Framework for Optimal Economic Exploration and Exploitation of Petroleum Resources in Cameroon

A thesis submitted to the faculty at African University of Science and Technology in partial

fulfilment of the requirements for the degree of Master of Science

in the Department of Petroleum Engineering

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CERTIFICATION

This is to certify that the thesis titled **‘’Framework for Optimal Economic Exploration and Exploitation of Petroleum Resources in Cameroon”** submitted to the school of post graduate studies, African University of Science and Technology (AUST) Abuja, Nigeria for the award of the Master of Science (MSc.) degree is a record of original research carried out by Azah Daizy-Clay Che in the Department of Petroleum Engineering.

DECLARATION

Framework for Optimal Economic Exploration and Exploitation of Petroleum Resources in Cameroon

By

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A THESIS APPROVED BY THE PETROLEUM ENGINEERING DEPARTMENT

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ABSTRACT

Economic exploration and exploitation of petroleum resources is regarded as being optimal when the surrounding fiscal regime is mutually beneficial to both the government and the investors as well as other stakeholders, including petroleum host communities. Oil and gas in Cameroon started over forty years ago. This business however operates under old fiscal regimes forty or so years later. This research builds an economic model which incorporates the fiscal parameters governing petroleum exploration and production (E&P) activities to evaluate the petroleum fiscal regimes in Cameroon in terms of economic and system performance metrics, such as NPV, IRR and HGT. Stochastic simulation analysis using the @RISK simulation tool facilitates the impact of risk and uncertainty on the performance of petroleum investments in Cameroon. The effectiveness of the economic model is appraised through the adapted Cameroon decision guide as well as comparing with the existing model.

Applying historical data from a nearby field, a hypothetical field under existing fiscal regime in Cameroon and an assumed cost profile, has a positive NPV of 46 million dollars. The earning power of the investment on the field, IRR is estimated as 40.2%. It is estimated that the attractiveness of the operating fiscal regime measured as FLI is approximately 0, reflecting a significantly progressive fiscal regime. The contractor take, government take statistics, respectively are estimated as 34.6% and 65.4%. On the other hand, for the proposed system, a contractor NPV of 48 million dollars, IRR of 40.9%, PI of 4, PO of 4, FLI of -0.007, contractor take of 35.8% and the government take of 64.2% were obtained from the deterministic model. Following the designed decision guide, all the profitability measures are in line with the profitable range and the investment is not front end loaded.

Furthermore, an average increase of 5 million dollar is obtained in the NPV on stochastic basis for P10, P50 and P90, in comparison to the old system subject to the underlying cost assumption structure. Similarly, IRR is about 3% higher while the contractor and government takes are averagely higher by 1% for all 3 percentiles. This places the proposed system above the existing

system since higher values are desired by both the contractor and the government. This proposed system can thus attract IOCS to invest more in Cameroon E&P activities.

DEDICATION

This work is dedicated to my beloved Father, may his soul rest in peace. I still remember how you always called me “My Engineer, nimo Dhere”. I love you and may your legacy live on.

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To my supervisor; Professor Emeritus Omowumi Iledare, your professional guidance has been optimum in this work. I am very glad to have worked under your supervision because I have learnt quite a lot.

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To all my highly treasured friends especially Ronald, Opeyemi, Felicienne, Musa, Dona, Cyril and Nancy; words can't express my gratitude towards every moment our paths crossed. I am humbled by your goodwill.

God has always been at the forefront of my life and it's my pleasure to concede his hand throughout my studies at AUST and most especially in this thesis writing. All Praise and Glory to my King.

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CHAPTER ONE

1.0. INTRODUCTION

Cameroon is one of the potentially richest countries in Sub-Saharan Africa with a growing diversified population, varied climate, and an abundance of natural resources. Cameroon being a modest crude oil producer, is located in the Gulf of Guinea. Its population is estimated at 25million (2018), with 200 languages from more than 230 ethnic groups. Cameroon is graced with natural resources such as forest resources, several minerals, timber, oil and gas, agricultural products such as coffee, cocoa, cassava, maize, and cotton. About 70% of the population depends on agriculture, fishing and livestock rearing for survival (Bank, 2017). Despite all this natural resources, Cameroon's growth pattern indicates an economy that is not attractive to foreign investors as such is not competitive although growth is expected to reach 4.3% this year.

There are two main types of sedimentary basins in Cameroon which are the coastal sedimentary and the intracratonic basins (SNH, 2021). The coastal basins are producing and consist of Rio Del Rey and Douala/Kribi-Campo whereas the intracratonic basin is non-producing and is comprised of Logone Birni, Mamfe and Garoua basins.

Oil exploration in Cameroon began in 1947 but the first commercial deposits was discovered in 1972 and commercial production commenced in 1977 (SNH, 2021). Production was started by a French company called Elf-Aquitaine on the west coast of Cameroon in the Rio del Rey basin. Cameroon's oil reserve is estimated at two hundred million (200,000,000) barrels of proven oil reserves and accounts for about 0.0% of the world's oil reserves (Worldometer, 2016). Cameroon is a small oil producer in the world market with a daily production of 92,469 barrels per day (as of 2016) which is equivalent to 16.9% of its proved reserves and ranking 52nd in the world. Cameroon exports 43% of its oil production (40,216 barrels per day in 2016) and consumes about 40,000 barrels per day. At this consumption rate and without net exports, 14 years of oil is bound to be left. Oil production gradually fell from 67.68 Mbbl/D in March 2020 to 64.51 Mbbl/D in February 2021 (Atlas, 2021). **Error! Reference source not found.** provides summary statistics characterizing the oil and gas industry in Cameroon relative to the global oil and gas industry statistics. Figure *1* and Figure *2* indicate the reserves, oil production and oil consumption from 1980-2016 (BP, 2019).

Table 1: Oil Production and Consumption

		Global Rank
Oil Reserves	200 MMbbl	55th in the world
	Barrels per Day	Global Rank
Oil Production	92,469	52nd in the world
Oil Consumption	40,000	110th in the world
Daily Surplus	+52,469	
Oil Imports	40,950	
Oil Exports	81,166	
Net Exports	40,216	

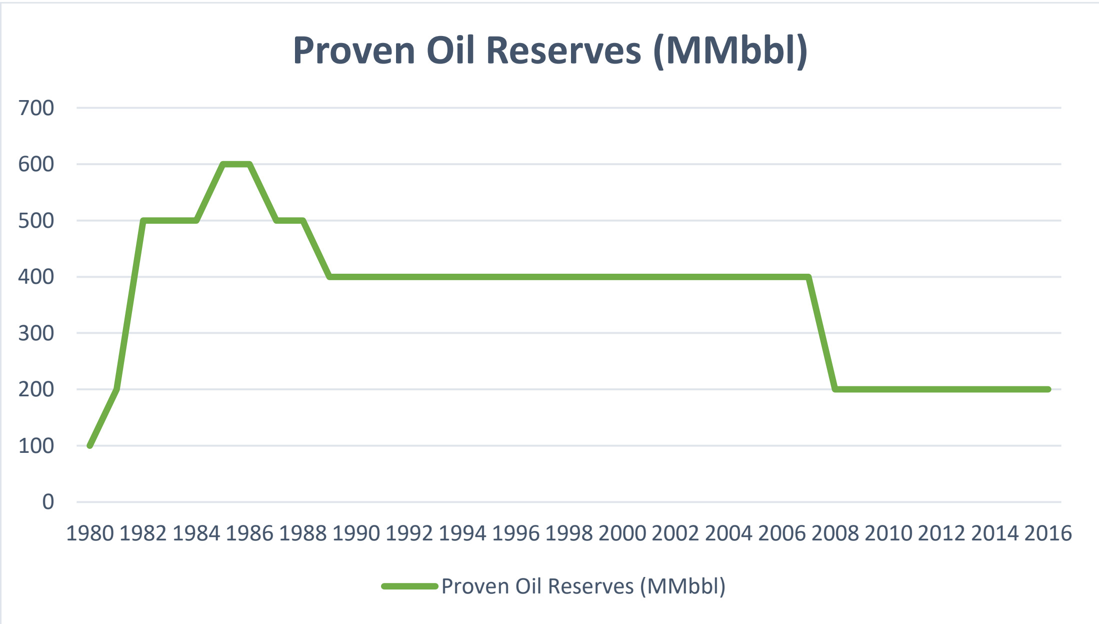


Figure 1: Proven Oil Reserves

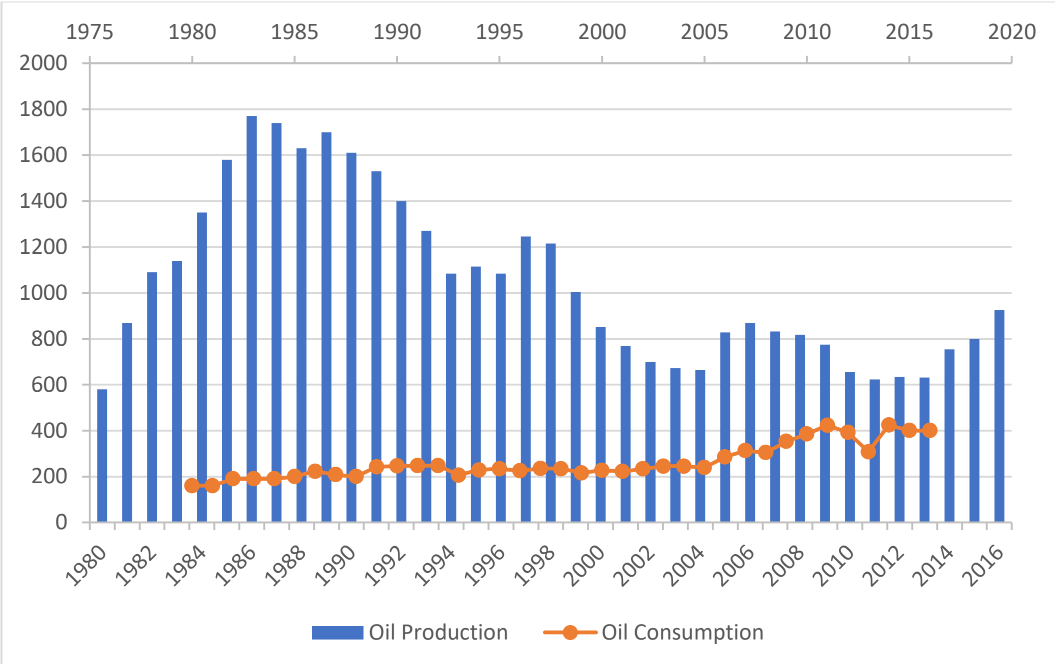


Figure 2: Oil Production and Consumption (1975-2020)

Cameroon is susceptible to weak/poor governance thus hindering its ability to develop and attract investors as expected (THE, 2019). Thus, economic services are higher than necessary, transport cost is high and there exists a lot of poor maintenance and high level of corruption. Furthermore, inappropriate management and lack of transparency has crippled the economy. The country has become one of the countries whose resources is a "curse" to the nation, with a decreasing growth performance since independence (1964). (Ghebremusse, 2014) defined a resource curse as "a combination of harmful political and economic effects which describes the negative effect of the rise of the value of the country's currency to non-extractive industries".

An enticing fiscal system is the core for a proper and organized petroleum code so that Cameroon can compete internationally. An attractive fiscal system is believed to be the starting point to pull in investors. Imagine a country where political stability is of utmost importance and the fiscal system favored both the government and the investor.

Cameroon was once known to be a peaceful country before the anglophone crisis began in late 2016. Resolution of this problem is vital to the economy and the oil and gas industry as well.

1.1. Aim

The aim of this study is to review the current governance, the administration, the fiscals, corporate and social responsibility of stakeholders and proffer solutions to challenges and constraints to E&E optimality in Cameroon.

1.2. Problem Statement

Cameroon needs a total revamp of her fiscal system. The world has become dynamic but Cameroon still plays by medieval policies, high tax rates and an unappealing fiscal system in a dying economy. An economy as such leads to a collapsing GDP, diminishing living standards and high unemployment rates. The growth of the country is continuously regressing due to lack of competition and pretentious content in the economy. On the other hand, transparency and accountability in the oil and gas sector is not commonly glimpsed as 54% of fortune derived from oil resources constantly vanishes (Gauthier et al., 2014).

1.3. Objectives

In other to efficiently and effectively evaluate the economic framework for petroleum resource exploration and exploitation, the following goals are stipulated:

- Evaluate the petroleum fiscal system used in Cameroon.
- Develop and apply an economic modelling framework for optimal economic exploration and production to maximize value for stakeholders.
- Proffer solutions to challenges facing the oil and gas industry in order to revive the dying uncompetitive economy through the oil and gas sector in Cameroon.

1.4. Research Questions

- Is Cameroon using an outstanding optimal economic framework for upstream petroleum resource evaluation and management?
- Does the recent petroleum code attract or creates a constrain for investors in the oil and gas sector?
- Would the model provided significantly impact the petroleum fiscal system, and consequently the economy, if the suggested solutions were to be correctly implemented?

1.5. Significance of Study

This research aims to help the Cameroon government to recalibrate the petroleum framework. This research also provides a framework by which policy makers, the industry sector, stake holders and legislators can use as a guide for decision making in the petroleum upstream sector.

Furthermore, up-to-date policies reassures investors and as such, improves earnings and increases production. This will help students in Cameroon build a research strategy to document and publish vital dossiers in the Cameroonian academic community thereby building a new research perspective in the Cameroonian oil and gas sector. To boot, research as this could cause a re-evaluation and transforming Cameroon's dwindling oil and gas reserves thus placing her on the map for better economic growth.

1.6. Scope of Study

This work limits itself to the petroleum regulations governing oil and gas resources in Cameroon. In recent times both the concession and production sharing contracts exist in Cameroon but the research will focuses on production sharing contract (Cameroon, 2019) which is more commonly used than the concessionary regime.

A spreadsheet model is coded with secondary data from SNH, MINEE and MINIMIDT. Deterministic analyses of economic and system performance metrics using Microsoft Excel offers great perspectives on investment performance in Cameroon oil and gas industry. While stochastic analyses using Monte Carlo Simulation algorithm in Palisade @RISK software, provides good understanding of the impact of risk and uncertainty on E&P business in Cameroon. Sensitivity analysis is obtained through the variation of some model parameters and based on the results; solutions are recommended that will satisfy the aim of the research.

CHAPTER TWO

2.0. LITERATURE REVIEW

2.1. The Economy of Cameroon

Heraclitus said and I quote “change is the only constant in life”: this statement seems to be a fallacy in Cameroon. In the 2021 world energy mix, every energy supplying country seeks to improve its economy given the potentials endowed by virtue of its resources. Improvement cannot be made without changes in regulations and policies governing these resources. Cameroon has been producing crude oil for decades now but still operates on the old petroleum laws enacted in 1999. Furthermore, there seems to be little or no relationship between crude oil production and the economic growth of the country.

Tamba (2017) analyzed the crude oil sector to determine whether there existed a relationship between crude oil production and economic growth in Cameroon. Little or no research had been done before Jean on the causation between oil production and economic growth. This is due to lack of transparency by the government on such matters. There is no official data as of date on Cameroon’s crude oil consumption, revenues of crude oil and subsidies from the government on the export, import, purchase and sale of crude oil in international markets. Jean found out that crude oil does not significantly impact the economic growth of Cameroon because the conduct of most petroleum operations and businesses are not transparent and accountability is nonexistent.

Since 2012, projected rise in oil production has been lower below expectations, due to delay in operating new fields. However, the economic growth in Cameroon remains disappointing because of weak governance, ignorance, unpleasant business environments, poor infrastructure and prebendalism (Bank, 2017). Government policy on freezing retail prices for petroleum products lead to the revenue shortfalls for SONARA and other fuel importers. Despite this, the Kribi gas station (216 MW) was expected to reduce power bottlenecks and improve in the economic status in Cameroon. The economy can be ameliorated by increasing trade diversification, increasing efficiency in public spending and prudent management. Public spending seems to be going to less impactful areas as such, there is an uneven spread of money across the country. The subsidies on petroleum products are so high and significantly burdens the system, this is a call for concern. The rich tend to benefit from fuel subsidies (except kerosene) while the poor in rural areas get little or no satisfaction from it. The consumption of petroleum products is very low even within the highest consumption sectors (transport, public administration and forestry). Agriculture represents the largest share of economic activities but consumes on a marginal scale (Bank, 2013).

Fiscal terms are designed to act as a balance for the host government and the IOC (Wahab et al., 2017) This is done to ensure that the objectives intended for the country are met and the project is economically viable. A fiscal system is a collection of rent extraction instruments for taxation of oil and gas assets. Figure 3 presents a diagrammatical representation of the fiscal term structure to optimize maximum economic development of hydrocarbon resources (Wahab et al., 2017).

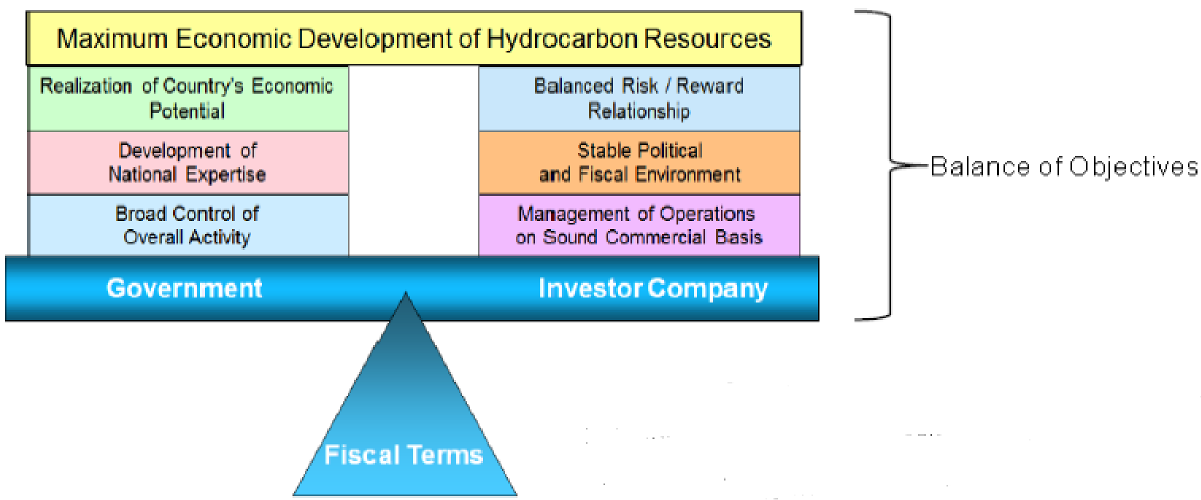


Figure 3: A Design of Fiscal Terms (Wahab et al., 2017)

While the Cameroon government seeks to attend the intended objectives towards vison 2035, the IOC focuses on optimizing their asset portfolio with the use of economic measures to assess the profitability of the project, the risk-reward profile and compare alternative investment opportunities worldwide.

Many oil-producing countries in Africa lack the capability to explore and produce crude oil for themselves and thus rely solely on IOC to move forward. The States makes use the petroleum fiscal system as a ladder to attract foreign investment and IOCs to conduct petroleum operations (exploration and production), and to efficiently maximize the generation of revenue from oil taxes (Ghebremusse, 2014). These two (2) objectives seem to be conflicting and striking a balance between both entails designing a feasible petroleum fiscal regime that will bring about economic growth. Countries differ in the social and economic conditions as well as their visions, as such, fiscal systems vary from one country to another. Therefore, in other to meet the ever-growing needs and demands of a country, the fiscal regime must be country- specific and focused on achieving the set objectives. To better understand petroleum resources in Cameroon and its governance, an economic evaluation of the fiscal regime and a comparative survey of the contractual scheme will be used as an analytical framework for petroleum exploration and exploitation. Hence, the key to forester growth in Cameroon through the oil sector, is by designing a standard fiscal system that will be effectively implemented by law.

Cameroon’s economy is challenged with dwindling oil reserves as less oil fields are being discovered. Perhaps this is because of a decline in exploration activities.

2.2. Industry Structure

2.2.1. The Oil Sector in Cameroon.

Cameroon’s real GDP decline by 2.769% in December 2020 but forecasted to grow at 3.437% in December 2021 (International, 2018). The oil sector is very important in most petroleum producing any economies, as well as the fiscal arrangements governing the sector. In Cameroon, the nucleus of the oil sector is a public organization directly controlled by the presidency through the National Hydrocarbon Company (Société National de Hydrocarbures, SNH). It is the current joint venture associate in oil production, oil regulator and the transit of the overall government take. In current times, a new public corporation has been created, named SONAMINES. SONAMINES is a public company with the state as a shareholder, whose mission is to develop and promote the mining sector and to manage the state’s interest in mining activities. Cameroon’s growth is less dependent on oil production and oil exports as compared other African oil exporting countries. Oil accounts for about 45% of her exports and 20% of fiscal revenues (World Bank Statistics, 2020).

