IMPLICATIONS OF PRODUCTION DECLINE PATTERNS, COST DEPRECIATION METHODS AND FISCAL REGIMES ON OFFSHORE PROFITABILITY IN NIGERIA

A Thesis

PRESENTED TO THE DEPARTMENT OF PETROLEUM ENGINEERING,

AFRICAN UNIVERSITY OF SCIENCE AND TECHNOLOGY

In partial fulfilment of the requirements for the award of the degree of

MASTER OF SCIENCE

By

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ABUJA. FCT.

DECEMBER, 2011

IMPLICATIONS OF PRODUCTION DECLINE PATTERNS, COST DEPRECIATION METHODS AND FISCAL REGIMES ON OFFSHORE PROFITABILITY IN NIGERIA

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ABSTRACT

Upstream petroleum industry remains one of the most prolific industries in terms of technology and risk capital transfer. Consequently, governments all over the world try to formulate political as well as economic structures that could favourably attract investments to their petroleum provinces. These structures are spelt out in their petroleum fiscal systems. A good fiscal system tends to find a common ground for both government and the contractor by way of optimizing both efforts and benefits. Nigeria belongs to a region where hydrocarbon discovery risks are low compared to the world average. Therefore, the government designs fiscal regime that would seemingly extract more economic rent than normal from her petroleum resources. This research effort examined how to evaluate E & P business and determine the profitability of upstream business venture under the proposed petroleum industry bill (PIB).

The methodology adopted a typical Niger-Delta offshore field with vast proved reserves, and applied the three Arps (exponential, hyperbolic and harmonic) decline equations during production. Based on each decline method, automated spreadsheet cash flow models were developed for 2005 PSC and the proposed PIB 2009 fiscal systems. The cash flow had pre-production and operating costs expensed while depreciating the development costs by applying different depreciation methods.

The results showed that deepwater investment in Nigeria is profitable under both fiscal systems, given that the field production declines exponentially, irrespective of the depreciation method applied. It was also observed that contractor profit got maximized when Unit of Production (UOP) depreciation method was applied in the proposed PIB 2009 cash flow model while straight line depreciation (SLD) gave better profit measures for 2005 PSC, given that the terms of the fiscal systems remained constant. It was also confirmed that the proposed bill would give government greater share of the gross revenue.

As an incentive in the proposed PIB, it is recommended that the contractor be allowed to spread costs over time by applying unit of production depreciation method for cost recovery and tax calculation purposes.

DEDICATION

In loving memory of my family head

"LATE MAZI GOODLUCK ONYEMAECHI ONWUKA".

Who departed in the course of my stay in AUST.

May his gentle soul rest in perfect peace. Amen.

ACKNOWLEDGEMENT

My gratitude goes to God Almighty, the Rock upon which I stood all through in AUST. I also want to appreciate the immense contributions of the following individuals, friends and organizations:

- Petroleum Technology Development Fund (PTDF), for my sponsorship in AUST and for conditioning me into loving Petroleum Engineering.
- My able supervisor, Professor Omowumi Iledare, who in spite of his busy itinerary granted me maximum audience and guidance.
- My committee members; Professor David Ogbe and Dr. Alpheus Igbokoyi
- My family; for granting me full support. I am so proud because of you
- HNDJOE for providing a leaning shoulder when the work seemed rough.
- All my colleagues in Petroleum Engineering stream in particular and AUST community at large.
- Redeemed Christian Church of God, House of Praise, Abuja for solid spiritual partnership.

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CHAPTER ONE

INTRODUCTION

1.0 PREAMBLE

The petroleum industry is one of the most prolific global industries in terms of movement of technology and capital. Exploitation of resources requires application of new technology, adequate risk-capital and extensive experience with oil and gas upstream operations; and for these reasons the governments invite multinational corporations to participate in upstream oil and gas operations (Vikas et al, 1997). However, the response given to this call by the multinational corporations is a function of many risk factors which may range from political to economic tendencies that prevail in the petroleum geographical domain. For this reason, governments all over the world try to formulate political as well as economic structures that are in the least investor-friendly, such that they could attract development and technology to their domains using petroleum resources as a vehicle. This structure is generally referred to as the fiscal system.

Petroleum fiscal system (PFS) is the basket that carries "the legislative, tax, contractual and fiscal elements underlying exploration and production operations in a petroleum province, region or country" (Iledare, 2004). It is the intention of the host government to formulate PFS that is attractive to investors while at the same time promoting economic and technological development in her petroleum province. For example, Brazil discovered large oil reserves in the pre-salt areas of Santos Basin, the government proposed to change the fiscal system from R/T to PSC, reason being that exploration risk in this basin is very low. Evidently, government wants larger share of

Production (Lima et al, 2010). This shows how flexible fiscal systems could be in undergoing transformations. The trend of flexibility is centred on exploration and development risks. It is generally known that Nigeria belongs to a region where risks of hydrocarbon discovery are low compared to world average (Economides et al, 2003). Just like Brazil, Nigeria in August 2008 started a process of changing the terms of her fiscal system. This proposed fiscal system, popularly called the Petroleum Industry Bill (PIB) is the work of the Oil and Gas Implementation Committee (OGIC) sent to the National Assembly for passage into an Act. Since 2008, the PIB has assumed different versions because of conflicting interests that surround the various terms and conditions in the bill. This conflict of interests has attracted many researchers in petroleum economics to find a means of optimizing this bill that would subsequently be passed safely into an Act governing the petroleum industry in Nigeria.

The bill appears to be interested mainly in the economics of the petroleum industry without much recourse to the technicalities of how the hydrocarbon is extracted and how this can affect profitability. For example, It is true that based on natural phenomena, production may decline in different ways (Arps, 1945). These may be exponential, hyperbolic or harmonic. The implication is that time of production is either shortened or extended beyond expectations. This constitutes a major uncertainty in the formulation of the bills that are time-conscious. By assumption, many researchers including Lima et al (2010), Vikas et al (1997), Iledare (2010) and Oyekunle (2011) have built cash flow models based on production forecasts predicated on exponential decline which is widely accepted as being very conservative and very easy to compute. However, the time of effective production may seem to be very short. The oil mining license (OML) on the average could last for 20 years, after which it could be renewed. In the real sense, there are wells known to be

producing far beyond the forecasted economic time limit. Applying other decline methods like hyperbolic and harmonic in forecasting production would help in reducing the uncertainty surrounding total time of production which in turn has its own effects on both government and contractor takes per time.

If the production duration is shortened or elongated, there is cost implication on continued operation. Depending on how these costs are treated, profitability may or may not be maximized. Since the bill seeking to redirect the affairs of the oil and gas business has been put forward, it becomes expedient to make available different ways in which government can make the proposed fiscal system attractive to both new and existing investors. Different researchers have looked into this. Muscolino et al (1993) studied the effect of cost recovery ceiling on contractor profitability. He noted that sharing the excess cost oil as profit oil between the host government and the contractor neutralizes any economic effect as cost recovery limit is varied. Using meta-modelling approach, Adenikinju et al (2009), investigated the impact of tax rate, royalty rates, discount rates and profit oil sharing on the economic measures of the contractor. Since there has not been any conscious effort to investigate the impact of other production and economic factors such as decline methods and cost treatment on contractor profitability, it becomes expedient that such should be done to give more insight into effective and efficient economic decision making.

1.1 PROBLEM STATEMENT

Each investment environment has its own fiscal system which could range from being simple and rewarding to being harsh and repugnant to investor's profitability. This therefore, calls for the need to investigate the entire E&P business sphere to determine the profitability of the contractors in each prevailing fiscal system with Nigeria's PSC as case study.

This has attracted the interest of so many researchers who have succeeded in putting together different cash flow scenarios to determine both the government and contractor takes.

In most works, it has been observed that in building the production profile of the venture, only exponential production decline rate method was adopted. The reasons given for this include computational simplicity and the conservative production profile associated with the decline rate. It is not always true that exponential decline rate is representative of all the reservoirs encountered in real life, as hinted earlier. This assumption could have implications on the final cash flow of both the contractor and the host government. Therefore, it is the intention of this work to build production forecast profile considering all the production decline methods available.

When it comes to the fiscal systems, cost recovery pattern has been observed to be a key feature as each location defines how it must be done. Interest is taken in the depreciation method applied in most works carried out before now. However, in the Proposed PIB 2009, the contract shall determine the treatment of recoverable costs, including whether costs shall be expensed or depreciated, the method of depreciation and the treatment of pre-production costs (Section 400(4), redraft PIB 2009). It has been observed that straight line depreciation method has enjoyed most patronage for diverse reasons. This work intends to include in its model, not just the straight line depreciation method but also other methods of depreciation and to observe the implications on profitability.

Finally, the above observations would be used to build complete cash flow models based on current PSC and PIB 2009. This would open doors for unbiased comparisons to be made and effective investment decisions taken in order to optimize efforts and benefits.

1.2 SCOPE OF INVESTIGATION

This research study shall limit itself within the following.

The Nigerian fiscal system: The Nigerian fiscal system has evolved over the years. Both the concessionary and the contractual systems are operational. However, this study shall focus generally on the contractual fiscal system and more specifically the production sharing contract of 2005 (PSC 2005) and the proposed PIB 2009.

Shallow and deep water operations: Offshore field exploration and development is currently on the rise all over the world. This could be associated with very huge reserves discoveries recorded in recent years from the golden triangle. Nigeria holds huge reserves potential in shallow and deep water E & P operations. Recent trend suggests that major IOCs are shifting operations gradually offshore Nigeria due to the Niger-Delta unrest which affects their operations onshore.

Crude oil economics: The Nigerian economy is a developing one which relies mainly on crude oil economics for sustenance. Due to poor gas gathering facilities and utilization, economics of pure gas production remains unfavourable to the investors in Nigeria. This study would be limited within the economics of crude oil.

Niger-Delta data: The input parameters would be representative of the offshore Niger-Delta basin. A typical reserve in this basin may go into several million barrels of oil with high recovery factors. The production profiles and cost analysis representative of this basin shall be used in this study.

Spreadsheet model: An automated spreadsheet-based cash flow model would be developed as a tool for analysis. It is easier to present the production profile and subsequent cash flow in Excel format than any other format such as MATLAB, JAVA or C++.

Sensitivity analysis: Both the deterministic and probabilistic approaches shall be employed. The deterministic variations shall be done manually in the developed spreadsheet model while the

probabilistic variations shall be by the use of @RISK, an MS Excel add-in function capable of multiple simulations.

1.3 MOTIVATION FOR THE STUDY

Huge oil reserves: Nigeria has an estimated proved oil reserves that rose from 16 thousand million barrels in 1988 to 37.2 thousand million barrels as at end of 2010 (BP world energy statistics, 2011). DPR reported an increasing trend in terms of reserves addition as alluded in Fig 1.1. Currently, attention is shifting towards deep and ultra deep waters of the Niger Delta basin which has estimated potential reserves of 70 Billion BOE. Consequently, many blocks are available to interested investors through competitive bidding exercise (DPR, 2003).

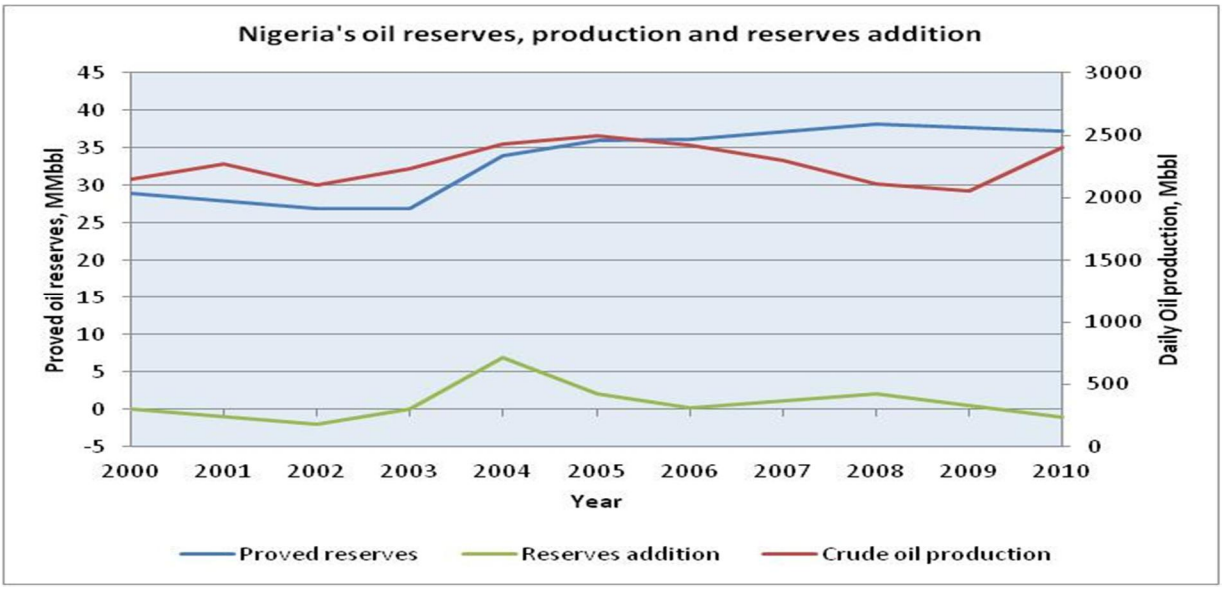


Fig 1.1 – Crude oil reserves and production trend (data sources: BP statistics, 2011 and indexmundi.com)

Contribution to fiscal system formulation: Optimization of efforts and benefits is the hallmark of a well formulated fiscal system. Nigeria is at the brink of changing the rules guiding oil and gas business in her territory. A bill seeking to review the fiscal system in the Nigerian Petroleum sector is currently before the National Assembly for passage into an Act. A key benefit for an oil-producing

country is the government revenue that is generated. It is therefore critical that the fiscal regime be designed to secure the government maximum revenue, while providing investors with sufficient incentives to undertake exploration and development. For this reason, Lima et al (2010) reported that Brazil was changing her fiscal regime from concessionary (R/T) to Production sharing contract PSC). This change was intended to give the government more access to the gross revenue as well as creating flexible conditions that would allow for quick payback period for the contractor. The major contents of the PSC include royalties, crypto taxes, cost recovery ceiling, profit sharing and the income taxes. Treatment of these terms could either make a fiscal system flexible or unattractive to the investors.

Deepwater investment: The global trend has it that deepwater ventures are on the increase compared to onshore ventures as shown in fig 1.2. That cannot be said to be true for Nigeria though her potential is very great. A recent report from Wood Mackenzie links the decline in offshore

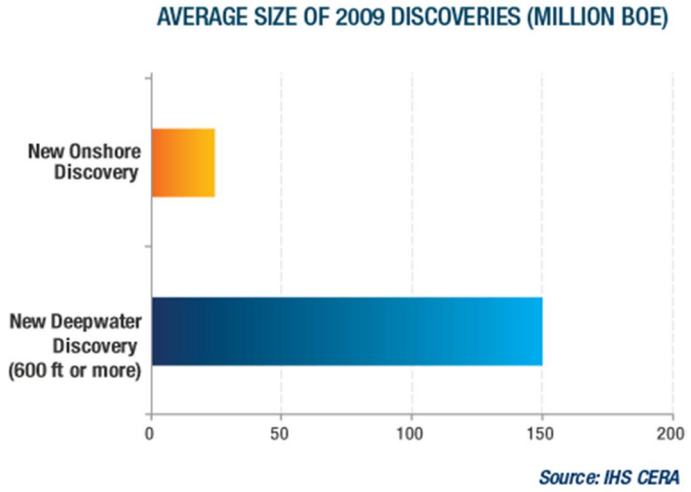


Fig 1.2 – 2009 Global discoveries.

discoveries to the fact that the majors who have driven deepwater activity and growth in Nigeria showed little interest in the last three exploration bidding rounds which placed many deep offshore blocks on offer. National Petroleum Investment Management Services (NAPIMS) sources estimate

the loss of investments in the sector over the last two years at US$24 billion. By far the biggest impediment in the way of further growth of the Nigerian deepwater sector is the opposition of the IOCs to the Petroleum Industry Bill, PIB, which is the vehicle with which government wants to drive a comprehensive reform of the industry (http://www.nigerianoilgas.com/?p=335). To reverse this trend, every meaningful contribution is needed towards the optimization of the PIB to a level acceptable to both the government and the IOCs.

CHAPTER TWO

LITERATURE REVIEW

2.0 INTRODUCTION

Crude oil can aptly be described as the engine that drives the development of most economies in the world. It is the most significant and highly traded primary commodity in the international market (Iledare and Pulsipher, 1999). This commodity happens to be the mainstay of many developing economies. As the goose that lays the golden egg, due attention should be given to the petroleum sector to improve or at worst maintain the momentum of foreign exchange generation to the economy.

Many Fundamental Petroleum Engineering literatures have contributed so much to the understanding of this commodity and how it can be developed and consequently be used to develop the economy. This research seeks to focus on Nigeria, her petroleum policies, efforts and benefits of investments.

2.1 PETROLEUM EXPLORATION AND EXPLOITATION TRENDS

Oyewole and Economides (2003) traced the history of hydrocarbon exploration back to 1908 by the German-Nigeria Bitumen Corporation and the British Colonial Petroleum Company, which drilled to target the cretaceous Abeokuta formation near the heavy oil seep deposit in the northern part of the Niger Delta. The Shell-BP completion of the first commercial well (Oloibiri-1) in June 1956 ushered Nigeria into the league of petroleum producing nations. From the first oil export

in 1958 and modest 5,000 BOPD production, the country has risen to be the leading producer and exporter of oil in Africa.

Today, Nigeria has an estimated proved oil reserves that rose from 16 thousand million barrels in 1988 to 37.2 thousand million barrels as at end of 2010 (BP world energy statistics, 2011). As far as the world is concerned, Nigeria occupies an enviable position in the business of oil and gas. Fig 2.1 shows the province with oil discoveries exceeding 1 billion barrels of oil between 1990 and 1999, as observed by Esser (2001).

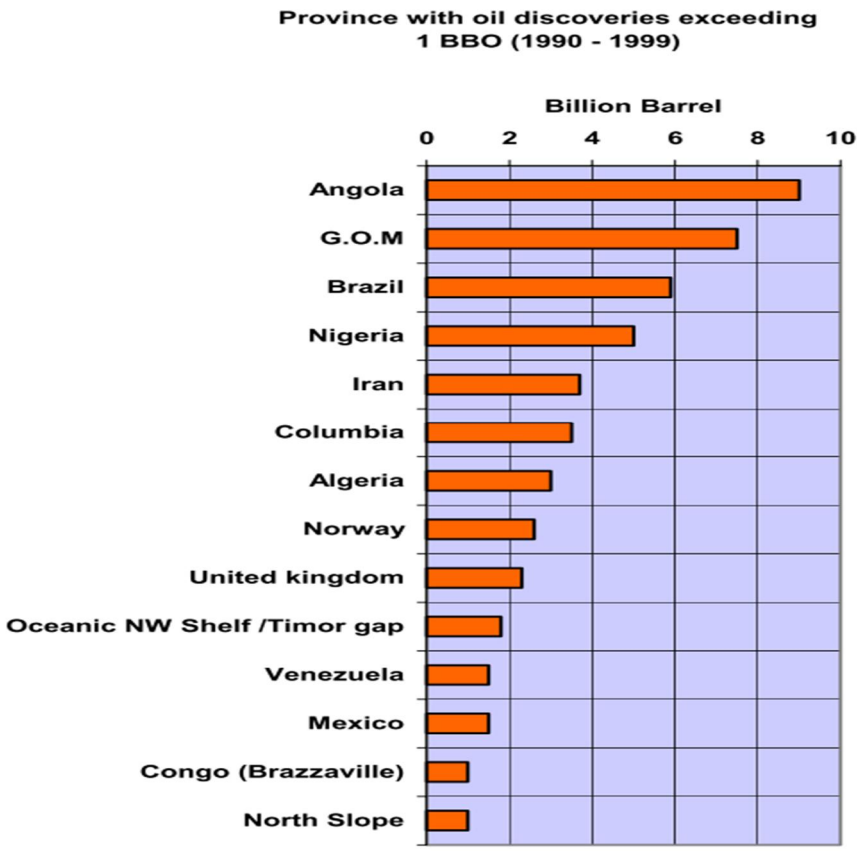


Fig 2.1 - Province with oil discoveries exceeding 1 billion barrel (Source: Esser, 2001)

This impressive increase could be attributed to the success of petroleum prospecting both onshore and offshore. More than 250 oil and gas fields have been discovered. Most oil fields are found at

1000 m to 4000 m depth and contain less than 300 million barrels reserves, each. Gas fields contain mostly less than 2Tcf, each, at depth ranging between 1000 m and 4500 m (Economides et al, 2003). These gas fields were discovered accidentally during oil exploration campaigns. There has not been any direct exploration target for gas fields in the Niger Delta (nor for that matter anywhere else in Nigeria). This is a direct consequence of immature gas utilization facilities in the country. Most operators opt to flare the gas as it is more economical. Nigeria flares its natural gas chiefly because her oil fields lack the infrastructure to produce and market associated natural gas (Ogbe, 2010). This submission drives most of the investments towards oil mining; hence this work would tilt towards this trend.

According to NAPIMS (2011), there are 500 fields in the Niger Delta. Over 55 per cent of these are onshore, while the remaining is in the shallow waters (less than 500 meters). Of these fields, 193 are currently producing while 23 have either been closed-down or abandoned. In addition, the opening up of the Frontier Areas in the deep and ultra-deep sections of the Nigerian offshore as well as the inland basins, along with the marginal fields, has given interested participants - local and foreign - a room not only to grow but also to collaborate and engage in profitable business alliances. Added to this competitiveness is the far lower cost of finding oil in Nigeria compared to other petroleum climes.

Petroleum exploration has taken an interesting adventure into the deep and ultra-deep water terrains. Sandrea et al (2007) recalled that offshore crude oil production started in the early 1940s and has grown from a modest 1 million barrels a day (1MMB/D) in the 1960s to nearly 25 MMB/D in 2005 to represent one third of world crude oil production. On the other hand, onshore crude production needed six decades to reach 25 MMB/D in 1963. However, unlike onshore oil

production, offshore production has never experienced sharp downward fluctuations and has grown consistently over the years (Fig. 2.2). The same trend could still be narrowed down to Nigeria as the acreage allocation deep offshore is on the increase. Fig 2.3 shows this trend for Nigeria in terms of acreage allocation. The downward trend onshore could also be attributed to other reasons. The deepwater extraction plants are less disturbed by local militant attacks, seizures due to civil conflicts, and sabotage. These advancements offer more resources and alternatives to extract the oil from the Niger Delta, with hopefully less conflict than the operations on land (Wikipedia, 2011).

