and gas companies in Peru are as follows:

- Corporate income tax (CIT) rate — 31.5%
- Dividend tax — 5%

Production or R-factor based Royalties

Companies can choose between two methodologies (but once the licensing contract is signed, cannot change):

a) Production Scale

Level of Fiscalized Production (MBPCD); Royalty (%)

Less than 5; 5%

Between 5 and 100: 5-20%

More than 100: 20%

b) Based upon Economic Results

R = Rf + Rv

Rf: fixed royalty, set at 5%

Rv: Variable royalty, defined as percentage

FB: base R factor, established at 1.15

Variable royalty applied when Rt-1 >= 1.15 and when this belongs to the range 0% < Variable Royalty < 20%

Xt-1: Last year revenue at moment of calculating the variable royalty

Yt-1: Last year expense at moment of calculating variable royalty

Rt-1: Ratio between revenues and expenses since the subscription of the contract til period t-1 (R - factor)

Rv = [(Xt-1 - Yt-1)/Xt-1] * [1 - [1/(1 + (Rt-1 - FB)]] * 100
Romania
The fiscal regime that applies in Romania to companies operating in the petroleum industry generally consists of corporate income tax (CIT), petroleum royalty and other oil-related taxes for special funds. In summary, the main elements are as follows: CIT rate — 16% Royalties — 3.5% to 13.5% on oil extraction, 10% on certain transportation/transit of oil and 3% on the underground storage of natural gas Production based Royalties [based on the value of gross production] Crude oil/Condensate ('000s tons/quarter): Below 10: 3.5% for fields which produce Between 10 and 20: 5% Between 20 and 100: 7% Above 100: 13.5%
Russia

The fiscal regime that applies in Russia to the petroleum industry consists of a combination of royalties (called mineral extraction tax (MET)), corporate profits tax and export duty.
• Profits tax rate — 20%
• Royalties (MET):
    ○ Crude oil — RUB919 ($14.3) per tonne adjusted by coefficients
    ○ Natural gas — RUB35 ($0.6) per 1,000 cubic meters adjusted by coefficients
    ○ Gas condensate — RUB42 ($0.7) per tonne adjusted by coefficients
• Export duty:
    ○ Crude oil — 30% to 45% (linked to oil price)

Trinidad and Tobago
Companies engaged in upstream operations in Trinidad and Tobago (T&T) are subject to a special fiscal regime, principally governed by the Petroleum Taxes Act (PTA). In

summary, the following taxes, levies and imposts apply to companies engaged in the exploration and production of oil and gas:

- Petroleum profits tax (PPT) — 50% of taxable profits (petroleum operations in deepwater blocks: 35%)
- Unemployment levy (UL) — 5% of taxable profits
- Supplemental petroleum Tax (SPT) — The applicable rate of tax is based on the weighted average crude price and is applied to the gross income from the disposal of crude oil, less certain incentives (see section B); not applicable on gas sales
- Petroleum production levy (PPL) — Lower of 4% of income from crude oil for producers of more than 3,500 barrels of oil per day (BOPD) or proportionate share of local petroleum subsidy
- Royalties — Every exploration and production licensee must pay a royalty at a rate stipulated in the license on the net petroleum won and saved from the licensed area. Historically, applicable royalty rates have ranged from 10% to 15% for crude oil and US$0.015/mmcf for natural gas.

APPENDIX B – INCENTIVES IN THE MEMORANDUM OF UNDERSTANDING (MOU)

Source: Oil Producers Trade Section (2009):www.opts-ng.com

1. **Tax Inversion:** This is a strategy that allows the companies under the Joint venture (JV) to enjoy reduced tax rates as a result of the reduction in operational cost arising from per unit cost efficiency. The tax inversion rate is currently 35 per cent and it's only applicable to producers with operating cost below US$1.70 per barrel contingent upon a smooth production not impeded by quota restrictions, interruptions arising from sabotage and/or community disruption.
2. **Restriction on Penalty Charges:** Penalties are not exempted on operating cost below US$2.30/bpd for companies producing more than 175,000 billion barrel per day (bpd) and operating cost below US$3.00/bpd for companies producing below 175, 000 bpd.
3. **Minimum Guaranteed Notional Margin:** This is designed to guarantee a definite profit margin after tax and royalty payments for the Joint Venture (JV) companies on their equity crude or NNPC crude intake regardless of market conditions. The margin is applied as follows;
   - Company's Equity Crude: US$2.50 per barrel was increased to US$2.70 per barrel for companies that incurred capital investment cost above US$2.00 per barrel; while
   - NNPC Crude: US$1.25 per barrel was increased to US$1.35 per barrel for capital investment cost above US$2.00 per barrel.

Thus, the margin is contingent upon the Technical Cost (TC) of operations not exceeding the fiscal technical cost of $4.00/bbl (4.00 US$ per barrel) (Omoregbe, 2005). Furthermore, it is expected that if the market price of crude oil is below US$15.00/bbl., the minimum guaranteed margin decreases by US$0.18 for every US$1.00 drop and increases by US$0.10 for every US$1.00 increase if the price is above US$19.00/bbl.