The revenue generated from the taxation of oil production will continuously contribute to the national budgets and development of oil-rich African countries as long as new oil fields are discovered and oil prices remain high (Ghebremusse, 2014). With fattening in the national budget due to the generated taxes, these oil-rich countries have the potential to fund projects and build suitable infrastructures such as roads, hospitals and school.

2.2.2. Main Actors in Cameroon Oil and Gas Sector.

In Cameroon, oil exploration and production are done by international oil companies (IOC) in a joint venture agreement with the State, represented by SNH. SNH was created on the 12th of March 1980 and is mandated as a regulator and operator (SNH, 2020). SNH promotes, develops and monitors oil and gas activities in Cameroon. In addition, SNH operates the Mvia field which has been operational since 2009. The present active IOCs participating in the production of oil includes Perenco Cameroon (a subsidiary of French Perenco), Total E&P Cameroon (a subsidiary of French Total), and Pecten Cameroon (a subsidiary of Royal Dutch Shell), (Bernard & Albert, 2011). Presently, over 90% of oil and gas activities are handled by Perenco Rio del Rey and Addax Petroleum Company. However, 11 companies are involved in oil exploration activities though production is mostly offshore and a majority of the produced oil is exported. SNH has shares in downstream sectors such as SONARA (Société Nationale de Raffinage), the country's only refinery. World bank 2020 insights that SNH portfolio also includes shares in 12 other domestic companies. They include; Hydrocarbures Analyses Controles (HYDRAC), Société de Trading et D'exportation de Petrole (TRADEX) S.A., Chanas Assurances S.A., Cameroon Oil Terminal S.A. (COTSA), Cameroon Shipyard and Industrial Engineering, Addax Petroleum Cameroon Company S.A., Perenco Cameroon, Perenco Rio Dey Rey, Cameroon Petroleum Depots Company (SCDP), Cameroon Hotels Cooperation (CHC-Hilton), National Refinery Company (SONARA), and Cameroon Oil Transportation Company (COTCO). Four types of crude oil are produced in Cameroon; LOKELE (22° API), KOLE (32° API), EBOME (34° API) and MOUDI (38° API) (Transparency & Eiti, 2006). Oil produced is sold in international markets by both IOCs and SNH though the official sales price of oil is determined by both IOCs and SNH in a joint commission. The income generated from the sale of crude oil is then transferred to the Public Treasury so as to contribute to the State budget financing. Transfers are done on a monthly basis and included on the Table of Oil Operations and State (TOPE). The International Monetary Fund validated TOPE after it was conceived by the Cameroon

Government. SNH, Cameroon's public oil regulating agency ends up with 65% equity share in all activities.

Oil Fields	IOC Operators	Joint Venture Associates
Rio del Rey	Total	Pecten, SNH
Lokélé	Pecten/Shell	SNH
Moudi	Perenco	ExxonMobil, SNH
Ebomè	Perenco	SNH

Source: Le secteur pétrolier au Cameroun, 2007

Figure 4: Main Oil Fields, Operators and Joint Venture Associates (2007)

Two ministries also share some responsibility in the oil sector: The Ministry of Energy and Water (MINEE) and the Ministry of Mines, Industry and Technological Development (MINMIDT). MINEE focuses on supervising the energy sector, planning and defining national energy policy and strategies while MINMIDT is responsible for insuring mining titles for oil extraction.

Amin (1998) carried out a study on the fiscal policy of Cameroon with a focus on the relationship between private and public investment. Oil once was the main driver of economy in Cameroon and sustained a high economic growth between 1978 and 1985, thus boosting the GDP growth by 17%. High performance was kept constant due to the country's creditworthiness and credibility abroad. In 1986, Cameroon fell into a great economic recession because of the collapse in crude oil prices, resulting in an aggregate economic decline.

During this time, the government tried to remedy the situation by slashing public expenditure, spending foreign reserves, financing deficit from foreign borrowing and domestic debts, and by trimming the salary of workers. Fiscal policies are pillars to sustainable investments and consequently, economic growth. In recent times, oil has been an important revenue source for Cameroon and its absence could take us back to what happened in 1986. In an attempt to understand the fiscal policy of Cameroon and its effects on macroeconomic performance, Amin developed two models to empirically analyze the government expenditure and revenue. The models showed that public expenditures on infrastructure have cosmic returns and there exists some causality moving from infrastructure to private investment and to growth. Amin suggested that more of such investments be made on infrastructure for continuous growth.

2.2.3. Cooperate and Social Responsibilities (CSR) of Stakeholders

Cameroon is a coastal economy with important ports, large and dynamic cities, a very strong agricultural base and abundant natural resources. This in itself is supposed to be a focal point for huge investments leading to large expansions in key sectors.

The first view on CSR is for the companies to maximize profits while keeping the environment friendly. Anything more than obeying the existing business regulations and laws is unnecessary since it mostly leads to increased cost. Some companies clearly see it as the governments channel to ensure the communities' welfare through laws. Companies should follow these laws, but not do more by themselves, since this would be harmful to their business (Friedman, 1970). The second approach to CSR contains the idea that corporations are seen using CSR as a marketing tool. That is, CSR is sometimes used as a lift to persuade people of their good action when not fully following the stated commitment (Carroll, 2009). The third view on CSR is that many entities like NGOs, governments, and corporations see CSR as a useful tool to make the world a fairer and more livable place (Freeman et al., 2004). Although this view recognizes the importance of corporations on the growth of the world economy and improving the living standards of people around the world, more focus is on the importance of respecting human rights and the environment. Only then can businesses operate with a clear conscience.

Corporations must respect laws stating these principles in those countries where such laws exist and do the same in developing countries where human rights and the environment may not be sufficiently protected. These conflicting views on CSR have made it to be a highly debated topic during the recent years in most developed and developing countries. Although CSR is often perceived as something quite new, (Asongu, 2007) argues that it is "as old as trade and business itself". Indeed, the concept of CSR had been already used by Howard R. Bowen in his book in 1953 for the first time. Thus, it can be said that CSR has emerged in the 1950's, but the discussion around it has changed due to various influences. The CSR concept as we know it today started in the 1990s, however the definition is still debated today. The CSR definition is complex due to the large number of rules though the concept has some applications.

The European Commission published a report in 2011 putting forward a new definition of CSR as "the responsibility of enterprises for their impacts on society. Businesses need to have in place a process to integrate social, environmental, ethical, human rights and consumer concerns into their business operations" (European Commission, 2011). Therefore, CSR is considered to be a voluntary activity in which businesses manage not only their economic but also social and environmental impacts of their surroundings. Before examining measurement tools that are related to CSR, it is important to understand who the impacted stakeholders are. Friedman (1970) supported the shareholder theory, which states that managers should only focus on working the company's interests. Since according to Friedman, business should not have social responsibilities and should only be accountable to its shareholders. Thus, businesses have to take into account all groups of stakeholders and not only focus on shareholders as Friedman suggests (Mallin et al., 2013). Moreover, Lawrence and Weber (2016) divided stakeholders into two groups. The first group is called the market stakeholders: market stakeholders include any individual who is engaged with the company in economic transactions such as employees or even customers. The second group is then composed of much bigger entities such as governments, communities, or NGOs. Lawrence and Weber named it the nonmarket stakeholders. The main difference being that the second market is not engaged in any financial transaction with the company but can still be affected by the company's actions.

2.3. The Fiscal Regime

Petroleum fiscal systems (PFS) describe the legislative, tax, contractual and fiscal elements underlying exploration and production operations in a petroleum province, region or country. The primary purpose of PFS is to determine equitably how costs are recovered and profits are shared between host governments and the contractors (Iledare, 2004).

In the past years, since (1964), the oil sector activities were governed and directed by the mining law (Loi 64-LF-3). At that time, while other countries used either production sharing or concessionary agreements, Cameroon's oil taxation was functioning on a uniquely complex system called guaranteed mining income system which was regulated by the establishment conventions. In 1978, a modified system was adopted in accordance with the 1964 code called the Production Sharing Arrangement (PSA). This agreement defined the rights and duties of both parties with clearly stated conditions specific to each permit (lease). In an attempt to simplify the legislation, a new law (Law No 99/013) was adopted in December 22, 1999 to institute the Petroleum Code with the aim to provide a more friendly fiscal environment for International Oil

Companies (Centurion, 2016)The focus was to improve incentives for exploration and crude oil production, thereby attracting more investors in the oil sector. However, all extraction activities still operate under the old concession contract and only oil exploration is carried out under Law No 99/013.

Centurion (2016) suggested that there are two regimes for taxation of upstream petroleum operations in Cameroon. The first regime is governed by Law no. 64 – LF-4 for the regulation (flats fees, tax basis, royalties, and mining taxes) of petroleum agreements that are undertaken before the petroleum code was communicated. The second regime is governed by the petroleum code and it aims at modulating contracts agreed upon after the signing of the petroleum code.

In a nutshell, there are two regulatory frameworks that govern petroleum operations in Cameroon according to (PWC, 2018). They include:

1. Conventions of Establishment concluded before the Petroleum Code of 1999 (some of which are still in force)
2. The Petroleum Code (published in 1999).

In accordance to the former, petroleum operations cover exploration and exploitation operations and any other related activities. Whereas the latter made this definition clearer, by defining petroleum operations as hydrocarbon prospection, exploration, exploitation, transportation activities, and storage activities, excluding activities relating to the refining and distribution of petroleum products. The Petroleum code allows negotiation of three types of contracts recognized by the industry: the production sharing contract, the concession contract and the risk service contract.

In addition to the conventions of establishment and the petroleum code, the following laws and regulations also apply to oil operations (PWC, 2018):

- Law N° 64/LF/4 of 6th April 1964 laying down the tax base and the mode of recovery of flat fees, royalties and mining taxes;
- Law N° 78/24 of 29 December 1978 laying down the tax base and the mode of recovery of flat fees, royalties and mining taxes;

- The Decree N° 2000/465/PM of 30 June 2000 laying down the implementing rules of the Petroleum Code;
- The Decree N° 2002/032/PM of 03 January 2002 establishing the tax base and the modalities of recovery of fees and charges applicable to hydrocarbons; and
- The Petroleum Contracts signed between the State of Cameroon and oil companies.

Modifications have been made to the laws and the latest is Law No 2019/008, of 25 April 2019. Thus, the 2 systems coexist in practice and are summarized in **Error! Reference source not found.** (Ministry, 2006).

Table 2: Old and New Code Systems

	Old System	New Oil Code System
Mining Certificates	Research/exploration license Mining concession	Associated or non-associated authorization Exploitation authorization
Contractual System	Establishment convention Association contract/agreement	Concession contract Production sharing contract

Ghebremusse, (2014) used four factors - the extent of oil dependence; the stage of development of the oil industry; the government's financial position; and the state participation in the oil sector to evaluate the fiscal system of Nigeria, Ghana, and Cameroon.

In Cameroon, oil accounts for about 50% of export earnings and provides about USD 12.2 billion (approximately 30%) to the national budgetary revenues annually. Cameroon's main exporting commodity is therefore inferred to be oil. This insinuates that Cameroon is highly dependent on oil revenue. However, the petroleum fiscal regime does not encompass measures to underpin economic diversification nor does it mirror the State's dependence on revenues from oil. Because oil is depleting, the government should consider directing oil revenue to developing the downstream sector and to create other sources of revenue generation. (Ghebremusse, 2014) suggest that for Cameroon to solve the diminishing reserve problem, she could become a regional hub in the Gulf of Guinea if developments were implored in that direction. By so doing, taxes could be levied by the government and income generated from such oil refining activities.

The age of the oil sector highly impacts the State's ability to tax. Nigeria is old in the oil sector; Ghana is new and Cameroon on the other hand is between Nigeria and Ghana. Due to the depleting reserves in Cameroon, the petroleum fiscal system should have been modified by the government, to generate more revenue before the end of production which happens to be around the conners. This is however not the case because standard regulations were set before signing a PSC with the oil company.

Cameroon is amongst the Heavily Indebted Poor Countries (HIPC), and projections of its public debt are not positive and restricted by low development, infrastructure gaps, financial sector weakness and high political risk resulting from uncertainty over presidential succession. Nonetheless, government debt levels are regarded to moderate due its participation in the CEMAC zone which limits macroeconomic risks (REUTERS, 2012).

The Cameroon government participates in petroleum activities either directly or through SNH. She has the ability to incorporate flexibility in the petroleum agreement but doesn't appear to be doing so. Even though the petroleum resource is depleting, her efforts to continue participating in oil operations is guaranteed if she engages in related oil operations rather than stay only focused on oil production. Ghebremusse (2014) added that it was not clear whether Cameroon negotiates progressive rates or high percentage shares in the PSC.

Other criteria used to evaluate petroleum fiscal regimes include efficiency, risk sharing, clarity, stability, neutrality, effectiveness and equity.

2.3.1. Petroleum Authorizations

The rights to explore, develop and extract oil and gas by contractors is acquired through an authorization from the State and entering into a contract with the Ministry of Mines, Industry and Technology. The contract defines the terms of the authorization which is of four types (Jean-Jacques & Bob, 2016):

1. Non-exclusive prospecting authorization

   The holder is permitted to carry out preliminary surface prospecting on a non-exclusive basis for a period of 2 years with a possibility of 1 renewable period of up to a year. Disposal or transfer of rights from this authorization is not allowed.

2. Exclusive exploration authorizations

   Contracts under such authorizations are granted exclusive rights of exploration for a period of 3 years with the possibility of 2 renewal periods of up to 2 years each.

3. Exclusive interim production authorization

   During the exploration period, the holder is granted interim production rights for a maximum period of 2 years.

4. Exclusive production authorizations

   Exclusive production right is granted for a maximum period of 25years with one renewal period of 10 years maximum. This works in both PSC and Concessionary regime.

2.3.2. Petroleum Legal Arrangements

Petroleum legal arrangements are the contract types entered by the State and the contract holder in petroleum upstream system. The fiscal regime or fiscal system includes all legislative, taxation, contractual, and fiscal elements. The fiscal arrangements can be generally grouped into Concessionary Arrangements (CA) and Contractual Arrangements. A detailed summary of the legal arrangements is represented on Figure 5 (Iledare, 2020).

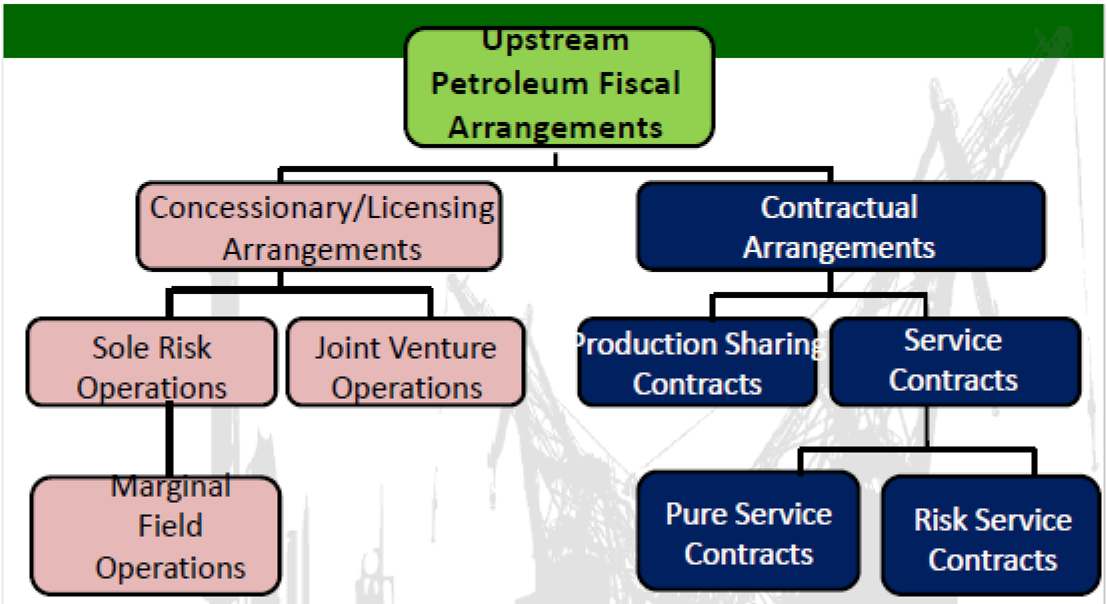


Figure 5: Upstream Petroleum Fiscal Arrangements (Iledare, 2020)

The latest modified petroleum code in Cameroon defines 3 types of contracts for upstream activities (Cameroon, 2019);

1. Concessionary Contracts

   Concessionary contracts are signed prior to the lease acquisition (hydrocarbon exploration permit). The contractor assumes all the operating and financial risks nonetheless, the permit confers the rights and obligations of both the State and the holder during the validity period. In the case of the discovery of commercially exploitable hydrocarbons, exploitation rights are defined in the concession contract as well. The states thus collect royalties in kind as per the contract.

2. Production Sharing Contract.

   The permit holder is granted exclusive rights to explore hydrocarbons and exploit in the case of hydrocarbon discovery. The state partakes either directly or through a duly mandated public body, by hiring the services of the permit holder. The holder is responsible for the operating and financial cost and the recovered hydrocarbon product is shared in accordance with the contract terms. Reimbursement of petroleum cost incurred by the permit holder during the petroleum operations is done in kind as such, the name production sharing. This form of cost reimbursement is commonly termed "production" or "cost oil" (Tamba, 2020); may vary depending on the specified production, recoverable petroleum costs and special amortization. Post to cost recovery is the "profit oil" or "production for compensation"; it is usually shared between the State and permit holder in accordance to the terms of the agreement.

3. Risk Service Contract

   The contractor is simply remunerated in cash for services rendered and has no entitlement over the production proceeds. The qualified holder bears the financial risk with the exclusive hydrocarbon exploration and exploitation rights bestowed on him.

   The summary of the terms in the Production sharing contract (PSC) and the Concession arrangement is summarized on **Error! Reference source not found.** (Mian, 2011).

Contract Type	Contractor	Host Government
Concession	All risk/all reward	Share in reward
Production sharing agreement	Exploration risk/share in reward	Share in reward
Joint venture	Proportionate share in risk and reward	Proportionate share in risk and reward
Pure service contract	Some risk	All risk
Risk service contract	Some risk	Some risk

Figure 6: Risk and Reward of Main Contract Types (Mian, 2011)

2.3.3. Fiscal Instruments

In Cameroon, all contractors are generally obligated to pay taxes and other contributions under the Petroleum Code, General Cameroon Tax Code and Petroleum Contract (Ernest & Young, 2019). Contract negotiations is usually done by MINMIDT and Contractors are subject to the following types of taxes and fees;

1. <u>Bonuses</u>

   There are two types of bonuses: signature and production bonus. A one-time (lump sum) signature bonus is often paid to the State on the effective date of signing the petroleum contract. On the other hand, production bonuses are negotiated with the state depending on the type of contract. In Cameroon, production bonus is generally paid twice: a lump sum is paid at the beginning of production and another when the cumulative hydrocarbon reaches a specified quantity as agreed in the PSC contract (Ernest & Young, 2019)

2. <u>Fixed Entry Fees</u>

A fixed fee (flat fees) is usually paid upon granting and renewal of petroleum permits/authorizations (PWC, 2018). The fee depends on the type of authorization:

- Prospecting authorization requires the sum of six million (6,000,000) CFAF which is approximated to $10,000
- Exploration authorization requires CFAF 15,000 per km^2 upon granting and CFAF 10,000 per km^2 at renewal.
- Production authorization requires CFAF two hundred and fifty million (250MM) upon granting, renewal and transfer.

3. Royalty

Royalty is a fundamental element of designing an international fiscal system and is sometimes considered regressive because it is independent on whether profits are made from the oil and gas business, but is rather dependent on the production or gross value. A progressive royalty scheme is otherwise suggested by (Echendu et al., 2016).

When a lease is obtained, a royalty is commonly retained by the land owner (mineral interest owner. The land owner is called the lessor while the one acquiring the lease is termed the lessee. In the case of Cameroon, all minerals beneath the ground belongs to the government, as such, she is the original lessor of all petroleum leases. In some cases, royalty is often 12.5% of the oil and gas free of any costs (Mian, 2011): 100% cost is handled by the contractor resulting from the acquired lease.

Royalty is a percentage of gross value and amount of production, which can be paid in cash and or kind. It represents the cost of doing business and thus tax deductible. The royalty rate R ($R < 0 < 1$) depends on the location (geology) and time the acreage is leased and the incentives scheme in place (Echendu et al., 2016). The different types of Royalty include;

i. Fixed percentage

ii. Fixed payment royalty

iii. Sliding scale Royalty

Fixed percentage royalty is a system where by a fixed percentage of the gross revenue is paid to the mineral right owner for usage of the property. Payment is either done in kind or cash and is calculated following equation 11. The oil price doesn't affect the percentage applied. Examples of African countries that practice such fixed percentage royalty (R(Φ)) scheme includes Niger, Sierra Leone, Ghana, Liberia, Mali, Chad etc.

$$ROY_t = R(\Phi) \times GR_t \tag{1}$$

Fixed payment royalty on the other hand is a royalty process in which a standard amount is paid to the mineral owner irrespective of whether profits are made. Fixed percentage royalty is widely used in the Gulf of Guinea while fixed payment is no longer used as in the past.