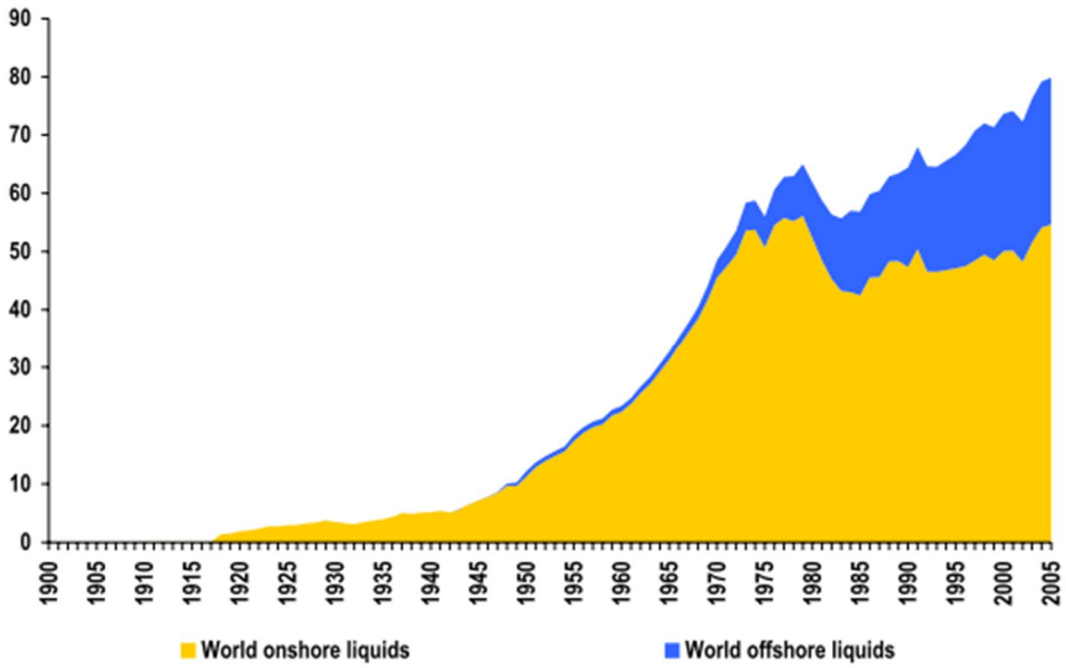


Fig 2.2 - World onshore/offshore oil production, mb/d (source: Sandrea et al, 2007)

Brazil through their NOC, Petrobras, announced a huge discovery in excess of 10 billion barrels of oil in the pre-salt area in the Santos basin recently and the government is bent on making the most out

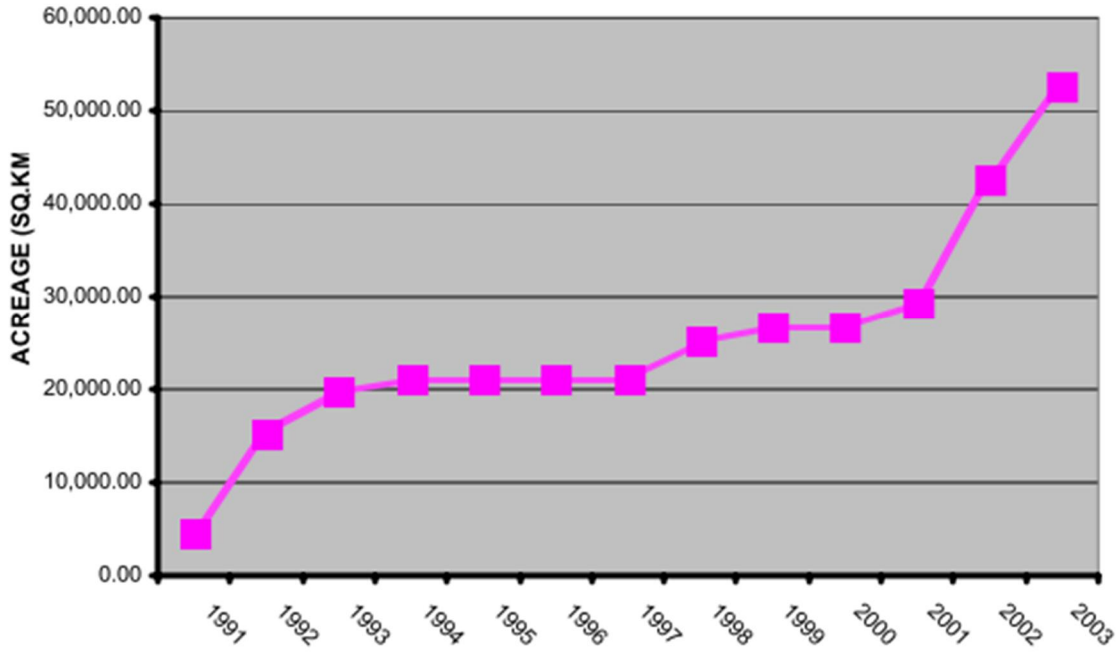


Fig 2.3 – Acreage allocation trend deepwater Nigeria (source: indigopool.com/Nigeria, 2011)

of it (Lima et al, 2010). Today in Nigeria, much promise has been shown in the deep water exploration. The result of which brought on stream huge fields like Agbami, Bonga and Akpo to mention but a few. More can be discovered in few years to come and the government must create that attractive environment to make this happen. For these reasons, shallow and deep offshore activities are receiving ample attention in terms of research.

2.2 PETROLEUM PROJECT EVALUATION

In the previous sections, it has been established that Nigeria is endowed with rich petroleum resources. Any project evaluation begins with these available resources. Petroleum resources are said to be the stock of oil deemed extractable in an undefined future. Petroleum resources presumed recoverable under currently known technology and economic conditions are referred to as reserves. Reserves cannot be measured, they can only be estimated and some degrees of

uncertainty are involved. Time line is associated with each reserve estimate, hence the term "original oil in place" or "ultimate recovery". Eggleston (1962) documented that crude oil and gas reserves are generally classified under two categories or divisions:

- Proved developed reserves
- Proved undeveloped reserves

These could further be subdivided into two classes:

- Producing
- Nonproducing

Proved reserve must be recoverable with a high degree of confidence if estimated by deterministic methods. It must have at least a probability of 90 percent that the actual recovery exceeds the estimated quantities, if probabilistic methods are used. The probable and possible reserve definitions frequently used by industry do not enjoy official sanction by the SPE at the present time. Probable reserves are quantities of recoverable hydrocarbons estimated on the basis of engineering and geological data that are similar to those used for proved reserves but that lack, for various reasons, the certainty required to classify the reserves as proved. Probable reserves are less certain to be recovered than proved reserves. Possible reserves are quantities of recoverable hydrocarbons estimated on the basis of engineering and geological data that are less complete and less conclusive than the data used in estimates of probable reserves. Possible reserves are less certain to be recovered than proved or probable reserves (Forrest, 1985).

Eggleston (1962) provides several reasons for reserve estimations. Some of the most important ones are as follows .

1. For corporate purposes in setting depletion and depreciation rates for corporate accounting and tax accounting.
2. For tax purposes such as income tax, inheritance tax and county or state taxes.
3. For financing purposes which include bonds, debentures and bank loans.
4. For the purposes of purchase or sale of companies or properties
5. For budget purposes which may include production income and development drilling expenses.
6. For purposes of unitization or joint operations (division of ownership in a field or property).

2.3 ESTIMATING RESERVE VOLUMES

Reserve estimating methods usually are categorized into three families:

1. Analogy
2. Volumetric,
3. Performance techniques.

The performance technique methods usually are subdivided into simulation studies, material-balance calculations, and decline trend analyses.

2.3.1 PRODUCTION ESTIMATION BY ANALOGY

Mian (2002) noted that this is a useful way of determining reserves and the associated production forecast, specifically for the fields/wells with insufficient information. It is widely used on new wells drilled in a developed field and/or exploratory wells. Wells in adjacent sections have their reservoir characteristics used, in drilling wells in a developed field. For wildcats, analogy can be used from other fields producing from the same type of expected hydrocarbon accumulations. In his

contribution, Forrest (1985) stated that if little or no production from the target formation exists, then statistical data from wells completed in formations having characteristics anticipated for the target zone are used. Because no factual information from the reservoir being studied is included in the analogy approach, reserve estimates so derived have the lowest confidence and usually are expressed in a minimum to maximum range. For this reason, this work would not adopt this method of production forecast.

2.3.2 PRODUCTION ESTIMATION BY VOLUMETRIC ANALYSIS

Mian (2002) identified this method of oil and gas reserve estimation as being used at the early times in the life of a field. He recognized that reservoir heterogeneities are a commonly overlooked factor which makes the volumetric estimates often different from those obtained by evaluating performance. The data required for estimating the initial oil in place, N are formation thickness (h, feet), drainage area (A, acres), porosity (ϕ, fraction), formation oil saturation (S_o, fraction) and oil formation volume factor (B_o, RB/STB). The following equation is used in estimating the initial oil in place.

$$N = \frac{7758\phi(1 - S_{wi})hA}{B_{oi}} \quad \text{----------} \quad 2.1$$

Where S_{wi} is the formation water saturation.

For gas reservoir, the initial gas in place, G is calculated by the following equation.

$$G = \frac{43560\phi(1 - S_{wi})hA}{B_{gi}} \quad \text{----------} \quad 2.2$$

Where B_{gi} is the gas formation volume factor (ft^3/scf)

The porosity and water saturation are obtained from well logs or core analysis or both. The formation thickness is estimated from resistivity logs or from geologic maps if the well is in a developed reservoir. Structural and stratigraphic cross-sectional maps help to establish the reservoir's areal extent and to identify reservoir discontinuities, such as pinch-outs, faults, or gas-water contacts (Ahmed, 2006).

This estimation method requires just a minimal set of information. It can be done early in the life of the reservoir. The computation is really fast. However, there are many assumptions (area, recovery factor) made which may not be true. These may result in gross errors.

2.3.3 PRODUCTION ESTIMATION BY RESERVOIR SIMULATION

This requires that the reservoir be divided into units called cells. For each cell, permeability, porosity, thickness, elevation, saturation (initial), initial pressure, rock compressibility etc. are assigned. Petroleum reservoir simulation is the planning, construction and operation of a model whose behaviour approximates the behaviour of the actual reservoir. It involves building of models. This means that for each reservoir, a *unique* model must be built (Ogbe, 2011).

For reservoir simulation to be successful there has to be sufficient data of very high quality, which would be inputted into the model in order to have a good history match. It has been observed that obtaining a good history match is not easy. Consequently, performance prediction generally depends on quality history match.

It has the advantage of handling different rock and fluid properties in different areas of the reservoir. It can also predict production from individual wells. Once history match is obtained, it can study the effects of different producing schemes.

The disadvantage borders on the time to do the study, cost implications, amount of input data and assumptions made in order to get a match.

2.3.4 PRODUCTION ESTIMATION BY MATERIAL BALANCE CALCULATION

This is a method of petroleum evaluation in which the reservoir is considered to be zero dimensional, hence evaluated using a tank model. It is based on volume to volume replacement of the reservoir fluid extracted. It works on a very simple computational principle as presented in the equation below.

$$Volume\ entering - Volume\ leaving = Net\ change\ in\ Volume \quad \text{----------} \quad 2.3$$

As simple as it may look, much data is required to account for any change in fluid volume in the reservoir. In computation, there must be an understanding of the drive mechanism prevailing in the reservoir. This means it can be used later in the life of the reservoir, as drive mechanism can only be ascertained if there is on-going reservoir fluid flow.

This is a very accurate method if there is enough data for computation. Data required include those of pressure, production history, fluid properties and rock properties. The advantages include that there is no assumptions necessary for areal extent, thickness or recovery factor. However, pressure data is not easy to come by.

2.3.5 PRODUCTION ESTIMATION BY DECLINE TREND ANALYSIS

Decline curve analysis is a graphical procedure used for analyzing declining production rates, and forecasting future performance of oil and gas wells. This is achieved by curve fitting the past production performance using the rate-time data and extrapolating it to predict future

performance, with the primary aim of estimating reservoir remaining reserves and/or remaining productive life (Aderemi at al, 2008). Reasons why production declines could range from technical to issues bordering on economics of extraction. There could also be political angle to it. Some of these reasons include

- Rate at which reservoir pressure falls
- Physical and fluid properties of the reservoir
- Rate of water encroachment
- Cost of production
- Price of oil

The purpose of decline curve analysis is to determine future production and therefore ultimate recovery for wells/fields with some production history. Since decline curve analysis depends on a curve-fit of past performance, the accuracy is expected to be higher for a well/field with several months or years of production history than for a well with only a limited history. Decline analyses are based on the following

1. Sufficient past production performance is available in order to make a reasonable match of this performance and extrapolating its future performance.
2. The past production history is based on capacity production with no changes in operational policy such as artificial lift, stimulation, etc. it is assumed the property will continue to be operated in the same manner in the future (Mian, 2002).

In its simple form, decline curve analysis can be performed by finding a curve that approximates the past production history and extrapolating this curve into the future.

Historically, Arps (1945) was credited to have studied production decline outside the period of production curtailment of those years. Fitting a line through the performance history and assuming this same line trends similarly into the future, forms the basis for the decline curve analysis concept. They were generally hyperbolic curves. He identified three variants of these curves and classified them as

- Constant percentage or exponential decline curves
- Hyperbolic decline curves
- Harmonic decline curves

According to Poston (2009), Brons (1963) and Fetkovich (1983) applied the constant pressure solution to the diffusivity equation to show that the exponential decline curve actually reflects single phase, incompressible fluid production from a closed reservoir. In other words its meaning was more than just an empirical curve fit. Fetkovich (1980) (1983) developed a comprehensive set of type curves to enhance the application of decline curve analysis.

(Poston, 2009) recognized that in order to locate a hyperbola in space one must know the following three variables.

- The starting point on the “y” axis. (qi), initial rate.
- (Di).the initial decline rate
- The degree of curvature of the line (b).

Applying this Arps’ concepts, (b = 0) goes for the exponential case, (0<b<1) for the hyperbolic case, and (b = 1) for the harmonic case.

Curve characteristics

- All rate-time curves must trend in a downward manner.
- The semi-log rate-time curve is a straight line for the exponential equation while the hyperbolic and harmonic decline lines are curved
- The Cartesian rate-cumulative recovery plots are a straight line for the exponential case, while the hyperbolic and harmonic lines are curved.
- A semi-log rate-cumulative production plot for the harmonic equation results in a straight line while the exponential and hyperbolic declines are curved.

Figure 2.4 presents the general semi-log rate-time plot for the Arps exponential, hyperbolic and harmonic equations. Note how the harmonic curve tends to flatten out with time. However, in Cartesian plane, it is as shown in Fig 2.5.

Theoretically, the b-exponent term included in the rate-time equation could vary in a positive or negative manner. A negative b-exponent value implies an increasing production rate which indicates that production extends to infinity, hence cumulative production must be infinite for the ($b > 1$) cases. This statement shows why the b-exponent term cannot be greater than unity. These studies indicate the decline exponent must vary over the ($0 < b < 1$) range to apply the

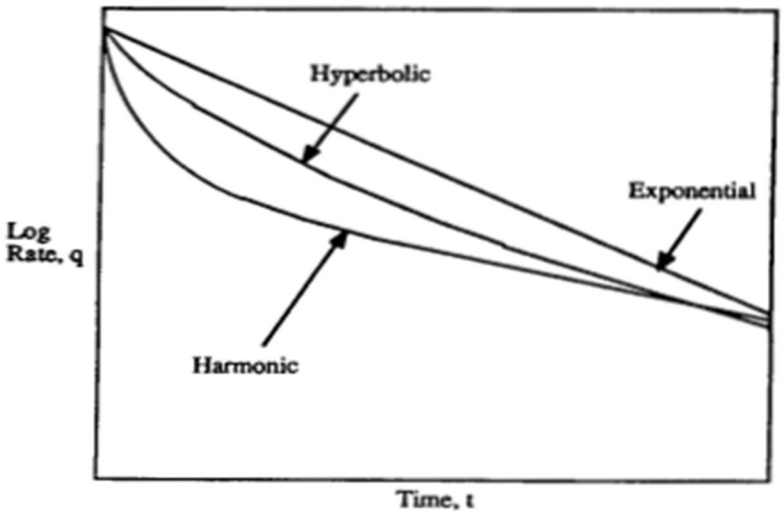


Fig 2.4 - Semi log plot of rate vs. time (source: Lee et al, 1996)

Arps curves in a practical sense. The harmonic case should be used only with reservations because a forward prediction would result in an infinite cumulative recovery estimate.

EXPONENTIAL DECLINE EQUATIONS

The exponential decline equation also called constant percentage decline equation evolved from the general equation of a hyperbola which McCray (1975) expressed as

$$\frac{d\left(\frac{q}{dq/dt}\right)}{dt} = -b \text{ ---------- } 2.4$$

Integrating equation 2.4

$$\frac{q}{dq/dt} = -bt - a \text{ ---------- } 2.5$$

Where

a = positive constant

b = hyperbolic exponent

q = production rate and

t = production time.

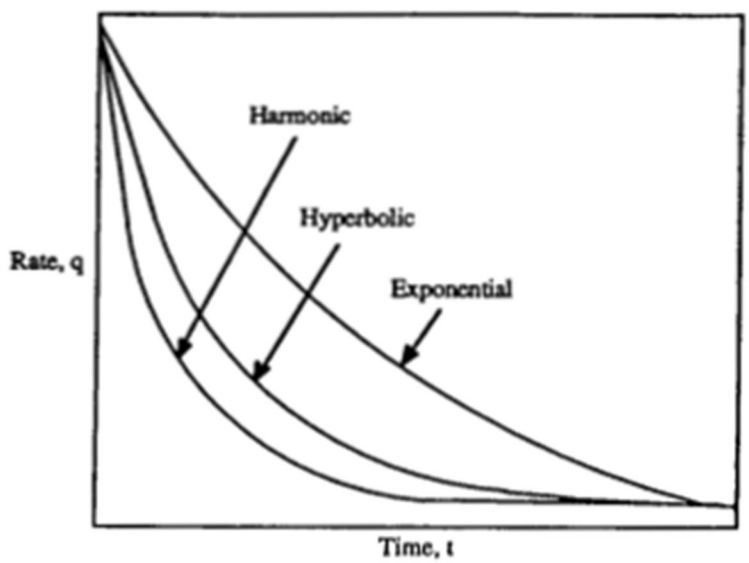


Fig 2.5 - Hyperbolic decline curves (source: Lee et al, 1996)

As established earlier, exponential decline is obtained when b=0. Therefore, equation 2.5 becomes

$$\frac{q}{dq/dt} = -a \quad \text{----------} \quad 2.6$$

Solving this equation for q we have

$$\frac{dq}{q} = -\frac{dt}{a} \quad \text{----------} \quad 2.6b$$

$$q = q_o \exp(-\,{}^{t}/_{a}) \quad \text{----------} \quad 2.7$$

Where

q_o is the initial flow rate and

$1/a = D$ *which is the exponential decline rate.*

Integrating equation 2.7 with respect to time t, we have for the range 0 to t.

$$\int_0^t q dt = \int_0^t q_o \exp(-\, t/a\,)\, dt \text{ ---------- } 2.8$$

Let $\int_0^t q dt = N_p$,

Then

$$N_p = \left[-a q_o \exp(-\, t/a\,)\right]_0^t \text{ ---------- } 2.8b$$

$$N_p = a q_o \{1 - \exp(-\, t/a\,)\} \text{ ---------- } 2.8c$$

$$N_p = a\{q_o - q\} \text{ ---------- } 2.8d$$

This is the cumulative production from the start of decline to any time, t within decline phase.

Therefore,

$$D = \frac{\{q_o - q\}}{N_p} = \frac{\ln(q_o/q)}{t} \text{ ---------- } 2.9$$

This is the nominal decline rate at time t, or after cumulative production, N_p

The effective decline rate, d is given as

$$d = \frac{\{q_o - q\}}{q_o} = 1 - \exp(-\, Dt\,) \text{ ---------- } 2.9b$$

The relationship between d and D is given by

$$D = -\ln(1-d) ----------------------------------2.9c$$

The unit of decline rate is given in per time. It should be predicated on the unit upon which production rate is expressed. Conversion could be done from monthly to yearly effective decline rates and vice versa, thus

$$d_y = 1-(1-d_m)^{-12} ---------------------------------2.9d$$

Or

$$d_m = 1-\left(1-d_y\right)^{1/12} ---------------------------------2.9e$$

Where d_y and d_m are the yearly and monthly effective decline rates respectively (Mian, 2002).

HYPERBOLIC DECLINE EQUATIONS

The hyperbolic decline is a concave upward curve when plotted on semi-logarithmic graph paper. As a consequence, D is not a constant value but rather is the slope of the tangent to the rate-time curve at any point. In other words, the decline characteristic, D, changes with producing time. The curvature of the curve is defined by hyperbolic exponent; b. Hyperbolic exponent is constant with time (Mian, 2002). To obtain the b exponent from the rate-time curve, three points are needed: (0, q_i), ($t_{2,}$ q_2) and ($t_{1,}$ q_1). , q_1 is obtained as a square root of the product of qi and q_2. Then by Newton Raphson's iterations, b can be estimated (Ahmed, 2006).

Hyperbolic behaviour is the most practical form of decline trend as it is neither too conservative nor too optimistic.

The hyperbolic equations are generated from equation 2.5.

$$\frac{q}{dq/dt} = -bt - a \quad \text{----------} 2.5$$

The hyperbolic exponent is in the range 0<b<1, hence solving the above equation for time 0 to t, we have that

$$q = q_o \left\{1 + \frac{bt}{a}\right\}^{-1/b} \quad \text{----------} 2.10a$$

Or

$$q = \frac{q_o}{\{1 + bdt\}^{1/b}} \quad \text{----------} 2.10b$$

This is the equation for the production rate at any time during the decline phase. Rearranging equation 2.10b would give decline rate d.

$$d = \frac{\left(\frac{q_o}{q}\right)^b - 1}{bt} \quad \text{----------} 2.11$$

Integrating equation 2.5 gives the cumulative production, N_p. Thus

$$N_p = \left\{\frac{q_o}{d(1-b)}\right\}\left\{1 - \left[\left(\frac{q_o}{q}\right)^{(1-b)}\right]\right\} \quad \text{----------} 2.12$$

Decline rate can also be rewritten in terms of cumulative production, thus

$$d = \left\{\frac{q_o}{N_p(1-b)}\right\}\left\{1 - \left[\left(\frac{q_o}{q}\right)^{(1-b)}\right]\right\} \quad \text{----------} 2.13$$

There should be unit consistency between the decline rates and the flow rates.