APPENDIX C – INCENTIVES IN THE PETROLEUM PROFIT TAX (PPT) ACT AND OTHER ACTS

Source: Oil Producers Trade Section (2009):www.opts-ng.com

1. Capital Allowance (CA): As outlined in the PPT Act, capital allowance is claimable on four categories of assets or qualifying capital expenditure (QCE) items.
   - Capital Expenditure on Plant, Machinery and fixtures;
   - Capital Expenditure on Pipelines and storage tanks;
   - Capital Expenditure on Building construction or works of permanent nature on buildings;
   - Capital Expenditure on Drilling activities like acquisition of rights in or over petroleum deposits, searching, discovering and testing deposits and construction of any works or structure likely to be of little use when petroleum operation ceases.
2. Capital Allowance include;
   - Annual Allowance: This is granted to companies in respect of the depreciation to the QCE to encourage crude oil exploration. This is computed on a straight line basis by writing off 20 per cent of the cost of the asset annually in the 1st to 4th year and 19 per cent in the 5th year. The balance of 1per cent remains in the books until the asset is sold. However, capital allowance deductions in any accounting period are limited to the extent that the actual tax payable by the company is not less than 15 per cent of the assessable tax in the absence of capital allowances (Atuokwu, 2009).
   - Petroleum Investment Allowance (PIA): It is a one-off allowance available to the JV companies as well as the indigenous or sole risk operators and claimable in the accounting period in which an asset with QCE was first used.

The PIA rates are applicable on graduated basis as follows;

i. On-shore Operations are 5 per cent of the asset cost

ii. Off-shore Operations

- Water depth of up to 100 meters – 10 per cent;
- Water depth of between 100 - 200 meters - 15 per cent;
- Water depth of beyond 200 meters - 20 per cent

iii. PSC Companies that signed their contract agreements prior to 1st July 1998- 50per cent

- **Investment Tax Credit (ITC):** This is a tax-offset, which is deductible from assessable tax and claimable by the PSC companies in deep water exploration and production that signed their contract agreements prior to 1st July 1998. The applicable rate under the Deep Offshore and Inland Basin Production Sharing Contract Act is currently 50 per cent for companies with QCE.
- **Investment Tax Allowance (ITA):** Is granted to PSC Companies that signed their contract agreements after 1St July 1998. It is computed by applying 50 per cent flat rate on QCE which is added to capital allowance and deducted from assessable profit.
- **Balancing Allowance:** This is an allowance granted to petroleum companies if the tax written-down-value exceeds the income received on disposal of a QCE asset.
- **Provisions for Losses:** Losses can be carried forward and recouped from future profits indefinitely for the companies.
- **Concessionary Profit Taxes:** These are reduced tax rates granted to PSC companies in order to encourage and increase investments and cushion the effect of high cost and risks involved in the upstream sector/deep offshore waters (water depths over 200 meters) and the inland basin areas. New companies in the onshore waters are also granted reduced tax rates to encourage operations. The applicable rates are;

i. PPT at 50.0 per cent instead of 85.0 per cent for the duration of the PSC in deep offshore waters

ii. PPT at 65.75 per cent instead of 85.0 per cent for the first five years for new companies in onshore operations.

iii. Royalties for deep shore PSC are graduated according to water depth as against the 20 per cent for onshore waters as follows;

- 200 – 500 meters water depth---------------12.00per cent
- 501-800 meters water depth ---------------- 8.00 per cent
- 800 – 1000 meters water depth ------------4.00per cent
- Beyond 1000 meters water depth ----------0.00per cent
- Inland basins ------------------------------------10.00per cent

APPENDIX D – CASHFLOW METRICS CONSIDERING TIME VALUE OF MONEY

Source: Petroleum and other liquids, (online) http://www.eia.gov

<table>
<tr><th>Metric / Calculation</th><th>Description / Useful For</th><th>Limitations / Issues / Common Errors</th></tr>
<tr><td rowspan="2">Net Present Value (NPV_{@ Discount Rate})

Indicative of SIZE AND SCALE</td><td colspan="2">$\text{Net Present Value (NPV)} = \text{Sum}\left(\frac{\text{Each Period Net CashFlow}}{(1 + \text{Discount Rate})^{\text{Period \#}}}\right)$</td></tr>
<tr><td>Description
• Present value of net cash flows discounted at a rate of return; converts a string of cashflows into a single number
• Notionally, the indifference point to exchange a bag of money today for a stream of future cash flows
• Most meaningful when discount rate used reflects the potential risks / volatility of the opportunity

Useful for
• Understanding opportunity size and scale
• Comparing opportunities with different lifetimes
• Assessing degree of extra return (or loss) relative to the discount rate</td><td>Key Limitations
• Does not measure efficiency with which value is generated
• Using NPV calculated at a single discount rate to compare & select projects with different risk profiles can under-promote projects offering high reward relative to risk taken and over-promote projects offering low (or negative) reward versus risk taken

Issues
• Often used as a "hurdle rate"
• Determining the appropriate discount rate reflecting underlying "riskiness" of the cash flow