However, sliding scale royalty is becoming fashionable as it accounts for a variety of uncertainties such as geologic factors, field size, oil price, average daily production, engineering factors and economics. Sliding scale royalties could be jumping or incremental sliding scale. In jumping scale royalty, the value or percentage to be paid is dependent on the tranche (level) specified, while in incremental scale royalty, an effective value/percentage is calculated based on the tranche reached. Incremental sliding scale could be logarithmic or linear scale. The different royalty schemes can be summarized on Figure *7* (Echendu et al., 2016). An example of sliding scale for Cameroon is given on **Error! Reference source not found.** (Iledare, 2020).

Table 3: Cameroon's Sliding Scale Royalty

Royalty Rate (%)	Production Rate (MBOPD)
2	1.0
6	7.7
9	13.4
11	19.0
12.5	>19.0

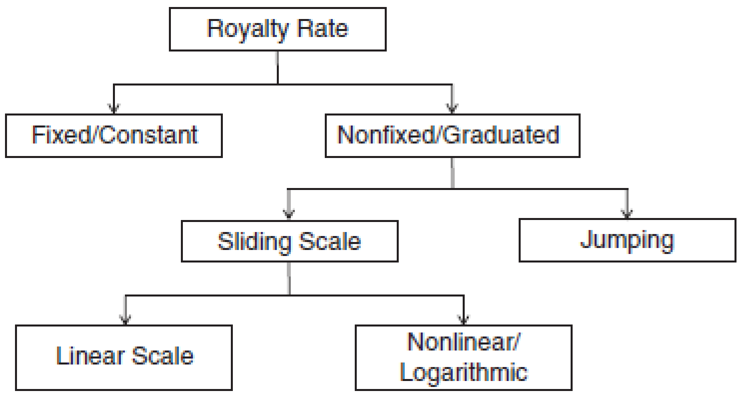


Figure 7: Royalty Classification

Two types of royalties exist in Cameroon:

a. Surface area royalty

Surface area royalty (rental tax) is paid annually and depends on the type of authorization or phase of petroleum operations. Surface rental tax is eminent only for PSC and service contract holders while Concession contract holders are entitled to a monthly proportional royalty tax. For Exploration permit, the annual payments increase from CFAF 1,750/km^2 in year 1 to 5,500/km^2 in year 5 according to (Mckenna, 2013). However, (Ernest & Young, 2019) suggest that the annual payment vary for the first four years and then remains constant after year four.

- First year – XAF 1,750/km^2
- Second year – XAF 2,000/km^2
- Third year – XAF 3,500/km^2
- The following years – XAF 5,500/km^2

Considering production authorization, a sum of CFAF 100,000/km2 is paid starting with a minimum levy of CFAF 6MM (Mckenna, 2013) on an annual basis. Royalty can be paid in cash or kind as defined the PSC.

b. Proportional royalty

In Cameroon, this applies to concession contract holders or businesses. A monthly royalty which depends on the production volumes is paid to the Cameroon Government. The rate, declaration, settlement, basis of calculation, and recovery of this royalty are specified in the concession contract.

4. <u>Taxes</u>

   Taxes are a compulsory contribution to the state revenue, imposed by the government and on business profits and workers' income. It is a means by which the government funds public projects and expenditures. Just like any other law, failure to pay taxes is punishable by law. Petroleum revenues generated from taxes provides a stable source of income to finance development objectives, promote economic growth and supporting the growth of medium and small sized enterprises (Ghebremusse, 2014).

   a. Additional petroleum tax

      Based on the profitability of the petroleum project, concession contract holders are required to pay an additional profit tax.

   b. Corporate income tax (CIT)

      CIT is also referred to as the company tax and is calculated on the net profits (revenue after subtracting all petroleum operation costs) of the contractor. It is actually levied on the taxable profits of the contractor. It usually ranges from 33% to 50% (Mckenna, 2013) and is negotiated on the profits made on oil.

5. <u>Cost oil and Profit oil</u>

   This applies to the PSC and differentiates it from the concession contract. Cost oil also referred to as reimbursement oil is the portion of the available production applied for the restoration of petroleum cost. Petroleum costs are determined following accounting principles: they are actually expenses birth from the production of oil within the framework of the PSC (Ernest & Young, 2019).

   Once the cost oil has been subtracted, the remaining production volumes is split between the government and the contractor. This is termed profit oil; the oil split is done based on a sliding scale R-factor in Cameroon. Profit oil sharing is usually termed a progressive taxation scheme because it is tied to cumulative investment (Ghebremusse, 2014). Profit oil therefore closely correlates to profitability since it is attached to the cost of production. The R-factor is defined as the ratio between the "net cumulative revenue" to the "cumulative investments". Table 4 indicates the host government and contractor share of profit oil as a function of R-factor (PWC, 2018).

Table 4: R-Factor Range for Profit Oil Split

R value	**State Share**	**Contractor Share**
$0.0 \leq R < 0.25$	10%	90.00%
$0.25 \leq R < 0.5$	12.50%	87.50%
$0.5 \leq R < 1.0$	17.50%	82.50%
$1.0 \leq R < 1.50$	20.0%	80.00%
$1.50 \leq R < 2.0$	25.0%	75.00%
$2.0 \leq R < 0.25$	32.5%	67.50%
$0.25 \leq R < 3.0$	42.5%	57.50%
$R \geq 3.0$	55%	45.00%

Contractors have the obligation to supply the domestic market a defined part of their production (Mckenna, 2013).

6. <u>Custom fees</u>

   During the exploration and production phase, all imports of products, equipment, materials, tools and machinery exclusively related to petroleum operations are exempted from customs duties. However, during the first five years of production, a 5% reduction rate is applied to all production related imports (Mckenna, 2013). This corresponds to both contractors and subcontractors.

7. <u>Non-recoverable expenditures</u>

   These are payments made for the settlement of charges, expenses or fees that are indirectly related to the petroleum operations. They are considered in the PSC to be lost (irrecoverable) expenditures by the contractor. They include payments such as signature bonuses, external auditing cost, penalties and cost related to period prior to the effective signing date.

8. <u>Abandonment cost.</u>

   This cost is applicable on production authorizations wherein, the cost is deposited as defined by the contract.

9. Incentives.

Holders of petroleum contracts under the Petroleum Code in Cameroon are exempted from withholding tax on dividends; from registration fees on contracts directly linked to petroleum operations; from all export duties of the entitled hydrocarbons; and from interest on loans granted by non-resident financiers funding development operations (Centurion, 2016).

The conditions and extent of any such exemptions are particularly laid out in the Petroleum Code, PSC and any other complementary regulatory instruments. A summary of the fiscal instruments for PSC and CA are presented on **Error! Reference source not found.**.

Table 5: Fiscal Instruments for PSC and CA

Fiscal Tax Instrument	**PSC**	**CA**
Corporate Income Tax (CIT)	33%-50%	33%-50%
Annual surface rental tax	The first year - XAF 1,750/km² The second year - XAF 2,000/km² The third year - XAF 3,500/km² The following years - XAF 5,500/km²	N/A
Additional petroleum tax	N/A	Negotiable
Signature Bonuses	Negotiable	Negotiable
Proportional royalty	N/A	Negotiable
Cost oil (Cost recovery limit)	Often 60%	N/A
Capital allowance	SLD	SLD

2.4. Model Framework

2.4.1. Resource and Reserve Classification

To economically evaluate reserves, it is important to understand its classification mechanism. Resources and reserves are assets owned by oil companies and from which profits are made. They differ in that, resources are stock of oil which is deemed extractable in an undefined future (Moridis et al., 2019) whereas, reserves are quantities of petroleum that estimated to be commercially recoverable from a defined date forward under currently known technological and economic analysis. Petroleum volumes are thus classified into 3 types; Reserves, Contingent resources and Prospective resources.

Reserves

Reserves typify the amount of crude oil that can be financially recovered given the technological feasibility at the current price of oil. They change over time and its classification procedure is done depending on the level of certainty. Reserves must satisfy 4 conditions (Moridis et al., 2019)

i. They must be discovered
ii. They must be recoverable
iii. They must be commercially variable
iv. They must be remaining

Reserves are also categorized into 3

- ❖ Proved Reserves (1P)

  They are low estimate of reserves and represent a reserve probabilistic estimate of P90. That is, there is a 90% probability (P90) that 10% of the reserves recovered will equal or exceed the low estimates, given the required economics and technology. A very low risk tolerance is generally observed and this interests a risk adverse investor who is willing to accept a low rate of return to preferable preserve capital.
- ❖ Proved plus Probable reserves (2P)

They are best estimate of reserves and represent a reserve probabilistic estimate of P50. For the 2P reserves, there is a 50% (P50) chance to recover 50% of the anticipated reserves. A risk neutral investor will desire such investments

- Proved plus Probable plus Possible reserves (3P)

  They are high estimate of reserves and represent a reserve probabilistic estimate of P10. This implies given the economic and technological availability, there exist a 10% (P10) probability that 90% of the recovered reserves will equal or exceed the high estimates. If the reserves here are recovered, then the rate of return on the investment is expected to be high based on the 90% reserve acquired. Risk seeking investors usually quest after such adventures for increased NPVs. In terms of the estimated volumes, 3P > 2P >1P.

Contingent Resources

They "are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies" (SPE et al., 2017). The contingencies include the absence of market viability, insufficient evaluation and in some cases the technology required is under development. Contingent resources are categorized into 3; 1C, 2C, and 3C represents the low, best and high estimate of contingent resources respectively.

Prospective Resources

Prospective resources are defined as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects" (SPE et al., 2017). They can also be categorized into 3; 1U, 2U and 3U designates unrisked low, best and high estimates respectively. The estimates are termed "unrisked" because the possible hydrocarbon estimates have not discounted based on the associated or unknown risk. The resource classification framework for the hydrocarbon volumes is summarized on **Error! Reference source not found.** (SPE et al., 2017).

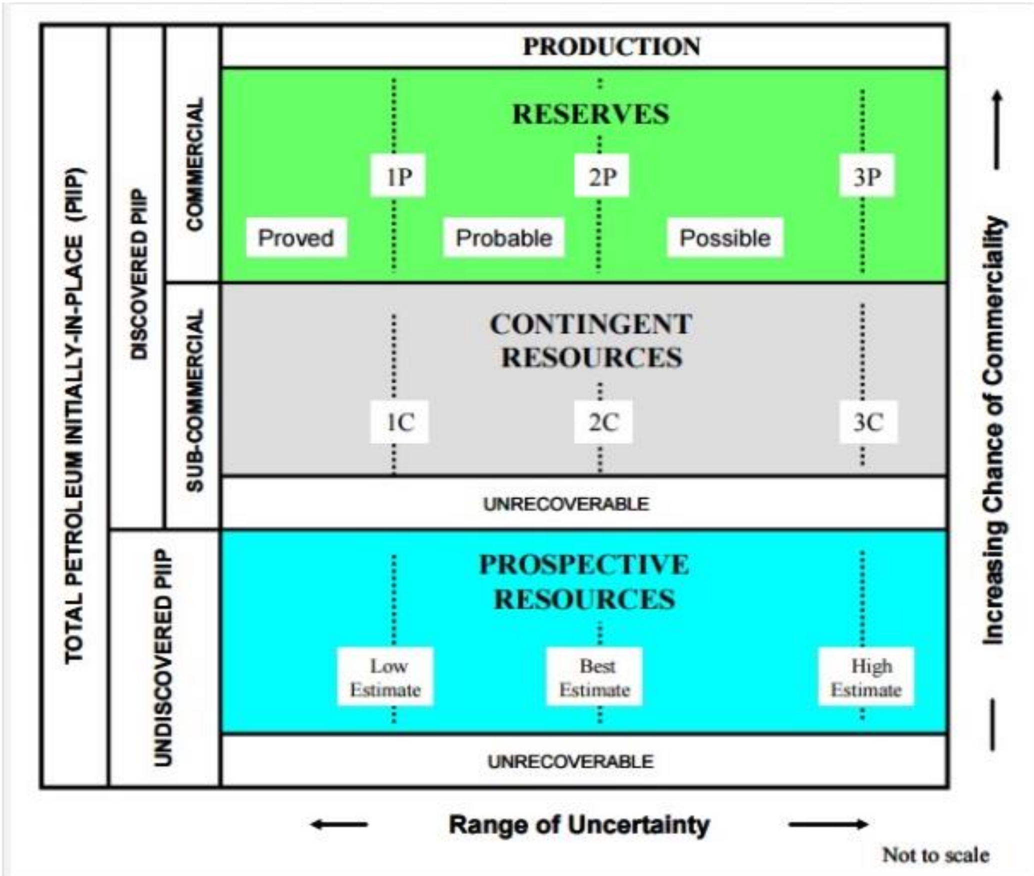


Figure 8: Reserves Classification (SPE et al., 2017).

Production of oil from reserves often goes through 3 phases: Build up, Plateau and decline phases respectively. A typical production profile is represented by Figure *9*.

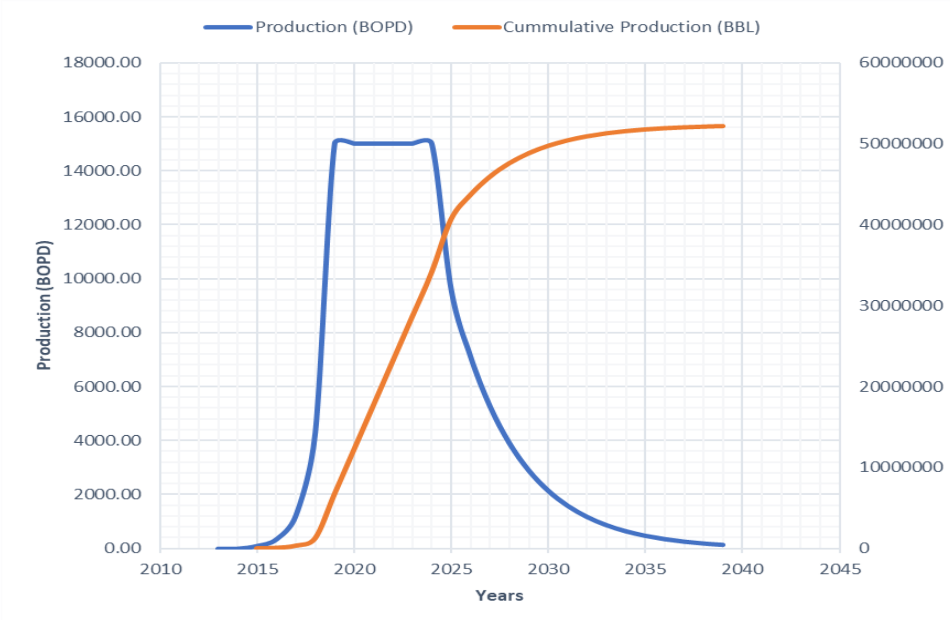


Figure 9: A Typical Production Profile

2.4.2. Reserve Estimation

Reservoir estimates are usually done to determine the amount of original oil in place (OOIP) and the original gas in place (OGIP). Estimates are done using 5 methods (Mian, 2011) depending on the amount and quality of data at that given time.

Volumetric estimates

The requirements for volumetrics include a producing well, logs, cores, estimate of drainage area and fluid properties. The total volume of hydrocarbon accumulated is known as the Stock Tank Oil Initially in Place (STOIIP), for oil and Original Gas in Place (OGIP), for gas.

$$STOIIP = \frac{7758(1 - S_{wi})\Phi hA}{B_{oi}} \tag{2}$$

$$G = \frac{43560\Phi hAS_{gi}}{B_{gi}} \tag{3}$$

where,

STOIIP = N (STB)

Φ = Porosity (fraction)

B_{oi} =Initial oil formation volume factor (RB/STB)

S_{gi} = Initial gas saturation (%)

h = formation thickness (ft)

OGIP = G (ft^3)

A = Drainage area (Acre)

B_{gi} = Initial oil formation volume factor (Scf/cf)

S_{wi} = Initial water saturation (%)

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

Volumetric estimates are relatively fast and require minimal information though it requires lots of assumptions leading to gross errors.

Analogy Methods

This method is used to estimate ultimate recovery or unit recovery factors of oil/gas for new or undrilled locations. It is assumed that analogous well or reservoir is comparable to the subject reservoir in terms of the geological structure, reservoir drive mechanism, initial temperature and pressure, reservoir-fluid properties, average ratio of net to gross pay, and petrophysical properties. It is mostly used for the estimation of reserves in the early stages of development and production. Once sufficient pressure and production data from the well is obtained, a dynamic method is preferable used. The requirements for volumetrics include well logs, recovery factor (RF), isopach maps, structure maps and fluid properties.

Decline Curve Analysis

The decline curve analysis (DCA) may be applied to individual fields and wells, to identify well production problems and predict well performance and the life of the well (Guo, Boyun; Lyons, William; Ghalambor, 2007); given some production data. This method is quite simple to use without considerations of reservoir or well parameters, and can be used for different reservoirs. DCA is used to predict well performance based on the following assumptions;

Future performance can be modeled with past history. That is the factors affecting the present performance will be constant for future production.

Production must be declining and the data is only valid given sufficient past production history for over some years. This helps to make reasonable production forecast and can’t be used for data under transient flow state. Arps in 1945, developed 3 empirical production decline models which are related through the classical formulation of the Arps decline rate equation (Guo, Boyun; Lyons, William; Ghalambor, 2007).

$$\frac{1}{q}\left(\frac{dq}{dt}\right) = -bq^{d} \tag{4}$$

Where b and d are empirical constants that are determined from production data. the value of d differentiates the different models.

The different DCA models are;

- Exponential decline
- Harmonic decline
- Hyperbolic decline.

Exponential decline (b = 0)

The relative decline rate and production rate decline equations for the exponential decline model can be derived from volumetric reservoir model. The exponential decline also known as the constant percentage decline is commonly used by engineers because it is simple, easy to use and it gives conservative results. Its final form with b equal to 0 is represented as

$$q_t = q_i e^{-at} \tag{5}$$

$$N_p = \frac{q_i(1 - e^{-at})}{a} \tag{6}$$

$$a = -\frac{\ln(1 - d)}{t} \tag{7}$$

$$a = -\frac{\ln\left(\frac{q_t}{q_i}\right)}{t} \tag{7}$$

where,

qt = final production rate at time t (bbl/d)	qi = initial production rate at t=0 (bbl/d)
a = nominal decline rate (fraction)	t = time (years)
d = effective decline rate (fraction)	Np = Cumulative production (stb)

Hyperbolic decline (0 < b > 1)

The other 2 models are generated from the hyperbolic model as such, it considered a more general model. When plotted on a semi-logarithmic graph paper, the hyperbolic decline curve is a concave upward curve. As a result, the decline characteristics, a, is not a constant value but rather is the slope of the tangent to the rate-time curve at any point. It is mostly used in known cases of late history of pressure supported production. The hyperbolic exponent, b, is constant with time. Its final form is represented as

$$q_t = q_i(1 + abt)^{-\left(\frac{1}{b}\right)} \tag{8}$$

$$N_p = \frac{q_i\left[1 - (1 + abt)^{-\left(\frac{b-1}{b}\right)}\right]}{a(1 - b)} \tag{9}$$

$$a = \left(\frac{1}{bt}\right)\left(\left(\frac{q_i}{q_t}\right)^b - 1\right) \tag{10}$$

$$a = \left(\frac{1}{bt}\right)\left(\frac{d}{(1 - d)^b} - 1\right) \tag{11}$$

Harmonic Decline (b = 1)

The harmonic decline is a special hyperbolic decline case with b equal to 1. In this specific case, a plot of the inverse of the production rate versus time on a linear scale should also yield a straight line (Guo, Boyun; Lyons, William; Ghalambor, 2007). The final form of the harmonic decline is represented as

$$q_t = q_i(1+at)^{-1} \tag{12}$$

$$N_p = \frac{q_i}{a}\ln(1+at) \tag{13}$$

$$a = \left(\frac{1}{t}\right)\left(\frac{q_i}{q_t} - 1\right) \tag{14}$$

$$a = \left(\frac{1}{t}\right)\left(\frac{d}{1-d}\right) \tag{15}$$

Figure 10 represents the Arps decline equations for Exponential, Hyperbolic and Harmonic decline.