HARMONIC DECLINE EQUATIONS

This is a special case of hyperbolic decline with the hyperbolic exponent, b=1. The rate-time relationship can be straighten out on a log-log graph paper after shifting and assumes a slope of 45° (unit slope). The following equations are used in the same way as with hyperbolic decline.

$$q = \frac{q_o}{\{1 + dt\}} \text{----------} 2.14$$

And following the same pattern established before now, the cumulative production is as expressed in equation 2.15

$$N_p = \frac{q_o}{d} \ln \frac{q_o}{q} \text{----------} 2.15$$

By mere change of subject the decline rate, d could be obtained from equations 2.14 and 2.15

$$d = \frac{\left(q_o/q\right) - 1}{t} = \frac{q_o}{N_p} \ln \frac{q_o}{q} \text{----------} 2.16$$

Table 2.1 is a summary of the variants of Arp's production decline curve equations.

Table 2.1 - ARP'S EQUATIONS

	EXPONENTIAL	HYPERBOLIC	HARMONIC
DECLINE RATE,(a_i)	$\frac{q_i - q_t}{N_p}$	$\frac{\left(\frac{q_i}{q_t}\right)^b - 1}{bt} = \left\{\frac{q_i}{N_p(1-b)}\right\}\left\{1 - \left[\left(\frac{q_i}{q_t}\right)^{(1-b)}\right]\right\}$	$\frac{\frac{q_i}{q_t} - 1}{t} = \frac{q_i}{N_p} \ln \frac{q_i}{q_t}$
PROD.RATE, (q_t)	$q_i \exp(-a_i t)$	$\frac{q_i}{\{1 + ba_i t\}^{1/b}}$	$\frac{q_i}{\{1 + a_i t\}}$
CUM.PROD, (N_p)	$\frac{q_i - q_t}{a_i}$	$\left\{\frac{q_i}{a_i(1-b)}\right\}\left\{1 - \left[\left(\frac{q_i}{q_t}\right)^{(1-b)}\right]\right\}$	$\frac{q_i}{a_i} \ln \frac{q_i}{q_t}$

2.4 RELEVANCE OF DECLINE PATTERNS

Cutler (1924) stated that most decline curves normally encountered are hyperbolic, with values of b between 0 and 0.7 though Arps (1945), later suggested it was between 0 and 0.4. Fetkovich (1973) showed that b theoretically, ranges from 0 to 0.5 for gas reservoirs and from 0.5 to 0.667 for dissolved gas-drive reservoirs.

Lin et al (1982) noted that not all the production declines follow exponential pattern. He explained that even though exponential is more conservative, hyperbolic is by far more realistic. In comparison, he pointed out that exponential decline is often resorted to owing to the fact that it has just one unknown, d, in its equation while hyperbolic has two unknowns, d and b. He also observed that harmonic decline is rarely encountered in natural reservoir decline behavior. Earlier, Slider (1968) hinted that most engineers were given to using exponential decline in their analyses.

2.5 PETROLEUM PRODUCTION ECONOMICS

Every investor has his eyes fixed on profitability of his intended investment; to make the most out of it. In the oil and gas business, the trend remains the same. There are several factors that affect investment in exploration and production ventures. These range from technical obligations, cost implications to fiscal systems at work in the investment environment. Technical aspect, in its simplest form, involves all what it takes to bring the oil and gas from the reservoir to the point of sale. All productions stop as soon as economic limit is reached, except there is government incentive for continued operation. Economic limit is the production rate that will just meet the direct operating costs.

It has been established from the preceding sections that the first step to any investment evaluation in the petroleum sphere is to forecast production. Then the prevailing price of the petroleum product is applied to the commodity and gross revenue is generated. This revenue less cost of extraction and handling gives profit. For this to happen there must be certain principles laid down as guides. These are usually well-defined and documented in fiscal systems.

2.5.1 PRICING OF PETROLEUM

Oil is currently quoted in US dollars per barrel with consideration for crude specification in terms of API gravity and sulphur content. Crude with low sulphur content is said to be sweet crude while that with quality API gravity is said to be light crude. Hence we have Bonny light, Brent, Saudi light or Western Texas Index Crude as Marker crude (Iledare, 2011).

Normally oil price obeys the basic laws of demand and supply. However, there are players in the industry that can influence the price of crude regardless of laws of demand and supply. OPEC, OECD, brokers and speculators are major players in this regard.

Mian (2002), in his appraisal of product price predicted that oil price would not cross the US$30 mark. Today, the most volatile commodity price in the world is oil price. This buttresses the fact that there is huge uncertainty hanging over price of crude oil. Unfortunately, the whole essence of petroleum business and many world economies depend on it (Inikori et al, 2001). The trend in world crude oil prices was captured from 1946 till date in the curve presented in Fig 2.6.

McLaughlin et al (2007) noted that the oil, gas and natural gas liquid prices are some of the most critical components in determining the future of a property. He emphasized that reserves must be economic, and therefore, pricing must be a key factor in the quantity of reserves determined. Furthermore, It is required that future cash inflows shall be computed by applying year-end prices of

oil and gas related to the enterprise's proved reserves. Future price changes shall be considered only to the extent provided by the contractual arrangements in existence at the year-end.

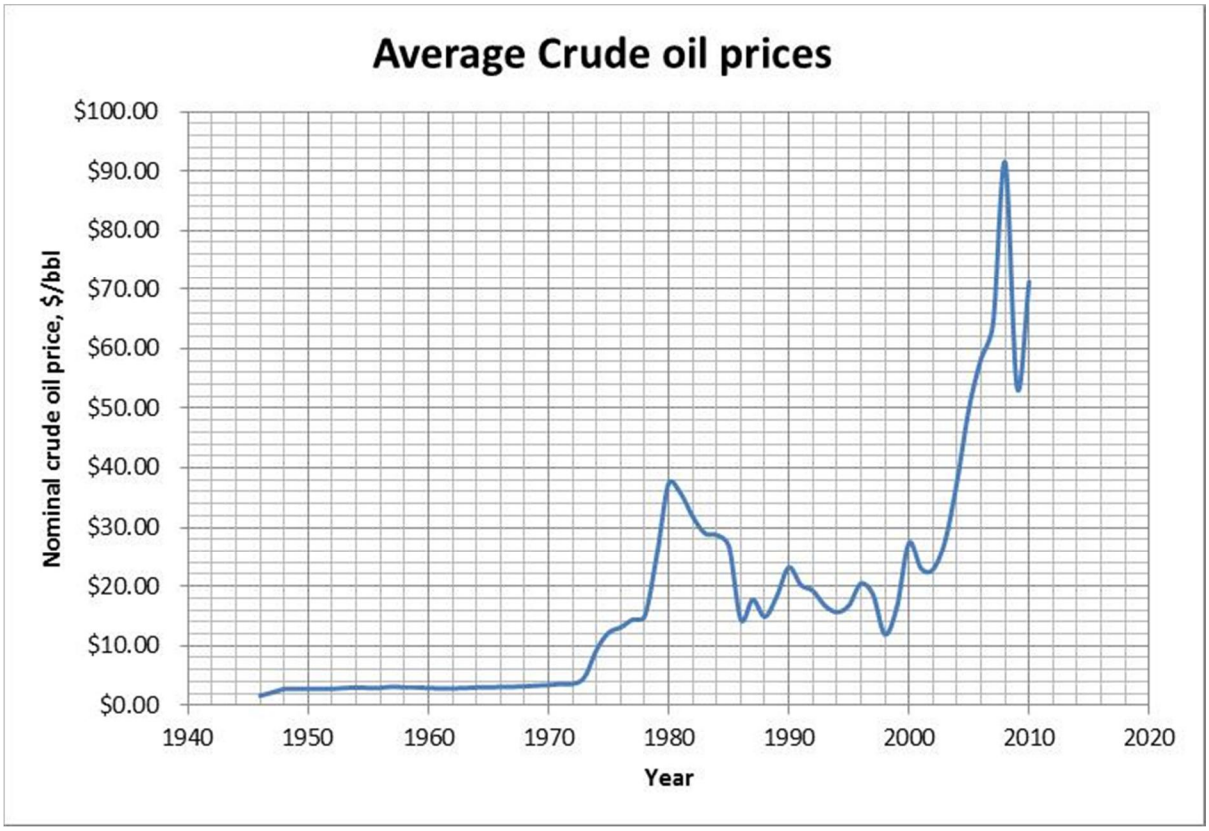


Fig. 2.6 - Annual Average Crude Oil Prices (data source: inflationdata.com)

2.5.2 PETROLEUM INVESTMENT AGREEMENTS

Every investment thrives in an environment that is conducive for business. Oil and gas business is a unique one because it involves very high initial capital investment. The host governments do not have the economic resources to develop their natural resources. Hence they seek to reach out to the international oil companies (IOCs) for collaboration in extracting these resources. Vikas et al (1997) observed that the petroleum industry is one of the most viable global industries in terms of movement of technology and capital, as exploitation of resources requires application of new

technology, adequate risk-capital and extensive experience with oil and gas upstream operations; and for these reasons the governments invite multinational corporations to participate in upstream oil and gas operations. Before any multinational company can operate in Nigeria, it has to sign an agreement or contract under which all the terms and conditions must be specified. It is therefore imperative to define these terms and conditions guiding such collaborations.

2.5.3 PETROLEUM FISCAL SYSTEMS

Johnston (2003) identified different types of Petroleum Fiscal Systems as implemented in different countries. These are pictorially described in Fig 2.7. There are two major classifications of petroleum fiscal system in the world. These are

- Concessionary or Royalty & Tax (R/T) system
- Contractual system

Concessionary System: This fiscal system is also popularly called the Royalty and Tax system. It allows private ownership of the resources through transfer of rights and payment of bonuses, royalties and taxes to host government. The hydrocarbons extracted by the companies belong to them. The host government bears no risk with the contractor. Government's reward comes from bonuses, royalties and different forms of taxes. In this fiscal system, cost recovery is called deduction.

Contractual System: In this fiscal system, mineral ownership lies with the host government and the oil companies are just contractors. This was first introduced in Indonesia in 1966. It is classified into: Production sharing contract (PSC) and service contract (pure & risk). Johnston (2003) stated that the primary difference between the two depends upon whether "reimbursement" and "remuneration"

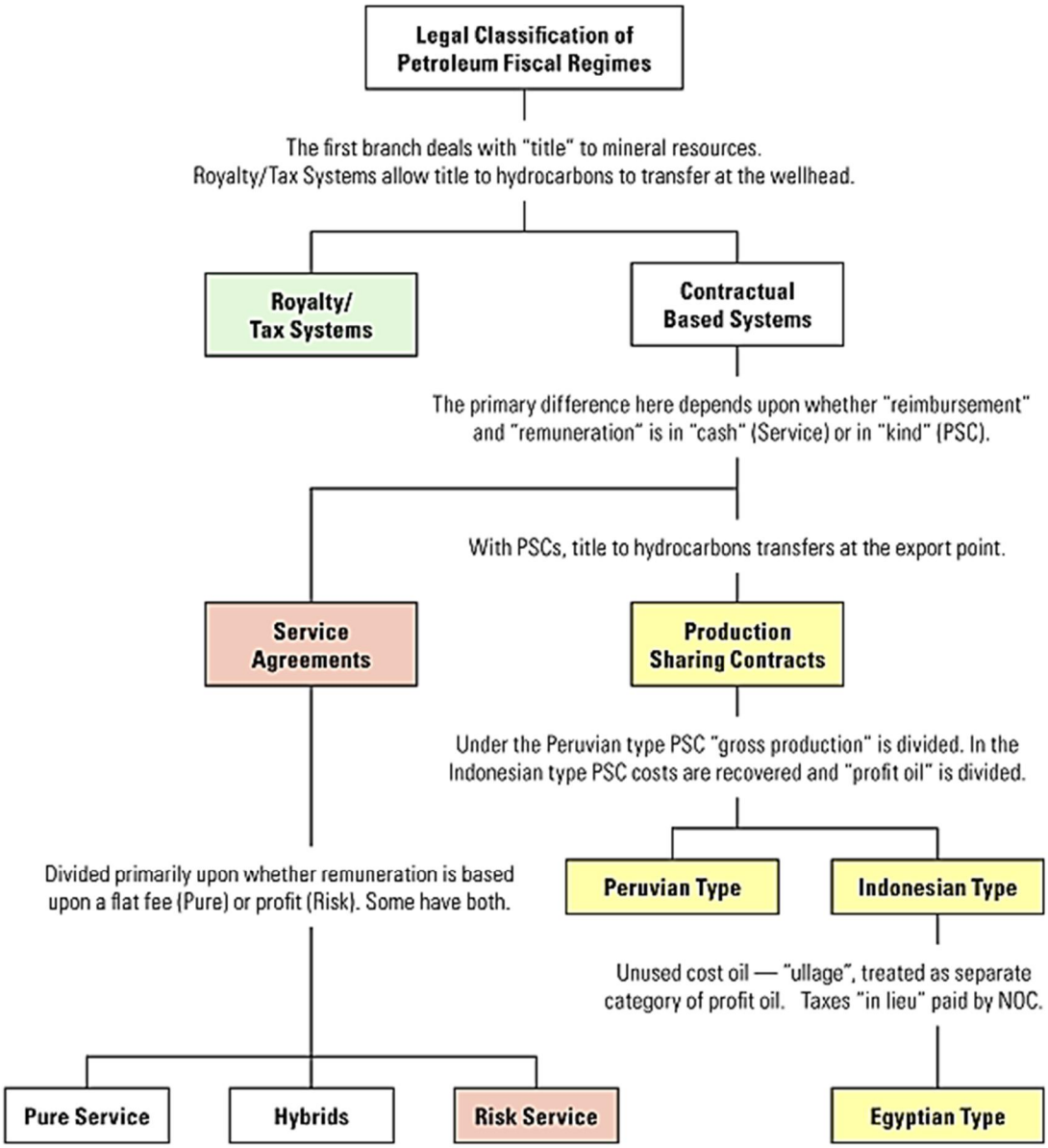


Fig. 2.7 - Legal classifications of petroleum fiscal systems (source: Johnston, 2003)

is in "cash" (service) or in "kind" (PSC). The hydrocarbon extracted by the contractor belongs to the host government. Private ownership is not allowed. Host government could bear some risks with the contractor, who could as well opt out of the risk (pure service). The major distinction between concessionary system and PSC is the eminence of cost recovery and profit sharing in terms of the

mechanics of the two fiscal systems. The contractor is allowed to recover all or part of his costs depending on legislation. Government take is not limited to only bonuses, royalties and taxes. Government participates in sharing of the profit oil. The more popular contractual fiscal system is the Production sharing arrangement (PSC).

A key interest of an oil-producing country is to generate as much revenue as possible from her petroleum resources. It is therefore critical that the fiscal regime be designed to secure the government maximum revenue, while providing investors with sufficient incentives to undertake exploration and development. For this reason, Lima et al (2010) reported that Brazil was changing her fiscal regime from concessionary (R/T) to Production sharing contract PSC). This change was intended to give the government more access to the gross revenue as well as creating flexible conditions that would allow for quick payback period for the contractor. Similarly, Vikas et al (1997) reported earlier that the government of India had drafted a new exploration licensing policy (NELP) with a view to attract greater private investments. This policy, they observed, had made the terms and conditions for multinational companies (MNCs) even more attractive. Adenikinju and Oderinde (2009) agreed that these changes in fiscal policies revolve around two conflicting objectives: increase in host government take and preservation of contractor incentives. To optimize these objectives Nigeria has set up several fiscal regimes over time.

Iledare (2004) summarized the two types of fiscal arrangements with multinational oil and gas companies for oil exploration, development, and production in Nigeria. These he identified as joint venture contracts (JVA) and Production sharing contracts (PSC). He further explained that a Joint venture contract is a modified form of the traditional royalty/tax fiscal arrangement with government participation. The overall production from the JVs presently accounts for nearly all (about 95%) of Nigeria's crude oil production. He however, concluded that joint venture reduces

the estimated present worth of a project for both the operator and the host government as a result of government participation. The production sharing contracts (PSC) minimize government participation, though not common as the contractor supplies all the initial risk capital for the project while the host government receives share of the profit oil, taxes and other front-loaded payments. The contractor is allowed to recover all allowable costs invested in the project. It could be agreed upon that the type of fiscal regime does not matter but the terms and conditions contained therein. In order to make investment more attractive over time, government has put in place different versions of the PSC operational mainly offshore.

The current fiscal regime for deep water depends on the PSC Model series, which are:

- The 1993 PSC Model series
- The 2000 PSC Model series, and
- The 2005 PSC Model series

Table 2.2 provides an overview of the terms and conditions of these PSCs for a water depth exceeding 1000 meters (IAT, 2009).

Table 2.2 -

Current fiscal terms for deep water PSCs for oil for more than 1000 meter water depth

	1993 PSCs	2000 PSCs	2005 PSCs
Royalties	0%	8%	8%
PPT Rate	50%	50%	50%
Credits/Allowances	50% ITC	50% ITA	50% ITA
Education Tax	2%	2%	2%
NDDC charge	3%	3%	3%
Production Sharing:			
Cost oil limit	100%	80%	80%
Profit Oil split based on cumulative volume:			
up to 350 mln bbls	20%	30%	n/a
up to 700 mln bbls	35%	35%	n/a
up to 1000 mln bbls	45%	47.5%	n/a
up to 1500 mln bbls	55%	55%	n/a
up to 2000 mln bbls	60%	65%	n/a
over 2000 mln bbls	negotiable	negotiable	n/a
Profit Oil split based on R-factor:			
Minimum R - 1.2	n/a	n/a	30%
Maximum R - 2.5	n/a	n/a	75%

Source: (IAT, 2009)

Wood McKenzie (2009) concluded that the 2005 PSC gives the government outrageous share of the gross revenue, thereby terming it as being harsh to investment. Considering the terms of the 1993 and 2000PSCs, the inter-agency team (IAT) explained that incremental investments in the small fields would greatly be unattractive (IAT, 2009). In the light of the foregoing, there was need to unify the PSCs. Consequently, a bill was sent to the Nigerian National Assembly seeking to optimize both the interests of government and the contractors. This bill is presently known as the Petroleum Industry Bill (PIB). From the time it was submitted for consideration till the present moment, there has been a lockdown between the executive and the legislative arms over the terms and conditions of this bill.

Many articles have been published on this impasse over the PIB. The aim is to find a common ground for the good of the Nigerian people who entrusted their petroleum resources in the hands of

government. Iledare (2010) dissected the proposed bill, noting the major differences from the current PSCs. He observed that there were changes in the areas of taxation structure, front-loaded government take, production and signature bonuses. The taxation structure changed from what used to be petroleum production tax (PPT) to Nigerian Hydrocarbon Tax (NHT) and corporate income tax (CITA). To fund the institutions established by the bill, an institutional levy called RIFT, was introduced. The remaining terms of this bill are presented in the appendix.

The important question is why is there a rift between the government and those opposing the terms of PIB? Wood McKenzie (2009) carried out a probe into this and concluded that government would still maintain an outrageous share of the gross revenue while the IAT claimed otherwise. According to IAT, the government take depends on the field size as depicted in Fig 2.8.

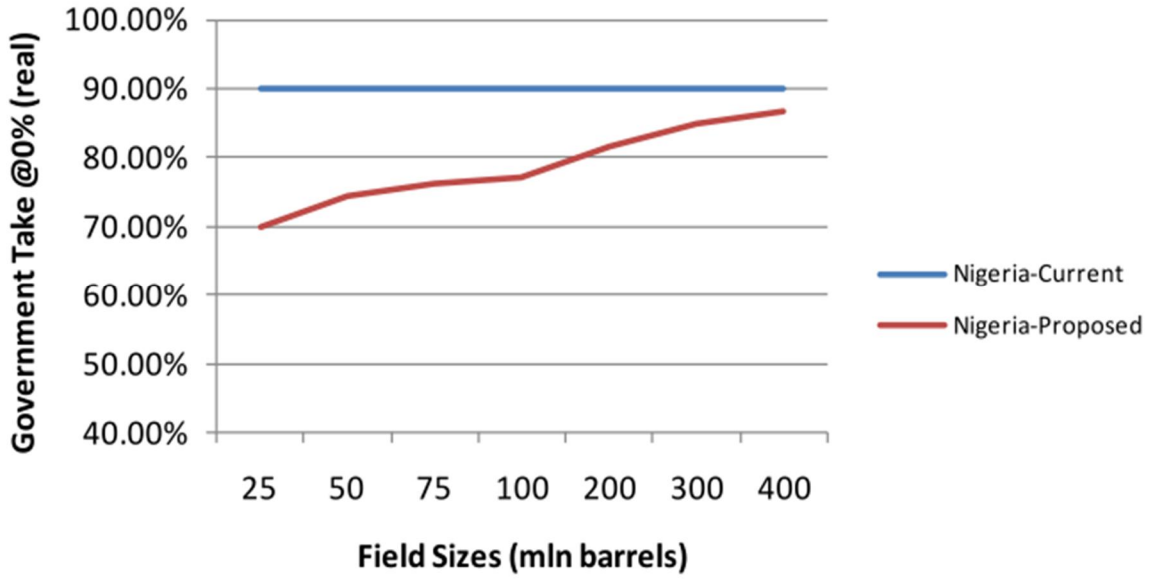


Fig 2.8 - Government takes vs. field sizes. (Source: IAT, 2009)

From the curve, it could be observed that given the same conditions of production, PIB would give government a take that is less than 90%. McKenzie disagreed stating that the government would have more than 90% take. Oyekunle (2011) believes that PIB would give government more access to

revenue than 2005 PSC for deep water. The curious question is who is getting the terms wrong and what could be done to make the PIB more attractive to investment especially in the deep and ultra-deep offshore? Can other factors that are technical other than fiscal affect profitability presented by PIB? Can cost treatment play any role in tweaking the PIB to a level of acceptability? Section 400 sub 4 of the redraft PIB (2009) indicates that the contract shall determine the treatment of the recoverable costs, including whether costs shall be expensed or depreciated, the method of depreciation and the treatment of pre-production costs.

2.6 SUMMARY

The chapter began by highlighting the relevance of oil and gas to the world economy. It was identified as being the mainstay of many developing economies like Nigeria.

The field/well production distribution in terms of location was hinted. It was said that offshore exploration and production was increasing while that of onshore has been on the decline over the years.

Petroleum project evaluation was revisited, where production analysis was first carried out. It was noted that proved reserves remained the greatest asset of any investment.