Common Calculation Errors
• Different "Time 0" reference points used for different opportunities can distort comparisons
• Lack of understanding of Excel NPV calculation timeframe, and error potential if nulls/blanks in the NCF line
• See detailed calculation guidance for further</td></tr>
</table>

		discussion and calculation
DCFR -- Discounted Cash Flow Rate of Return **Indicative of ECONOMIC EFFICIENCY**	DCFR = Discount Rate such that NPV = 0 for Sum $\left(\frac{\text{Each Period Net CashFlow}}{(1\ +\ \text{Discount Rate})^{\text{Period \#}}}\right)$	
	Description • An efficiency indicator of how quickly an investment returns both initial capital and a return (growth) on capital invested. Useful For • Single measure of return on investment • Enables quick comparison of opportunities, provided they are of similar characteristics, e.g. investment scale, risk, duration & effort	Key Limitations • Not indicative of economic risk or scale • If used to compare projects of different duration, then assumes that returned from shorter project is reinvested at same rate *(or alternate approaches such as MIRR – modified internal rate of return required)* • Fiscal systems can "fine-tune" DCFR return to be attractive in particular price ranges but less favorable in others Common Calculation Errors • Not checking for multiple roots which invalidate DCFR as a valid economic metric • Excel calculation errors if nulls / blanks in NCF line, See detailed guidance for further discussion and calculation
NPV / PVI (Sometimes known as PVR = PV Ratio) **Indicative of ECONOMIC EFFICIENCY**	NPV / PVI = $\frac{\text{Net Present Value}_{@\text{Discount Rate}}}{\text{Present Value Investments}}$	
	• Ranking tool to compare projects to see which ones "generate" NPV most efficiently • Allows comparison of projects with early spending versus those with later spending • Provides a view of both economic size / scale and	Key Limitations • Not indicative of size or scale • Not indicative of risk unless Discount Rate or Cash flows appropriate adjusted • As with NPV, use of a single discount rate for all projects can skew risk /

	efficiency with shown with NPV	reward perceptions Issues / Considerations • Discount rate for investments can be lower than cash flows as investments generally more certain (i.e. fewer fundamental drivers) than prices & reserves Common Errors • Imprecise communication of what metric actually been calculated and is being shown as there are several ways to calculate economic return per investment dollar – e.g. NPV/PVI, APV / I, 1+ NPV/PVI, NPV / I, etc.

Cashflow Metrics NOT Considering Time Value of Money

<table>
<tr><th>Metric / Calculation</th><th>Description / Useful For</th><th>Limitations
Issues / Common Errors</th></tr>
<tr><td rowspan="2">**Actual Value Profit (AVP)**

Indicative of SIZE AND SCALE</td><td colspan="2">Actual Value Profit (AVP) = Sum (Each Period Net Cash Flow)</td></tr>
<tr><td>Description
• Simple sum of each year's net cash flow; no discounting.
• Equal to NPV @ 0% discount rate
• Equal to total Book Net Cash Generated and Book Profit over project life

Useful For
• Measure of total cash generated
• Understanding project size and scale in terms of how much cash would actually be received over time</td><td>Limitations
• Does not consider time value of money
• Does not measure capital efficiency
• Tends to introduce longer-term bias as out-year values generally much larger due to inflation (even if no "real" change in value)

Issues / Considerations / Common Errors
•</td></tr>
<tr><td rowspan="2">**Profit to Investment Ratio (P / I)**

Indicative of ECONOMIC EFFICIENCY</td><td colspan="2">$P / I = \dfrac{\text{Actual Value Profit (AVP)}}{\text{Investment}}$</td></tr>
<tr><td>Description
• Measure of how efficiently investment dollars are converted into profit dollars
• Same value for book or cashflow economics *(assuming same taxes over time)*

Useful For
• Initial assessment of capital risk under various options or political / regulatory risks
• Can be useful when comparing projects of the</td><td>Limitations
• Does not consider time value of money
• Not helpful for comparing large and small projects as does not provide scale

Considerations

Common Errors
• As with NPV/PVI, imprecise communication of what metric is actually being shown as there are many ways to calculate capital efficiency</td></tr>
</table>

	same relative investment size, risk, and duration. • Provides a view of both economic size / scale and efficiency with shown with NPV profit.	
Payback (or Payout) **Indicative of ECONOMIC RISK**	$\text{Payback} = \text{Time}_{\text{First Investment}} \text{ until (Cumulative Net Cash Flow)} = 0$	
	Description • Time required for to recover the original investment (i.e. Return OF Capital only; No return ON capital)	Limitations • No time value of money; no return • Not helpful for comparing large and small projects

Commonly Used Book Metrics

<table>
<tr><th>Metric / Base Calculation</th><th>Description
Useful For</th><th>Limitations
Issues / Common Errors</th></tr>
<tr><td rowspan="2">Net Book Income
or
Book Profit
Or
Book Earnings
Or
Financial Earnings

Indicative of SCALE</td><td colspan="2">Net Book Income * (for a given period) = Revenue $- \text{Cash}\ \&\ NonCash\ Expenses\ - Taxes$</td></tr>
<tr><td>Description
• The profit (Revenue – Expenses – Taxes) generated by a company under accounting concepts which allocate a portion of past, current, and future expenses to the revenue generated in a period (i.e. to match the revenue with the all-in cost of the items required to produce it)
• Based on “accrual” accounting where revenues and expenses are allocated to the period when the obligation was agreed vs. when cash receipts and bill payments were actually made)

Useful for:
• Broad measure of the total economic return achieved by capital and assets that the company controls
• Used by market as measure of performance, assuming companies are reporting consistently per generally accepted accounting practices (GAAP).
• Understanding how an</td><td>Limitations
• No time value of money; thus limited utility to determine where to invest. Some utility in understanding how an investment(s) might be perceived by the public
• Earnings have limited relationship to actual cash flow; a company can be earnings positive yet go out of business due to lack of cash flow (i.e. Earnings do not “pay the bills”; cash does!)

Issues / Concerns:
• While GAAP exist, there is still latitude for interpretations which can increase or decrease reported earnings
• All else equal, will increase as assets depreciate and can mask failure of a company to invest in new income producing opportunities

Common Calculation Errors
• Can be calculated in many different ways; consult internal calculation guidance to ensure consistency between groups.