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

Figure 10: ARPS Decline Equations

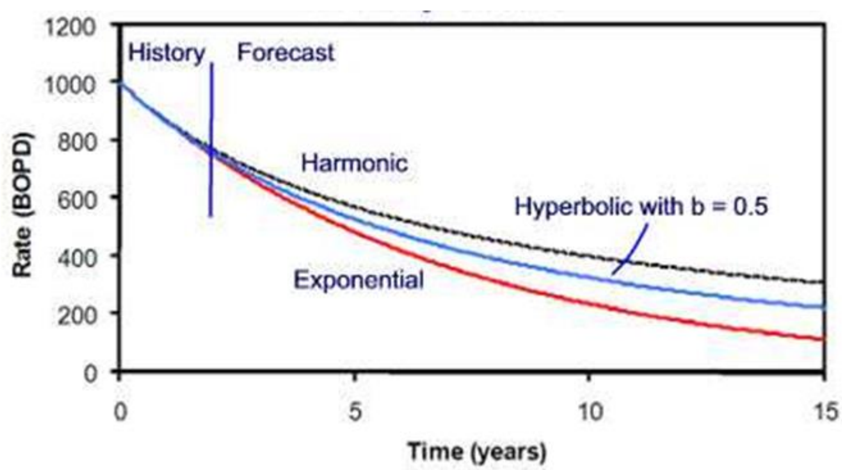


Figure 11: Graphical Representation of all 3 Decline Curves

A graphical representation of the 3 models is shown in Figure 12 (*Petrocenter*, n.d.).

Material Balance Estimates

Material balance is a method that can be used to account for the movement of reservoir fluids within the reservoir or to the surface where they are produced. The material balance accounts for the fluid produced from the reservoir through expansion of existing fluid, expansion of the rock, or the migration of water into the reservoir (Craft & Hawkins, 2015). This method is used to determine the in-place reserves (IGIP, OOP), calculate water influx and predict reservoir performance. The concept is derived from volumetric balance and based on the principle of a tank model. The material balance equation (MBE) states that the amount of fluid present in a reservoir is equal to the original amount of fluid, plus natural influx, plus the amount injected in the reservoir, minus that withdrawn from production from the reservoir.

$$Volume\ entering - Volume\ leaving = Net\ change\ in\ volume \tag{15}$$

$$Expansion + Influx = Production \tag{16}$$

The basic assumptions (Ahmed & Nathan Meehan, 2012) for the use of material balance equations include;

1. Reservoir is a homogenous tank (i.e. Pressure, temperature, rock and fluid properties are the same throughout the reservoir, and are not space dependent).

2. It is zero dimensional, meaning that fluid production and injection occur at single production and injection points.
3. It does not matter whether there is pressure equilibrium or total lack of pressure equilibrium, provided an average pressure decline for the reservoir is established.
4. Adequate and valid pressure and production data exist (several years)
5. PVT data are accurate
6. Reservoir is equated to a tank with a constant volume
7. Uniform pressure throughout the reservoir at all times
8. Variations in properties are well represented by averages

The usage of material balance method requires knowledge on PVT data, average reservoir pressure, surface production volumes, rock and water compressibility, and interstitial water saturation.

Reservoir Simulation

Petroleum reservoir simulation is the planning, construction and operation of a model whose behavior approximates the behavior of the actual (real) reservoir. Mathematical equations (models) are employed to infer the behavior of the physical reservoir. Reservoir simulation is based on the principle of Darcy’s law, equation of state (EOF), and conservation of mass, energy or momentum in a collection of blocks;

$$[Rate\ of\ change\ within\ a\ system] = [Rate\ of\ fluid\ in] - [Rate\ of\ fluid\ out] \quad (17)$$

Reservoir simulation is a dynamic modelling procedure and has a wide range of uses which begin from identifying reservoir flow behavior to describing complex reservoir flow processes, to designing techniques, to improve oil and gas recovery, and forecasting future performance tool for planning reservoir development and management.

The basic assumptions (Craft & Hawkins, 2015) for the usage of reservoir simulation includes:

- The reservoir is treated as a collection of individual blocks; each has its own set of properties and can behave differently.
- The blocks are interdependent because of fluid continuity.
- Does not have same limiting assumptions as conventional reservoir engineering

The data required to conduct reservoir can be obtained from well logs, core data, geological descriptions (e.g lithofacies), seismic surveys (faults), and production data.

2.4.3. Crude Oil Pricing

Crude oil prices change over time and cannot be pivoted on a single factor but on a variety of price determinants. Crude oil is a vital global energy source in the world. Its ever-increasing demand over the years has led to a complexity in the market and pricing of crude. Back in the 1860's when the oil markets began, the price of crude was mainly determined by demand and supply (Gyagri et al., 2017). Crude oil demand arises from the heavy usage and dependence by the transportation, industrial, economic and domestic sectors. As time went on, major oil companies materialized and have had great control over the market and pricing of crude as well as other factors.

Though crude oil is a non-renewable liquid, political and critical decisions are made based on this reserve exploration, development, production and marketing. It is for this reason that understanding the factors governing this complex market is key in decision making for both the host government with the resource and the E&P industry. A wide range of factors contributing to the oil price volatility include demand and supply, government decisions, natural factors, other energy sources, economic and industrial growth, geopolitical conflicts and wars, multinational oil companies, and organizations such as Organization of Petroleum Exporting Countries (OPEC), and Organization of Economic Cooperation and Development (OECD).

Crude oil is traded in US dollars per barrel depending on its API (American Petroleum Institute) gravity and sweetness (lower Sulphur content). The sweeter and higher the API gravity (range from 5°-55° API), the more desirable and priced the crude is. Following this, there exists oil price benchmarks such as Brent Blend, West Texas Intermediate (WTI) and OPEC reference basket made of 13 blends across the OPEC membership countries. Benchmark crudes is therefore the basis for which buyers and suppliers of this commodity trade. Trading transactions could be done in spot or contract markets thereby adding the participants (speculators and hedgers) in these markets as oil price determinants (Duhon, 2015).

2.4.4. Cashflow Modeling

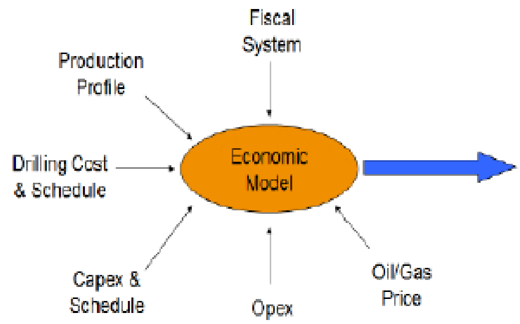
Cash flow analysis is the process of reaching a decision between alternative investment projects (Mian, 2011). In the simplest terms, a cash flow is a financial statement consisting of all cash entering and leaving an enterprise/company over time. It stores the records of the total oil or gas production, revenue, expenses and fiscal instruments used for economic analysis. The bedrock of any successful economic analysis is a correct cash flow forecast. Economic analysis is performed for the purpose of decision making by investors and regulation by the management team. Cash flow forecast therefore cuts across many independent sectors such the department of reservoir engineering, drilling engineering, production and the Economist. A cashflow births the net cashflow which is the cash received (gross revenue) minus cash spent during a period (usually considered as 1 year). Net cashflow (NCF) predictions are usually made over the project's economic life (abandonment). NCF can be mathematically represented as,

$$NCF = Receipts - Disbursements \tag{18}$$

Gross revenue is usually the product stream (oil/gas) multiplied by the product price (Mian, 2011). The cash spent is divided into 3 categories as capital expenditure (CAPEX); operating expenditure (OPEX); and abandonment costs, production taxes, and sunk costs. CAPEX is further divided into geological and geophysical (G&G) costs, drilling, and facility costs. However, during the implementation phase of the project, the operating cost is regarded as the capital cost. Apart from the 3 categories of cash spent, there is also the government or state take which comprises income taxes, royalties, and bonuses. Costs are generally affected by inflation, market conditions, transportation from the source, taxes and import duties, climatic and terrain condition, and also local wage levels and production (Mian, 2011). A cash flow model is therefore a combined forecast of all these variables to calculate the viability yardsticks. Once the cash flow model is up-to-date, the merit of any proffer fiscal term can be assessed. From the yardstick calculations, an informed decision can be devised.

2.4.5. Deterministic Cash Flow Model

A deterministic cash flow model is a model that describes an uncertain problem. It is based on a single definite output variable outcome, given the static input variables. A insight of some deterministic cashflow items (the production profile, oil price, CAPEX, OPEX and the fiscal system) is summarized in figure 12 (Wahab et al., 2017).



Yardstick	Definition	Significance
Discounted		
DCFR	Discount rate at which NPV is zero	Effective interest rate earned by investment
NPV(r)	Sum of annual cash flow discounted at given rate	Total value of investment at given discount rate
Undiscounted		
AVP	Sum of annual cash flow	Value of company earnings
MCI	Largest negative value of cumulative cash flow	Amount of investment at risk
Payout	Length of time required to recover investment	Length of time that investment is at risk

Figure 12: Economic Model Scheme (Wahab et al., 2017)

Capital Expenditure (CAPEX)

CAPEX is cost usually incurred at the beginning of the project and also referred to as front-end costs (Mian, 2002). It is in fact the foundation for investments in the oil and gas sector and without which there would be production. These are large expenditures seldomly incurred several years before the generation of revenue. They consist of geologic and geophysical (G&G) costs; drilling costs; tankers; offshore platform construction and installation, process facilities; wellheads, flow lines, and trunk lines to transport oil and gas; supply bases; camps and accommodation; storage tanks or vessels; etc.

CAPEX may also be incurred during the economic life of the project for example recompletion of wells into another formation; major upgrading/replacement of existing facilities; installing artificial lift facilities if the wells were initially on natural flow; sidetracking an existing well with a horizontal well; and installing facilities for secondary recovery (waterflood or gas injection) or enhanced oil recovery (EOR).

CAPEX is generally classified as Tangible and Intangible CAPEX. Tangible Capex is the one that has physical presence with sustained value (sellable in the future) while intangible CAPEX is not physical, cannot be seen or touched but still adds value beyond the time it was acquires. Tangible CAPEX must be depreciated for tax purposes and this is majorly the distinction from OPEX while intangible property must be amortized. Examples of tangible CAPEX include machinery while intangible include franchise, copyright, license fee and seismic survey.

Operating Expenditure (OPEX)

These are cost required to run day-to-day activities such as maintenance of facility and wells. OPEX is also called the lease operating expenditure (LOE) as it occurs periodically and is usually expressed per yearly basis in CF analysis. These are direct costs associated with production or injection. They are expenditures that benefits only the period in which they are made, no sustained value and no operating costs if there are no ongoing production or injection. They could be categorized as direct or indirect costs and treatment varies depending on tax code. OPEX can sometimes be estimated at 5% of CAPEX. It consists of 5 elements (Mian, 2002):

1. Fixed cost
2. Variable cost per unit of production
3. Maintenance of facilities
4. Maintenance of wells (Workovers)
5. Overheads

Abandonment Costs and Sunk Costs

Abandonment cost is a special kind of CAPEX which is closely tied to the safety of the environment at the end of the project life. The wells and facilities are expected to be abandoned such that the environment is not polluted nor the livelihood of inhabitants of that area. Abandonment cost are not small and may be as high as the initial cost of development. As a rule of thumb is 10% of original CAPEX (Mian, 2011).

On the other hand, sunk costs are usually historic cost incurred before the projection of the first period of a cash flow. For example, previous exploration costs incurred before the procession of the development analysis. It is important to note that sunk costs do not affect the future financial decisions because the money has already been spent.

Depreciation

Depreciation is a deductible non-cash expense for income tax purposes. It is defined as a loss in the value of an asset over the time it is being used. It is important to note that depreciation is not an actual cash outflow as such is not subtracted from the annual cashflow as an expense. The aim of depreciation is to spread investment costs over time, for income tax and financial report purposes. Depreciation actually converts the cost of assets into expense items during the useful life of the asset. Capital recovery of fixed assets is made possible through depreciation. Events that can cause the depreciation of property include deterioration, wear and tear, obsolescence and age. Depreciation of a property begins at the time the property is placed in service for use in business or trade and ends when the cost of the property is recovered or retired from service. There are generally 4 depreciation methods though the straight-line depreciation method is commonly used.

1. Straight-line depreciation (SLD)

SLD involves the equal distribution of the depreciable cost over the useful life of the asset. It is mathematically represented as

$$D_n = \frac{C - S_v}{n} \quad (19)$$

Where,

Dn = depreciation in the nth year.

C = total cost of the depreciable asset

Sv = salvage value

n = useful life of the asset.

The salvage value is also referred to as the scrap value, residual value or terminal value. It is the anticipated value of property at the end of its useful life.

2. Declining balance depreciation

This method is also referred to as the accelerated depreciation method. It involves an annual deduction of a fixed percentage of the book value (total value of asset less accumulated depreciation of previous years) of the asset. The fixed percentages applied can be 200%, 175%, 150% and 125%. When 200% declining balance is applied, it is referred to as the double declining balance depreciation method. The fixed percentage is calculated by dividing the either of the 4 mentioned percentages above by the asset life.

3. Sum-of-Years'-digit depreciation (SYD)

"This method produces a declining depreciation charge each year by applying a declining charge to the total cost of the asset (depreciation base). The declining charge is determined each year by dividing the remaining life of the asset by the sum of the years' digits".

$$Depreciation = Declining\ Charge \times Total\ Cost\ of\ Asset \tag{20}$$

$$SYD = \frac{n(n+1)}{2} \tag{21}$$

Where n is the useful life of the asset as specified in the contract.

4. Units of Production depreciation

This method of depreciation is used based on how much the asset produces or is used rather than the passage of time. In this case, the physical wear and tear is not the dominating factor in the useful life of the asset but rather the units service rendered. The annual depreciation charge is calculated by multiplying the depreciation rate by the activity per period.

$$DR = \frac{C - S_v}{TLA} \tag{22}$$

where,

DR = Depreciation Rate

C = Cost

Sv = Salvage Value

TLA = Total Lifetime Activity

CHAPTER THREE

3.0. METHODOLOGY

The success of any project lies in the efficient economic evaluation (capital investment evaluation) of its available resources. This is done by building project cashflow models, followed by simulation and performing sensitivity analysis either on a well or an entire field, over a longer period of time. Time is a major factor as such, the time value of money must be considered for the cashflow generated. The engineer is thus faced with a challenge to analyze and predict the returns on investments. Petroleum activities are generally capital intensive and need special accuracy to mitigate the risk and uncertainties that come with the projects. This research focused on building an economic model framework that defines the petroleum fiscal system of an idealized field in Cameroon. An economic evaluation worksheet is generated in Microsoft Excel, following the spreadsheet from (Mian, 2011) and (Iledare et al., 2018).

No qualitative data is used to economically analyze the petroleum fiscal regime in the framework. The data used is obtained from SNH reports, relevant academic papers, international financial institutions, development banks and reports from Cameroon Ministries. The research involved scouting relevant literature in order to identify optimum instruments that can affect the fiscal regime, gathering data to be used in building an analytical model and providing a standard fiscal regime that could be used as a framework for petroleum exploration and exploitation in Cameroon.

To effectively evaluate the economics behind this project, the right production profile must be forecasted. This is to avoid errors in the production profile which will translate to the cashflow model and thus produce faulty results. A brief summary of the procedure applied to this work begins with an adequate production profile. The production profile is made of three phases: buildup, plateau and the decline phase. Production field data is forecasted on an excel spreadsheet form which the cost outlay is generated. A deterministic model is built based on the fiscal instruments, bonuses, royalties, taxes and expenditures involved with project. To account for uncertainties and risk, a stochastic model is generated and a Monte Carlo simulation run to predict the outcomes of the different probabilistic combinations using @RISK Simulator. The economic indicators (profitability measures) being evaluated include Net Present Value, Internal Rate of Returns, Profitability Index (PI), Take Statistics (Government take and Contractor Take), Front end loaded Index (FLI), Payout Period (PO). Sensitivity analysis are done and based on the results obtained, solutions and proposals are made to significantly impact the petroleum fiscal system as such, optimizing exploration and exploitation of petroleum resources in Cameroon.

In this research, the procedure for Economic Analysis will be structured into four steps:

1. Construct a Production Forecast Profile
2. Build a Deterministic Cash Flow Model
    - Royalty Scheme
    - Cost Outlay and Depreciation
    - Cost Recovery Treatment
    - Before Income Tax Net Cashflow Model (BITNCF)
    - After Tax Cash Flow Model (AITNCF)
    - Economic Indicators
3. Build a Probabilistic Model
    - Define the input variables
    - Run the Monte Carlo Simulation using @RISK
4. Perform Sensitivity Analysis

3.1. Production Profile

The production profile describes the amount of extractable reserve over time and will be represented annually in this work. It is composed of three phases; Build-up phase, the Plateau phase and the Decline phase. An idealized production curve is presented in figure 12 (Höök, 2009). A discovery well is usually drilled, followed by an appraisal well. An appraisal well is drilled to determine the development potentials of the reservoir. It is not uncommon to mark the first oil production during development, this is the beginning of the build-up phase. As more of the oil is being produced, the reservoir reserve is being diminished.

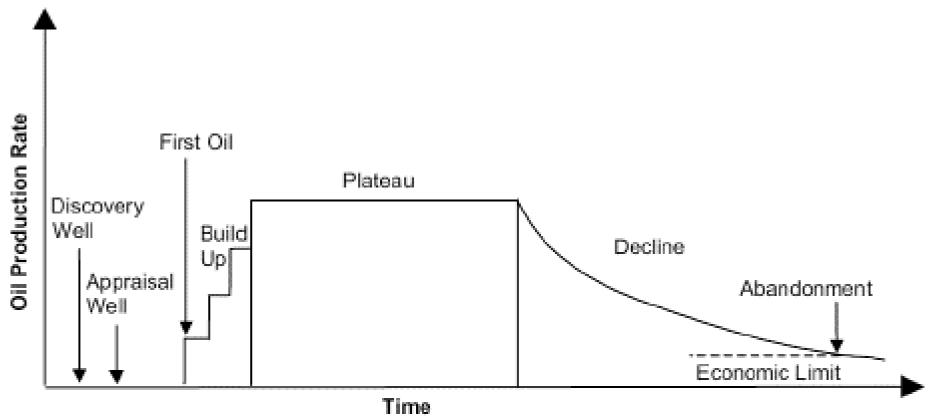


Figure 13: Idealized Production Profile (Gate, 2009)

3.1.1. Build-up phase.

The build-up phase consists of an initial oil production followed by a linear increase in the produced oil. In this phase of the field development plan, new wells are drilled, well completion processes are carried out, and production facilities installed. At this stage, the wells do not flow at an optimum capacity though an increase in the oil rate is observed. Oil production continues until an optimum or maximum or peak production capacity is built up. The well is set to have reached its full production potential; this marks the onset of the plateau phase. The exponential Arps (1945) equation is used to calculate the build-up rate and annual production are as follows

$$q_1 = q_i e^{-a_1 t} \tag{23}$$

$$N_{p1} = \frac{365 \times (q_i - q_1)}{a_1} \tag{24}$$

Where,

q_1 = Daily plateau rate (bbl/d)

Np1 = Annual production (STB)

$$a_1 = -\frac{\ln\left(\frac{q_t}{q_i}\right)}{t}$$

3.1.2. Plateau Phase

From the build-up phase, the field enters the plateau phase where the well is constantly producing at its full potential. The same quantity is processed annually but there is however an overall increase the oil produced over time when cumulated. At this point the full installed extraction capacity is used and a constant reservoir pressure is observed. Production operators normally try to maintain this production phase for as long economic and technical attainability authorizes. This is because the annual production is greatest and more revenue is achieved as desired by the contractor and the government. Small fields usually have a very short plateau phase, more like a sharp peak while large fields have a prolonged plateau phase. The exponential Arps equation used during the phase is,

$$q_2 = q_1 = q_i e^{-a_1 t} \tag{25}$$

$$N_{p2} = 365 \times q_2 \tag{26}$$

3.1.3. Decline Phase

This is the large stage of the field development plan which leads to abandonment of the field. At this stage the reservoir pressure constantly declines until the primary drive mechanism can no longer support the production of oil and requires an external (secondary or tertiary drives) source of energy at some point. Abandonment is determined by the Political reasons, economic limit of the project and the technological feasibility. This research is focused on abandonment due to the economic limit of the project; the point where the cost of production becomes higher than the revenue generated and profits are no longer made. The decline rate and annual production is gotten from the Arps (1945) given by,

$$q_3 = q_f \times e^{-a_3 t} \tag{27}$$

$$N_{p3} = \frac{365 \times (q_2 - q_f)}{a_3} \tag{28}$$

$$a_3 = -\frac{\ln(1-d)}{t} \tag{29}$$

3.2. Deterministic Cash Flow Model

The decision between alternative investment projects starts with capital investment analysis. A cash flow model is a framework for profit calculation: it provides data on the cash inflows (receipts) cash outflows (disbursements) of a business/company and the time span for the investment on an annual basis. A net cashflow is the total revenue (cash received from the sales of oil and gas) minus the total expenditure (cash spent technical and non-technical). A positive net cashflow (NCF) is indicative of an addition in the cash reserves while a negative cashflow reveals the unprofitable nature of the project.

$$NCF = Inflow - Outflow \tag{30}$$

Aside from the cash flow profit model, there are 2 other profit models used to determine profits. The Financial profit model and the Tax profit model produce financial net income and taxable income respectively. The cash flow (CF) model is preferred for economic analysis of Cameroon's fiscal regime because it produces a net cash flow and accurately places the timing of funds to and from projects.