Petroleum production economics was discussed briefly. Pricing of petroleum was established as being very volatile and unpredictable.

The various fiscal systems as prevalent in Nigeria were reviewed. The most interesting being the optimization of the PIB 2009.

CHAPTER THREE

METHODOLOGY

3.0 Introduction

Petroleum project evaluation begins with identification of resources, reserves and capacity available. In a PSC agreement, the contractor, typically a multinational company (MNC) explores for, develops, and produces hydrocarbons (Vikas et al, 1997). The principal asset of oil and gas business is reserves, apart from human resources. When reserves meet investment, a viable asset is created.

This section seeks to describe the methodologies available to determine or evaluate the economics or profitability of a petroleum asset, considering technical and investment issues like reservoir production decline rate patterns, the government fiscal systems, and cost treatment offshore Nigeria.

The model approach adopted would be spreadsheet based and are similar to those presented by Mian M.A (2002), Johnston D. (2003) and Iledare (2010).

To build a complete economic model, it is vital that the production profile of the field be first established. This work would assume a prolific offshore field that could either be green or near-abandonment and has the following characteristics:

- a large oil or gas reserve
- a good recovery factor
- reasonable instantaneous and peak production rates that would bring about good build up period.

- Sustained plateau period
- The economic life of the field could vary based on the decline method to be applied.

In calculating the decline rates, the exponential method was used as default. This was meant to shift to harmonic and hyperbolic by Excel-based logic programming, so that different variants of the profile could be handy. The same was also done for the build-up rates. Production constraints were factored into the program to determine the economic limit of the field, in the production forecast.

Thereafter, the price of oil was applied to annual production to give annual gross revenue. The fiscal systems used in this work were made to reflect those which govern operations in Nigeria. Two fiscal systems were invoked in this work; PSC 2005 and the proposed Petroleum Industry Bill 2009. Based on these fiscal systems, royalties were deducted from the gross revenue and bonuses were treated as costs. It is worthy of note that technical costs offshore are on the high side as compared to onshore costs (Egbon, 2011 and Lechner et al, 1994). The main interest of this work was centred on the treatment of these technical costs, as it affected depreciation and to find out how profitability was affected. By default, cost depreciation was executed using the Straight line depreciation (SLD) method and by logic variations Sum of Years' Digits (SOY) depreciation, Declining balance depreciation (DBD) and Unit of production depreciation (UOP) methods could be set up as options. This led to front loaded government and contractor cash flow calculations.

Applying the tax conditions spelt out in the fiscal systems to the model, an after tax cash flow for both host government and the contractor is developed. The profitability criteria adopted in the work were NPV at a certain hurdle rate, internal rate of return and profitability index.

The various production decline methods used were compared against these profitability criteria to determine their various impacts. The same was done for the different cost depreciation methods.

Sensitivity analyses were invoked or employed to determine the impact of decline rate, reservoir size, oil price, cost depreciation and the corporate income tax on the profitability criteria using @RISK. However, the model has been automated to allow for input data variation.

3.1 DATA REQUIREMENT

The model building would be in two folds:

- Technical
- Non-technical

Technical part involved the production forecasting of a typical offshore field in Nigeria. Hence, production data used were generic and could be determined by the user of the model. The production data could be generated by simply supplying the expected ultimate recovery, the instantaneous production rate, the production peak rate and the production economic limit. Due to the flexibility of the soon-to-be-built model, the lease acreage would be left variable and at the discretion of the user.

The non-technical part involved the Nigerian fiscal systems (PIB 2009 and PSC 2005) and cost assumptions typical of a Nigerian offshore lease. However, these costs could be made user-specific to reflect true individual realities. The oil price would reflect the lease acquisition year constant dollar-per-barrel. This price could still be made variable, real or nominal as desired by the user and the prevailing conditions.

3.2 CASH FLOW MODEL FORMULATION

In petroleum industry, rate of production determines what the cash flow would appear to be. No matter what techniques are used if these do not translate into higher rates, it does not make economic sense. Hence higher rates breed higher revenue to the investor and host government alike, ceteris paribus. It is also true that without appropriate technology, the reservoir may not produce to its optimum potential.

Therefore, in this work, cash flow model would be predicated upon both technical aspects of petroleum production and the investment of the contractor to explore and exploit petroleum.

A major step in cash flow analysis is to estimate reserves and forecast the reservoir production profile.

There are different methods of estimating reserves as briefly alluded in Section 2.2.1. These include volumetric, material balance, reservoir simulation and decline curve analysis methods. The decline curve analysis method was adopted in this work. This was due to the fact that only production history would be needed for the analysis. Hence, there were no in-depth assumptions about size, type or other properties of the reservoir.

3.3 PETROLEUM PRODUCTION FORECASTING

There were three typical phases adopted in this work, for production forecasting. These include:

- Build-up phase
- Plateau phase
- Decline phase

3.3.1 BUILD-UP PHASE

This phase of the model indicates the initial conditions of reservoir production. It is the earliest stage of reservoir depletion in mostly new fields. During this stage, the wells are being drilled and the production facilities are being put in place, hence the wells cannot flow at full capacity. This condition was factored into the model by first flowing the wells at a low instantaneous production rate, q_i . Gradually, the flow was increased at a specific build up rate,a_i for some time, t, until peak production rate, q_p was reached.

How this increase in rate was achieved remained a function of the reservoir and fluid properties. The reservoir properties might necessitate linear increment of the flow rates until peak level is attained. However, this model used Arp's equations to reflect the different rates decline and build up patterns. This was to establish uniformity in the behavioural assumptions in the build-up as well as the decline phases of this investigation. Arps (1945) presented different equations for the decline patterns that are prevalent during production. These equations are for exponential, hyperbolic and harmonic decline patterns as summarized in Table 3.1 below.

Table 3.1 - ARP'S EQUATIONS

	EXPONENTIAL	HYPERBOLIC	HARMONIC
DECLINE RATE,(a_i)	$\frac{q_i - q_t}{N_p}$	$\frac{\left(\frac{q_i}{q_t}\right)^b - 1}{bt} = \left\{\frac{q_i}{N_p(1-b)}\right\}\left\{1 - \left[\left(\frac{q_i}{q_t}\right)^{(1-b)}\right]\right\}$	$\frac{\frac{q_i}{q_t} - 1}{t} = \frac{q_i}{N_p} \ln \frac{q_i}{q_t}$
PROD.RATE, (q_t)	$q_i \exp(-a_i t)$	$\frac{q_i}{\{1 + ba_i t\}^{1/b}}$	$\frac{q_i}{\{1 + a_i t\}}$
CUM.PROD, (N_p)	$\frac{q_i - q_t}{a_i}$	$\left\{\frac{q_i}{a_i(1-b)}\right\}\left\{1 - \left[\left(\frac{q_i}{q_t}\right)^{(1-b)}\right]\right\}$	$\frac{q_i}{a_i} \ln \frac{q_i}{q_t}$

Where

a_i = decline rate in per unit time.

q_i & q_t are flow rates in bbl per unit time.

b = the hyperbolic exponent. This could be obtained by Newton Ralphson's Iterations (Ahmed, 2000)

t = time in days, months or years: care was taken to maintain consistency in time units

N_p = the cumulative production in bbls.

The build-up rate could be viewed as the reverse of decline rate, as changing the sign convention of one would reflect the behavior of the other. The build-up stage of the production profile was generated by using and transforming the Arp's equations as presented in the second and the third rows of Table 3.1.

For exponential build-up behavior, the following were the governing equations used in the coding of the model:

$$\text{Buildup rate, d} = -a_i = -\frac{q_i - q_p}{N_p} = \left(\ln\frac{q_p}{q_i}\right)\Big/_t \text{ ----------3.1}$$

$$Production\ rate\ at\ any\ time, t, before\ plateau\ phase, was\ obtained\ by\ the\ equation$$

$$q_t = q_i \exp(dt) \text{ ----------3.2}$$

$$Cumulative\ production, N_p = \frac{q_t - q_i}{d} \text{ ----------3.3}$$

$$Annual\ production, N_a = \frac{q_{t+1} - q_t}{d} \text{ ---------- 3.4}$$

For hyperbolic build-up behavior, the following were the governing equations used in the coding of the model:

$$Buildup\ rate, d = \frac{\left(\frac{q_i}{q_t}\right)^b - 1}{bt} \text{ ---------- } 3.5$$

$Production\ rate\ at\ any\ time, t, before\ plateau\ phase, was\ obtained\ by\ the\ equation$

$$q_t = \frac{q_i}{\{1 + bdt\}^{1/b}} \text{ ---------- } 3.6$$

$$Cumulative\ production, N_p = \left\{\frac{q_i}{d(1-b)}\right\}\left\{1 - \left[\left(\frac{q_t}{q_i}\right)^{(1-b)}\right]\right\} \text{ ---------- } 3.7$$

$$Annual\ production, N_a = N_{p(t+1)} - N_{p(t)} \text{ ---------- } 3.8$$

For harmonic build-up behavior, the following were the governing equations used in the coding of the model:

$$Buildup\ rate, d = \frac{\frac{q_i}{q_p} - 1}{t} \text{ ---------- } 3.9$$

$Production\ rate\ at\ any\ time, t, before\ plateau\ phase, was\ obtained\ by\ the\ equation$

$$q_t = \frac{q_i}{\{1 + dt\}} \text{ ---------- } 3.10$$

$$Cumulative\ production, N_p = \frac{q_i}{d} \ln \frac{q_i}{q_t} \text{ ---------- } 3.11$$

$$Annual\ production, N_a = N_{p(t+1)} - N_{p(t)} \text{ ---------- } 3.8$$

3.3.2 PLATEAU PHASE

This phase in the life of a field starts as soon as the build-up period is over. Many wells would have been completed and the facilities for production and transportation would have been duly put in place. Therefore, the wells could flow up to full acceptable capacity. The production rate is at its peak throughout the life of this phase. The operators are interested in maintaining this phase for as long as it is technically and economically feasible. Strong pressure support is observed in the

reservoir within this period. During this period it is expected that the bulk of the investment made by the contractor will have been recovered.

In the model, this was easy to incorporate. Consider the production profile represented in Fig 3.1. The area of the rectangle covered by the plateau phase is given by the peak rate,q_p multiplied by the time duration, t, of the phase. This is the cumulative production for that period. Hence, cumulative production, N_p was obtained in the model by using equation 3.12a below.

$$Cumulative\ production, N_p = q_p t \text{ ---------- } 3.12a$$

$$Annual\ production, N_a = q_p t \text{ ---------- } 3.12b$$

where t in eq. 3.12b is the monthly or yearly time within the plateau phase.

Equation 3.12 remained the same for all the decline regimes (exponential, hyperbolic and harmonic) used in the model.

3.3.3 DECLINE PHASE

This is the last phase in the life of the reservoir. It starts as soon as the plateau production is over. During this period the reservoir pressure is constantly on the decrease, which is reflected by gradual fall in the rate of production. The contractor embarks upon a lot of pressure maintenance and enhanced hydrocarbon recovery projects to keep up production and increase the life of the field before economic limit. Economic limit could be driven by different factors which range from socio-political to real economic issues.

Depending on the physical and fluid properties of the reservoir, decline could manifest in three ways:

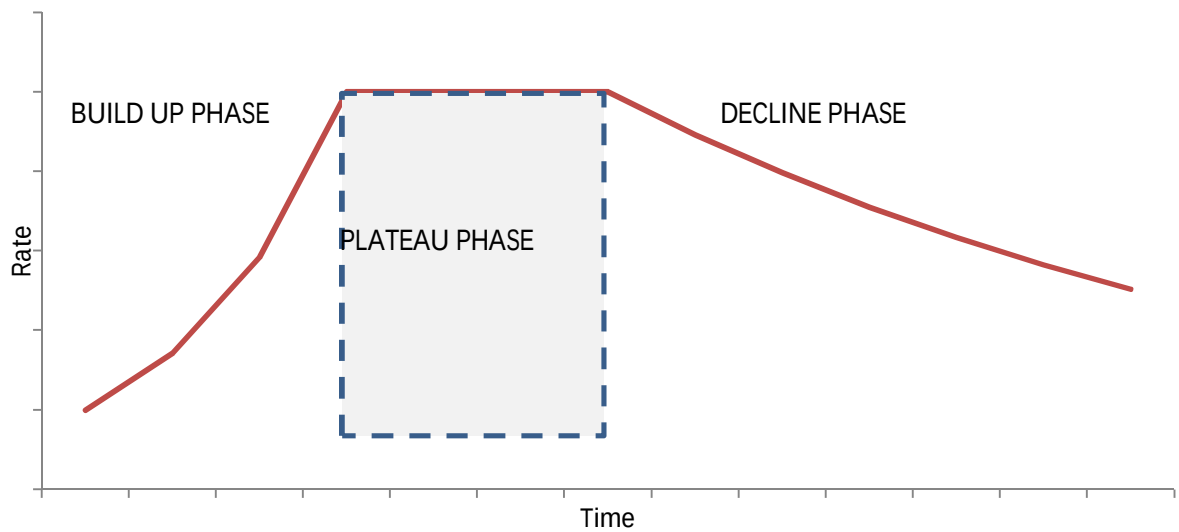


Fig 3.1 - Typical production profile showing build-up, plateau and decline phases.

- Exponential
- Hyperbolic
- Harmonic

This research assumes that the production decline pattern in this phase is similar to what was done in the build-up stage. As mentioned in section 3.3.1, Arp's equations were the building blocks of the model-building process used in this research work. A model was built for each decline pattern.

For exponential decline behavior, the following were the governing equations used in the coding of the model

$$\text{Decline rate, } a_i = \frac{q_p - q_{el}}{N_p} \quad \text{----------} \quad 3.13$$

Where q_{el} is the economic limit rate. This rate was considered to be zero in order to calculate the decline rate, a_i since exponential decline rate is a constant percentage and N_p is the total ultimate

recovery during the decline period. However, if cumulative production in the decline region up to economic limit was known as an input, equation 3.13 could accurately be used.

Care was taken to maintain unit consistency between flow rate and decline rate.

$Production\ rate\ at\ any\ time, t, after\ the\ plateau\ phase, was\ obtained\ by\ the\ equation$

$$q_t = q_p \exp(-a_i t) \quad \text{----------} \quad 3.14$$

$$Cumulative\ production, N_p = \frac{q_p - q_t}{a_i} \quad \text{----------} \quad 3.15$$

$$Annual\ production, N_a = \frac{q_t - q_{t+1}}{a_i} \quad \text{----------} \quad 3.16$$

For hyperbolic decline behavior, the following were the governing equations used in the coding of the model:

$$\text{Decline rate}, a_i = \left\{\frac{q_p}{N_p(1-b)}\right\}\left\{1 - \left[\left(\frac{q_{el}}{q_p}\right)^{(1-b)}\right]\right\} \quad \text{----------} \quad 3.17$$

Where b is the hyperbolic decline curve exponent.

$Production\ rate\ at\ any\ time, t, after\ plateau\ phase, was\ obtained\ by\ the\ equation$

$$q_t = \frac{q_p}{\{1 + ba_i t\}^{1/b}} \quad \text{----------} \quad 3.18$$

$$Cumulative\ production, N_p = \left\{\frac{q_p}{a_i(1-b)}\right\}\left\{1 - \left[\left(\frac{q_t}{q_p}\right)^{(1-b)}\right]\right\} \quad \text{----------} \quad 3.19$$

This is strictly the cumulative production within the decline period only. For total cumulative production, addition to that before decline phase was effected.

$$Annual\ production, N_a = N_{p(t+1)} - N_{p(t)} \text{ ---------- } 3.8$$

For harmonic decline behavior, the following were the governing equations used in the coding of the model:

$$\text{Decline rate}, a_i = \frac{q_p}{N_p} \ln \frac{q_p}{q_{el}} \text{ ---------- } 3.20$$

It should be noted also that the N_p used was that for decline phase only.

$Production\ rate\ at\ any\ time, t, after\ plateau\ phase, was\ obtained\ by\ the\ equation$

$$q_t = \frac{q_p}{\{1 + a_i t\}} \text{ ---------- } 3.21$$

$$Cumulative\ production, N_p = \frac{q_p}{a_i} \ln \frac{q_p}{q_t} \text{ ---------- } 3.22$$

This is strictly the cumulative production within the decline period only. For total cumulative production, addition to that before decline phase was effected.

$$Annual\ production, N_a = N_{p(t+1)} - N_{p(t)} \text{ ---------- } 3.8$$

3.4 REVENUE BASE

As soon as the production profile has been established, it is then easy to forecast how much benefit could be made from the produced or soon-to-be-produced hydrocarbon each year for the life of the project. This forms the basis for investment decisions on the part of the contractor. It is worthy of note that as more hydrocarbon is produced, access to gross revenue for both the host government and the contractor increases. For the purpose of this thesis, gross revenue is defined as the mathematical product of produced hydrocarbon and the prevailing market price.

In this research work, consideration was given to both types of price regimes; the nominal and the real or constant dollar. This created a need to introduce price index into the model to account for changes in price level with time. Price index could be effected by using any of GDP deflator, Producer Price Index (PPI) or Consumer Price index (CPI). Therefore, GDP deflator or Price Index relates real price to nominal price by equation 3.23.

$$Price\ Index = \frac{Nominal\ Price}{Real\ Price} \times 100\% \text{----------} 3.23$$

Nominal value refers to a value expressed in money terms (that is, in units of a currency) in a given year or series of years. By contrast, real value adjusts nominal value to remove effects of price changes over time. Escalation is usually calculated by examining the changes in price index measures for a good or service. It is worthy of note that if price index is 100%, then nominal price equals real price. Otherwise, equation 3.24 applies.

$$Nominal\ Price = \frac{Price\ Index}{100\%} \times Real\ Price \text{----------} 3.24$$

In the build-up phase of section 3.3.1, annual gross revenue was determined by multiplying equations 3.24 and 3.4 for exponential decline model while for hyperbolic and harmonic decline models eq. 3.24 was multiplied by eq. 3.8.

In the plateau phase of section 3.3.2, annual gross revenue was determined by multiplying equations 3.24 and 3.12b for all the decline models built.

In the decline phase of section 3.3.3, annual gross revenue was determined by multiplying equations 3.24 and 3.16 for exponential decline model while for hyperbolic and harmonic decline models eq. 3.24 was multiplied by eq. 3.8.

3.5 FISCAL SYSTEM-BASED MODELING

Previous sections presented the production profile formulation and the revenue base without considering the terms of the fiscal systems. Fiscal terms for upstream investment refer to the agreement between a government and an oil and gas exploration company to explore, develop and produce hydrocarbons (Centre for Energy Economics, Univ. of Texas). A fiscal system contains definitions of the relationship between mineral owners (host government) and the oil and gas companies (IOC, NOC & DOC). This relationship could range from taxation, legislations, contracts, whether or not costs are recoverable and how to share profit between host government and oil and gas companies. From the foregoing, it could be deduced that a fiscal system is location specific, as each country has a unique system that works for her. Nigeria has practiced both the R/T and PSC fiscal systems.

This research focused on the PSC system as is prevalent in the offshore terrains of the Nigerian territory. The PSC systems modelled include the current PSC 2005 and the proposed Petroleum Industry Bill (PIB) 2009. This was to bring out a basis of analysis for this investigation. Summary of the fiscal systems are presented in the Appendix.

3.5.1 COST TREATMENT AND ASSUMPTIONS

In any PSC, the contractor typically assumes the cost of extraction of the hydrocarbon from the reservoir till it is sold and converted into revenue. These costs are in two folds: technical and non-technical. Technical costs include CAPEX, OPEX and abandonment costs. CAPEX could either be tangible or intangible. Fig 3.2 is a tree diagram showing cost classifications used in the cash flow model.

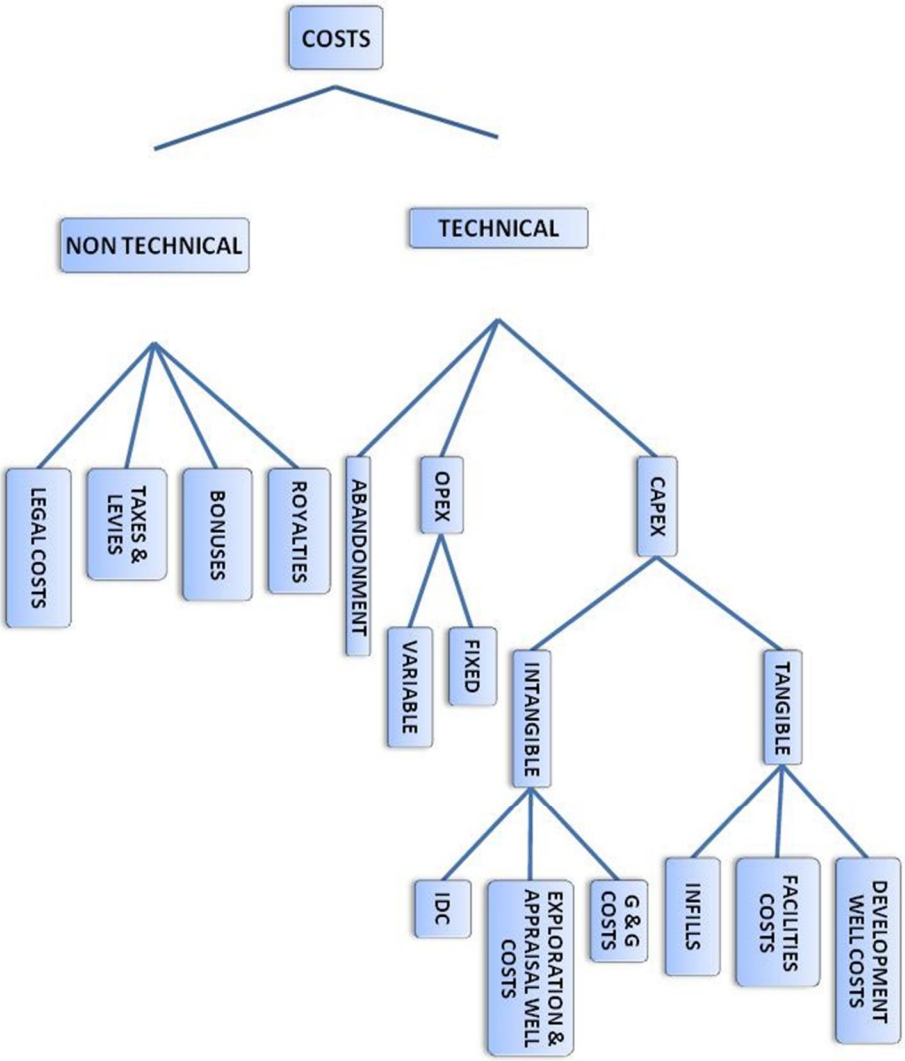


Fig 3.2 - Tree diagram of costs.