* Broadly, very high level for</td></tr>
</table>

<table>
<tr><td></td><td>investment strategy might be viewed by the public as it plays out in reported earnings.</td><td>discussion purposes; among others, Non-Cash expenses includes depreciation and reserves for future obligations such as abandonment & site restoration)</td></tr>
<tr><td rowspan="2">Net Cash Generated (Typically also “Operating Cash Flow”

Indicative of SCALE</td><td colspan="2">Net Cash Generated* (for a given period) = Net Book Income + Depreciation + (Beginning - Ending) Acct Receivables + (Beginning - Ending) Undepreciated Assets (e.g. PP&E, Inventories, etc.) + (Beginning - Ending) Working Capital + (Ending - Beginning) Accounts Payable + (Ending - Beginning) Short-Term Debt</td></tr>
<tr><td>Description
A measure of the amount of cash generated by a company's normal business operations (excluding investment & financing activities)
Close match to actual net cash flow before capital expenditures & loan principal injections / repayments are included
Useful for:
Understanding whether a company is able to generate sufficient positive cash flow to maintain its operations, pay dividends, and make new investments, or whether it may require external financing.
Generally applied at an Affiliate / Corporate level vs. individual opportunity</td><td>Limitations
Can be calculated in multiple different ways
Issues / Concerns:
Widely used term; many approaches → really understanding what is / is not included
Common Calculation Errors
Consult internal calculation guidance to ensure consistency between groups.
* Broadly, very high level for discussion purposes – there are many adjustments to Net Book Income to isolate actual cash movements into and out of the company not related to financing & investing activities</td></tr>
<tr><td rowspan="2">Return On Investment (ROI)

(also called “Book Rate of Return”)</td><td colspan="2">$$\text{ROI (for a given period)} = \frac{\text{Net Book Income}}{\text{Average Book Value}}$$</td></tr>
<tr><td>Description
Measure the amount of</td><td>Limitations
Can increase over time for</td></tr>
</table>

<table>
<tr>
<td>Indicative ECONOM EFFICIEN Y</td>
<td>income generated per unit of undepreciated book value
• A measure of how efficient existing assets are at generating income
• Can be calculated two different ways: as an annual number or as a project average number.

Useful for
• Measure the return achieved by money that is sunk in the business.</td>
<td>no reason other than statutory depreciation schedules and thus skew comparisons; will become “infinite” as book value goes to zero
• Can mask failure of a company to invest in new income producing assets
Issues / Considerations
• Often (and inappropriately) used as a proxy for DCFR
Common Calculation Errors
• Can be calculated in many different ways (e.g. some companies use average undepreciated book value vs. average remaining book value).</td>
</tr>
<tr>
<td rowspan="2">Return On Capital Employed

Indicative of ECONOMIC EFFICIENC Y</td>
<td colspan="2">$$\text{ROCE} = \frac{\text{Net Book Income}}{\text{Average Remaining Book Value} - \text{Site Restoration} - \text{Deferred Taxes}}$$</td>
</tr>
<tr>
<td>Description
• Efficiency Indicator showing unit income generated unit value of undepreciated assets
• Net book income includes accruals for future events.
• Accrued site Restoration costs removed as obligation exists but money not yet spent
• Similarly, Deferred taxes indicative of difference in depreciation rates under “Tax Books” and “Statutory Books”
• ROCE is effectivey ROI calculated on a corporate basis</td>
<td>• Similar to ROI, will tend to increase for no reason other than statutory depreciation; can mask failure of a company to invest in new income producing assets
• Excludes time value of money
• Not helpful for comparing large and small projects
• Aggregation at portfolio level will include assets being built but not yet in service → skew the view of the producing assets
Issues / Considerations
• Often (inappropriately) used as a proxy for DCFR. ROCE tends to be inflated above DCFR in many cases, such as:
○ Older, more depreciated projects</td>
</tr>
</table>

	Used For • Book based measure of capital efficiency • Used by market as measure of performance • Typically reflected on a larger portfolio / regional basis	○ Longer projects (inflation impacts) ○ Slower depreciation rots ○ Non-earnings events such as deferred taxes, etc. Common Errors • Multiple was to calculate ROCE; See calculation guidance
Earnings Per Barrel **Indicative of ECONOMIC EFFICIENCY**	$\text{Earnings per Barrel} = \dfrac{\text{Book Income}}{\text{Produced Reserves}}$	
	Description • An efficiency indicator of how much income is generated per barrel of resource produced • Generally a book measure but will have same value on cashflow basis over the entire life of a project. Useful for • View of projects / portfolios on same basis as annual report values. • Enables comparisons of between companies using public data • Used by market as measure of performance • Can be useful when comparing projects of the same relative investment size, and risk.	Limitations • Provides limited economic information when used on a yearly basis. • Not helpful for comparing large and small projects as measures efficiency, not size • Produced reserves can be measured on multiple bases (e.g. gross, operated, working interest, or net) and can give conflicting / contradictory views of project efficiency based on the volume view taken. • See detailed guidance for further discussion and calculation

<table>
<tr><th>Metric / Base Calculation</th><th>Description
Useful For</th><th>Limitations
Issues / Common Errors</th></tr>
<tr><td rowspan="2">AVP_{Real} per net Interest Oil Equivalent Barrel