3.2.1. Royalty Scheme

Royalty is subtracted from the bases of the gross revenue in this project. The royalty payment is tied to the rental surface as such, it is regarded as a regressive extraction scheme. For PSC, only surface rental royalty is included in the model. It is a fixed amount but tied to the exploration or production surface as the case may be.

$$ROY_t = R(\Phi) \times S_t \tag{31}$$

Where,

$R(\Phi)$ = surface royalty ($/km^2)

ROY_t = Royalty

S_t = Exploration or Production surface

3.2.2. Cost Outlay

The Cost Outlay consist of the expenses incurred during the life span of the project. That is the total technical cost of the project. It is composed of 2 elements, Capital Expenditure (CAPEX) and Operating expenditure (OPEX).

$$Total\ Technical\ Cost\ (TC) = CAPEX + OPEX. \tag{32}$$

3.2.3. Depreciation

The depreciation method used for this work is the straight-line depreciation method with a five (5) year life span of the asset. Each asset is depreciated individually for 5 years as shown on the cashflow (appendix A).

3.2.4. Cost Recovery Economics

The cost recovery element in specific to PSC and it's fashioned to succor companies recuperate the costs of exploration, development, and operations. The contractor cannot recover all the cost for a particular year due to the restriction by the cost recovery limit mechanism. In Cameroon, we would assume a cost recovery limit of 60% for the PSC holder. This translates into equation 35 (Iledare, 2020), where the "cost to recover" by the contractor is given by,

$$CR_t = CC_t + CAPEX|I_t + Dep_t + INT_t + INV_t + DECOM_t \tag{33}$$

Where,

CR_t = Cost to recover in year t

CC_t = Cost recovery carried over from year t-1

$CAPEX|I_t$ = Intangible CAPEX in year t

Dep_t = Depreciation of the tangle CAPEX

INT_t = Interest on financing in year t

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

A limit is usually placed on how much revenues will be used to recapture the cost in a given period; hence the name cost recovery limit. 75% of PSC cost recovery limits (CRL) usually range between 40% and 100%, and allow the unlimited carry forward of cost for that year.

Different methods/technics are used for cost recovery calculations with the most common

$$Cost\ Recovery = CR\ Limit * NR\ after\ royalty \quad (34)$$

starting from the cost oil;

Once the allowed cost has been recovered, the excess cost recovery (ECR) still needs to be split between the government and the contractor in a like manner as the cost recovery.

$$ECR_t = CR_t - TC_t - CTR_{t-1} \quad (35)$$

Where,

ECRt = Excess Cost Recovery for year t

TCt = Technical Cost for year t

CTRt-1 = Cost recovery for year t-1

The costs to be recovered can be indefinitely carried forward to subsequent years if unrecovered in any particular year. Cost oil is constrained in value through a functional relation where by the value, may be based on a sliding scale or constant.

The revenues left from cost recovery and royalties have been subtracted is known as the profit oil. The profit oil is split between the government and the contractor at an agreed profit split rate.

$$PO_t = NR_t - CR_t \quad (36)$$

The main aim for the cost recovery treatment is to calculate the contractor' profits before taxes can be applied. This is so because the government does not pay taxes on oil in Cameroon. This leads us to the computation of the contractor's share of ECR and Profit oil as well as the government's.

$$PO_t = PO|C_t + PO|G_t \quad (37)$$

Where,

PO|Ct = PO(Φ)POt

PO|Gt = (1- PO|Ct)

PO(Φ) = Profit oil split, 0 <= PO(Φ) <= 1

The total profit oil (Project total profit after the recovery of all cost and losses carried over, TP) is gotten from the addition of the ECR and the profit oil.

$$Total\ Project\ Profit = (1 - CRL) \times NR + ECR \quad (38)$$

The profit oil split between the contractor and the government varies with either the R-factor or cumulative production. The R-factor is the ratio of the "net cumulative revenue" over the "cumulative investments". Other formula (Iledare, 2020) for calculating the R-factor includes,

$$-RF = GR/TC \quad (39)$$

$$-RF = (GR - ROY)/TC \quad (40)$$

$$-RF = GR/(TC + ROY) \quad (41)$$

$$-RF = (GR - ROY - TAX)/TC \quad (42)$$

The tranches used for the profit oil split is based on cumulative production as indicated in **Error! Reference source not found.**.

Table 6: Cumulative Tranche for PO Split

Cumulative production (MMbbls)	Company	State
<110	40%	60%
110-220	35%	65%
>30	30%	70%

This implies that the profit share for the government and the contractor can be respectively given as

$$TP_G = (ECR_{Project} - ECR_{Contractor}) + (PO_t - \mathrm{PO|Ct}) \quad (43)$$

$$TP_C = (TP - TP_G) \quad (44)$$

3.2.5. Before Tax Cash Flow Model

After obtaining the total profit of the project, the split volumes between the contractor and the government proceeded to come up with BITNCF ("before tax net cash flow"). BITNCF consists of the total profits of the contractor and the government after treating expenses. Its role is to capture the earnings of the government and the contractor (the taxable income of the contactor) before the application of taxes. Only the positive revenue is of the contractor is taxed, that is, taxes are applied only when the contractor starts making profits. BITNCF of the contractor can be gotten from the equation below.

$$BITNCF = GR - TC - (Royalty + Fixed\ entry\ fee + CR|g + ECR|g + Bonus) \quad (45)$$

The losses for succeeding years are carried forward to calculate and deduct the corporate income tax and all related taxes levied by the government.

3.2.6. After Tax Cash Flow Model

The only paid tax is the corporate income tax which range from 33%-50%. The main purpose for this cashflow is to capture the contractors' profits after payment of all taxes. The taxable income is established along with CITA as follows

$$Taxable\ Income\ (TI) = GR - TC - TP_G \quad (46)$$

$$CITA = Tax\ rate \times TI \quad (47)$$

After the application of CITA, the take statistics of both the contractor and the government can be computed following the equations;

$$GTake\ after\ tax = GTake\ before\ tax + Taxes + Bonuses \quad (48)$$

$$CTake\ after\ tax = BITNCF - CITA \quad (49)$$

At this point the net cash flows for both parties have been established and the time value of money principle can be applied to the individual sums using a discount rate of 12%. From here on, all the economic indicators used in the project is calculated.

3.2.7. Economic and System Metrics

These are project-specific quantities that vary with numerous system parameters, unique to the project as well as non-project specific variables (Wahab et al., 2017). Some economic indicators as NPV and are based on the concept of time value of money (Smith, 2007). The results of the economic evaluation process are summarized into various indicators upon which project decisions are made. A combination of these indicators is usually essential to efficiently evaluate a contract's economic performance. For an adequate investment analysis to be settled, it imperative to put forward a realistic cash flow estimate. It is thus easy to calculate the profitability measures, once the right cashflow estimate has been generated. The economic indicators and system measures that will be used in this work include;

1. Net present value (NPV)

The NPV yields an evaluation of the project's net worth to the investor absolute terms. That is, it is the present value of the cash inflows less the present value of cash outflows over time. NPV is used in investment planning to appraise the performance of a project. The present value (PV) is also referred to as the discount rate or minimum acceptable rate of return and is calculated using the weighted average cost of capital of the investor. NPV can be calculated from the formula presented by (Mian, 2011).

$$NPV = \frac{S_1}{(1+i_d)^1} + \frac{S_2}{(1+i_d)^2} + \frac{S_3}{(1+i_d)^3} + \cdots \ldots \ldots \ldots + \frac{S_n}{(1+i_d)^n} - I_o \qquad (50)$$

$$NPV = \sum_{i=1}^{n} \frac{S_t}{(1+i_d)^t} - I_o \qquad (\ldots)$$

$$NPV = \sum_{i=1}^{n} \frac{NCF_t}{(1+i_d)^t} \qquad (51)$$

where,

NCF = Net Cash Flow (GR - LOE - taxes)

S_t = Expected NCF at the end of year t

i = Discount rate

n = The project's economic life in years

I_o = the initial investment outlay at time zero, e.g 1/1/2020

2. Internal rate of return (IRR)

IRR is the discount rate at which the present value of cash inflows is equal to the present value of cash outflows i.e., the discount rate by which the NPV is exactly equal to zero (0). It is also defined as the interest rate received for an investment consisting of payments (negative values) and income (positive values) that occur at regular periods (Mian, 2011). IRR is also referred to as the rate of return (ROR), discounted cash flow rate of return (DCFROR), the investor's method, marginal efficiency of capital and internal yield. IRR is mostly used to rank projects for capital budgeting. IRR can be gotten from the NPV equation below

$$\sum_{i=1}^{n} \frac{NCF_t}{(1+IRR)^t} = 0 \tag{52}$$

Alternatively, IRR can be manually calculated either graphically by plotting NPVs (y-axis) against discount rates (x-axis) or by the trial-and-error method.

3. Present value ratio (PVR)

PVR shows the net PV dollars generated per PV of every capital investment dollar. (i.e., the capital investment is already recovered and the value of the PVR is the net gain over every dollar invested). PVR is given by,

$$PVR = \frac{NPV}{PV\ of\ Capital\ Investment} \tag{53}$$

Independent projects with PVRs greater than zero (0) are acceptable while those with projects less than 0 are not acceptable as being viable.

4. Profitability index (PI)

Profitability index also called investment efficiency ratio normalizes the value of the project revenue relative to the total CAPEX investment. PI is an economic indicator which is used to overcome the limitations of NPV and IRR to reflect the size of the initial investment and the efficiency of an investment. The PI shows the relative profitability of an investment, or the present value of benefits per the present worth of every dollar invested. It is thus a dimensionless ratio derived by dividing the present value of future operating cash flows by the present value of the investment. PI answers the question: How much in present value benefits is created per dollar of investment (Mian, 2011)? If comparing between 2 projects, the higher the PI the more dollars is generated per dollar invested and vice versa. It is mathematically represented by,

$$PI = 1 + \frac{NPV}{PV\ of\ Capital\ Investment} \tag{54}$$

$$PI = 1 + PVR \tag{55}$$

For independent investments, a general rule would be to accept projects with PI greater than 1 for reject projects with PI less than 1.

5. Unit technical cost (UTC)

The unit technical cost is defined as the ratio of the total cost (CAPEX and OPEX) over the economic life of a project to the total expected reserves from the project. It is usually reported in \$/Stb, \$/BOE, \$/MMBtu, \$/MScf, or \$/ton. UTC is also referred to as long-run marginal cost (LRMC) or finding cost. UTC is independent of the price of oil as such gives an estimate of the cost of product development as well as the production.

$$UTC = Unit\ CAPEX + Unit\ OPEX \tag{56}$$

6. Discounted payback period (DPO)

The payback period of a project is the number of years required to recuperate the initial investment. At this exact point, the cash disbursements equal the cash receipts. It reveals how long it would take to start making profits upon original investments. Even though this economic measure is not enough to determine the profitability of the project, it enough to determine whether the project will gain some returns within the economic life of the investment. If the economic life and payback period are equal, then an opportunity loss occurs considering that the capital would have been invested somewhere else to yield some return. DPO typically answers the question: "How long will it take to get my money back after the investment has been made?" DPO is calculated in 2 ways. By cumulating the negative NPV each year until it turns positive: it is therefore the time between the negative and positive NPVs. The equation below is used to calculate DPO

$$DPO = Cum - ve\ NPV\ (years) + \frac{1}{+veNPV - (-veNPV)} \times -(-veNPV) \tag{57}$$

DPO can alternatively be obtained by plotting the cumulative NPV versus time. The payback period is read at the intersection of the time line at zero cumulative net cash flow.

7. Front-end loaded index (FLI)

The front-end loading index (FLI) highlights the spread in the discounted and undiscounted takes. FLI demonstrates the effect of payment timing to government in the calculation of contractor and government takes. High front-end loaded fiscal terms tend to increase the government take on a discounted basis: they are generally less attractive to contractors. A high front-end loaded fiscal regime is due to signature bonuses, discovery bonuses, sales tax, value-added tax, impute duties etc. An ideal case would be such that FLI is zero and implies no front-end loading. FLI is calculated following the equation below

$$FLI = \frac{Discounted\ \ GT}{Undiscounted\ \ GT} - 1 \tag{58}$$

8. Undiscounted take statistics

Take statistics are quantitative economic indicators that are used to measure the overall effect of a particular fiscal system. It is a vital yardstick for the comparative evaluation of the fiscal terms with respect to another. The division of net cash flow (in accord with contract terms and fiscal regime) between the host government and the contractor is called government take (GT) and the contractor take (CT) respectively. They exclusively kingpins on the division of profits between the state and the contractor. The take statistics directly tally's with the field size, thresholds reserve values and other measures of relative economics (Mian, 2011).

A detailed cash flow model is mandatory for the computation of the contractor and government takes. The take statistics can be calculated by,

$$Undiscounted\ Government\ Take = \frac{Government's\ \ NCF}{Government's\ \ NCF + Contractor's\ NCF} \tag{59}$$

$$Undiscounted\ Contractor\ Take = 1 - Government\ Take \tag{60}$$

Where,

$$Government's\ NCF = Bonus + Royalty + PO/G + Tax \tag{61}$$

$$Contractor's\ NCF = GR - TC - GT \tag{62}$$

9. Discounted Take Statistics

Take statistics varies as a function of time, over the life history of a field and is best computed on a discounted cumulative basis to account for the distribution of the cash flow and the distinct manner in which the contractor and government value money (Nwosi-Anele et al., 2018). This method orchestrates from the time value of money concept. The discounted take statistics is calculated in the same way as the undiscounted take statistics except that the NPVs for the contractor and government are used instead of the NCFs.

$$Discounted\ Government\ Take = \frac{Government's\ \ NPV}{Government's\ \ NPV + Contractor's\ NPV} \tag{63}$$

$$Discounted\ Contractor\ Take = \ 1 - Government\ Take \tag{64}$$

3.3. Monte Carlo Simulation Analysis

The oil and gas business is highly capital intensive as such, investors can rely on deterministic values. The uncertainties and risk involved during field development planning cannot be eradicated. To improve success rates, a stochastic analysis of the project was done with the use of @RISK simulator. The simulation analysis will help the IOCS to understand the fiscal regime for the petroleum resources in Cameroon. Risk analysis is particularly done to cover up for the lapses due to uncertainties in estimation capital, reserves and assumed fiscal elements.

@RISK simulator uses Monte Carlo simulation in its risk analysis to define uncertain values. Monte Carlo simulation is a statistics-based analysis tool that yields probability-vs.-value relationships for key parameters, including oil and gas reserves, capital exposure, and various economic yardsticks, such as net present value (NPV) and return on investment (ROI) (Murtha, 1997). Risk analysis is however any form of analysis that examines and attempts to quantify different risks associated with investments.

Empirical solutions of complex probability models can be obtained by applying the ‘Monte Carlo method. A single simulation with ten thousand iterations was run on six (6) basic input variables while analyzing 9 profitability measures. Here, the impact of the input variables on the profitability measures will be evaluated and their sensitivities pointed out. The procedure for this simulation is summarized as follows;

- Define the input variables as summarized in **Error! Reference source not found.**
- Define the Output parameters such as NPV, IRR, PI, Take Statistics and FLI.
- Run the simulation for 1000 iterations.
- Save the results and the sensitivity charts for discussions.

3.4. Data Gathering

3.4.1. Data Processing

In this work the field development plan is limited to an economic evaluation for a well in a new field. Production history is gotten from a close-by field and assuming that both fields have same geological properties and reservoir characteristics, the economic analysis can be easily done.

Data collected on the oil flow rates against the years is recorded in other to determine the initial (qi) and the optimum (qf) flowrates. The Arps (1945) exponential decline equation is rearranged as shown in equation 65

$$\ln(q_t) = -at + \ln(q_i) \tag{65}$$

A graph of time (in years) is plotted on the abscissa against ln(qt) on the ordinate and the initial flowrate extrapolated as the intercept, while the negative slope is decline exponent. Post determination of qi and a1, the peak production is set based on the demand and market price of oil. Production is largely dependent on these forces to avoid a situation where oil is produced and stored over a long period of time, more so the storage facilities maybe unavailable. Apart from qt, other parameters to define include the buildup period, the plateau period and the decline phase. This is also controlled by the quantity of reserves available for production. depending on how fast the reservoir is to be depleted, a rational value of the decline exponent is guessed to be used in further calculations. With the alignment of all the parameters, the production forecast can be done by writing a logical statement on Excel spreadsheet.

$$= IF(AND(B15 >= \$B\$8, B15 < \$D\$8), (\$B\$4 * EXP(-\$B\$6 * (B15 - \$B\$15))), IF(AND(B15 >= \$D\$8, B15 < \$D\$9), \$B\$5, \$B\$5 * EXP(-\$F\$3 * (B15 - \$F\$8)))) \tag{66}$$

Where,

B15 = start of production year

B4 = initial flowrate (qi)

D8 = Start of plateau

B6 = decline exponent for the buildup phase (a1)

D9 = End of plateau

B8 = Start of buildup phase

B5 = Peak production rate

F3 = decline exponent (a2)

F8 = Start of decline phase

From the production forecast, the annual production and the cumulative production can be gotten following equation 4. The economic limit is generally defined as the point where the revenue can no longer cover up the cost of production.

3.4.2. Data Assumptions

1. The production fixed entry fees is converted from frs to dollars at the rate of $1 = 600frs
2. Discount rate of 12% (BOY)
3. The terms of the contracts vary e.g signature and production bonus are negotiated as per contract.
4. The CAPEX values are assumption based on an actual field.
5. CRL of 60%
6. A2 is assumed to be 0.099 for a gradual decline.
7. The brent crude price of 71 $/bbl is used

3.4.3. Production Profile Input Data

The input variables used to generate the production profile are summarized on Table *7*.

Table 7: Parameters for the Production Profile Generation

Input	Value	Unit
STOOIP	12800	Mbbl
Initial Production, qi	1326.1	(bbl/D)
Plateau rate, q2	1688.31	(bbl/D)
Buildup period	5	years
Plateau phase	6	years
Decline phase	9	years
Decline rate	0.099	1/y

3.4.4. Base Case Deterministic Model Data

The input data used for the base case model is given on **Error! Reference source not found.**.

Table 8: Base Case Model Input Data

Capital Allowance	5	year SL cost
Fixed (Flat) entry fees ($)	Exploration ($/km2)	Production ($)
	25	416667
Surface Royalty	Exploration ($/km2)	Production ($/km2)
	2.92	1000
Company Tax (CITA)	33%	
Oil price	67	($/bbl)
OPEX	15%	of Revenue
Cost Recovery Limit	60%	
Discount Rate	12%	
Exploration period	4	years

Production Period	20	years
Exploration surface	300	km2
Production surface	100	km2
Abandonment Cost	120	$M
Signature Bonus	2000	$M
Production Bonus	$M	Mbbls
	1000	25000
	1500	50000
	3000	100000

3.4.5. Monte Carlo Simulation Input Data

Table 9: Monte Carlo Input Variables and the Corresponding Distributions

Input	Distribution	Minimum	Most Likely	Maximum
Exploration and Appraisal ($M)	Triangular	1800	2000	3000
OPEX (%Revenue)	Triangular	0.135	0.15	0.165
CITA	Triangular	0.30	0.33	0.5
Oil Price ($/bbl)	Triangular	63	67	78.1
Initial Production	Normal			

CHAPTER FOUR

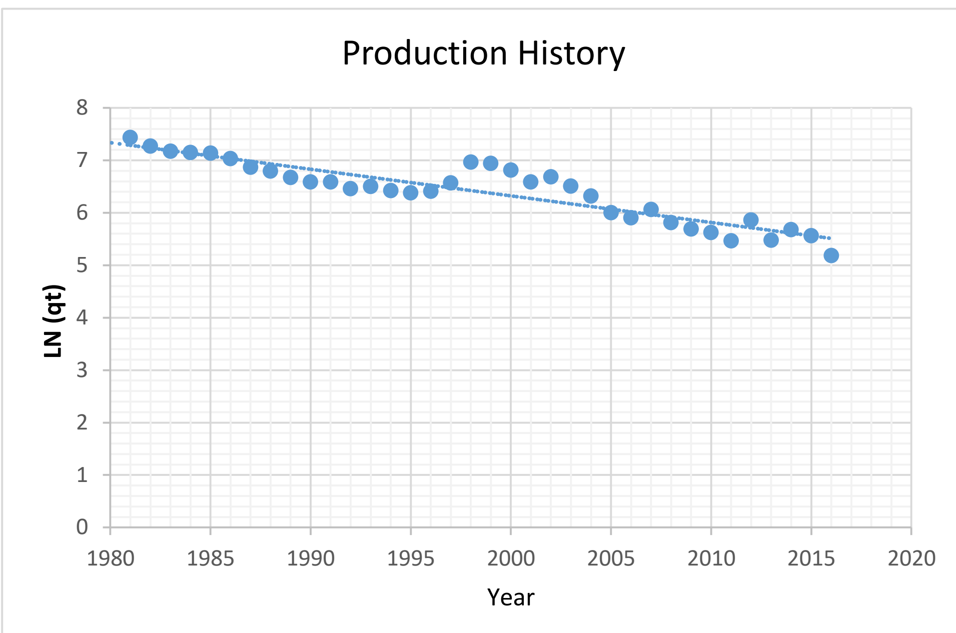
4.0. RESULTS AND DISCUSSIONS

This chapter discusses on the field production forecast, the deterministic and built, following CHAPTER THREE

METHODOLOGY. The performances of both the existing and the proposed fiscal regimes are analyzed from point values and for a range of outputs resulting from simulation runs.