3.5.2 CAPEX

Every capital expenditure incurred before the start of production was categorized as exploration and appraisal CAPEX and those incurred afterwards were tagged development and facilities CAPEX. The exploration and the appraisal CAPEX include the geological and geophysical costs, the exploration and appraisal costs. These costs were expensed the same year they were incurred by the model assumptions. The development and facilities CAPEX includes the development well costs,

facilities costs and infill wells costs. According to both PSC 2005 and proposed PIB 2009 models, the development and facilities CAPEX were depreciated.

3.5.3 CAPEX DEPRECIATION

Depreciation is defined as a loss in the value of an asset over its useful life. It is a method of redistribution of tangible costs over a period of time, called useful life, for income tax calculation purposes. There are different methods of depreciation applied during cost treatment.

These are

- Straight line depreciation (SLD)
- Declining balance depreciation (DBD)
- Sum of year's digit depreciation (SOY)
- Unit of production depreciation (UOP)

There are other variants of depreciation methods which could involve switching from one method to the other.

In modelling cash flow for PIB 2009, all the methods above were incorporated, but the declining balance depreciation was modified by switching to SLD in order accelerated depreciation. Section 400 sub-section 4 of the inter-agency PIB 2009 stipulates that the contract shall determine the treatment of the recoverable costs including whether costs shall be expensed or depreciated, the method of depreciation and the treatment of pre-production costs.

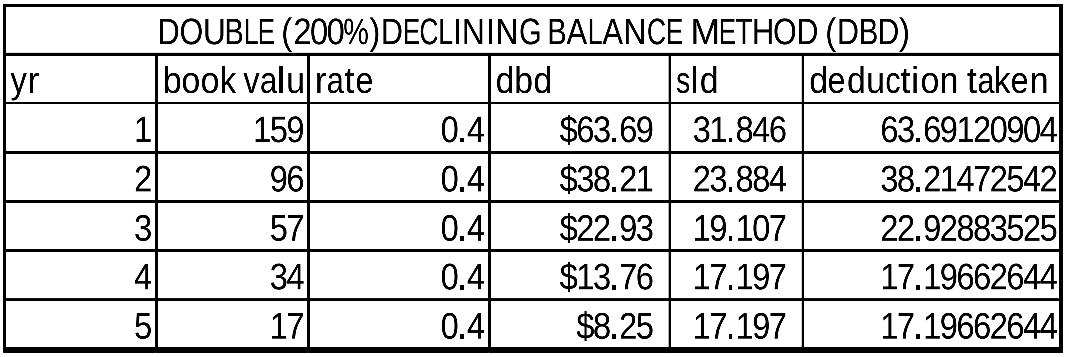
Given depreciable cost, C, the useful life, t and the salvage value, S, of the asset, the following depreciation equations were used in building the model.

For Straight line depreciation (SLD),

$$D_n = \frac{C - S}{t} \text{ −}3.25$$

For Declining balance depreciation (DBD), the calculation took some extra steps as demonstrated in Table 3.2 below. In the model, a switch to SLD was assumed for accelerated cost recovery.

Table 3.2 - Numerical demo of DBD with a switch to SLD



DOUBLE (200%)DECLINING BALANCE METHOD (DBD)					
yr	book valu	rate	dbd	sld	deduction taken
1	159	0.4	$63.69	31.846	63.69120904
2	96	0.4	$38.21	23.884	38.21472542
3	57	0.4	$22.93	19.107	22.92883525
4	34	0.4	$13.76	17.197	17.19662644
5	17	0.4	$8.25	17.197	17.19662644

The initial step taken was to assume a DBD factor of 200%. Then a constant depreciation factor was obtained by dividing by the useful life of the asset, t i.e.

$$rate = \frac{200\%}{t} \text{ −} 3.26$$

The initial value (cost) of the asset was then multiplied by this factor. The value obtained was subtracted from the initial cost of the asset to determine the book value of the asset in the following year. This process was repeated until the useful life of the asset was complete. However, a constant comparison with SLD was made each year and the greater between the two depreciation deductions was taken.

For Sum of year's digit depreciation (SOY), the sum of year is given by

$$SOY = \frac{t(t + 1)}{2} \text{ −}3.27$$

SOY was used in the calculation of the depreciation given cost, C, the remaining useful life, t_r and the salvage value of the asset, S. Thus

$$D_n = \frac{(C-S)t_r}{SOY} \text{----------} 3.28$$

For unit of production depreciation (UOP), the unit of comparison is not time but the total life time activity, A of the depreciable asset. This was determined as ratio of the annual production, N_a to total production, $\sum N_a$ attained during the useful life of the asset. Thus

$$D_n = \frac{(C-S)N_a}{\sum N_a} \text{----------} 3.29$$

It should be recalled that all the above depreciation equations were used in modelling the proposed PIB 2009 cash flow.

However, in PSC 2005, it was stipulated that straight line depreciation must be used in the order of 20%, 20%, 20%, 20% & 19% for 5-year depreciation. Therefore only SLD was modelled this way for PSC 2005 cash flow.

The non-depreciable CAPEX was expensed the same year it was incurred as mentioned earlier. The total CAPEX was obtained by combining both the depreciated and non-depreciated CAPEX. It should be observed that price escalation of the costs was effected the year they were incurred not after depreciation.

For cost oil calculation purposes, 2% of CAPEX was treated as being non recoverable as stipulated in the proposed PIB 2009. This was not observed in the PSC 2005 model.

3.5.4 OPEX

This is also called lease operating expenditure (LOE). It is a direct cost associated with production. OPEX together with CAPEX make up technical cost. No operating costs if there is no ongoing production or injection. OPEX could be divided into variable and fixed costs. In the cash flow analysis, it is usually treated as a percentage of CAPEX or gross revenue and measured in $/month, $/year or $/bbl.

In the production sharing contracts, including PSC 2005 and proposed PIB 2009, operating costs are expensed the same year they are incurred. Consequently, in all the cash flow models considered, OPEX was treated accordingly.

3.5.5 FRONT-LOADED GOVERNMENT TAKE CASH FLOW

Usually, the host government wants to capture as much economic rents as possible. These are done through imposition of levies, taxes, royalties, rentals and bonuses using the fiscal system as a vehicle. Any economic rent that goes to the host government which is not tied to assessable profit is said to be front-loaded. The contractors pay this whether profit is made or not.

This cash flow could be viewed in two folds.

- Pre-discovery
- Post-discovery

The pre-discovery cash flow involves the bonuses and the rentals paid the government just before production. In the PSC 2005 model, signature bonus was thus specified as outlined in Table 3.3 below. However, the proposed PIB 2009 only mentioned that bonus is expected to be paid without

any payable range. In the models, provision was made for bonus payment as a negotiable input. It should be noted that signature bonus was tied to nothing in particular unlike production bonus.

Table 3.3 - Minimum Signature bids for 2005 PSC (source: Wood McKenzie, 2009)

Terrain	Bonus
Frontier	$0.5 million
Onshore	$5 million
Shelf	$5-10 million
Deepwater	$50 million

Surface rental payment featured in the models. It is based on acreage. Table 3.4 is the summary of rental stipulations of PSC 2005 while Table 3.5 shows the summary for proposed PIB 2009. Cash flow for each fiscal system was modelled based on the respective stipulations.

Table 3.4 - Surface rent payment for PSC 2005 (source: Wood McKenzie, 2009)

RENTALS	
LICENCE, $/sqKM	
OPL	10
OML(<10YRS)	20
OML(>10YRS)	15

Table 3.5 - Surface rent payment for Proposed PIB 2009.

RENTALS			
	LICENSE ($/sqKM)		
YEAR	PEL	PPL	PML
1	10	100	1000
2	10	100	1000
3	10	300	1000
4	10	300	1000
5	10	500	1000
6+	10	500	1000

PPL has a gas retention clause that could jump to $10,000/sqKm.

Another pre-discovery cash flow item modelled was the NDDC levy. For both fiscal systems it was tied to the technical cost. It is generally 3% of the technical cost.

Post-discovery cash flow items included in the model were the royalties and the crypto taxes. PIB 2009 subjects all petroleum production in Nigeria to royalty payments calculated by both volume and value. This provision is as summarized in Tables 3.6 and 3.7.

Table 3.6 - PIB 2009 royalty provisions by volume

	OIL			NATURAL GAS	
Area/Royalty	5%	12.50%	25%	5%	12.50%
Onshore	0 - 2Mb/d	2 - 5Mb/d	>5Mb/d	0 - 100MMcf/d	>100MMcf/d
Shallow water	0 - 5Mb/d	5 - 20Mb/d	>20Mb/d	0 - 200MMcf/d	>200MMcf/d
Deepwater	0 - 50Mb/d	50 -100Mb/d	>100Mb/d	0 - 500MMcf/d	>500MMcf/d

Table 3.7 - PIB 2009 royalty provisions by value

OIL PRICE PER BBL	ROYALTY %	GAS PRICE PER MMBTU	ROYALTY %
$0 - $70	0	$0 -$2	0
$70 - $100	0.4/$	$2 -$7	0.2/10cents
$100 - $140	12+0.2/$	$7 - $13	10+0.15/10cents
$140 - $190	20+0.1/$	$13 - $19	19+0.10/10cents

The royalty provisions in PIB 2009 are applied by sliding scale. To calculate the effective royalty rate for both volume and value used in modelling the cash flow, the following sliding scale equations were used.

For volume, given shallow water and production oil rate, q_t in Mb/d, between 5 – 20Mb/d, then effective royalty rate percentage, R is

$$R = \frac{25 + (q_t - 5) \times 12.5}{q_t} \quad \text{----------} 3.30$$

If q_t>20Mb/d, then

$$R = \frac{212.5 + (q_t - 20) \times 25}{q_t} - 3.31$$

For volume, given deep water and production oil rate, q_t in Mb/d, between 50 – 100Mb/d, then effective royalty rate percentage, R is

$$R = \frac{250 + (q_t - 50) \times 12.5}{q_t} - 3.32$$

If q_t>100Mb/d, then

$$R = \frac{875 + (q_t - 100) \times 25}{q_t} - 3.33$$

Royalty calculation by value was done based on the prevailing oil price. Given that oil price is \$P/bbl which is in the range of \$100 - \$140, then the royalty rate could be calculated by equation 3.34 below.

$$R = 12\% + 0.2(P - 100)\% - 3.34$$

The royalty provisions in the PSC 2005 assumed a jumping scale rule and are based on location and water depth. It is summarized in Table 3.8 below.

Table 3.8 - PSC 2005 royalty provisions by location

ROYALTIES						
WATER DEPTH(MAX)(m)	100	200	500	800	1000	>1000m
SWAMP/SHALLOW	18.5%					
SHELF		16.5%				
DEEP			12.0%	8.0%	8.0%	8.0%

Generally, royalties were calculated as a mathematical product of royalty rate, R and the gross revenue. Finally, PIB 2009 introduced a type of crypto tax that would be used to fund the

institutions established by the bill. It is a severance tax called RIFT. It is specified as $0.5/bbl of crude oil. However, in the PSC 2005 model it was not present. In the model this was also accounted for.

3.5.6 COST RECOVERY SPECIFICATION

Cost recovery is a feature in the PSC which provides means through which contractors can redeem the costs of exploration, development and operations. If a business venture must be viable, it is only natural that such business should have the potential to reproduce the investment capital pumped into it. Cost recovery model implements how this could be done.

A limit is usually set to determine the proportion of revenues that can be used for cost recovery in a given period. Most PSCs place a limit on cost recovery, hence the term cost recovery limit (C/R limit), which is also known as cost oil. The unrecovered eligible costs per period could be carried forward indefinitely until they are duly recovered. It should be noted that gross revenue less cost oil and royalties gives profit oil. This is the only true distinction between concessionary systems and PSC in terms of the mechanics of the two fiscal systems.

In the PSC 2005 and the proposed PIB 2009, a limit of 80% of gross revenue less royalties was defined as cost oil. Therefore, profit oil was computed as 20% of gross revenue less royalties. In both models, bonuses and royalties were not recoverable by means of cost oil calculations. Also not recoverable were 2% of total technical costs. Therefore the eligible recoverable cost was calculated using equation 3.35

$$Recoverable\ costs = 98\%TC + Total\ FLGT - Bonuses - Royalties \quad \text{--------} \quad 3.35$$

Where,

TC is the total technical costs

FLGT is the front-loaded government take.

Costs carried forward (C/F) was calculated by equation 3.36, provided there were unrecovered costs.

$$C/F = C/R - cumulative\ recoverable\ cost \text{ ---------- } 3.36$$

Where $C/R = cost\ oil.$

As soon as all the eligible costs were recovered whatever was left of equation 3.36 was termed excess costs recovery (ECR). Muscolino et al (1993) observed that if the ECR is shared between the host government and the contractor, the effect of changing cost recovery limit on metric measures is marginal. The sum of ECR and the profit oil gave the total assessable profit oil meant to be shared between the host government and the contractor.

At this juncture, default fiscal stipulations on profit sharing would be evoked. In PSC 2005, it was based on R-factor as summarized in Table 3.9 below. As shown in the table, if the R – factor was 1.2 or less, the contractor share of the assessable profit would be 70%. If R – factor was between 1.2 and 2.5, it was stipulated that the effective sharing factor should be based on the linear sliding scale rule given in equation 3.37.

$$Effective\ contractor\ share = 25\% + \frac{2.5 - R}{2.5 - 1.2} \times (70\% - 25\%) \text{ ---------- } 3.37$$

Where R = R – factor of equation 3.39

If R – factor of equation 3.39 went above 2.5, the effective share of the contractor should be 25%. It should be noted that the extreme conditions were treated based on jumping scale while the intermediate range was based on the sliding scale rule. Also for cost recovery purposes, the PSC 2005 defined what should constitute assessable profit. Thus,

Assessable profit = sales revenue – royalties – operating costs – exploration – intangible

costs –3.38

Table 3.9 - PSC 2005 Profit sharing fiscal term

PROFIT SHARING			
R- FACTOR(MAX)	1.2	2.5	>2.5
%age	70%	70% - 25%	25%

$$R - factor = \frac{profit\ oil + cost\ oil}{cumulative\ technical\ costs + cumulative\ rentals} - - - - - - - - - - - 3.39$$

In the proposed PIB 2009, profit sharing was not based on the R – factor but on the cumulative volume of production. Table 3.10 is a summary of host government's profit share.

Table 3.10 - PIB 2009 Profit sharing fiscal term

PROFIT SHARING				
Np (MMBbl)	<750	1000	2000	>2000
% Share	20%	30%	40%	negotiable

This profit sharing was also tied to sliding scale rule.

$$HGT_{PO} = \tau_g \times (ECR + PO) - 3.40$$

Where,

τ_g is the government profit share factor

ECR is the excess cost recovery

PO is the profit oil

3.5.7 BEFORE INCOME TAX (BIT) CASH FLOW

This is the net inflow and outflow of cash in any venture in preparation for federal income taxation. Any inflow to government is an outflow to contractor and vice versa. The before income tax (BIT)

cash flow items may vary from one fiscal system to the other. This cash flow creates a base for the final federal income tax, hence the total takes of both the contractor and government, which in turn forms a basis for investment decisions.

In the proposed PIB 2009 cash flow model, care was taken to arrive at the share of both government and the contractor. The first cash flow item treated was the technical cost. The PIB 2009 stipulated that only 80% of all the technical costs incurred outside the country would be viewed as allowable deductible costs. This was integrated in the model at this stage. The next cash flow item was the total payments made to the government. The model included these as royalties, bonuses, RIFT, NDDC and of course, the front-loaded government take.

The proposed PIB 2009 split the current Petroleum Profit Tax (PPT) into Nigerian Hydrocarbon Tax (NHT) and the Corporate Income Tax (CITA) with respect to PSC 2005. The major constituent of the BIT was the calculation of the NHT base. Thus,

$$NHT\ Base = Gross\ Revenue - FLGT - Bonus - Allowable\ TC \quad \text{----------} \quad 3.41$$

Where

FLGT is the front loaded government take

TC is the technical cost

Taxable loss carry forward was done to take care of cash outflows in years of no production. Hence, there was no tax calculation during this period. Tax calculations took effect as soon as there was assessable profit in the cash flow. This assessable profit was tagged taxable income.

Special allowances were taken off the taxable income before applying the NHT. These allowances were as summarized in Table 3.11. Jumping scale rule was applied. NHT was pegged at 30% for deep water operations and 50% for shallow waters.

Table 3.11 - Special Production Allowances in PIB 2009

SPECIAL PRODUCTION ALLOWANCES		
AREA	ALLOWANCE	CUM. PROD (MMBbl
ONSHORE	min($30/Bbl, 30% of Price)	10
	min($12/Bbl, 30% of Price)	<75
SHALLOW WATER	min($30/Bbl, 30% of Price)	20
	min($12/Bbl, 30% of Price)	<150
DEEP WATER	min($ 7/Bbl, 30% of Price)	all prod. Levels

In PSC 2005, the first cash flow items treated were the operating costs and other intangible costs. The aim was to arrive at assessable profit of which education tax would be paid. Hence in PSC 2005, the BIT was actually to obtain a base for education tax calculation as against NHT in the proposed PIB 2009. This base in PSC 2005 was defined by equation 3.42 below.

$$Assessable\ Profit = Gross\ Revenue - Royalties - OPEX - intangible\ costs ----3.42$$

As stipulated in the fiscal system, the rentals were treated as part of operating costs. The education tax was 2% of assessable profit of equation 3.42

Thereafter, based on the stipulated profit sharing arrangement, before income tax takes were obtained for both fiscal models.

For PIB 2009 it was calculated for government as

$$HGT_{BIT} = FLGT + NHT + HGT_{PO} ----------3.43$$

For contractor, it was

$$CT_{BIT} = Gross\ Revenue - HGT_{BIT} - TC ---------- 3.44$$

For PSC 2005, it was calculated for government as

$$HGT_{BIT} = FLGT + ETAX \text{ ---------- } 3.45$$

For contractor, it was

$$CT_{BIT} = Gross\ Revenue - HGT_{BIT} - OPEX - Intangible\ costs \text{ ---------- } 3.46$$

$Where,$

HGT_{BIT} $is\ the\ Host\ Government\ Take\ before\ income\ tax.$

CT_{BIT} $is\ the\ Contractor\ Take\ before\ income\ tax.$

$FLGT\ is\ the\ Front-loaded\ Government\ Take.$

$ETAX\ is\ the\ Education\ Tax.$

$TC\ is\ the\ total\ Technical\ Cost.$

3.5.8 AFTER INCOME TAX (AIT) CASH FLOW

This is the cash flow that is obtained after the application of the federal income tax to assessable profit. Generally, it is expected that this cash flow would see the take for the host government being on the increase while that of the contractor dwindles due to tax payments. Certain fiscal conditions like depreciation, special production allowances, foreign expenditure, uplifts etc are strictly implemented here to avoid miscalculations in the federal income tax base.

In the proposed PIB 2009, federal income tax was split into two: NHT and CITA. Therefore, the after income tax cash flow centred on determination of CITA base, hence the final takes for both government and contractor. However, in calculating total technical costs, consideration was not given to foreign expenditure clause of the fiscal system. All 100% technical cost was CITA deductible. Also the bonus was not treated as deductible cost just like in the NHT base calculations. The Taxable income was calculated by equation 3.47.

$$Taxable\ income = Gross\ Revenue - TC - HGT_{BIT} - NHT \text{ ---------- } 3.47$$

Room was given for all the outstanding allowable costs to be recovered before arriving at the taxable income of equation 3.47. For all offshore investments, CITA was given as 30% of the taxable income. It should be noted that education tax in PIB 2009 was made to be a surcharge tax, taken after CITA. The education tax base was determined as

$$ETAX\ Base = Eligible\ CAPEX + taxable\ income \quad \text{----------} \quad 3.48$$

Where eligible CAPEX stands for the CAPEX within the production period. The education tax (ETAX) is stipulated to be 2% of equation 3.48.

In the PSC 2005, the federal income tax was the petroleum profit tax, PPT. It was treated as a percentage of PPT taxable base calculated using equation 3.49 below.

$$PPT\ taxable\ income = Assessable\ profit - ETAX - tangible\ CAPEX - ITA \quad \text{-----} \quad 3.49$$

Where ITA means Investment Tax Allowance, which is an uplift that allows the contractor to recover an additional percentage of capital investment through cost recovery. This was replaced by production allowance in the proposed PIB 2009. ITA was specified in the PSC 2005 as summarized in Table 3.12 below.

Table 3.12 - PSC 2005 ITA specifications (source: Wood McKenzie, 2009)

Water depth	ITA (% of CAPEX)
Inland/deepwater	50%
Onshore	5%
< 100m	10%
100m-200m	15%

Education tax in PSC 2005 was deductible for PPT calculations. PPT was given as summarized in table 3.13 below.

Table 3.13 - PSC 2005 PPT provisions (source: Wood McKenzie, 2009)

Water depth	PPT
Inland/deepwater	50%
Onshore/shelf (first 5 years)	65.75%
Onshore/shelf (thereafter)	85%

In PIB 2009, the undiscounted after income tax government take was calculated using equation 3.50 while equation 3.51 gave that for contractor.

$$HGT_{AIT} = HGT_{BIT} + CITA + ETAX \text{ ---------- } 3.50$$

$$CT_{AIT} = Gross\ Revenue - HGT_{AIT} - TC \text{ ---------- } 3.51$$

In PSC 2005, it should be recalled that the profit sharing was based on R-factor stipulated in equation 3.39 and table 3.9 in favour of the contractor. Generally, the total oil was first shared after deduction of PPT to arrive at the respective takes of government and contractor. Thus the host government profit oil was calculated as

$$HGT_{PO} = \tau_g \times (PPT\ Taxable\ income - PPT) \text{ ---------- } 3.52$$

Where $\tau_g is\ the\ profit\ sharing\ factor\ for\ government.$

Finally, the government take was obtained by equation 3.53

$$HGT_{AIT} = HGT_{BIT} + HGT_{PO} + PPT \text{ ---------- } 3.53$$

For the contractor, the take was the same as given in equation 3.51.