Posited as Indicative of ECONOMIC EFFICIENCY</td><td colspan="2">$$AVP_{Real} / NI\ OEB = \frac{AVP\ (Real) = Net\ Cashflow\ discounted\ @\ inflation}{Net\ Interest\ OEB}$$</td></tr>
<tr><td>A rough-proxy Earnings per Net Interest Barrel as would be calculated using accounting measures (e.g GAAP)
Posited as providing a view of how a proposed investment would be viewed on a public reporting basis over its lifetime.</td><td>Limitations / Concerns
Tends to underestimate GAAP earnings for several reasons including (a) AVP_{Real} is a time discounted value based on Netcashflow and thus will overcompensate early-year investments and undercompensate later-year revenues; (b) Removing inflation reduces total earnings altogether
All else equal, will tend to favor shorter-term investments vs. longer-term
Similar to NIOEB metrics in general, difficult to compare projects operating under different fiscal regimespotential to suggest high unit-efficiency but provide lower overall absolute earnings
Not useful for near-term capital allocation (i.e. short duration)
Common Errors
See detailed guidance on calculating Net OEB</td></tr>
<tr><td>Profit / Price Elasticity (PPE)

Indicative of</td><td colspan="2">PPE = Slope of Line between [NPV at $LowPrice /bbl and NPV @ $HighPrice/bbl]
$$\left(x\ axis\ = \frac{Price}{bbl}, y\ axis\ =\ NPV\right)$$
2015 -- $Low Price currently $40/bbl; $High Price = $120/bbl</td></tr>
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ECONOMIC EFFICIENCY & VOLATILITY		
	• Indicative of the efficiency of an investment to convert change in price to Net Present Value → *"How much do we gain or lose in NPV as prices change?"* • Provides a means of ranking potential investments in terms of return volatility overall or with respect to the total portfolio • Implicitly includes the impact of fiscal regimes	Limitations / Concerns • Works well in "typical" tax-royalty regimes but may over / underestimate impacts in PSC or Risk-Services regimes given possible "kinks" in price vs. NPV line at different price levels which arise due to fiscal terms Common Calculation Errors • Not common so greater error potential; see detailed guidance (TBD)

Financing and Funding Metrics

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Indicative of SCALE</td><td colspan="2">Maximum Cash Impairment = Most Negative Value (Cu</td></tr>
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• The maximum cash outlay before any cash is returned

Useful for
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<tr><td>Description
• An indicator of the ability to cover debt using shareholder resources (≤ 1indicative of full coverage)
• A ratio showing the effective 3rd party vs. equity investor ownership of an organization

Useful For:
• Assessing degree of</td><td>Limitations
• Useful primarily at the Portfolio level (or in project financing covenants)</td></tr>
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<tr><td rowspan="2">Current Ratio

(Also called “liquidity Ratio)</td><td colspan="2">$$\text{Current Ratio} = \frac{\text{Current Assets}}{\text{Current Liabilities}}$$</td></tr>
<tr><td>Description
• An indicator of the ability to cover short-term liabilities with short-term assets (≤ 1 indicative of not being ab le to do so)</td><td>Limitations
• Useful primarily at the Portfolio level (or in project financing covenants)</td></tr>
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Value Chain Metrics

<table>
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<tr><td colspan="2">Description
• The per-unit cost of developing a resource, making it merchantable, and moving it to a given point in the value chain, including the return for each value chain element.
• COS can be calculated along all or various parts of the value chain for additive or comparative purposes (provided they are all on a consistent unit basis – see Common Errors)

Useful For
• Assessing price needed vs. market price available for a given opportunity
• Understanding economic competitiveness of different supplies to service a given market or markets</td><td>Limitations / Issues
• COS values often quoted at different parts of the value chain and are not comparable

Common Errors
• Failure to maintaining volume consistency across value chain elements given fuel/ shrinkage, etc.
• Adding / comparing COS elements together which are calculated on different volumetric bases (i.e. wellhead vs. delivered; into plant vs. out of plant, etc)</td></tr>
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• Comparing different sales alternatives at a given point, especially for short-term transactions</td><td>Common Errors
• Not including all costs / revenues / tax changes of Alternative 1 vs. Alternative 2</td></tr>
<tr><td rowspan="2">Exploration Costs / BOE

Indicative of COST EFFICIENCY</td><td colspan="2">$$\text{Exploration Cost per Barrel} = \frac{\text{Total Exploration Cost}}{\text{Total Reserves}}$$</td></tr>
<tr><td>Description
• Normalization metric to assess / compare the cost of acquiring reserves

Useful for:
• Comparing opportunities in a given region / basin (all-else equal)</td><td>Limitations / Concerns
• Indicative only of cost, not potential revenue or ultimate economic attractiveness; overreliance can result in less expensive reserve adds that are uneconomic

Common Calculation Errors
• Lack of comparability as can be calculated at many different points in time & activity (e.g. with/without sunk costs such as seismic, lease payments & bonuses, etc.)</td></tr>
<tr><td rowspan="2">Development Cost Per Barrel

Indicative of COST EFFICIE</td><td colspan="2">$$\text{Development Cost per Barrel} = \frac{\text{Total Development Cost}}{\text{Total Reserves}}$$</td></tr>
<tr><td>Description
• An indicator of total development cost efficiency;</td><td>Limitations / Concerns
• Indicative only of cost, not</td></tr>
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NCY	Useful for • Initial screening purposes to assess overall economic attractiveness, for opportunities of similar size / character / risk (i.e. all-else equal)	potential revenue or ultimate economic attractiveness • Does not consider ongoing maintenance / upkeep / abandonment costs • Overreliance can result in less expensive developments that lack flexibility to react to changing needs over time, or are more expensive to operate over time. • Potentailly useful on a higher-level basis but not for micro-comparisions (e.g. 10 - 25 cents/bbl) Common Calculation Issues / Errors • Total Reserves" definition – 1P, 2P, etc. • Cost & Reserves for phased projects • Consistency in conversion factors for non-oil energy into OEBs • Lack of comparability as

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Indicative of COST EFFICIENCY</td><td colspan="2">$$\text{Finding \& Development Cost Per Barrel} = \frac{\text{WORKING Interest Investment}}{\text{NET Interest Reserves}}$$</td></tr>
<tr><td>Description
• Efficiency indicator for investments made (including royalty owners) vs. Net Volumes Retained – " How much is it costing us for the barrels we get to keep?"