4.1. Production Forecast

Figure *14* is a plot of ln(qt) versus t. The slope is (-0.0508/y) with an interception of qi (1326 bbl/D); These data was obtained from a nearby field. The initial production of the new field is



estimated to be similar to the nearby field, assuming the same conditions of the nearby field.

Figure 14: Production History

The production profile obtained from the field development plan is represented on Figure *14*. The field is a small field with the total reserve (STOIIP) estimated as 12.8MMbbl of oil. The production profile kicks off at a rate of 1326 bbl/d and linearly builds up to a peak (plateau) value of 1688 bbl/d. The build period last for 5years while the plateau period last for 6 years. Production starts declining at the eleventh year, at an exponential decline rate of 0.099 till the economic limit is reached; for a total decline period of 9 years. The reserves in this field are depleted for a total production life of 20 years. In the course of production, the reserves produced (cumulative production) at the end of buildup, plateau and decline are calculated to be 2.602 MMbbl, 3.697 MMbbl and 6.247 MMbbl respectively.

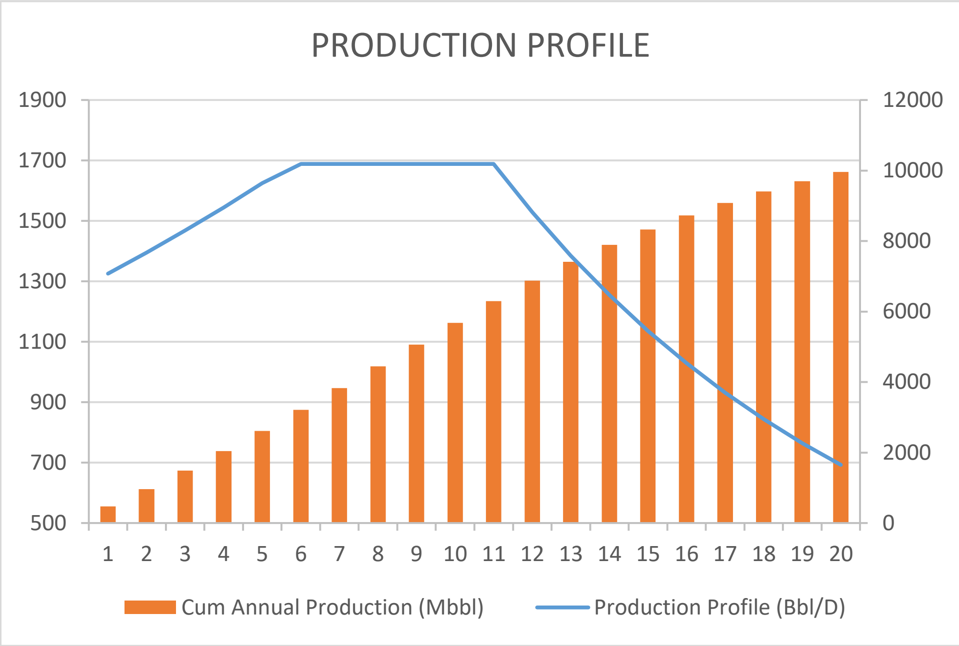


Figure 15: Production Profile

4.2. Cameroon's Fiscal System Decision Analysis Guide

The economic indicators (profitability measures) used to analyze petroleum exploration and exploitation in Cameroon for this study include;

- Net Present Value (NPV)
- Internal Rate of Return (IRR)
- Present Value Ratio (PVR)
- Profitability Index (PI)
- Front-Load Index (FLI)
- Government and Contractor Take Statistics
- Payout Period (PO)

The profitability measures are a basis for which relevant project decisions are made. The above listed profitability measures will thus help to evaluate and compare the existing fiscal system alongside the proposed fiscal regime. This is to aid both the government and IOCs in effective decision making. A decision guide adapted from (Iledare et al., 2018) is used as a basis for which a project is either accepted or rejected.

Table 10: Decision Guide

Profitability Measure	@r*, Accept If	@r*, Reject If
NCF	>0	<0
NPV	>0	<0
IRR	>r*	<r*
PVR	>0	<0
PI	>1	<1
FLI	~0	~1
POP	>= Desired	<= Desired

4.3. Deterministic Model Results

Performance of the Existing Fiscal System.

Table 11 represents the deterministic NPVs for the contractor and the government, IRR, PI, FLI and POP results for a field with reserve size of 12.8 MMbbl.

Table 11: Results of the Profitability Measures for the Existing Fiscal System

Indicators	Contractor	Government
NCF ($MM)	200.0	$379.0
NPV ($MM)	46.9	88.8
PV Capital Investment ($MM)	16.2	
IRR	40.2%	
PVR	2.9	
PI	3.9	
PO	4	
FLI	-0.0005	

Undiscounted Take Statistics	34.5%	65.5%
Discounted Take Statistics	34.6%	65.4%

The cumulative NCFs of both the contractor and the government are greater than 0, implying that the project is economically viable for both parties. This measure is not enough to make a decision on whether or not to pursue the project. Taking into consideration the effects of inflation and the time value of money, it is essential to compute the NPV. The NPV for the contractor is $46.9 MM while the government ends up with $88.8MM. There is a considerable difference between the Host government NPV and that of the contractor though both are greater than 0. When the NPV of an investment at a specific discount rate is positive, it pays for the cost of financing the investment or the cost of the alternative use of funds. It also implies the rate of return on the investment is at least equal to the discount rate. Conversely, a negative NPV indicates the investment is not generating earnings equivalent to those expected from the alternative use of funds, thus causing opportunity loss. IRR is calculated to be 40% which is more than three times the assumed discount rate of 12%. IRR normally measures the interest rate earned from an investment, reflecting the earning power of the investment. The greater it is compared to the discount rate, the better the project. Though NPV and IRR indicate the profitability of the project, they fail to reflect the size of the initial investment.

A PVR or value investment ratio (VIR) that is greater than 0, implies that the net present value dollar generated per present value of every capital spent has been generated and a net gain of 2.9 is obtained over every dollar invested. On the other hand, the profitability index (PI) is an effective measure of capital efficiency. If PI is greater than 1, this emphasizes on the fact that some invested benefits are created per dollar invested. A PI value of 3.9 delineates a profitable project that is capital effective. If a decision between 2 projects is to be made due to limited fund availability, then the project with a greater PI is a better choice. The payout period is the time in which the investor starts making profits upon the initial investment. The breakeven point for this project is 4 years, which implies that the project will gain some considerable returns before the economic life of the investment. Investors tend to invest more in projects with high PI and shorter POPs.

The division of the NPV between the contractor and the government is called the Take statistics. From Table *11*, the undiscounted government take is 65.5% while that of the contractor is

35.5%. Considering the time value of money, the discounted take statistics of the government and the contractor is 76.3% and 23.7% respectively. There is a slight increase in the contractor take and a decrease in the government take after discounting. FLI is 0.049, which is approximately 0; this is very attractive to investors because it stipulates that the variation in the undiscounted government take and discounted is very small or negligible. Also, the investment is not front load ended, that is, the front load ended parameters such as bonuses and fixed entry fees are not exorbitant in value.

Performance of the Proposed PSC Fiscal System.

The royalty system used in Cameroon is tied to the surface area for exploration or production. In order to efficiently evaluate the performance of the proposed fiscal system, and to design a standard fiscal system to be used in Cameroon, the royalty will be tied to production on a sliding scale basis rather than a fixed value. The impact of COVID-19 is visible in the dramatic drop in the oil and gas prices. In an attempt to keep the oil and gas sector booming, this fiscal model suggests a 3-5% reduction in taxes as the case of (Potter et al., 2017) in Louisiana. This will act as an incentive to attract more investors.

Table *12* represents the profitability measures for the proposed PSC fiscal system. It shows the deterministic NPVs for the contractor and the government, IRR, PI, FLI and POP results for a field with reserve size of 12.8 MMbbl.

Table 12: Results of the Profitability Measures for the Proposed Fiscal System

Indicators	**Contractor**	**Government**
NCF ($MM)	205	375
NPV ($MM)	48	87
IRR	41%	
PV Capital Investment ($MM)	16	
PVR	3.0	
PI	4.0	
PO	4	
FLI	-0.007	
Undiscounted Take Statistics	35.4%	64.6%
Discounted Take Statistics	35.8%	64.2%

From **Error! Reference source not found.**, the contractor NPV for the project is $48.7 million while that of the government is $87 million; they are both greater than zero (NPV>0). This implies that the project is profitable. An increase in the contractor NPV is observed from $46 million to $48 million, this is desirable for all contractors. The project viability is measured by a value of IRR greater than the assumed discount rate of 12% (IRR > 12.5%). IRR is calculated at 41% which is higher than that of the existing fiscal system. The proposed system is thus even-handed and the objective of the model achieved. PVR is 3 which is greater than 0 as such, there is reward on the investment. The profitability index (PI) is 4, which greater than 1 implying that value is added to the project and profit is made out of the investment. The field life of project is 20 years but the payout period is estimated at 4 years; This implies that the breakeven point is relatively short since all the expenses are covered up within 4 years.

The outcomes of the undiscounted take statistics for the Government and the Contractor are 35.4% and 64.6% respectively. This is a clear indication that the investment proves profitable for both of them despite the reduction in CITA from 33% to 30%. A non-negligeable 1% increase in the contractor take is seen from 34.5% to 35.4%. To incorporate the time value of money over the life of the field, the Government and Contractor takes are discounted. The Contractor and Government discounted takes are 35.8% and 64.2% respectively. There is a slight increase in the contractor take after discounting which accounts for the effect of front load ending instruments. The increase implies that the project is less front-load ended; this is observed in the value of FLI which is -0.007. FLI is approximately zero and implies the project is not front-load ended which is perfect of the investor.

4.4. Stochastic Model Results

In other to account for any uncertainties intrinsic in the model assumptions, sensitivity analyses are done to further evaluate the performance of the project. Sensitivity analyses are done to predict the degree receptiveness for the output parameters to changes in the input parameters.

The input parameters considered in this research include initial production, Oil price and CITA while the output variables being analyzed include Net Present Value (NPV), Internal Rate of Return (IRR), Profitability Index (PI), Front-Load Index (FLI), Undiscounted Government and

Contractor Take Statistics, and Discounted Government and Contractor take statistics. These analyses are done while comparing the existing fiscal system and the proposed fiscal system.

4.4.1. Stochastic Performance of the Existing Fiscal System

Error! Reference source not found. represents a summary of the stochastic outputs and the possible outcomes based on 10%, 50% and 90 percentiles for the existing fiscal system. P10 implies 90% certainty of occurrence while P50 and P90 represent 50% and 10% certainties respectively.

Table 13: Stochastic Profitability Measures for the Existing Fiscal System

Output	P10	P50	P90
NPV / Contractor (MM$)	36.77	42.42	47.16
NPV / Government (MM$)	83.71	90.20	98.46
IRR	36.2%	38.4%	40.3%
PI	3.26	3.61	3.90
FLI	0.00	0.01	0.01

Table 14: Government and Contractor Take Statistics for the Existing Fiscal System

Take Statistics	P10	P50	P90
Undiscounted Take / Contractor	28.7%	32.5%	34.9%
Discounted Take / Contractor	28.0%	32.1%	34.7%
Undiscounted Take / Government	65.1%	67.5%	71.2%
Discounted Take / Government	65.3%	67.8%	72.0%

From Figure *16* the contractor NPV proves to be positive all through the project no matter the probability. At 90% probability, the contractor will earn not less than $36.77 million net profit resulting from the investment. At 50% and at 10% certainty the contractor gets $42.42 and $47.16 million respectively. This implies that the project is profitable at a discount rate of 12% and this is desired by all contractors. On the other hand, from Table *13* it is stochastically observed that there is a 90% probability that more than or equal to $ 83.71 million of the government NPV will be obtained from the project. There is 50% chance that the NPV will be equal or more than $ 90.2 million and there is 10% chance that the NPV will be more than $98.46 million for the government. The likelihood of obtaining positive NPV throughout this project is thus very high as desired by the contractor and government.

The contractor NPV is most sensitive to CITA because taxes are paid on the profits of the contractor, and least sensitive to CAPEX since it is not variable during the project (see Figure *17*).

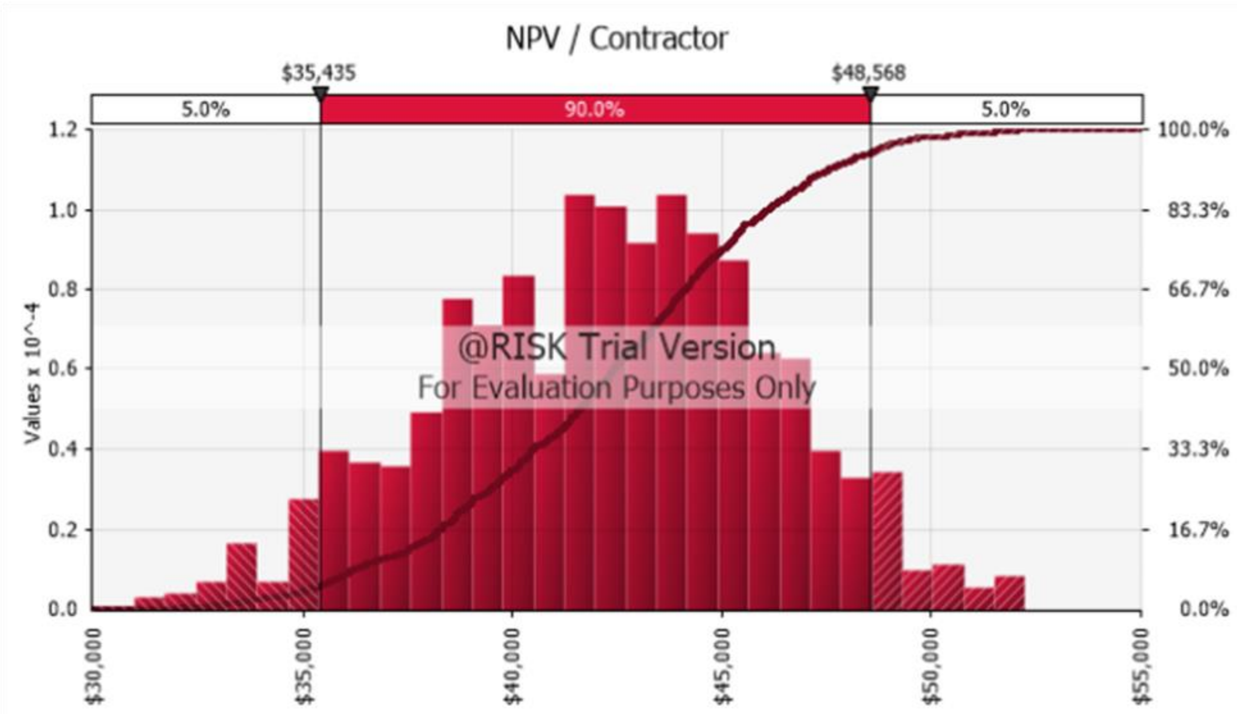


Figure 16: Contractor NPV for the Existing Fiscal System

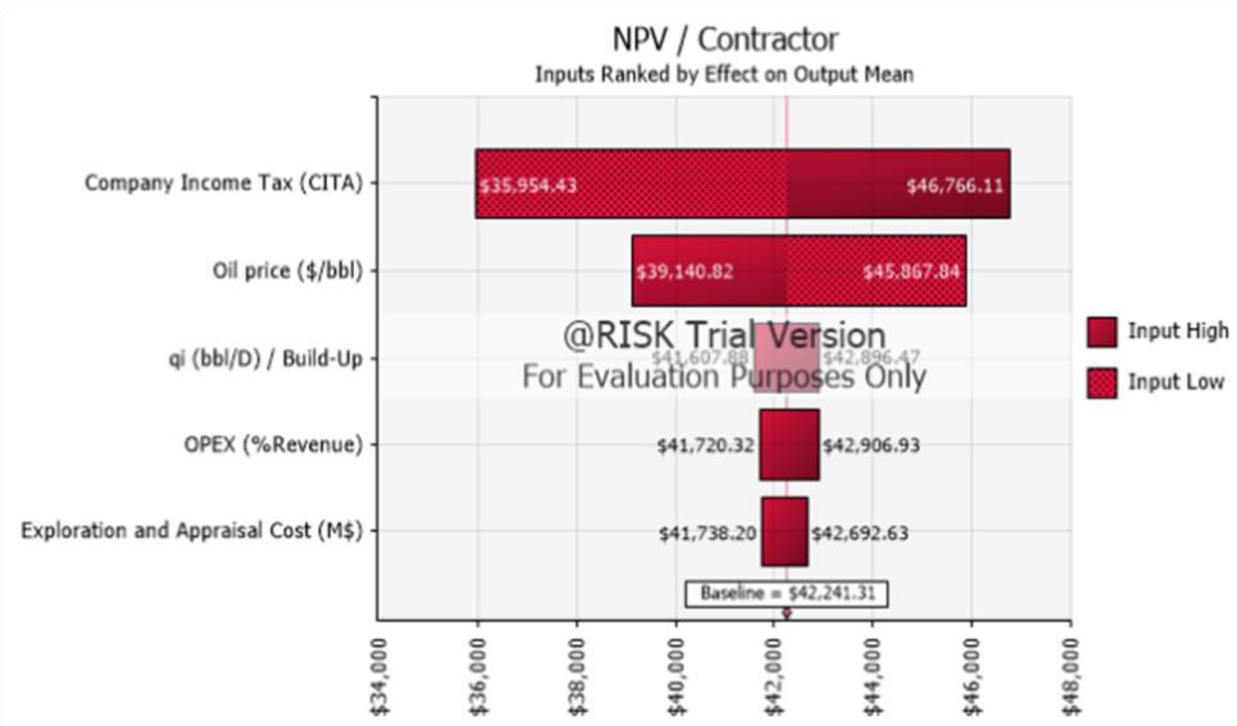


Figure 17: Sensitivity Plot for the Contractor NPV

From Figure *18*, the minimum value of IRR is 33.6% which is still higher than the discount rate of 12% and therefore indicates that profit would be made from the investment. There is a 90% probability that the value of IRR would be equal to or greater 36.2%. On the other hand, there exists a 50% and 10% chance than the value of IRR will be equal or higher than 38.4%and 40.3% respectively.

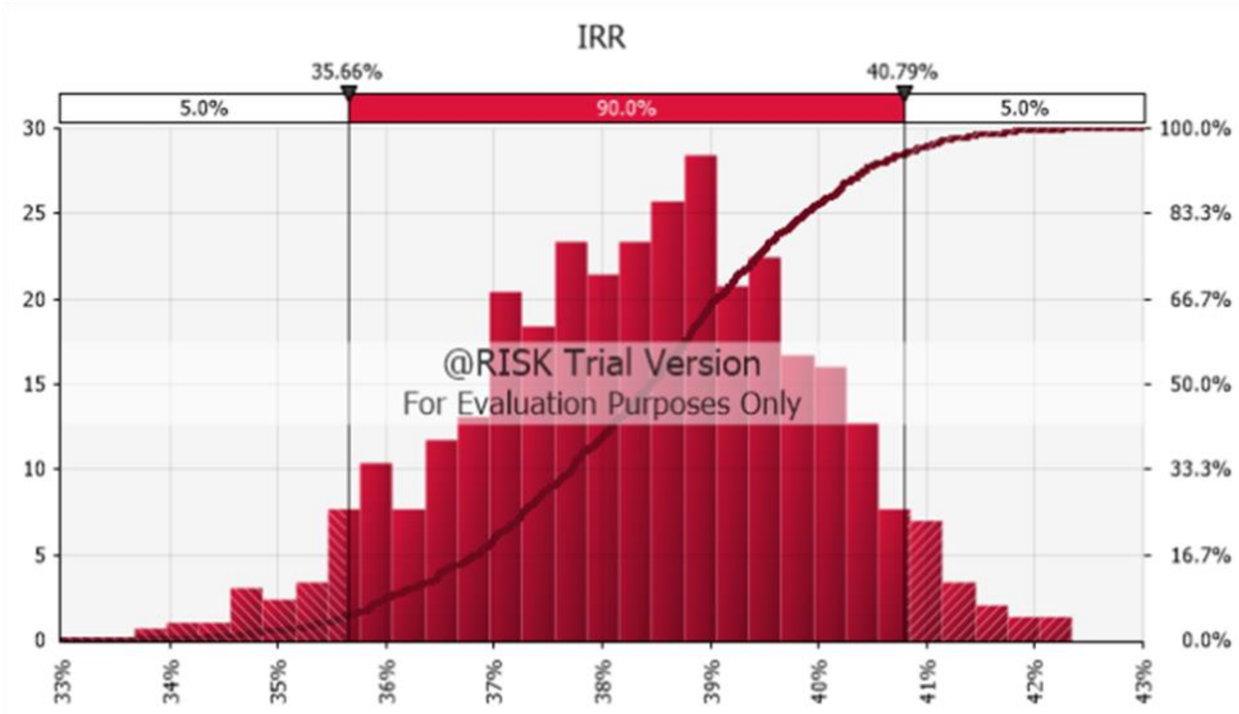


Figure 18: Internal Rate of Return (IRR) for the Existing System

From Table *13*, there is a 90% probability that PI will not be lower than 3.2. At 1% certainty, PI is still greater than 1, implying that the project is profitable provided the conditions prior to signing the contract doesn't change. At 50% and 10% certainty, PI is observed to be equal or more than 3.6 and 3.9 respectively.