3.5.9 PROFITABILITY INDICATORS

These are objective measures of the economic worth of investment. One of the main difficulties in capital budgeting is the large number of economic evaluation yardsticks used. Investment decision criteria provide a quick way to evaluate the economic merits of a proposed E & P venture or project. There is no single profitability criterion that incorporates all the important elements underlying E &

P business decisions and organizational goals. There is no general agreement about which criteria are best. Hence in this research work, several profitability measures were adopted, including:

- Net present value (NPV)
- Internal Rate of Returns (IRR)
- Payout Period
- Profitability Index (PI)
- Growth Rate of Return (GRR)
- Unit Technical Cost (TC)

NET PRESENT VALUE (NPV): This is also known as present value of cash surplus or present worth. It is obtained by subtracting the present value of periodic cash outflows from the present value of the periodic cash inflows. It is normally calculated at a discount rate, i_d which should reflect the value of the alternative use of funds. It is given as

$$NPV = \sum_{i=1}^{n} \frac{NCF_t}{(1 + i_d)^t} \text{----------} 3.54$$

Where

$NCF_t = net\ cumulative\ cash\ flow\ at\ any\ time\ t$

This research work adopted the year end discounting method to arrive at NPV. As a decision criterion, NPV is desired to be positive in project ranking.

INTERNAL RATE OF RETURNS (IRR): This is also known as rate of return (ROR), internal yield and marginal efficiency of capital. IRR is the discounted rate at which the net present value is exactly equal to zero or the net present value of cash inflows equal the net present value of cash outflows.

If IRR is greater than the return on the alternative use of funds or cost of capital. If the investment is on borrowed capital, IRR should be greater than the interest paid on the loan. IRR can be calculated using the equation below

$$\sum_{i=1}^{n} \frac{NCF_t}{(1+IRR)^t} = 0 ----------------------------------3.55$$

Graphically, IRR could be obtained as shown in fig 3.2 below

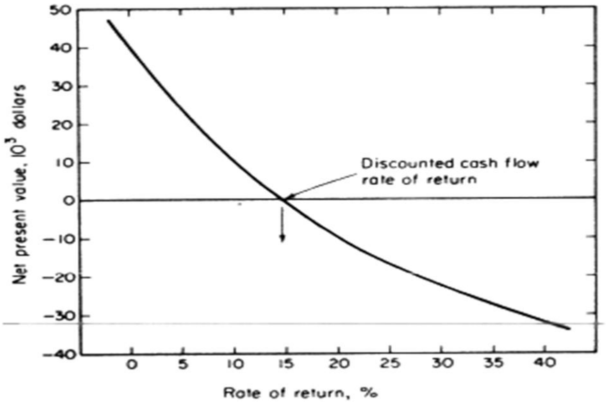


Fig 3.3 – Discounted cash flow IRR (source: McCray, 1975)

PAYOUT PERIOD: This is also referred to as the breakeven point. It is the expected number of years required for recovering the original investment. At this point, the receipt exactly equals the cash disbursements. On its own it cannot provide a yardstick for meaningful decision making. Low payback is desirable in decision making. It is calculated by the following equation.

$$Payback\ period = cum.(-ve\ NCF)years + \frac{-(-ve\ NCF)}{+ve\ NCF - (-ve\ NCF)} ---------- 3.56$$

PROFITABILITY INDEX (PI): This is a dimensionless ratio obtained by dividing the present value of future operating cash flow by the present value of the investment. It is desirable to have a PI that is greater than 1.

UNIT TECHNICAL COST (TC): it is also referred to as finding cost. This is the ratio of the total cost (CAPEX and OPEX) over the economic life of a project to the expected reserves from the project. It is independent of the prices of the product involved.

GROWTH RATE OF RETURN (GRR): since many managers believe IRR is not a reliable profitability indicator, then GRR was introduced. It is also referred to as equity rate of return or modified IRR. GRR resolves the shortcomings of IRR like trial-and-error calculations, reinvestment rate assumptions etc. in terms of PI, it is thus calculated.

$$GRR = (PI)^{1/t}(1 + i_d) - 1 \quad \text{----------} \quad 3.57$$

Equation 3.57 is based on annual compounding. A project is desirable if GRR is greater than the hurdle rate, i_d.

These Profitability indicators were used as outputs to perform sensitivity analysis on various input parameters using two methods

- Monte Carlo simulation via @RISK
- Designed model manual variations.

Details and results were as presented in chapter four of this work and the Appendix. The summary of the fiscal systems used are also presented in Appendix D.

CHAPTER FOUR

RESULTS AND ANALYSES

4.0 INTRODUCTION

This chapter presents the details of all the objective functions defined in the spreadsheet model built for both the PIB 2009 and PSC 2005 fiscal systems. These results are specific functions of the input variables defined in the models and may vary should these variables be redefined.

The base case study is done by incorporating all the available data (reservoir size, production rates, type of decline, type of depreciation, CAPEX, OPEX, oil price etc.) into the developed cash flow model. The results obtained in the base case study are deterministic. Sensitivity analysis would be performed on the base case variables to obtain probabilistic results. Consequently, stochastic perspective is given to the model using an MS Excel add-in, @RISK. This would be to account for the uncertainties inherent in some of the input data used in the base case of the models.

Model Assumptions

- The production analysis remains the same for all the fiscal systems modelled.
- The cost assumptions are the same for a particular lease location but vary according to water depth (deep or shallow water).
- The model recognized deep water to be more expensive than shallow waters.
- The field size is also assumed to increase with water depth.

4.1 PRODUCTION PROFILE RESULTS

The reservoir data used as input to draw up the production profile are presented in table 4.1.

It could be seen that for a lease of 2475 acres, all other conditions remaining constant, a stock tank oil initially in place (STOIIP) of 285.8MMSTB was obtained. Assuming the reservoir has a strong aquifer support, and then a 35% recovery factor is appropriately applied to obtain an ultimate recovery, Ur of approximately 100MMSTB of oil.

Table 4.1: Reservoir size assumptions

RESERVOIR DATA		
Thickness, h (ft)	h=	100
Porosity, Q	Q=	24%
Water saturation	Sw=	20%
FVF, (RB/STB)	Bo	1.29
Area, (Acres)	A=	2475
Recovery factor	Er=	35%
STOIIP, N (STB)	7758*Ah(1-Sw)Q/B =	285,783,070
Ultimate Recovery, Ur	Ur=N*Er =	100,024,074
Production before decline	32.5%	32,507,824
Recoverable reserve during decline,(STB)	Nr=	67,516,250

Given an instantaneous production rate of 1000stb/d, and peak production rate of about 40,000stb/d attained in 3 years, build up rates of -1.23, -0.547 and -0.325 per year were obtained for exponential, hyperbolic and harmonic reservoir depletion patterns respectively. Peak production was maintained for 2 years before inception of production decline. The production before decline inception was put at 32.5% of the ultimate recovery to leave recoverable reserve during decline at 67.5MMstb. Economic production rate was pegged at 100stb/d. This gave decline rates of 0.216, 0.425 and 1.296 per year for exponential, hyperbolic and harmonic reservoir depletion patterns

respectively. Table A1 of Appendix A shows a summary for the base case of input production data given the three decline patterns. The production forecasts are as presented in Fig A1 through Fig A3 of Appendix A. The results in the aforementioned figures were combined to obtain the comparative production patterns presented in figures 4.1 and 4.2.

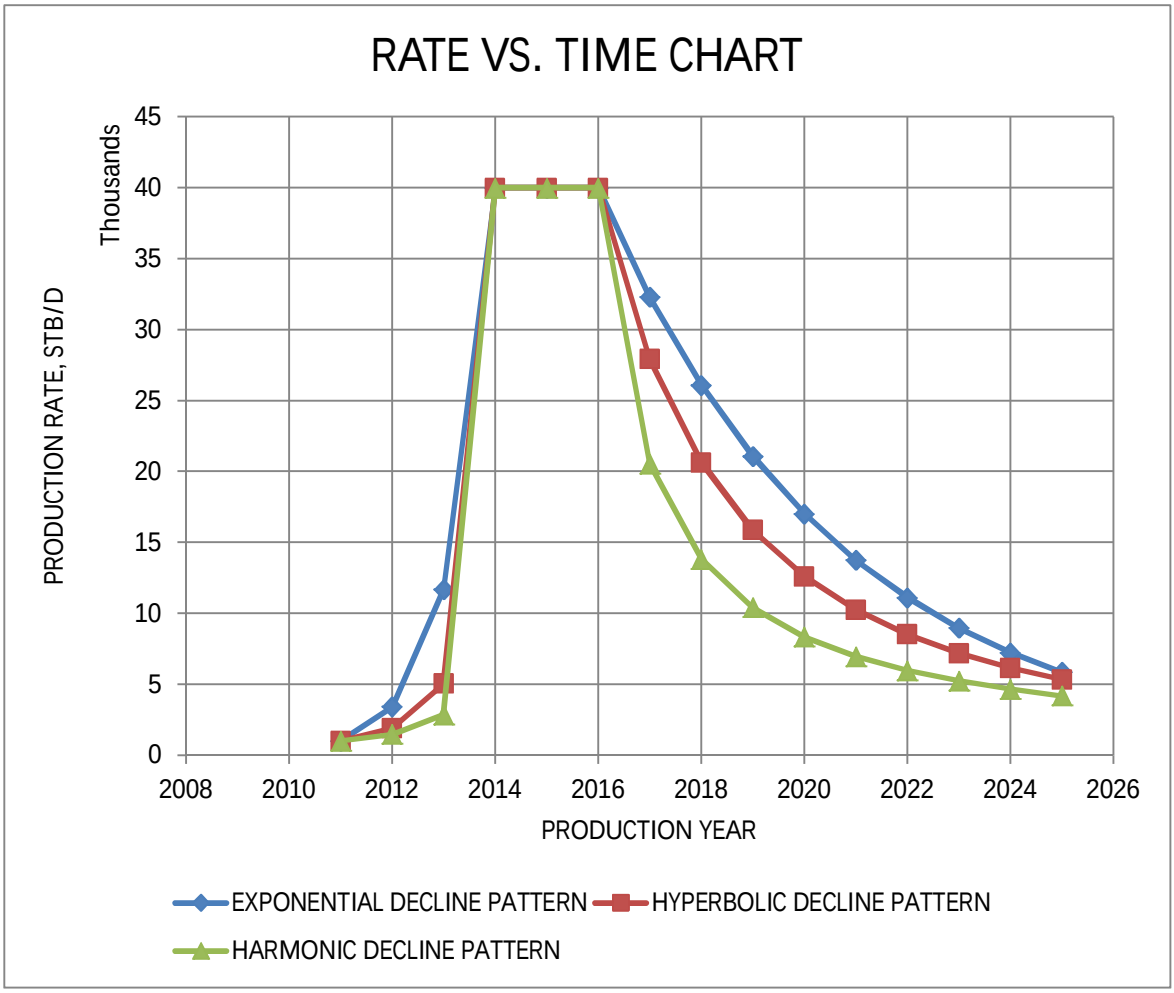


Fig 4.1: Production rate vs. time chart.

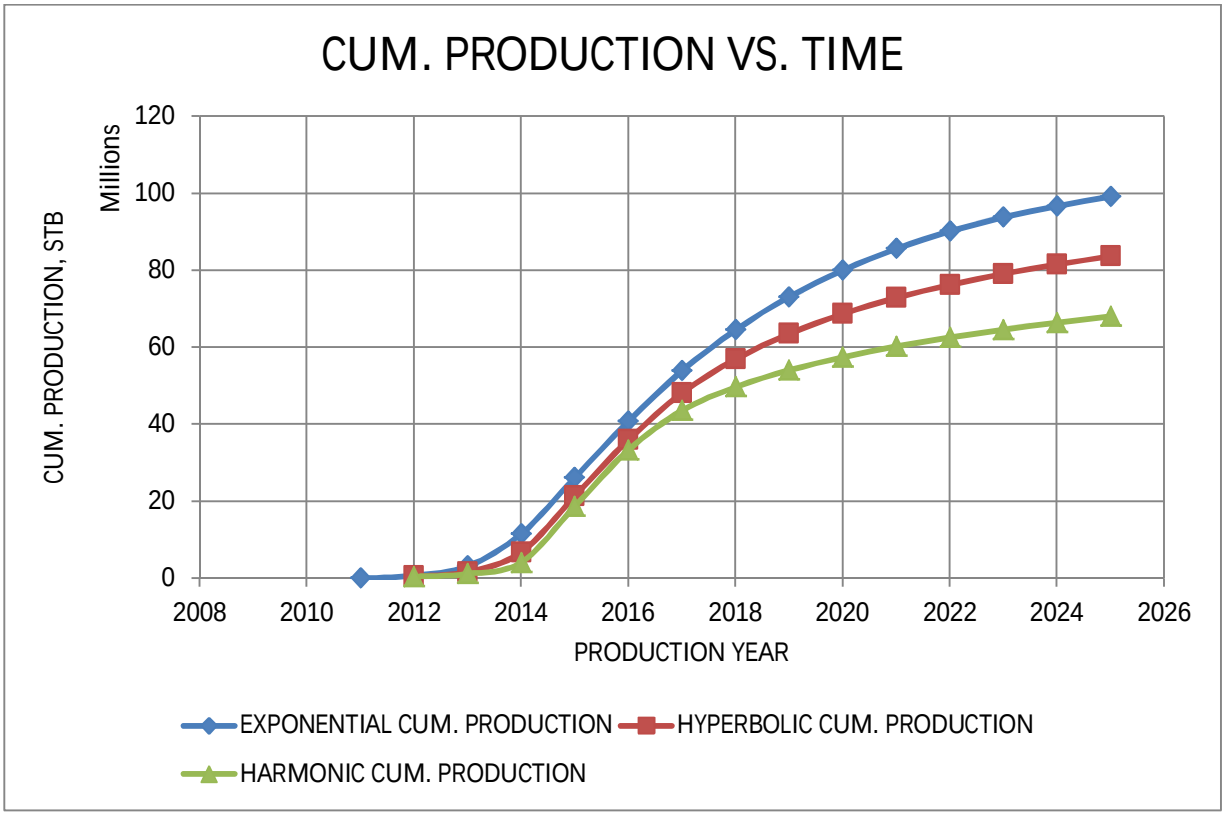


Fig. 4.2: Cumulative production vs. Time chart.

4.2 PRODUCTION PROFILE ANALYSES

Presented in this section is the analysis of the results obtained in the course of production as presented graphically in figures 4.1 and 4.2. It could be easily observed from these figures that given the time range between 2011 and 2025 for all decline patterns, that exponential decline pattern had the steepest rise from instantaneous to peak production. This was followed by hyperbolic and harmonic decline patterns, in that order. This means that at any point in time during the build-up period, a reservoir with exponential tendencies would be producing at slightly higher rates than hyperbolic and harmonic reservoirs in that order until close to plateau phase of production. During plateau phase, the model was constrained to produce at about 40MSTB/D for all the decline

patterns. Harmonic pattern showed the steepest decline than hyperbolic and exponential patterns in that order, within the time range under consideration.

Generally, it shows that reservoirs with exponential production pattern will always produce all the recoverable reserves in shorter time than reservoirs with hyperbolic behaviour, and reservoirs with harmonic behaviour will produce the recoverable reserves in the longest possible time as shown in the cumulative production-time curves of fig 4.2.

From all the results so far, it is tempting to believe that reservoirs with hyperbolic behaviour average those of exponential and harmonic behaviour, hence it could be said to give a more realistic reservoir prediction pattern. This is recommended if the reservoir behaviour is uncertain.

4.3 CASH FLOW RESULTS (DETERMINISTIC APPROACH)

This section would relate to the results of the interactions between productions, prices of oil, assumed costs of production and the imposed fiscal systems.

4.3.1 COST ANALYSES

The default technical cost used in the model is divided based on the location of production. Hence, for shallow and deep water operations the CAPEX and OPEX are presented in tables 4.2 and 4.3 below.

Deep water technical costs are assumed to be very high relative to what is obtainable in shallow waters or onshore. By the default assumptions in table 4.2, it is seen that the unit technical cost is about $20/STB in real terms of 2006, for a reservoir size of about 100MMSTB. With an oil price of $70/STB, a cost-price ratio of about 31% is attained.

The technical costs showcased in table 4.2 were treated in two ways for the purpose of this work:

- Expensed costs: these include the G & G, OPEX, exploration and appraisal drilling costs.
- Depreciated costs: these are the facilities, development and infill drilling costs.

The model used four different 5-year depreciation methods and considering the default assumed costs, the results are hereby presented in tables 4.4 to 4.7.

Table 4.2: Deep water total technical cost assumptions (in 2006 constant dollar).

DEEP WATER COST TREATMENT, (					2006	$ MILLIONS)		OPERATING COSTS			TOTAL
YEAR	G & G	EXPL. WE	APPRAIS/	DEVT WE	FACILITIE	INFILLS	TOTAL	FIXED	VARIABLE	TOTAL	COSTS
2006	10.00						10.00			-	10.00
2007	10.00						10.00			-	10.00
2008							-			-	-
2009		60.00					60.00			-	60.00
2010		60.00					60.00			-	60.00
2011			60.00				60.00			-	60.00
2012				57.00	100.00		157.00		4.00	4.00	161.00
2013				57.00	200.00		257.00		15.00	15.00	272.00
2014					300.00	114.00	414.00		50.00	50.00	464.00
2015					100.00	57.00	157.00		88.00	88.00	245.00
2016					100.00	57.00	157.00		88.00	88.00	245.00
2017						57.00	57.00		88.00	88.00	145.00
2018							-		88.00	88.00	88.00
2019							-		51.00	51.00	51.00
2020							-		41.00	41.00	41.00
2021							-		33.00	33.00	33.00
2022							-		27.00	27.00	27.00
2023							-		21.00	21.00	21.00
2024							-		17.00	17.00	17.00
2025							-		14.00	14.00	14.00
							1,399.00			625.00	2,024.00

Table 4.3: Shallow water technical cost assumptions (in 2006 constant dollar)

SHALLOW WATER COST TREATMENT, (2006 $ MILLIONS)								OPERATING COSTS			TOTAL
YEAR	G & G	EXPL. WE	APPRAIS/	DEVT WE	FACILITIE	INFILLS	TOTAL	FIXED	VARIABLE	TOTAL	COSTS
2006	5.00						5.00			-	5.00
2007	5.00						5.00			-	5.00
2008		6.00					6.00			-	6.00
2009		6.00					6.00			-	6.00
2010			10.00				10.00			-	10.00
2011			10.00				10.00			-	10.00
2012				9.00	60.00	9.00	78.00		0.46	0.46	78.46
2013				9.00	100.00	8.00	117.00		1.35	1.35	118.35
2014					150.00	10.00	160.00		3.98	3.98	163.98
2015					80.00	10.00	90.00		6.50	6.50	96.50
2016						9.00	9.00		6.50	6.50	15.50
2017						8.00	8.00		5.23	5.23	13.23
2018							-		3.05	3.05	3.05
2019							-		2.45	2.45	2.45
2020							-		1.97	1.97	1.97
2021							-		1.59	1.59	1.59
2022							-		1.28	1.28	1.28
2023							-		1.03	1.03	1.03
2024							-		0.83	0.83	0.83
2025							-		0.80	0.80	0.80
							504.00			37.01	541.01

STRAIGHT LINE DEPRECIATION

For the sake of comparative analysis with other methods of depreciation, a 20%, 20%, 20%, 20%, 20% rule was adopted for the results in table 4.4 below. The model also recognized that the fifth year depreciation factor could be 19% with 1% non-recoverable CAPEX. This is normally specified in the governing fiscal system.

Table 4.4 - 5-year Straight line depreciation.

YEAR END	DEPRECIABLE CAPEX	STRAIGHT LINE DEPRECIATION, ($ MILLIONS)								TOTAL CAPEX
2006	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-
2012	166.66	33.33	-	-	-	-	-	-	-	33.33
2013	275.54	33.33	55.11	-	-	-	-	-	-	88.44
2014	448.30	33.33	55.11	89.66	-	-	-	-	-	178.10
2015	171.71	33.33	55.11	89.66	34.34	-	-	-	-	212.44
2016	173.43	33.33	55.11	89.66	34.34	34.69	-	-	-	247.13
2017	63.59	-	55.11	89.66	34.34	34.69	12.72	-	-	226.51
2018	-	-	-	89.66	34.34	34.69	12.72	-	-	171.41
2019	-	-	-	-	34.34	34.69	12.72	-	-	81.75
2020	-	-	-	-	-	34.69	12.72	-	-	47.40
2021	-	-	-	-	-	-	12.72	-	-	12.72
2022	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-
		166.66	275.54	448.30	171.71	173.43	63.59	-	-	1,299.23

DECLINING BALANCE METHOD

There was a switch to straight line depreciation method considering the fiscal provision of 1% non-recoverable cost. By default, this rule has not been applied yet since it is fiscal system-

specific. Considering the same depreciable CAPEX used in the SLD, result obtained is presented in table 4.5 below.

Table 4.5- Declining balance method.

YEAR END	DEPRECIABLE CAPEX	DECLINING BALANCE METHOD WITH A SWITCH TO, SLD ($ MILLIONS)								TOTAL CAPEX
2006	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-
2012	166.66	66.66	-	-	-	-	-	-	-	66.66
2013	275.54	40.00	110.22	-	-	-	-	-	-	150.21
2014	448.30	24.00	66.13	179.32	-	-	-	-	-	269.45
2015	171.71	18.00	39.68	107.59	68.68	-	-	-	-	233.95
2016	173.43	18.00	29.76	64.56	41.21	69.37	-	-	-	222.89
2017	63.59	-	29.76	48.42	24.73	41.62	25.44	-	-	169.96
2018	-	-	-	48.42	18.54	24.97	15.26	-	-	107.20
2019	-	-	-	-	18.54	18.73	9.16	-	-	46.43
2020	-	-	-	-	-	18.73	6.87	-	-	25.60
2021	-	-	-	-	-	-	6.87	-	-	6.87
2022	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-
		166.66	275.54	448.30	171.71	173.43	63.59	-	-	1,299.23

SUM OF YEAR DIGITS DEPRECIATION METHOD

This method is considered as being independent of the SLD. The result of its application in the built model is presented in table 4.6 below. The same depreciable CAPEX used in the SLD applies here.

Table 4.6 - Sum of the years' digits depreciation.