Useful for
• Initial screening purposes to assess overall economic attractiveness, for opportunities of similar size / character / risk (i.e. all-else equal)
• Shows results as might be perceived an a public basis for comparison across companies</td><td>Limitations / Concerns:
• Can work well in a simple tax-royalty regime, but problematic is PSC, Service-Contract or mixed fiscal regimes which may impact Net Interest volumes
• Same basic overreliance issues as Development Cost per barrel
• Potentially useful on a higher-level basis but not for micro-comparisions (e.g. 10 - 25 cents/bbl)

Common Calculation Issues / Errors
• Same basic comparability, reserves, consistency & investment phasing issues as Development cost per Barrel</td></tr>
<tr><td>O&M</td><td colspan="2"></td></tr>
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<tr>
<td rowspan="2">Cost / BBL

Indicative of COST EFFICIENCY</td>
<td colspan="2">$$\frac{\textit{Total O\&M Cost}}{BOE}$$
$BOE\ may\ be\ Net, Total, WI, Etc.$</td>
</tr>
<tr>
<td><u>Description:</u>
• The average operating cost per unit of production

<u>Useful for</u></td>
<td>Limitations
• Not indicative of overall profit potential; just cost
• Overreliance can result in lower-margin opportunities being funded over higher margin-value-opportunities simply because of being lower cost.</td>
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<td rowspan="2">Commercial Margin</td>
<td colspan="2">Commercial Margin = Value Uplift (Point B - Point A) - Infras</td>
</tr>
<tr>
<td><u>Description</u>
• The non-capital related profit margin between two points in a value chain

Useful for:
• Breaking down & understanding value generated due to investment activity vs. commercial marketing operations along a value chain
• Providing side-bars on the amount of indirect capital included within a value-chain</td>
<td>Limitations:
• Organizational understanding of use & utility</td>
</tr>
</table>

Commonly Used Book Metrics

<table>
<tr><th>Metric / Base Calculation</th><th>Description
Useful For</th><th>Limitations
Issues / Common Errors</th></tr>
<tr><td rowspan="2">Net Book Income
or
Book Profit
Or
Book Earnings
Or
Financial Earnings

Indicative of SCALE</td><td colspan="2">Net Book Income * (for a given period) = Revenue $- \text{Cash} \ \& \ NonCash\ Expenses \ - \ Taxes$</td></tr>
<tr><td>Description
• The profit (Revenue – Expenses – Taxes) generated by a company under accounting concepts which allocate a portion of past, current, and future expenses to the revenue generated in a period (i.e. to match the revenue with the all-in cost of the items required to produce it)
• Based on “accrual” accounting where revenues and expenses are allocated to the period when the obligation was agreed vs. when cash receipts and bill payments were actually made)

Useful for:
• Broad measure of the total economic return achieved by capital and assets that the company controls
• Used by market as measure of performance, assuming companies are reporting consistently per generally accepted accounting practices (GAAP).
• Understanding how an</td><td>Limitations
• No time value of money; thus limited utility to determine where to invest. Some utility in understanding how an investment(s) might be perceived by the public
• Earnings have limited relationship to actual cash flow; a company can be earnings positive yet go out of business due to lack of cash flow (i.e. Earnings do not “pay the bills”; cash does!)

Issues / Concerns:
• While GAAP exist, there is still latitude for interpretations which can increase or decrease reported earnings
• All else equal, will increase as assets depreciate and can mask failure of a company to invest in new income producing opportunities

Common Calculation Errors
• Can be calculated in many different ways; consult internal calculation guidance to ensure consistency between groups.

* Broadly, very high level for</td></tr>
</table>

<table>
<tr><td></td><td>investment strategy might be viewed by the public as it plays out in reported earnings.</td><td>discussion purposes; among others, Non-Cash expenses includes depreciation and reserves for future obligations such as abandonment & site restoration)</td></tr>
<tr><td rowspan="2">Net Cash Generated (Typically also “Operating Cash Flow”

Indicative of SCALE</td><td colspan="2">Net Cash Generated* (for a given period) = Net Book Income + Depreciation + (Beginning - Ending) Acct Receivables + (Beginning - Ending) Undepreciated Assets (e.g. PP&E, Inventories, etc.) + (Beginning - Ending) Working Capital + (Ending - Beginning) Accounts Payable + (Ending - Beginning) Short-Term Debt</td></tr>
<tr><td>Description
• A measure of the amount of cash generated by a company's normal business operations (excluding investment & financing activities)
• Close match to actual net cash flow before capital expenditures & loan principal injections / repayments are included

Useful for:
• Understanding whether a company is able to generate sufficient positive cash flow to maintain its operations, pay dividends, and make new investments, or whether it may require external financing.
• Generally applied at an Affiliate / Corporate level vs. individual opportunity</td><td>Limitations
• Can be calculated in multiple different ways

Issues / Concerns:
• Widely used term; many approaches → really understanding what is / is not included

Common Calculation Errors
• Consult internal calculation guidance to ensure consistency between groups.