High front-ended projects are less desirable by contractors and is not the case here. At 90% likelihood of occurrence, FLI has a value of 0.001 which is by far less than 1. This implicitly means that the project does not heavily increase the government take after discounting which is good for the contractor. The 50% and 10% probabilities suggest that FLI would be equal or more than 0.005 and 0.013, see Table *13*.

Government take represents the share of economic profits that accrue to the government (Iledare et al., 2018), for PSC it consists of royalties, bonuses, fixed entry fees and taxes. A government take of 65% insinuates that for every dollar earned, 0.65 cents is paid to the government and the balance to the contractor. The government take is considerable, ranges from 65.3% to 72% and is tremendously sensitive to CITA. A little rise in CITA will lead to a jump in the government take and vice versa. There is an insignificant increase in the government take after discounting from

65.1% to 65.3%. This increase is captured by the value of FLI and explains why FLI is approximately 0.

IOCs are attracted to investments with low risk and high profits. A reflection of the profits earned by the contractor relative to the total profits is captured by the contractor take. At 90% certainty, the contractor take is 28.7%. At 50% and 10% probabilities, the undiscounted contractor takes are 32.5% and 34.9% respectively. **Error! Reference source not found.** shows the discounted contractor take probability distribution. At 90% certainty, the contractor take will not be less than 28.0% At 50% and 10% certainty of occurrence, the contractor take is 31.6% and 33.7%. Contractor take is most sensitive to CITA and oil price.

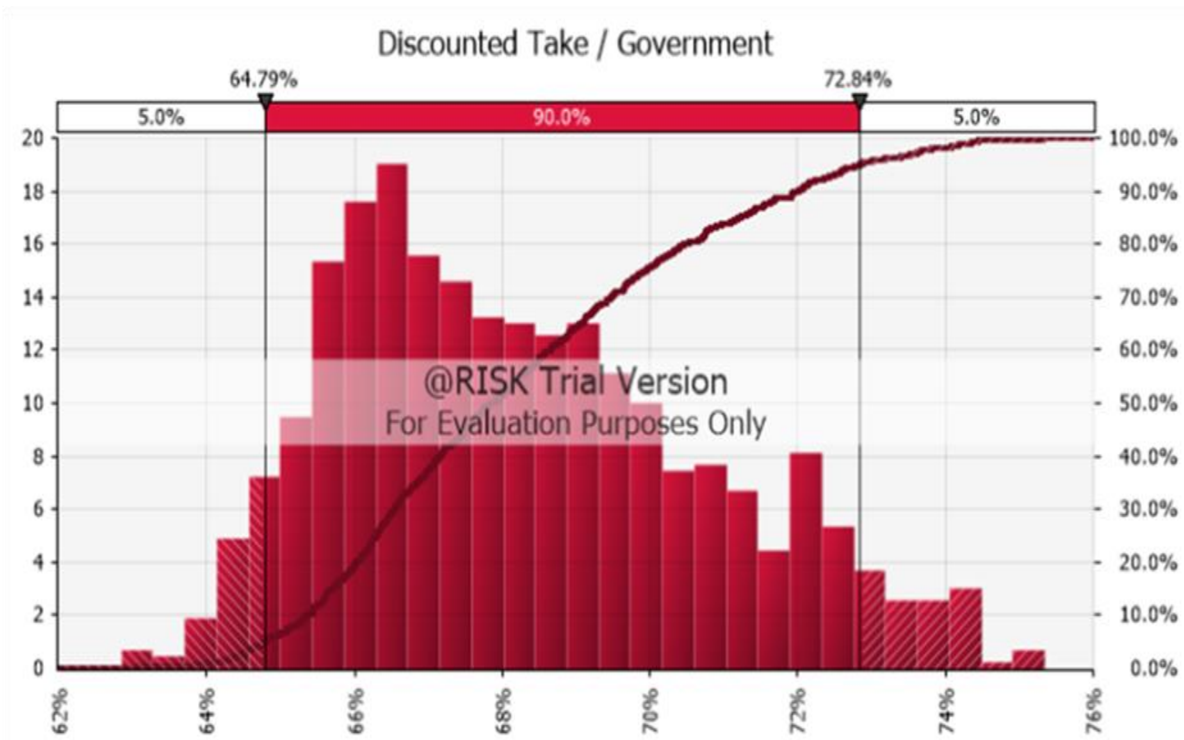


Figure 19: Government Take for the Existing System

4.4.2. Stochastic Performance of the Proposed Fiscal System

Table 15: Stochastic Profitability Measures for the Proposed Fiscal System

Output	P10	P50	P90
NPV / Contractor (MM$)	41.50	47.40	52.53
NPV / Government (MM$)	96.23	103.92	112.47
IRR	39.1%	41.4%	43.4%

PI	3.49	3.87	4.18
FLI	-0.004	0.002	0.007

Table 16: Government and Contractor Take Statistics for the Proposed Fiscal System

Take Statistics	P10	P50	P90
Undiscounted Take / Contractor	28.0%	31.6%	33.7%
Undiscounted Take / Government	66.3%	68.4%	72.0%
Discounted Take / Contractor	27.6%	31.5%	33.8%
Discounted Take / Government	66.1%	68.5%	72.4%

Table *13* gives a summary of the stochastic model results for the profitability measures at P10, P50 and P90. The stochastic model shows the influence of changes in the input variables on the output as well as the probability of occurrence. P10 values indicate a 10% chance that the values obtained will be equal or less than the given parameter. P50 implies that the value will be likely equal or less than the calculated value. P90 indicates 90% likelihood of occurrence of the obtained. The project is profitable and adds value to both the contractor and the government. NPVs for the contactor is computed to be $41.5, $47.4 and $52.5 million at P10, P50 and P90 respectively, see Figure *20*. Overall, the contractor NPV for P10, P50 and P90 are approximately half the government NPVs for all 3 percentiles. IRR is obtained at 39.1%, 41.4% and 43.4% for P10, P50 and P90 respectively; which are all greater than the hedge discount rate of 12%. The profitability indexes, PIs are greater than 1 with values of 3.4, 3.8, 4.1 for P10, 950 and P90 respectively. These values are generally acceptable following the decision guide table. FLI as earlier mentioned is the measure of how front loaded ended a project is. The project is not front load ended as the calculated values are all less than 0.

Sensitivity analysis represented on Figure *21*, Figure *23* and Figure *25* show that the project is most sensitive to CITA and oil price.

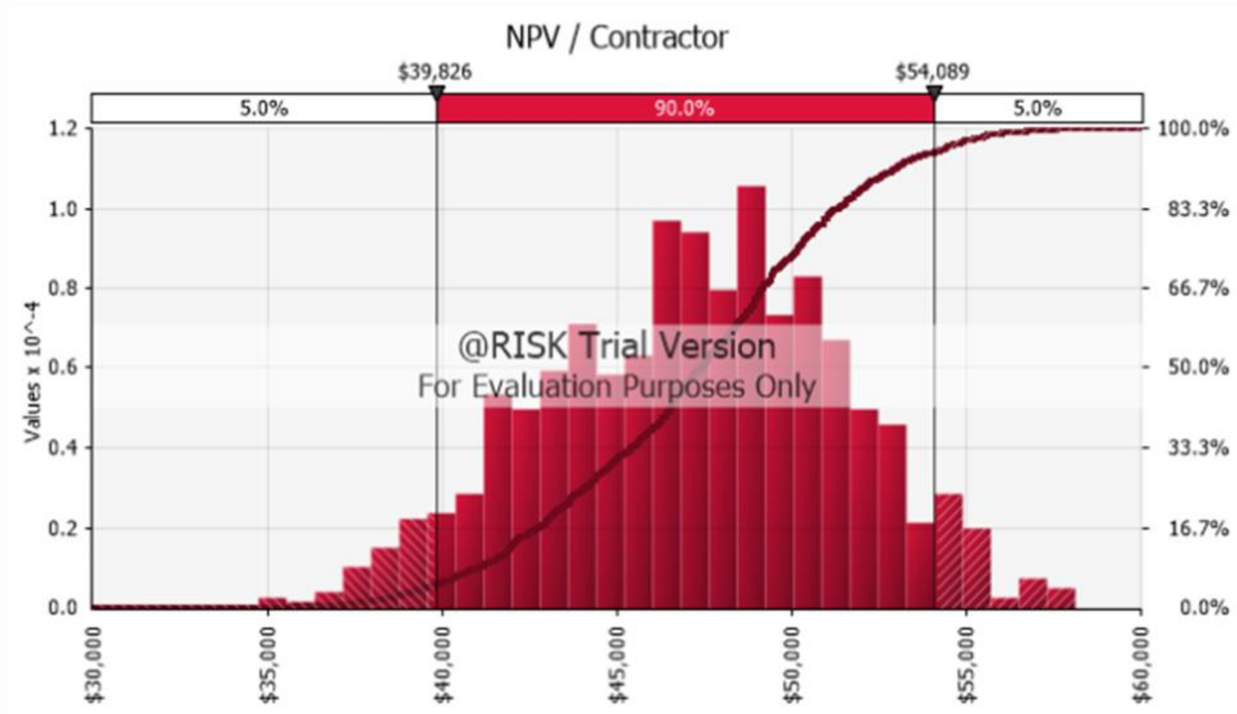


Figure 20: Contractor NPV for the Proposed Fiscal System

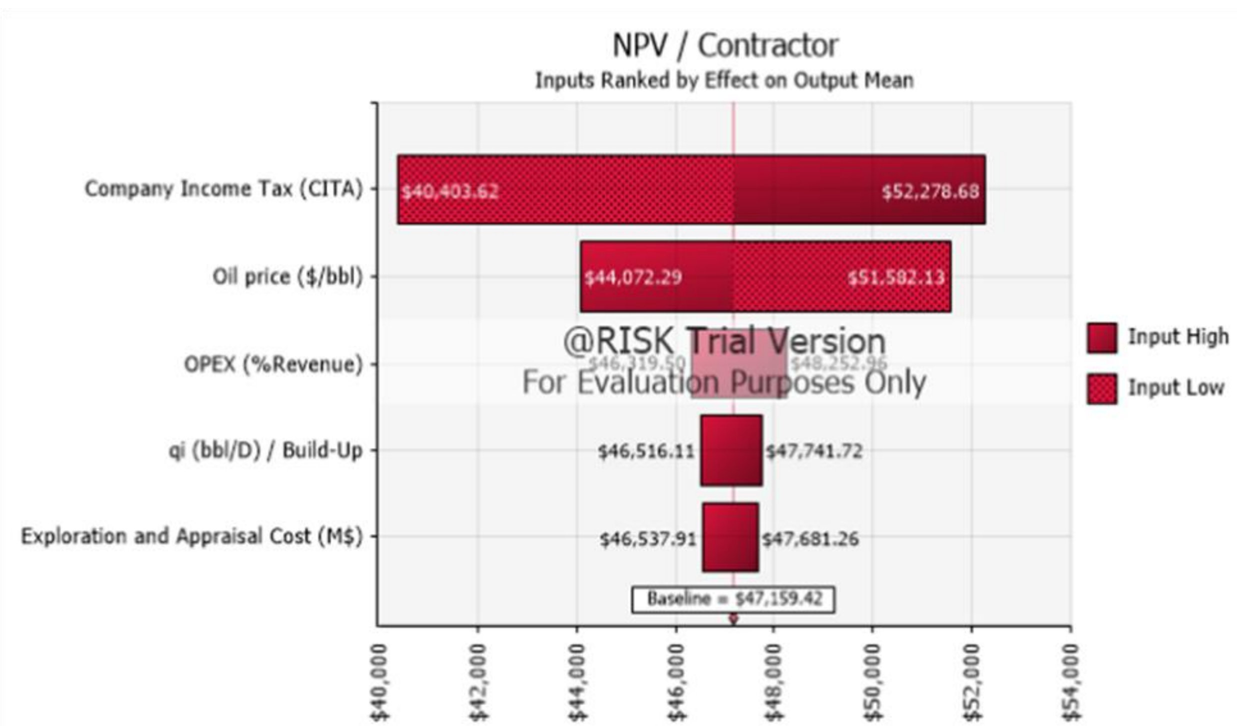


Figure 21: Sensitivity Plot of the Contractor NPV for the Proposed Fiscal System

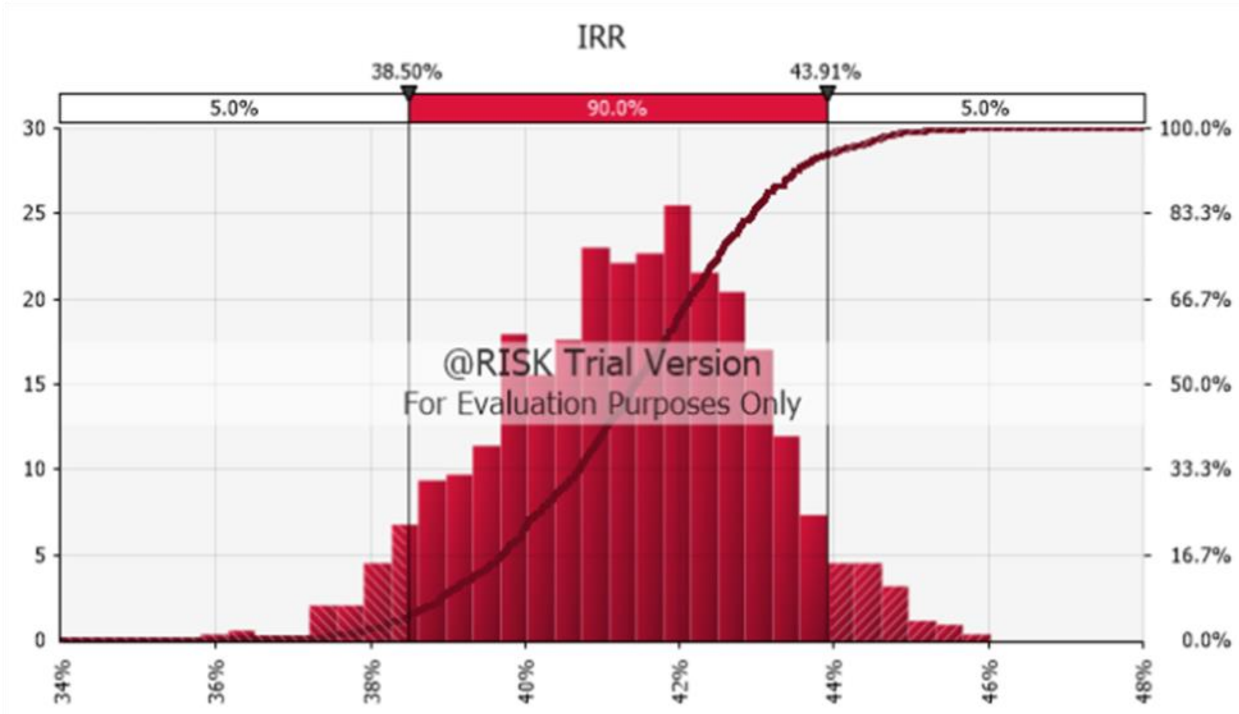


Figure 22: IRR for the Proposed Fiscal System

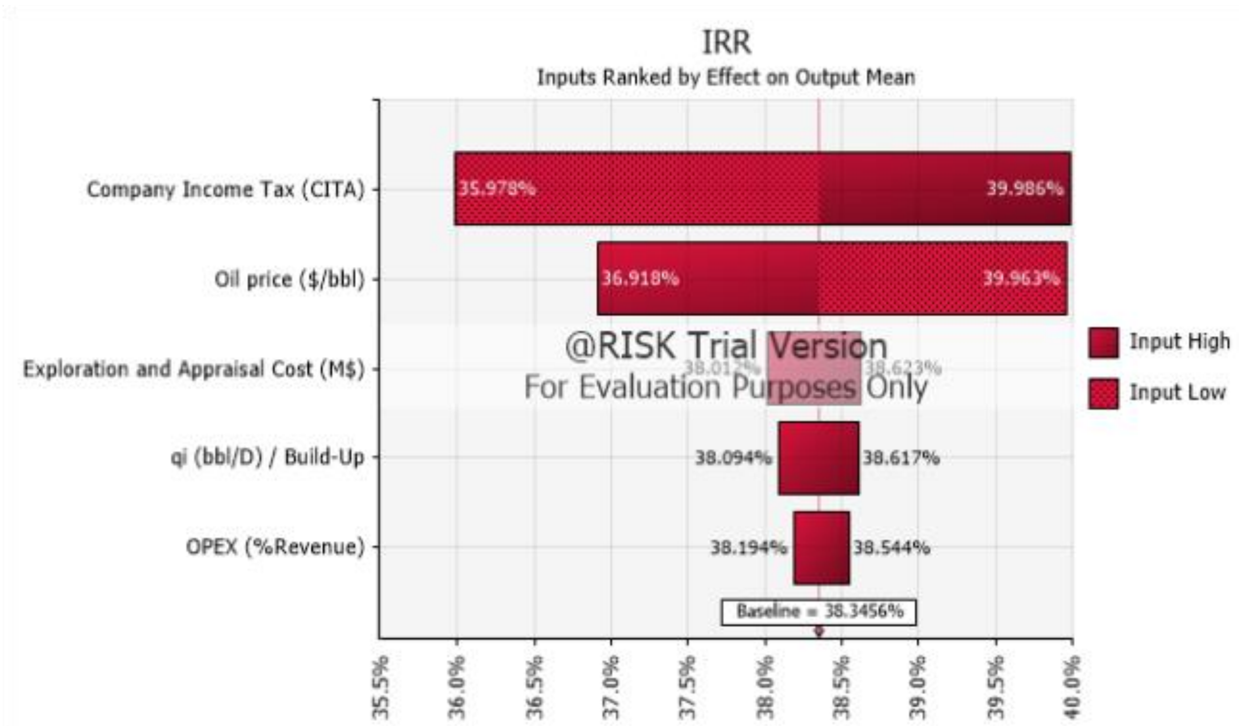


Figure 23: Sensitivity Plot of IRR for the Proposed Fiscal System

Error! Reference source not found. constitute the Take Statistics for both the Contractor and the Government for P10, P50 and P90. The take statistics typify the share of economic profits between the government and the contractor. An example for the undiscounted contractor take of 28.0% for P10 infers that for every dollar earned, 0.28 cents is paid to the contractor and the rest to the government. In other to attract investors, the contractor take should be considerable high; this could be done with the use of incentives. The contractor takes are 28.0%, 31.6% and 33.7% for P10, P50 and P90 respectively. On the other hand, the government takes are 66.3%, 68.4% and 72.0% for P10, P50 and P90 respectively. The slight decrease in the contractor take after discounting explains the negligible FLI values. For the 50% probability, the decrease in the value from 31.6% to 31.5% after discounting results from the front load parameters such as bonuses, fixed entry fee and rentals.