YEAR END	DEPRECIABLE CAPEX	SUM OF YEAR METHOD, ($ MILLIONS)								TOTAL CAPEX
2006	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-
2012	166.66	55.55	-	-	-	-	-	-	-	55.55
2013	275.54	44.44	91.85	-	-	-	-	-	-	136.29
2014	448.30	33.33	73.48	149.43	-	-	-	-	-	256.24
2015	171.71	22.22	55.11	119.55	57.24	-	-	-	-	254.11
2016	173.43	11.11	36.74	89.66	45.79	57.81	-	-	-	241.11
2017	63.59	-	18.37	59.77	34.34	46.25	21.20	-	-	179.93
2018	-	-	-	29.89	22.89	34.69	16.96	-	-	104.42
2019	-	-	-	-	11.45	23.12	12.72	-	-	47.29
2020	-	-	-	-	-	11.56	8.48	-	-	20.04
2021	-	-	-	-	-	-	4.24	-	-	4.24
2022	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-
	1,299.23	166.66	275.54	448.30	171.71	173.43	63.59	-	-	1,299.23

UNIT OF PRODUCTION DEPRECIATION METHOD

This depreciation method depends on the depreciable asset as a function of cumulative production. Given the default depreciable CAPEX, the built model presented the following results as shown in table 4.7 below.

Table 4.7: Unit of production depreciation method

YEAR END	DEPRECIABLE CAPEX	UNIT OF PRODUCTION DEPRECIATION METHOD, ($ MILLIONS)								TOTAL CAPEX
2006	-	-	-	-	-	-	-	-	-	-
2007	-	-	-	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-
2011	-	-	-	-	-	-	-	-	-	-
2012	166.66	2.85	-	-	-	-	-	-	-	2.85
2013	275.54	9.84	4.71	-	-	-	-	-	-	14.56
2014	448.30	34.00	16.28	7.67	-	-	-	-	-	57.95
2015	171.71	59.68	56.22	26.48	2.94	-	-	-	-	145.32
2016	173.43	60.28	98.67	91.47	10.14	2.97	-	-	-	263.53
2017	63.59	-	99.66	160.54	35.03	10.24	1.09	-	-	306.57
2018	-	-	-	162.15	61.49	35.38	3.76	-	-	262.78
2019	-	-	-	-	62.10	62.10	12.98	-	-	137.19
2020	-	-	-	-	-	62.73	22.77	-	-	85.50
2021	-	-	-	-	-	-	23.00	-	-	23.00
2022	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-
	1,299.23	166.66	275.54	448.30	171.71	173.43	63.59	-	-	1,299.23

4.3.2 ANALYSIS OF THE DEPRECIATION METHODS

Given the results on cost depreciations presented so far in the previous section, the analysis is hereby presented. For each depreciation method used in this work, a plot of yearly depreciation distribution was obtained and shown in fig. 4.3 below. This plot shows how each depreciation method spreads out base case depreciable capital expenditure between production years 2012 and 2021. This distribution represents how fast these costs could be recovered either for accounting purposes or tax calculation purposes. From the chart, it could be observed that DBD and SOY gave higher prospects of CAPEX recovery early in the life of production. This could be good news for investors who may want to recover as much costs as

possible early enough. On the other hand, the UOP showed a smooth distribution that seemingly delayed prospects of early capital costs recovery, as it is tied to production. SLD seemed to average out the other methods of depreciation. Later within the years of cost recovery, the trend tends to reverse accordingly with more costs being obviously recovered through UOP, followed by SLD.

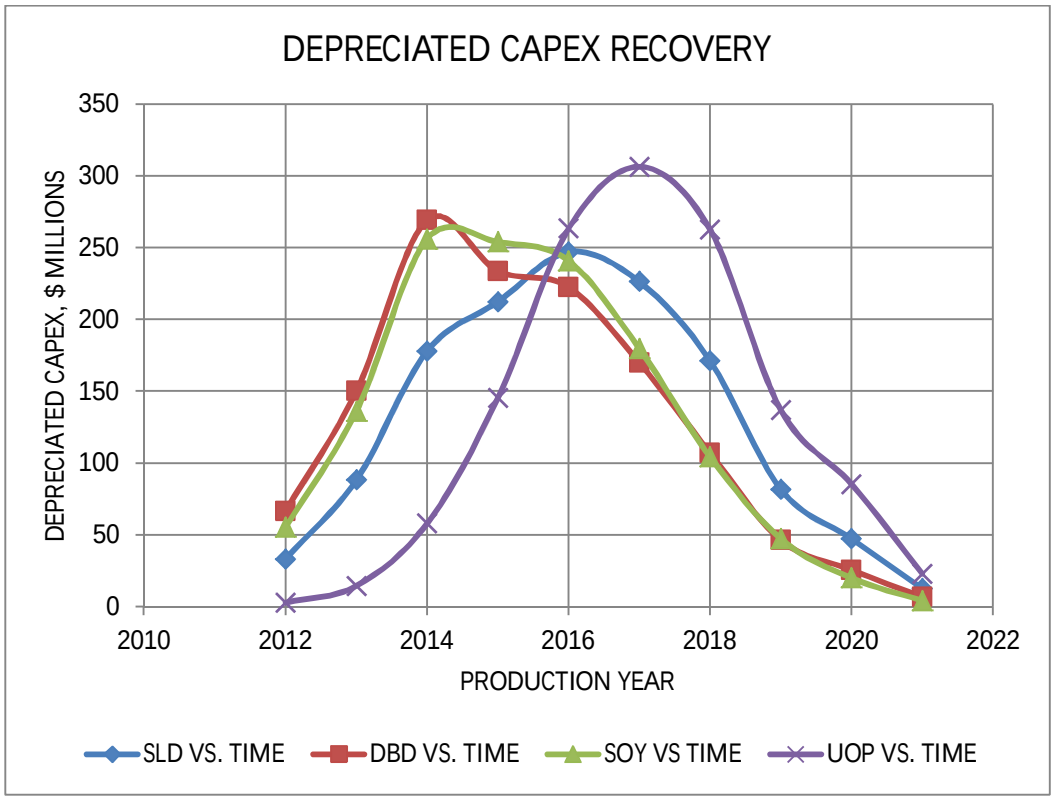


Fig. 4.3: Yearly CAPEX depreciation distribution

Since all the costs must be recovered, it is important that a track be kept on the cumulative recovered costs as production progressed from 2012 to 2021. Fig 4.4 shows the total depreciated CAPEX that may have been recovered given the different methods of depreciation.

From the base case presented all the costs will have been recovered by 2021. Before this time, the chart shows that the investor will recover his investment fastest, if DBD or SOY depreciation

is used. For example, by 2018, DBD, SOY, SLD and UOP will have recovered approximately 94%, 94%, 89% and 81% of the total depreciable CAPEX respectively.

It should however be noted that this behavior does not compare accordingly with variations in profitability measures when implemented under a fiscal regime.

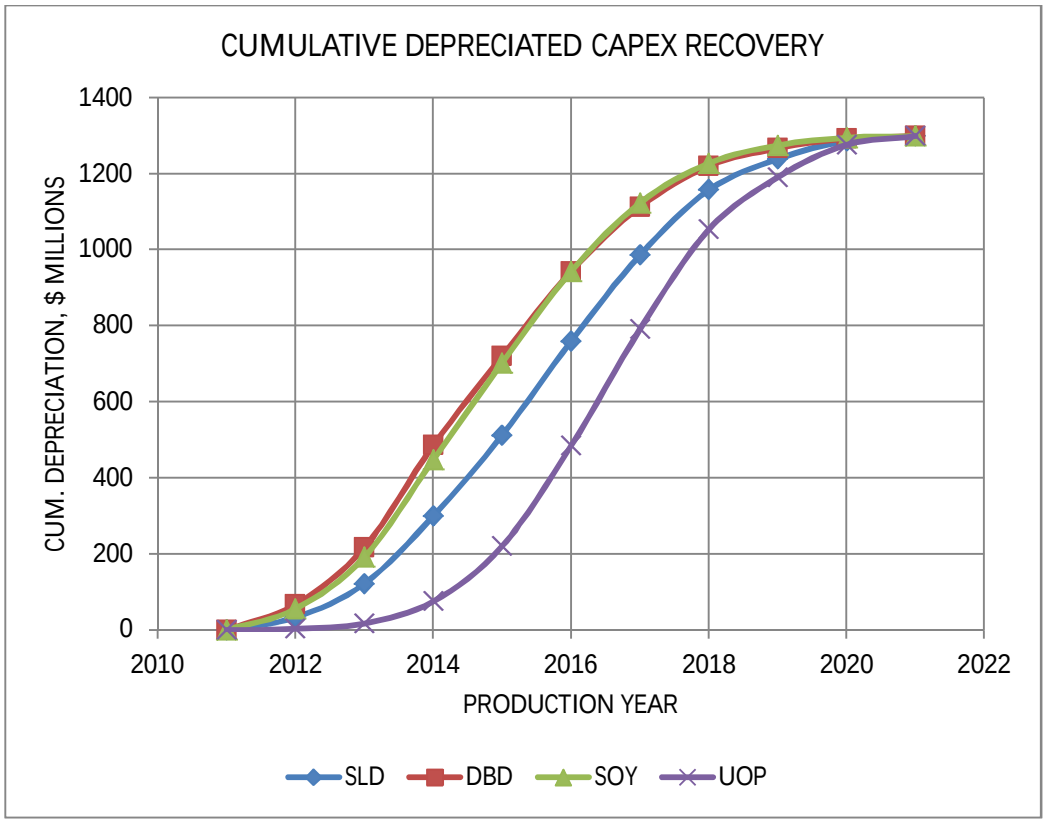


Fig. 4.4: Cumulative CAPEX depreciation

4.4 ECONOMIC METRIC MEASURES

Economic metrics are the profitability indicators used in screening options or ranking projects. In this work several of these were employed and they include

- Net present value (NPV) @12.5%

- Internal rate of returns (IRR)
- Profitability indices
- Payout period
- Discounted contractor takes
- Unit technical cost

4.4.1 DETERMINISTIC RESULT ASSUMPTIONS

The following assumptions were made to arrive at the results presented in this section. These include:

- Oil price of $70/STB
- Oil price escalation of 1%
- Cost assumptions presented in section 4.3.1 also applied
- All operating and exploration costs were expensed
- All development and facilities costs were 100% depreciated
- Field size of 100MMSTB was used
- Peak production was fixed at 0.04% of field size per day and lasted for two years
- Production build up lasted for three years from 1000 STB/D till peak capacity.
- Economic limit was constrained at 100 STB/D
- The hyperbolic decline curve exponent, b was taken to be 0.5194
- 1000 m of water depth was considered to be representative of deep offshore location
- All other terms of the fiscal systems used were applied accordingly.

4.4.2 EMPIRICAL RESULTS

Several scenarios created were tested against these measures and the results obtained are presented in this section. The aim of these combinations is to arrive at optimal input methods that would bring about the best economic benefits to the investor.

Different combinations of three production decline patterns and four depreciation methods produced twelve scenarios for each considered fiscal system. The full classifications and results are given summarized subsequently in tables 4.8 and 4.9 for PIB 2009 and 2005 PSC fiscal systems respectively. The graphical representations of these results were also made available in appendix B. It should be noted that these results are purely deterministic and resulted from changing of decline and depreciation variables in the built model.

4.4.3 DETERMINISTIC RESULTS FOR PIB 2009 FISCAL SYSTEM

The results are presented on the basis of some distinct metric measures tested. Based on the payout period, the following observations were made

- Evaluating a field or reservoir by applying UOP method of depreciation, showed on the average, the shortest payout period irrespective of the pattern of production decline the field or reservoir assumed.
- The UOP depreciation when applied to a reservoir that declined exponentially, turned out to give the overall shortest payout period, while a harmonically declining reservoir whose evaluation was done using DBD depreciation gave the longest payback period.
- When applied on any decline pattern, DBD and SOY presented similar results.

Based on the net present value at a base case discount rate of 12.5%, discounted contractor take, IRR and profitability index, the following observations were made

- Cash flow analysis based on UOP depreciation would produce the most favourable economic measures for any decline method, when weighed against other depreciation methods.
- A reservoir declining exponentially showed better economic measures than any other decline method irrespective of the depreciation method applied in the cash flow evaluation.

Table 4.8: PIB 2009 Economic Measures for Deep Water Investment.

SCENARIO	DEPR.	DECLINE TYPE	SYSTEM METRIC MEASURES, PIB 2009					
			PAYOUT	NPV	IRR	PI	DCT	UNIT TC
1	SLD	EXPONENTIAL	7.78	$255.18	27.60%	1.35	19.20%	22.09
2	DBD		8.33	$239.69	26.00%	1.31	18.50%	22.09
3	SOY		8.27	241.12	26.20%	1.32	18.60%	22.09
4	UOP		7.50	274.55	29.70%	1.40	20.00%	22.09
5	SLD	HYPERBOLIC	8.64	$176.07	22.80%	1.24	16.20%	22.37
6	DBD		8.99	147.13	20.50%	1.19	14.00%	22.37
7	SOY		8.95	152.44	20.50%	1.20	14.50%	22.37
8	UOP		8.04	207.39	25.80%	1.31	18.20%	22.37
9	SLD	HARMONIC	8.92	$86.81	18.00%	1.12	10.90%	22.37
10	DBD		9.47	46.53	15.20%	1.06	6.10%	22.37
11	SOY		9.40	53.51	15.60%	1.07	7.00%	22.37
12	UOP		8.33	125.93	21.70%	1.19	14.70%	22.37

Where

Payout is in years

NPV is in $ Millions

Unit TC is in $/STB

- It was also observed generally that the DBD and SOY depreciation methods showcased similar profitability metric trends for a given decline pattern.
- An exponentially declining production evaluated using UOP depreciation method presented the most profitable venture in terms of project ranking.

4.4.4 DETERMINISTIC RESULTS FOR 2005 PSC FISCAL SYSTEM

The results obtained from the 2005 PSC model would follow the presentation pattern established in the previous section. Based on the payout period, the following observations were made

- On the average, for a given decline pattern, the UOP depreciation method also showed the least payback period.
- Specifically, exponentially declining production whose cash flow evaluation was based on UOP depreciation gave the shortest payback time while that exhibiting harmonic decline with DBD depreciation, gave the longest payback time.
- The trend of DBD and SOY showing similar payback period for any decline pattern was also observed.

Based on NPV, IRR or discounted contractor take, the following were observed.

- It appeared that SLD and UOP depreciation methods had similar results given any production decline method. However, applying SLD on exponential production decline gave slightly more favourable NPV than when UOP depreciation was applied.

Table 4.9: 2005 PSC Economic Measures for Deep Water Investment.

SCENARIO	DEPR.	DECLINE TYPE	SYSTEM METRIC MEASURES, PSC 2005					
			PAYOUT	NPV	IRR	PI	DCT	UNIT TC
1	SLD	EXPONENTIAL	7.80	$237.66	28.10%	1.33	17.90%	22.09
2	DBD		8.32	$207.70	25.70%	1.27	16.10%	22.09
3	SOY		8.23	210.69	26.10%	1.28	16.30%	22.09
4	UOP		7.56	231.33	28.50%	1.34	16.80%	22.09
5	SLD	HYPERBOLIC	8.53	$168.11	23.50%	1.23	15.50%	22.37
6	DBD		8.75	136.54	20.90%	1.18	13.00%	22.37
7	SOY		8.72	139.72	21.30%	1.18	13.30%	22.37
8	UOP		8.01	178.2	25.00%	1.26	15.60%	22.37
9	SLD	HARMONIC	8.75	$109.80	20.00%	1.15	13.80%	22.37
10	DBD		9.01	75.15	17.30%	1.10	9.90%	22.37
11	SOY		8.97	78.73	17.60%	1.10	10.30%	22.37
12	UOP		8.48	109.65	21.00%	1.16	12.80%	22.37

Where

Payout is in years

NPV is in $ Millions

Unit TC is in $/STB

- Also for each depreciation method, exponential production decline gave the most favourable NPV while harmonic decline was obviously, the least.

- Exponential production decline with UOP depreciation applied showed the best IRR of 28.5% though it had the second best NPV.
- It was equally noted that in any decline method a production assumed, UOP depreciation method yielded the best IRR.
- In all, exponential production decline with SLD depreciation provided the most favourable discounted contractor take of about 18% while harmonic production decline with DBD depreciation had the least DCT of about 10%.

In the course of the sensitivity, it was generally observed that production with exponential decline would require less unit technical cost than others for all the considered fiscal systems. This is due to shorter production time provided by the exponentially declining production, hence OPEX is reduced.

PIB 2009 provided a slightly shorter payout period for exponential decline than in 2005 PSC and the reverse for both hyperbolically and harmonically declining productions for all depreciation methods except for UOP in harmonically declining production.

Respective NPVs for exponentially and hyperbolically declining productions were higher for PIB 2009 than 2005 PSC. However, NPV for harmonically declining production in 2005 PSC appeared to be better than that of PIB 2009 except for harmonic decline productions in the face of UOP depreciation method.

UOP was the most favourable depreciation method for both fiscal systems irrespective of the decline pattern. Finally, PIB 2009 provided the contractor with higher discounted take than 2005 PSC fiscal system.

4.5 CASH FLOW RESULTS (STOCHASTIC APPROACH)

This section presents the results obtained when the model was subjected to probabilistic variations of some input parameters. @RISK was used to carry out the simulations under different runs as the case may require. @RISK is an add-in tool in MS Excel capable of running simulations using the Monte Carlo approach. This process would be applied to the model under PIB 2009 and subsequently 2005 PSC fiscal systems. The process followed in section 4.3.3 would be a guide. The aim would be to have economic metric measures that are at least 50% probable given a range of input variables.

4.5.1 SIMULATION ASSUMPTIONS

The stochastic variables assumed include

- Crude oil price: This was given a triangular statistical distribution
- Lease acreage: This is in direct variation with reservoir size. It assumed a log normal distribution.
- Peak capacity: This is the peak production rate and it assumed a log normal distribution.
- CAPEX: This forms the basis for variations in depreciation methods. It assumed a triangular distribution.
- Cumulative production before the start of decline
- 1000 iterations were done in a two simulation runs.

The table below is a sample of the applied stochastic variables used in the simulation runs.

Table 4.10 - Sample of stochastic variables used.

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	Name	Worksheet	Cell	Sim#	Graph	Min	Mean	Max
	INPUT LEASE AREA FOR DEEP (ACRES)	STOIIP INPUT	H9	exponential UOP1	2,000 6,500	2485.747	2723.184	6171.774
	INPUT LEASE AREA FOR DEEP (ACRES)	STOIIP INPUT	H9	exponential UOP2	2,000 6,500	2487.656	2723.443	6270.796
Category: CAPEX, % OF TOTAL REVENUE								
	CAPEX, % OF TOTAL REVENUE / BONUSES	FISCAL TERMS	C19	exponential UOP1	18% 32%	20%	25%	30%
	CAPEX, % OF TOTAL REVENUE / BONUSES	FISCAL TERMS	C19	exponential UOP2	18% 32%	20%	25%	30%
Category: OIL PRICE, $/STB								
	OIL PRICE, $/STB / NOMINAL	FISCAL TERMS	C6	exponential UOP1	55 105	60.88445	80.00038	99.39849
	OIL PRICE, $/STB / NOMINAL	FISCAL TERMS	C6	exponential UOP2	55 105	60.55759	79.99957	99.17567
Category: Production before decline								
	Production before decline / Ur=N*Er =	STOIIP INPUT	E15	exponential UOP1	30% 65%	30.5%	33.4%	61.2%
	Production before decline / Ur=N*Er =	STOIIP INPUT	E15	exponential UOP2	30% 100%	30.5%	33.4%	93.8%
Category: Ratio of qpeak to UR								
	Ratio of qpeak to UR / DATA ASSUMED FOR PRODUCTION PROFILE	INPUT PROD.	G7	exponential UOP1	0.035% 0.080%	0.040%	0.044%	0.078%
	Ratio of qpeak to UR / DATA ASSUMED FOR PRODUCTION PROFILE	INPUT PROD.	G7	exponential UOP2	0.035% 0.080%	0.040%	0.044%	0.077%

The objective functions are the economic metric measures. They are functions that depend on the stochastic variables. The aim is to find their minimum, maximum and the most likely values. They include

- NPV @ 12.5% discount rate
- IRR

- Contractor take
- Unit technical cost
- PI
- Payout period

4.5.2 SIMULATION RESULTS FOR PIB 2009 FISCAL SYSTEM

The results presented in this section are on the basis of five input variables applied on six metric measures listed above. These are summarized in the table 4.11 below.

Based on the payout period, the following observations were made.

- Just like in the deterministic approach, it was confirmed that evaluating a field or reservoir by applying UOP method of depreciation, would always give the shortest payout period range while applying DBD method would produce the longest range of payout.

  Specifically, applying UOP depreciation on an exponentially declining reservoir showed the shortest payout range from 7.25 to 7.93 years with the most likely payout period being 7.68 years. There is a 50% confidence that the shortest payout would range from 7.63 to 7.77 years. On the contrary, a harmonically declining reservoir evaluated using DBD method would have the longest payout ranging from 8.88 to 15.24 years.

Table 4.11: PIB 2009 Stochastic Economic Metric Measures for Deep Water Investment.

SCENARIO	DEPR.	DECLINE TYPE	SYSTEM METRIC MEASURES, PIB 2009																	
			PAYOUT, YEARS			NPV ($ MILLIONS)			IRR, %			PI			DCT, %			UNIT TC, $/STB		
			MIN	MAX	MODE	MIN	MAX	MODE	MIN	MAX	MODE	MIN	MAX	MODE	MIN	MAX	MODE	MIN	MAX	MODE
1	SLD	EXPONENTIAL	7.78	8.75	8.15	78.82	560.15	220.44	17.3%	31.8%	24.1%	1.07	1.45	1.20	8.4%	20.4%	16.0%	19.45	35.96	27.87
2	DBD		7.92	9.56	8.96	16.90	445.66	206.47	13.8%	31.7%	21.2%	1.02	1.45	1.15	2.2%	19.6%	13.8%	18.55	36.13	29.22
3	SOY		N/A	N/A	N/A	N/A	N/A	218.73	N/A	N/A	21.7%	0.52	1.35	1.19	N/A	N/A	13.4%	N/A	N/A	28.38
4	UOP		7.25	7.93	7.68	97.21	645.37	261.47	20.8%	36.8%	25.3%	1.12	1.76	1.29	9.9%	21.6%	15.9%	14.51	36.13	28.38
5	SLD	HYPERBOLIC	8.34	9.46	8.85	(27.52)	348.35	116.15	10.1%	28.8%	19.2%	0.97	1.39	1.15	-4.5%	18.3%	10.1%	19.87	36.84	28.08
6	DBD		8.63	10.59	9.72	(74.55)	299.96	103.39	6.7%	25.9%	16.5%	0.93	1.31	1.09	-14.4%	16.3%	11.2%	20.40	36.84	28.08
7	SOY		N/A	10.49	9.73	N/A	N/A	87.25	7.1%	N/A	17.5%	0.54	1.29	1.10%	-76.8%	N/A	7.4%	N/A	N/A	28.88
8	UOP		7.93	8.39	8.11	89.40	512.71	160.16	14.4%	32.7%	21.4%	1.02	1.54	1.20	2.6%	20.3%	13.4%	18.14	36.84	28.08
9	SLD	HARMONIC	8.65	10.23	9.17	(141.68)	254.10	(45.57)	2.1%	24.3%	12.0%	0.89	1.26	0.99	-24.0%	15.5%	-1.4%	20.42	36.84	26.89
10	DBD		8.88	15.24	9.96	(270.28)	195.84	(81.57)	4.8%	21.0%	10.5%	0.84	1.19	0.93	-44.8%	12.3%	-8.3%	20.42	36.84	26.89
11	SOY		8.85	14.71	9.81	(248.30)	205.90	(65.24)	5.1%	21.6%	10.2%	0.84	1.20	0.95	-42.8%	12.9%	-4.7%	20.42	36.84	26.89
12	UOP		8.19	N/A	8.49	(97.21)	306.96	37.79	5.1%	28.5%	16.3%	0.91	1.35	1.02	-16.1%	17.7%	4.3%	20.42	36.84	26.89

On the basis of other economic metric measures, the following were also observed.