* Broadly, very high level for discussion purposes – there are many adjustments to Net Book Income to isolate actual cash movements into and out of the company not related to financing & investing activities</td></tr>
<tr><td rowspan="2">Return On Investment (ROI)

(also called “Book Rate of Return”)</td><td colspan="2">$$\text{ROI (for a given period)} = \frac{\text{Net Book Income}}{\text{Average Book Value}}$$</td></tr>
<tr><td>Description
• Measure the amount of</td><td>Limitations
• Can increase over time for</td></tr>
</table>

Indicative ECONOMIC EFFICIENCY	income generated per unit of undepreciated book value • A measure of how efficient existing assets are at generating income • Can be calculated two different ways: as an annual number or as a project average number. Useful for • Measure the return achieved by money that is sunk in the business.	no reason other than statutory depreciation schedules and thus skew comparisons; will become "infinite" as book value goes to zero • Can mask failure of a company to invest in new income producing assets Issues / Considerations • Often (and inappropriately) used as a proxy for DCFR Common Calculation Errors • Can be calculated in many different ways (e.g. some companies use average undepreciated book value vs. average remaining book value).
Return On Capital Employed Indicative of ECONOMIC EFFICIENCY	$\text{ROCE} = \dfrac{\text{Net Book Income}}{\text{Average Remaining Book Value} - \text{Site Restoration} - \text{Deferred Taxes}}$	
	Description • Efficiency Indicator showing unit income generated unit value of undepreciated assets • Net book income includes accruals for future events. • Accrued site Restoration costs removed as obligation exists but money not yet spent • Similarly, Deferred taxes indicative of difference in depreciation rates under "Tax Books" and "Statutory Books" • ROCE is effectivey ROI calculated on a corporate basis	• Similar to ROI, will tend to increase for no reason other than statutory depreciation; can mask failure of a company to invest in new income producing assets • Excludes time value of money • Not helpful for comparing large and small projects • Aggregation at portfolio level will include assets being built but not yet in service → skew the view of the producing assets Issues / Considerations • Often (inappropriately) used as a proxy for DCFR. ROCE tends to be inflated above DCFR in many cases, such as: ○ Older, more depreciated projects

	Used For • Book based measure of capital efficiency • Used by market as measure of performance • Typically reflected on a larger portfolio / regional basis	○ Longer projects (inflation impacts) ○ Slower depreciation rots ○ Non-earnings events such as deferred taxes, etc. Common Errors • Multiple was to calculate ROCE; See calculation guidance
Earnings Per Barrel **Indicative of ECONOMIC EFFICIENCY**	$$\text{Earnings per Barrel} = \frac{\text{Book Income}}{\text{Produced Reserves}}$$	
	Description • An efficiency indicator of how much income is generated per barrel of resource produced • Generally a book measure but will have same value on cashflow basis over the entire life of a project. Useful for • View of projects / portfolios on same basis as annual report values. • Enables comparisons of between companies using public data • Used by market as measure of performance • Can be useful when comparing projects of the same relative investment size, and risk.	Limitations • Provides limited economic information when used on a yearly basis. • Not helpful for comparing large and small projects as measures efficiency, not size • Produced reserves can be measured on multiple bases (e.g. gross, operated, working interest, or net) and can give conflicting / contradictory views of project efficiency based on the volume view taken. • See detailed guidance for further discussion and calculation

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Useful For</th><th>Limitations
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<tr><td rowspan="2">AVP_{Real} per net Interest Oil Equivalent Barrel

Posited as Indicative of ECONOMIC EFFICIENCY</td><td colspan="2">$AVP_{Real} / NI\ OEB = \frac{AVP\ (Real) = Net\ Cashflow\ discounted\ @\ inflation}{Net\ Interest\ OEB}$</td></tr>
<tr><td>• A rough-proxy Earnings per Net Interest Barrel as would be calculated using accounting measures (e.g GAAP)

• Posited as providing a view of how a proposed investment would be viewed on a public reporting basis over its lifetime.</td><td>Limitations / Concerns
• Tends to underestimate GAAP earnings for several reasons including (a) AVP_{Real} is a time discounted value based on Netcashflow and thus will overcompensate early-year investments and undercompensate later-year revenues; (b) Removing inflation reduces total earnings altogether
• All else equal, will tend to favor shorter-term investments vs. longer-term
• Similar to NIOEB metrics in general, difficult to compare projects operating under different fiscal regimespotential to suggest high unit-efficiency but provide lower overall absolute earnings

• Not useful for near-term capital allocation (i.e. short duration)

Common Errors
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<td>Description
Normalization metric to assess / compare the cost of acquiring reserves
Useful for:
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Finding and Development Cost Per Barrel **Indicative of COST EFFICIENCY**	$$\text{Finding \& Development Cost Per Barrel} = \frac{\text{WORKING Interest Investment}}{\text{NET Interest Reserves}}$$	
	Description • Efficiency indicator for investments made (including royalty owners) vs. Net Volumes Retained – *" How much is it costing us for the barrels we get to keep?"* Useful for • Initial screening purposes to assess overall economic attractiveness, for opportunities of similar size / character / risk (i.e. all-else equal) • Shows results as might be perceived an a public basis for comparison across companies	Limitations / Concerns: • Can work well in a simple tax-royalty regime, but problematic is PSC, Service-Contract or mixed fiscal regimes which may impact Net Interest volumes • Same basic overreliance issues as Development Cost per barrel • Potentially useful on a higher-level basis but not for micro-comparisions (e.g. 10 - 25 cents/bbl) Common Calculation Issues / Errors • Same basic comparability, reserves, consistency & investment phasing issues as Development cost per Barrel
O&M		