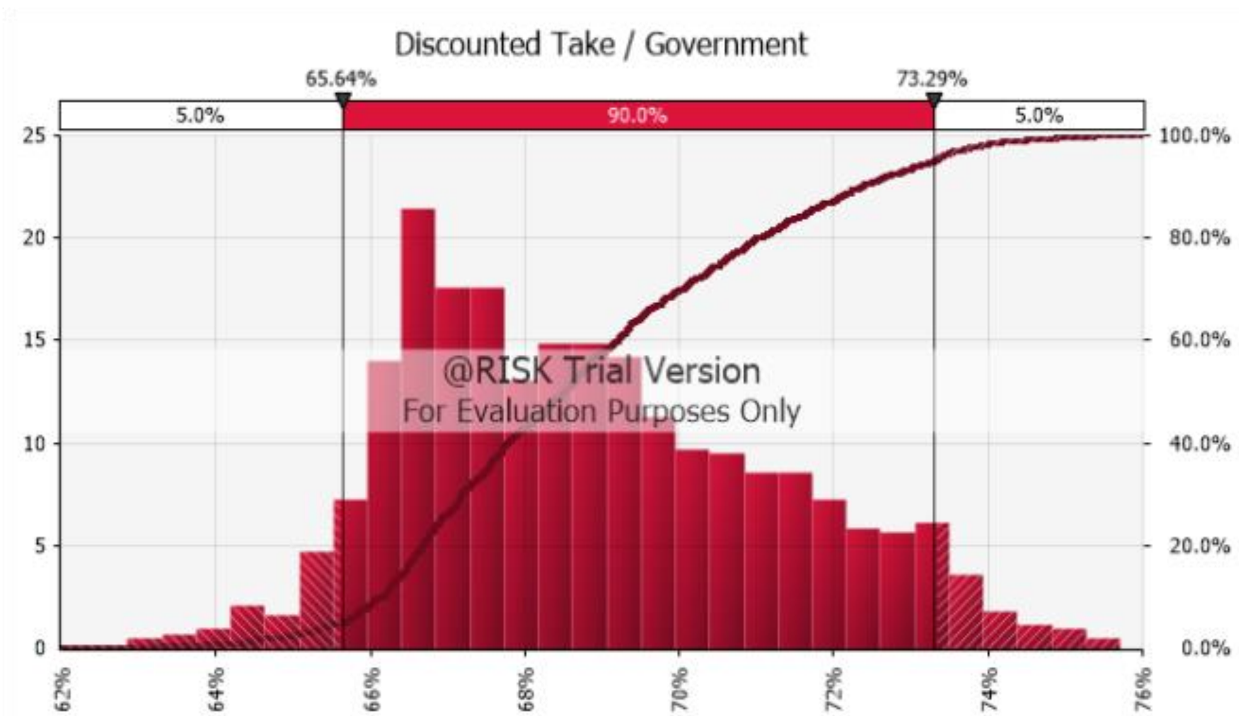


Figure 24: Host Government Take for the Proposed Fiscal System

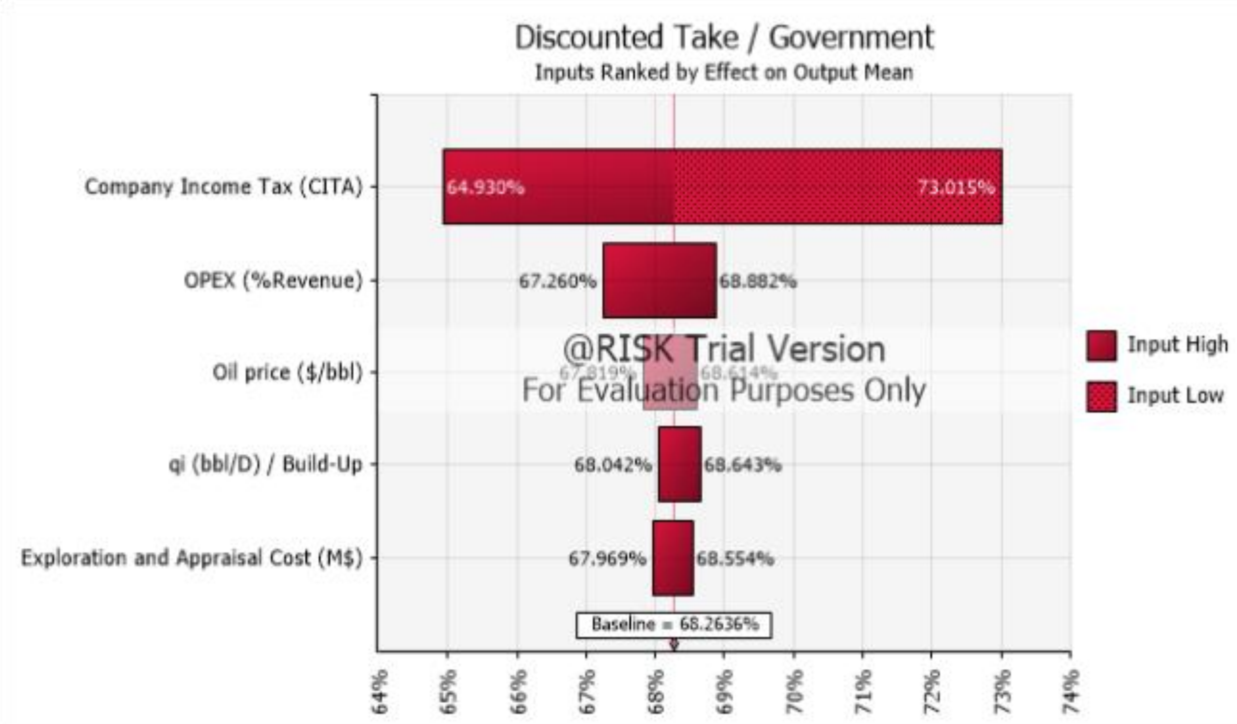


Figure 25: Sensitivity Plot of Government Take for the Proposed Fiscal System

4.4.3. Comparative Performance for the Existing Fiscal Model and the Proposed Fiscal Model

Table 17: Comparative Analysis between the Existing Fiscal System and the Proposed Fiscal System

	Existing Model Results		Proposed Model Results	
Indicators	**Contractor**	**Government**	**Contractor**	**Government**
NCF (MM$)	200.0	379.0	205.6	375.2
NPV (MM$)	46.9	88.8	48.7	87.3
PV Capital Investment (MM$)	16.2		16.2	
IRR	40.2%		40.9%	
PVR	2.8		3.0	
PI	3.8		4.0	
PO	4		4	
FLI	-0.0005		-0.007	
Undiscounted Take Statistics	34.5%	65.5%	35.4%	64.6%

Discounted Take Statistics	34.6%	65.4%	35.8%	64.2%

Table 18: Stochastic Comparison between the Existing Fiscal System and the Proposed Fiscal System

Output	P10		P50		P90	
	E	P	E	P	E	P
NPV / Contractor (MM$)	36.77	41.50	42.42	47.40	47.16	52.53
NPV / Government (MM$)	83.71	96.23	90.20	103.92	98.46	112.47
IRR	36.2%	39.1%	38.4%	41.4%	40.3%	43.4%
PI	3.26	3.49	3.61	3.87	3.90	4.18
FLI	0.001	-0.004	0.005	0.002	0.013	0.007
Undiscounted Take / Contractor	28.7%	28.0%	32.5%	31.6%	34.9%	33.7%
Undiscounted Take / Government	65.1%	66.3%	67.5%	68.4%	71.2%	72.0%
Discounted Take / Contractor	28.0%	27.6%	32.1%	31.5%	34.7%	33.8%
Discounted Take / Government	65.3%	66.1%	67.8%	68.5%	72.0%	72.4%

Table *18* shows a summary of the profitability measures for the existing fiscal model and the proposed fiscal model from a stochastic point view. There is an overall improvement in the profitability measures for the proposed fiscal system. An increase in the contractor NPV is observed with average values of 5 million dollar for 10%, 50% and 90% percentiles. The differences are not exorbitant but these minimal changes are very significant especially for small capacity oil fields wherein the sliding scale royalty method is preferred compared to the fixed royalty system. However, larger capacity production fields might end up exploiting the government if royalties are continuously paid on the surface area rather than being tied to production. All in all, the project is profitable with the use of both the existing and the proposed fiscal models. Slight increases are remarkable in the profitability indexes for all 3 percentiles. FLI values are lower for the proposed model with values of -0.004, 0.002 and 0.007 unlike the existing model with 0.001, 0.005 and 0.013 for P10, P50 and P90 respectively.

CHAPTER FIVE

5.0. CONCLUSION AND RECOMMENDATION

5.1. Summary

This thesis reviewed the current governance, the administration and fiscals in other to proffer solutions to challenges and design an effective fiscal system framework to be used by oil companies in Cameroon. This framework is a basis for decision making by both the government and the IOCs involved in the venture. An economic evaluation of the project helps to reduce the challenges faced at different levels of decision making especially for new investments. This study is therefore critical for Cameroon petroleum resources since it involves capital intensive investments.

The growth of Cameroon could be improved if competition is ignited as different IOCs compete or show more interest in petroleum resources. This is only possible if the fiscal system is attractive, competitive and provides investors with mutually beneficial policies within which petroleum resources can be explored and exploited. The economic model that was built provides a platform for which these resources can be produced. @RISK simulator was used to account for the risk and uncertainties involved in the investment in other to improve on decision making. Through the simulation runs, both risk adverse and risk seeking investors can fit into the project depending on the leverage on which they stand. A risk seeking investor always goes for a more profitable project at even 10% certainty whereas a risk adverse investor will prefer the maximum return with the maximum assurance of success.

5.2. Conclusion

- The Cameroon governance, administration and fiscals were successfully reviewed.
- The field development plan for petroleum exploration and exploitation was triumphantly crafted.
- An efficient fiscal regime has been effectively built as a framework for which petroleum resources can be explored and exploited.

- The NPV for both the government and the contractor are positive which implies that the investment will yield returns. Since the IRR is more than the assumed discount rate, its doubles down on the profitability of the project. More so, the payout period is relatively short.
- The FLI value is far less than 1 which makes the project efficient as desired by the contractor.
- The Profitability index is greater than the threshold of 1 which implies that the investment is value additive and similar projects can be pursued.
- Risk and certainties in investments can be accurately included in models with the successful implementation in this project.
- Via the stochastic analysis, the effect of the input variables can always be analyzed and sensitivity studies viewed upon the output parameters.

5.3. Recommendation

Royalty computations can be tied to annual production rather than to surface area as the case for exploration and production.

This model framework can be modified to suit concession agreements in Cameroon and further studied.

This framework for exploration and exploitation of petroleum products can be implemented by Cameroon government.

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NOMENCLATURE

TOPE	Table of Oil Operation	Qo,	Oil flowrate
SNH	Société Nationale des Hydrocarbures	GR	Gross Revenue
°API	American Petroleum Institute	NR	Net Revenue
GPD	Gross Domestic Product	PO	Profit Oil
CSR	Cooperate and Social Responsibilities	BITNCF	Before Income Tax Net Cashflow
TI	Taxable Income	AITNCF	After Income Tax Net Cashflow
Np	Annual Production	CAPEX	Capital Expenditure
TP	Total Profit	OPEX	Operating Expenditure
E&P	Exploration and Production	NCF	Net Cash Flow
PSC	Production Sharing Contract	CITA	Corporate Income Tax
PPT	Petroleum Profit Tax	CR	Cost Recovery
PFS	Petroleum Fiscal System	ECR	Excess Cost Recovery
NOC	National Oil Company	FLI	Front-end Loading Index
IOC	International Oil Company	NPV	Net Present Value
UTC	Unit Technical Cost	IRR	Internal Rate of Return
GTake, GT	Government Take	PVR	Present Value Ratio
CTake, CT	Contractor Take	PI	Profitability Index
i	Discount Rate	POP	Payout Period
		DPO	Discounted Payout

APPENDIX

PRODUCTION FORECAST			
Year n	Qt forecast (Bbl/D)	Np (MBbl)	Cum Np (MBbl)
0	1260.42		
1	1326.10	471.94	471.94
2	1395.21	496.53	968.47
3	1467.92	522.41	1490.88
4	1544.41	549.63	2040.51
5	1624.90	578.28	2618.79
6	1688.31	593.09	3211.88
7	1688.31	616.23	3828.11
8	1688.31	616.23	4444.34
9	1688.31	616.23	5060.57
10	1688.31	616.23	5676.81
11	1688.31	616.23	6293.04
12	1529.17	586.71	6879.75
13	1385.04	531.41	7411.16
14	1254.49	481.32	7892.48
15	1136.24	435.95	8328.44
16	1029.14	394.86	8723.30
17	932.14	357.64	9080.94
18	844.28	323.93	9404.87
19	764.70	293.40	9698.27
20	692.62	265.74	9964.01

Figure 26: Production Forecast

Date	Qoil (Bbl/D)	Annual Production, Np (MBbl)	Cum Np (MBbl)	Gross Revenue M$	Surface Area Royalty M$	Net Revenue after Royalty M$
1					$ 0.88	$ -
2					$ 0.88	$ -
3					$ 0.88	$ -
4					$ 0.88	$ -
5	1326.10	471.94	471.94	$ 33,507.66	$ 100.00	$ 33,407.66
6	1395.21	496.53	968.47	$ 35,253.83	$ 100.00	$ 35,153.83
7	1467.92	522.41	1490.88	$ 37,090.99	$ 100.00	$ 36,990.99
8	1544.41	549.63	2040.51	$ 39,023.90	$ 100.00	$ 38,923.90
9	1624.90	578.28	2618.79	$ 41,057.53	$ 100.00	$ 40,957.53
10	1688.31	593.09	3211.88	$ 42,109.22	$ 100.00	$ 42,009.22
11	1688.31	616.23	3828.11	$ 43,752.55	$ 100.00	$ 43,652.55
12	1688.31	616.23	4444.34	$ 43,752.55	$ 100.00	$ 43,652.55
13	1688.31	616.23	5060.57	$ 43,752.55	$ 100.00	$ 43,652.55
14	1688.31	616.23	5676.81	$ 43,752.55	$ 100.00	$ 43,652.55
15	1688.31	616.23	6293.04	$ 43,752.55	$ 100.00	$ 43,652.55
16	1529.17	586.71	6879.75	$ 41,656.54	$ 100.00	$ 41,556.54
17	1385.04	531.41	7411.16	$ 37,730.11	$ 100.00	$ 37,630.11
18	1254.49	481.32	7892.48	$ 34,173.77	$ 100.00	$ 34,073.77
19	1136.24	435.95	8328.44	$ 30,952.64	$ 100.00	$ 30,852.64
20	1029.14	394.86	8723.30	$ 28,035.13	$ 100.00	$ 27,935.13
21	932.14	357.64	9080.94	$ 25,392.61	$ 100.00	$ 25,292.61
22	844.28	323.93	9404.87	$ 22,999.17	$ 100.00	$ 22,899.17
23	764.70	293.40	9698.27	$ 20,831.33	$ 100.00	$ 20,731.33
24	692.62	265.74	9964.01	$ 18,867.83	$ 100.00	$ 18,767.83

Figure 27: Royalty Computation

Project Total Oil				Contractor Oil			Government Oil		
Cost Oil $M	Excess Cost Recovery $M	Profit Oil (PO) $M	Total Oil $M	Contractor Share of ECR $M	Contractor Share of PO $M	Total $M	HG Share of ECR $M	HG Share of Profit $M	Total $M
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
$ 9,511	$ 10,533	$ 13,363	$ 33,408	$ 4,213	$ 5,345	$ 9,559	$ 6,320	$ 8,018	$ 14,338
$ 9,773	$ 11,319	$ 14,062	$ 35,154	$ 4,528	$ 5,625	$ 10,152	$ 6,792	$ 8,437	$ 15,228
$ 10,049	$ 12,146	$ 14,796	$ 36,991	$ 4,858	$ 5,919	$ 10,777	$ 7,288	$ 8,878	$ 16,165
$ 10,339	$ 13,016	$ 15,570	$ 38,924	$ 5,206	$ 6,228	$ 11,434	$ 7,809	$ 9,342	$ 17,151
$ 10,644	$ 13,931	$ 16,383	$ 40,958	$ 5,572	$ 6,553	$ 12,126	$ 8,359	$ 9,830	$ 18,188
$ 6,301	$ 18,904	$ 16,804	$ 42,009	$ 7,562	$ 6,721	$ 14,283	$ 11,342	$ 10,082	$ 21,425
$ 6,548	$ 19,644	$ 17,461	$ 43,653	$ 7,857	$ 6,984	$ 14,842	$ 11,786	$ 10,477	$ 22,263
$ 6,548	$ 19,644	$ 17,461	$ 43,653	$ 7,857	$ 6,984	$ 14,842	$ 11,786	$ 10,477	$ 22,263
$ 6,548	$ 19,644	$ 17,461	$ 43,653	$ 7,857	$ 6,984	$ 14,842	$ 11,786	$ 10,477	$ 22,263
$ 6,548	$ 19,644	$ 17,461	$ 43,653	$ 7,857	$ 6,984	$ 14,842	$ 11,786	$ 10,477	$ 22,263
$ 6,548	$ 19,644	$ 17,461	$ 43,653	$ 7,857	$ 6,984	$ 14,842	$ 11,786	$ 10,477	$ 22,263
$ 6,233	$ 18,700	$ 16,623	$ 41,557	$ 7,480	$ 6,649	$ 14,129	$ 11,220	$ 9,974	$ 21,194
$ 5,645	$ 16,934	$ 15,052	$ 37,630	$ 6,773	$ 6,021	$ 12,794	$ 10,160	$ 9,031	$ 19,191
$ 5,111	$ 15,333	$ 13,630	$ 34,074	$ 6,133	$ 5,452	$ 11,585	$ 9,200	$ 8,178	$ 17,378
$ 4,628	$ 13,884	$ 12,341	$ 30,853	$ 5,553	$ 4,936	$ 10,490	$ 8,330	$ 7,405	$ 15,735
$ 4,190	$ 12,571	$ 11,174	$ 27,935	$ 5,028	$ 4,470	$ 9,498	$ 7,542	$ 6,704	$ 14,247
$ 3,794	$ 11,382	$ 10,117	$ 25,293	$ 4,553	$ 4,047	$ 8,599	$ 6,829	$ 6,070	$ 12,899
$ 3,435	$ 10,305	$ 9,160	$ 22,899	$ 4,122	$ 3,664	$ 7,786	$ 6,183	$ 5,496	$ 11,679
$ 3,110	$ 9,329	$ 8,293	$ 20,731	$ 3,732	$ 3,317	$ 7,049	$ 5,597	$ 4,976	$ 10,573
$ 2,815	$ 8,446	$ 7,507	$ 18,768	$ 3,378	$ 3,003	$ 6,381	$ 5,067	$ 4,504	$ 9,572

Figure 28: Oil Split

Year	BITNCF		AIT Net Cashflow		Net Present Value	
n	Contractor's BIT M$	Host Government M$	Contractor Take M$	Host Gov Take M$	Contractor Take M$	Host Gov Take M$
1	$ (4,008)	$ 2,008	$ (4,008)	$ 2,008	$ (4,008)	$ 2,008
2	$ (5,001)	$ 1	$ (5,001)	$ 1	$ (4,465)	$ 1
3	$ (8,501)	$ 1	$ (8,501)	$ 1	$ (6,777)	$ 1
4	$ (7,001)	$ 1	$ (7,001)	$ 1	$ (4,983)	$ 1
5	$ 13,642	$ 14,855	$ 13,642	$ 14,855	$ 8,670	$ 9,440
6	$ 14,652	$ 15,328	$ 13,404	$ 16,577	$ 7,606	$ 9,406
7	$ 15,277	$ 16,265	$ 10,236	$ 21,307	$ 5,186	$ 10,795
8	$ 15,934	$ 17,251	$ 10,676	$ 22,509	$ 4,829	$ 10,182
9	$ 16,626	$ 18,288	$ 11,139	$ 23,775	$ 4,499	$ 9,602
10	$ 14,283	$ 21,525	$ 9,570	$ 26,238	$ 3,451	$ 9,462
11	$ 14,842	$ 22,363	$ 9,944	$ 27,261	$ 3,202	$ 8,777
12	$ 14,842	$ 22,363	$ 9,944	$ 27,261	$ 2,859	$ 7,837
13	$ 14,842	$ 22,363	$ 9,944	$ 27,261	$ 2,552	$ 6,997
14	$ 14,842	$ 22,363	$ 9,944	$ 27,261	$ 2,279	$ 6,247
15	$ 14,842	$ 22,363	$ 9,944	$ 27,261	$ 2,035	$ 5,578
16	$ 14,129	$ 21,294	$ 9,467	$ 25,956	$ 1,730	$ 4,742
17	$ 12,794	$ 19,291	$ 8,572	$ 23,513	$ 1,398	$ 3,836
18	$ 11,585	$ 17,478	$ 7,762	$ 21,301	$ 1,130	$ 3,102
19	$ 10,490	$ 15,835	$ 7,028	$ 19,297	$ 914	$ 2,509
20	$ 9,498	$ 14,347	$ 6,364	$ 17,481	$ 739	$ 2,030
21	$ 8,599	$ 12,999	$ 5,762	$ 15,837	$ 597	$ 1,642
22	$ 7,786	$ 11,779	$ 5,216	$ 14,348	$ 483	$ 1,328
23	$ 7,049	$ 10,673	$ 4,723	$ 12,999	$ 390	$ 1,074
24	$ 6,261	$ 9,672	$ 4,195	$ 11,738	$ 310	$ 866

Figure 29: Cashflow Summary