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<tr>
<td rowspan="2">Cost / BBL

Indicative of COST EFFICIENCY</td>
<td colspan="2">$$\frac{\textit{Total O\&M Cost}}{BOE}$$
$BOE\ may\ be\ Net, Total, WI, Etc.$</td>
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<td><u>Description:</u>
• The average operating cost per unit of production

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<td>Limitations
• Not indicative of overall profit potential; just cost
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• The non-capital related profit margin between two points in a value chain

Useful for:
• Breaking down & understanding value generated due to investment activity vs. commercial marketing operations along a value chain
• Providing side-bars on the amount of indirect capital included within a value-chain</td>
<td>Limitations:
• Organizational understanding of use & utility</td>
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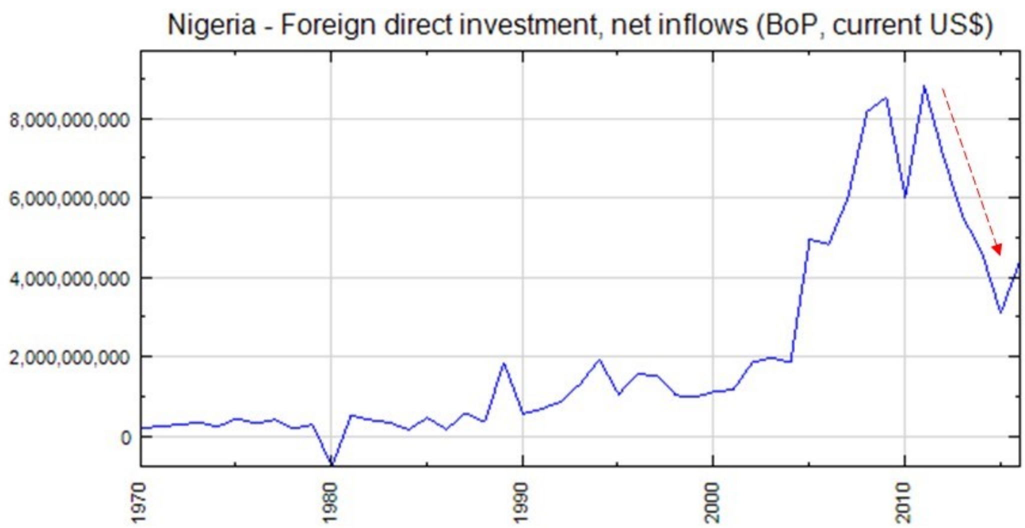
APPENDIX D – NIGERIA FDI PROFILE DURING THE PIB WINDOW

source: indexmundi.com



Key Insights

1. FDI in Nigeria mostly for the oil & gas industry; drops significantly and continues to drop post 2011.
2. Government's policies negatively impacting FDI into oil & gas sector.
3. Draft PIB fiscal and non-fiscal terms uncertainty and erosion of investors confidence.

APPENDIX E - NIGERIA CURRENT FISCALS (SUMMARY):

Source: Oil Producers Trade Section (2009):www.opts-ng.com

JV oil fiscal terms

Royalties

- Fixed royalties:
  - 20.0% Onshore
  - 18.5% 1-100 m water depth
  - 16.5% 101-200 m water depth

Taxes

- PPT 85%

Investment allowance (deduction)

- Petroleum Investment allowance (PIA):
  - 5% Onshore
  - 10% 1-100 m water depth
  - 15% 100-200 m water depth

Minor Taxes (deductible from PPT)

- Niger Delta Development Commission Levy: 3% of approved Opex & Capex budget
- Education tax: 2% of assessable profit

Profit

	Typical PPT Calculation
	Revenue
deduct	Royalty
deduct	Oper. & Explor. Expenses
deduct	Intangible Drilling & Dev. Costs
deduct	Losses (if any from prior years)
deduct	Education tax
=	**Assessable Profit**
deduct	Petroleum Investment Allowance
deduct	Capital Allowance (Depreciation)
=	**Chargeable Profit**
minus	**Chargeable Tax at 85% rate**
=	**Profit After Tax**

PSC 1993 terms

Royalties

- Royalty on water depth:
  - 12% < 500 m
  - 8% < 800 m
  - 4% < 1000 m
  - 0% > 1000 m

Taxes

- PPT: 50%

Investment tax credit (ITC)

- Investment allowances:
  - ITC 50%
  - ITA 50% (PSC 2000+)

Minor Taxes (deductible from PPT)

- Niger Delta Development Commission Levy: 3% of approved Opex & Capex budget
- Education tax: 2% of assessable profit

Share of profit to the contractor

- Profit Oil = Available Oil – Royalty Oil - Cost Oil – Tax Oil
- Allocation of profit oil to contractor based on cumulative production from contract area
  - 0-350 MB 80%
  - 351-750 65%
  - 751-1000 55%
  - 1001-1500 50%
  - 1501-2000 40%

Depreciation (Capital Allowance)

- 20% for the 1st 4 years, 19% in year 5
- Depreciation starts on year of spending with retention of 1% on book until asset is disposed of