- For each decline pattern, UOP depreciation produced the most the most favourable NPV range. Specifically, exponentially declining production evaluated by UOP method had the highest NPV range between $ 97.21MM to $645.37MM with the most likely NPV of $ 261.47MM. There is a 50% confidence level that the NPV would range between $ 247MM and $ 304MM.
- Generally, irrespective of the depreciation method used in cash flow evaluation, exponential decline pattern seemed the best in terms of general economic measures when weighed against other decline patterns. Harmonic decline, under the governing assumptions, would most likely turn out uneconomic. This makes it the worst economic reservoir scenario examined.

4.5.3 SIMULATION RESULTS FOR 2005 PSC FISCAL SYSTEM

The results obtained from the 2005 PSC model would follow the presentation pattern established in the previous section. The summary of the result is presented in Table 4.12 below.

Based on the payout period, the following observations were made

Reservoir evaluation based on UOP method of depreciation equally showed the shortest payout, irrespective of the reservoir decline pattern prevailing.

Table 4.12: 2005 PSC Stochastic Economic Metric Measures for Deep Water Investment.

SCENARIO	DEPR.	DECLINE TYPE	SYSTEM METRIC MEASURES, PSC 2005																	
			PAYOUT, YEARS			NPV ($ MILLIONS)			IRR, %			PI			DCT, %			UNIT TC, $/STB		
			MIN	MAX	MODE	MIN	MAX	MODE	MIN	MAX	MODE	MIN	MAX	MODE	MIN	MAX	MODE	MIN	MAX	MODE
1	SLD	EXPONENTIAL	7.54	8.40	7.86	100.90	731.67	246.38	20.7%	34.3%	27.4%	1.12	1.57	1.29	13.0%	23.9%	18.3%	16.99	35.87	28.2
2	DBD		7.69	8.88	8.48	90.82	617.87	291.75	18.4%	34.9%	22.7%	1.10	1.57	1.22	11.1%	25.5%	15.3%	18.50	36.13	29.22
3	SOY		N/A	11.46	N/A	N/A	628.76	257.03	4.2%	30.3%	22.6%	0.48	1.40	1.21	N/A	N/A	15.5%	N/A	N/A	28.38
4	UOP		7.43	7.77	7.65	13.02	675.45	308.58	14.3%	30.0%	27.6%	1.02	1.44	1.30	1.5%	19.4%	17.8%	14.51	36.13	28.38
5	SLD	HYPERBOLIC	8.28	8.87	8.66	(69.41)	501.70	176.84	17.0%	29.7%	21.5%	0.93	1.41	1.19	-14.3%	20.5%	14.3%	19.77	36.59	27.89
6	DBD		8.49	9.52	8.98	(51.41)	467.30	139.51	7.3%	29.1%	17.5%	0.95	1.41	1.10	-11.9%	21.0%	11.4%	20.42	36.84	28.08
7	SOY		N/A	10.67	8.85	N/A	421.40	171.45	7.5%	29.4%	17.7%	0.56	1.41	1.11	-32.5%	N/A	11.7%	N/A	N/A	28.88
8	UOP		7.83	8.38	8.06	(194.46)	465.51	220.36	19.7%	27.5%	23.9%	0.78	1.34	1.25	-34.6%	16.7%	16.3%	18.14	36.84	28.08
9	SLD	HARMONIC	8.62	9.26	8.79	(143.34)	314.08	97.01	11.4%	25.3%	18.0%	0.85	1.29	1.09	-42.0%	18.0%	11.7%	20.29	36.59	26.72
10	DBD		8.70	N/A	9.42	(129.33)	337.77	48.51	0.1%	24.8%	14.5%	0.87	1.29	1.02	-45.1%	18.5%	7.9%	20.42	36.84	26.89
11	SOY		8.68	N/A	9.39	(124.00)	339.46	53.39	0.1%	25.1%	14.8%	0.88	1.29	1.02	-42.5%	18.6%	7.9%	20.42	36.84	26.89
12	UOP		8.28	N/A	8.55	(278.06)	151.07	60.33	5.4%	21.5%	16.6%	0.68	1.17	1.05	-65.7%	10.2%	8.5%	20.42	36.84	26.89

Specifically, exponentially declining production pattern evaluated by means of UOP depreciation presented the shortest payout period that ranged from 7.43 to 7.77 years with the most likely being 7.65 years. There is a confidence level of 50% placed on the range 7.61 and 7.68 years. The longest payout period in the scenarios examined came from the harmonically declining production family.

On the basis of other economic metric measures, the following were also observed.

- Given the governing assumptions, exponentially declining production presented the best economic scenario with no possibility of the venture entering into uneconomic phase, unlike the other decline methods.
- If SLD depreciation method is used in evaluating cash flow for an exponentially declining production, the venture will appear to have the highest NPV range from $ 100.9MM to $ 731.67MM with most likely NPV as $ 246.38 and 50% confidence level ranging between $ 253MM and $ 339MM.
- The previous scenario showed a discounted contractor take between 17.36% and 19.12% at 50% confidence level. However, the maximum DCT of 25.5% came from the exponentially declining production with DBD as depreciation method. A maximum productivity index of 1.57 was observed for both exponential DBD and SLD.
- On the average, exponentially declining production with SLD depreciation produced the best economic metric measures when compared with other decline-depreciation scenarios examined.

In a concluding sense, it could be observed that the 2005 PSC provided more discounted take to the contractor than the PIB 2009. The maximum DCT observed for 2005 PSC was 25.5% while that for PIB 2009 was 21.6%. This is contrary to what was observed in the deterministic approach which presented more DCT in PIB 2009 than in 2005 PSC (20% against 17.9%).

More detailed results with graphs could be found in Appendix C.

CHAPTER FIVE

CONCLUSIONS AND RECOMMENDATIONS

5.0 OVERVIEW

Investment in the petroleum industry requires huge risk capital. Therefore, the investor is attracted to a clime that guarantees him early return on investment as well as maximum profit. The petroleum fiscal system (PFS) contains the terms and conditions that govern E & P business in any clime, hence constitutes an uncertainty indicator that influences investor's profit.

Nigeria with huge oil reserves tries to reduce the uncertainties of investment inherent in her PFS to lure better technology and economic development by changing from one fiscal regime to another over time.

This research investigated how production decline patterns and cost depreciation methods encountered in a fiscal regime could affect the rewards of investment. To achieve this, production and cost assumptions reflecting Niger-Delta offshore basin were used to formulate spreadsheet cash flow models for different fiscal regimes in Nigeria.

5.1 INTRODUCTION

E & P business in Nigeria has a long history. It became prominent shortly after Shell completed the first well, Oloibiri – 1 in 1956. Today, the oil reserve has grown up to 37.2 billion barrels, which is enviable in the world scale. These reserves are found both offshore and onshore. Following the

world trend, offshore production in Nigeria is on the increase when compared to onshore operations in recent years.

Petroleum project evaluation involves determining the volume of reserves that is recoverable within prevailing economic and technological realities. This is done for tax accounting, financing, budgeting and unitization purposes as well as setting of depreciation and decline rates for future production predictions.

Production estimation could be done by many methods. This research adopted production by decline trend analysis which involves curve-fitting the past production performance using rate – time data and extrapolating the curve to predict future performance. The assumption is that the conditions surrounding past production remain the same in the future. Compared to other methods, decline analysis requires minimum amount of data.

By Arps' concepts, a reservoir can decline naturally in three ways: exponential, hyperbolic and harmonic. Exponential decline is easier to compute and presents conservative estimates of production. Hyperbolic decline is the most realistic but difficult to compute while the harmonic is rarely encountered in natural reservoirs.

The economics of petroleum business considers production performance evaluation, oil and gas price, cost implications and the prevailing fiscal regime.

Price of crude oil is a major factor that drives E & P activities though it is the most uncertain economic item considered during evaluation.

Cost of production varies from one location to another. Deepwater investment requires higher risk capital than onshore investment. The fiscal regime may stipulate how these costs are treated. A cost can either be expensed or depreciated for cost recovery and tax calculation purposes. Tangible CAPEX can be depreciated in any of the following methods: straight line depreciation (SLD), sum of years' digits depreciation (SOY), declining balance depreciation (DBD) and unit of Production depreciation (UOP).

There are two most common fiscal regimes operational in the oil and gas business. They are Royalty & Tax (R/T) and production sharing contracts (PSC). In Nigeria, Joint venture agreements (JVA) and PSC are the mostly operational. JVA is basically R/T with government participation. Most deepwater operations are under PSC regimes. Government participation in the PSC cannot be eliminated, though not common. Nigeria has different series of PSC used in the deepwater ventures. These are 1993, 2003 and 2005 PSCs. The petroleum industry bill when passed into an Act will become part of the existing PSC series.

5.2 METHODOLOGY

The spreadsheet modelling approach similar to that adopted by Mian, Johnston and Iledare was used in this study. Assumptions of a prolific offshore field with huge oil reserve, good recovery factor, reasonable peak production capacity and decision-based decline patterns were made.

Production profile was first developed by transforming all the Arps equations into an automated spreadsheet based program. This program can automatically generate production forecasts under exponential, hyperbolic and harmonic decline conditions.

Oil price was applied to the production forecasts to generate gross revenue. The price was made to be either real or nominal by choice.

Front loaded government payments, FLGT were determined from the gross revenue and eligible technical costs based on the stipulations of two fiscal systems: PSC 2005 and the proposed 2009. These payments included royalties, rentals, signature bonuses, NDDC and institutional levies if required. The payments are not tied to profits.

Costs were treated in two ways: exploration CAPEX and operating costs which were expensed hence recovered in the year they were incurred; development costs which were depreciated hence they were spread beyond the year incurred.

Depreciation method applied was made a decision variable which presented an option of SLD, SOY, DBD or UOP in the model.

Cost recovery specifications of the fiscal regimes imposed on the model. Eligible recoverable costs were determined and removed from the cost oil which was obtained by removing the royalties from the gross revenue and multiplying by cost recovery limit factor. This was used to recover all eligible costs in a production year. Costs not recovered were carried forward indefinitely until they were fully recovered. The difference between the gross revenue and the cost oil gave the profit oil. Excess cost recovery, ECR was the cost oil after all the eligible costs had been recovered. ECR and the profit oil were shared between the host government and the contractor based on respective fiscal provisions.

Before income tax (BIT) cash flow was developed in the model by applying certain taxes and levies which were not the federal income taxes. These were strictly defined by the respective fiscal

systems, given that tax deductible items could vary from one fiscal system to another. For PIB 2009, the BIT was basically a cash flow for Nigerian Hydrocarbon Tax (NHT) calculations. For the 2005 PSC, it was basically a cash flow for education tax calculations. The host government BIT take, HGT_{BIT} was obtained as the sum of FLGT, share of profit oil and the non-federal income tax, while the contractor BIT take, $CT_{BIT}$was obtained by subtracting $HGT_{BIT}$and technical costs from gross revenue.

After income tax (AIT) cash flow was developed in the model by applying the federal income tax to assessable profit, as defined by the respective fiscal systems. In PIB 2009, the AIT cash flow included calculations for corporate income tax (CITA) and education tax. In 2005 PSC, it involved calculations for petroleum profit tax (PPT).

The host government AIT take, HGT_{AIT} for the PIB 2009 model was the sum of HGT_{BIT},

CITA and education tax, while in 2005 PSC, it was the sum of HGT_{BIT}, host government share of profit oil (HGT_{PO}) and PPT. the contractor take in both fiscal regimes was the difference gross revenue and the sum of the HGT_{AIT} and technical costs.

To measure the viability of a venture, profitability indicators were included in the model. These are objective measures of the economic worth of the investment. The y include net present value (NPV), internal rate of returns (IRR), payout period, profitability index (PI), growth rate of returns (GRR) and unit technical costs. These economic metrics were used as objective functions in both deterministic and stochastic approaches.

5.3 RESULTS AND DISCUSSIONS

The results obtained from the spreadsheet cash flow were both deterministic and probabilistic. The same production and cost assumptions applied to both 2005 PSC and the PIB 2009 fiscal models.

The deterministic results for PIB 2009 model revealed that an exponentially declining production evaluated using UOP depreciation method presented the contractor with the most favourable profitability metrics when compared with other decline – depreciation scenarios considered. For 2005 PSC, the most favourable profitability metrics for contractors came from an exponentially declining production evaluated using SLD method. However, for quickest payout, the UOP depreciation was the best for both fiscal systems irrespective of the decline pattern.

For stochastic results, different statistical variables distributions were assigned to crude oil price, reservoir size, peak capacity and CAPEX. The depreciation methods and production decline patterns combinations were made decision variables. By means of @RISK, an Ms Excel add-in, several simulation runs were performed and the profitability indicators observed.

The results for the PIB 2009 model confirmed that the best economic metrics for the contractor came from an exponentially declining production evaluated by means of UOP depreciation. Also irrespective of the decline pattern a reservoir might undertake, evaluation by UOP depreciation would always maximize contractor's profitability when compared with results from other depreciation methods.

The results for the 2005 PSC model revealed that on the average, exponentially declining production evaluated by SLD method yielded the best economic metrics for the contractor when compared with other decline – depreciation scenarios examined. However, for quicker investment payout, the

UOP depreciation presented the best option irrespective of the decline pattern undertaken by the production.

Generally, stochastic results showed that the contractor had slightly more favourable economic metric measures under 2005 PSC than in the PIB 2009 cash flow model.

5.4 CONCLUSIONS

Different results were obtained and the following conclusions could be drawn.

- Discounted cash flow models were successfully developed based on 2005 PSC and PIB 2009 fiscal systems.
- Production decline patterns and tangible CAPEX depreciation were successfully integrated into the models developed.
- Both deterministic and probabilistic results were obtained from the models built.
- These results were based on the base case input assumptions which had oil price fixed at $ 70/ STB; the unit technical cost was put at about $ 20/STB; the considered terrain was deep water; exploration costs were expensed while development costs were fully depreciated; field size was taken to be about 100MMSTB and 0.04% of the field size per day was used as the peak capacity.
- The deterministic results under PIB 2009 showed that applying UOP method of depreciation to a reservoir declining exponentially offered the most favourable economic metric measures to the contractor, while SLD method was the most favourable under 2005 PSC, given the same production decline pattern.

- @RISK was used to solve the uncertainty question raised by some stochastic variables such as crude oil price, field size, peak production, depreciable CAPEX and cumulative production before inception of decline.
- The stochastic results also confirmed the deterministic results. However, it became clearer that 2005 PSC would allow the contractor a maximum discounted take of 25.5% while PIB 2009 would only allow up to 21.6%.

5.5 RECOMMENDATIONS

The following recommendations could be considered for future study;

- Inter-agency Team (IAT) version of the PIB 2009 was used in this work. It is hereby recommended that other versions such as the Senate version be used in similar analysis.
- Incremental sliding scale royalty system was used as described in the PIB 2009 redraft. However, a straight line sliding scale system in which the equation of a straight line is used is hereby proposed.
- This work considered only single phase oil reservoirs. More work could be done by incorporating associated gas and condensate reservoirs or modelling for just single phase non associated gas reservoirs.
- Cash flow models could be developed using programming platforms like MATLAB, Java or C++ instead of using just spreadsheet applications.
- Worldwide fiscal outlook could be given to this research.

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NOMENCLATURE

AIT – After Income Tax

BBL – Barrel

BBO – Billion Barrels of Oil

BIT – Before Income Tax

BOPD – Barrels of Oil per Day

BP – British Petroleum

C/F – Cost Carried Forward

C/R – Cost Recovery

CAPEX – Capital Expenditure

CITA – Corporate Income Tax

CPI – Consumer Price Index

CT – Contractor Take

CUM. PROD. – Cumulative Production

DBD – Declining Balance Depreciation

DCT – Discounted Contractor Take

DEVT – Development Costs

DOC – Domestic Oil Company

ECR – Excess Cost Recovery

ETAX – Education Tax

EXPL. – Exploration Costs

FLGT – Front Loaded Government Take

FVF – Formation Volume Factor

G – Original Gas in Place

G & G – Geological and Geophysical Costs

GDP – Gross Domestic Product

GRR – Growth Rate of Returns

HGT – Host Government Take

IAT – Inter-Agency Team

IDC – Intangible Drilling Costs

IOC – International Oil Companies

IRR – Internal Rate of Returns

ITA – Investment Tax Allowance

JV – Joint Venture

JVA – Joint Venture Agreement

LOE – Lease Operating Expenditure

MMb/d – Million Barrels Per Day

Mb/d – Thousand Barrels Per Day

MMBBL – Million Barrels

MNC – Multinational Companies

N – Original Oil in Place

NAPIMS – National Petroleum Investment Management Services

NCF – Net Cash Flow

NDDC LEVY– Niger Delta Development Commission Levy

NELP – New Exploration Licensing Policy

NHT – Nigerian Hydrocarbon Tax

NNPC – Nigerian National Petroleum Co-Operation.

NOC – National Oil Company

NPV – Net Present Value

OECD – Organization for Economic Co-operation and Development

OPEC – Organisation of Petroleum Exporting Countries

OPEX – Operating Expenditure

PFS – Petroleum Fiscal System

PI – Profitability Index

PIB – Petroleum Industry Bill

PO – Profit Oil

PPI – Producer Price Index

PPT – Petroleum Production Tax

PROD. RATE – Production Rate

PSA – Production Sharing Agreement

PSC – Production Sharing Contract

R/T – Royalty and Tax

SLD – Straight Line Depreciation

SOY – Sum of Years' Digit Depreciation

SPE – Society of Petroleum Engineers

SqKM – Square Kilometre

STB – Stock Tank Barrel

STB/D – Stock Tank Barrel Per Day

STOIIP – Stock Tank Barrel

TC – Technical Cost

TCF – Trillion Cubit Feet

UOP – Unit of Production Depreciation

APPENDIX A

PRODUCTION FORECAST (EXTRA)

In this appendix section, additional tables and figures from the production profile inputs, results and analyses.

TABLE A1: SUMMARY OF BASE CASE OF PRODUCTION PROFILE

PRODUCTION PHASE/DECLINE PATTERN		EXPONENTIAL	HYPERBOLIC	HARMONIC
BUILD UP	qi, stb/d	1000	1000	1000
	qp, stb/d	40,000	40,000	40,000
	t, years	3	3	3
	d, /year	-1.23	-0.547	-325
PLATEAU	qp, stb/d	40,000	40,000	40,000
	t, years	2	2	2
	d, /year	0	0	0
DECLINE	qp, stb/d	40,000	40,000	40,000
	qel, stb/d	100	100	100
	t, years	20.5	42.6	83
	d, /year	0.216	0.425	1.296

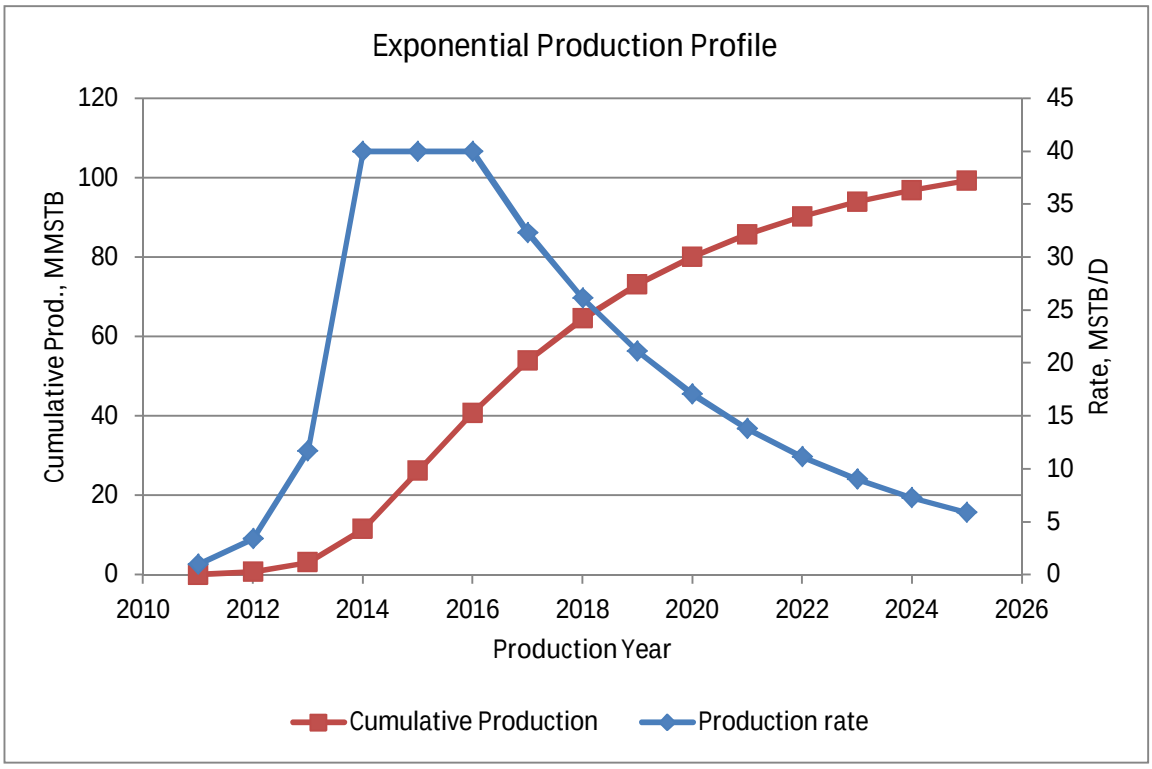


Fig A1 - EXPONENTIAL PRODUCTION FORECAST

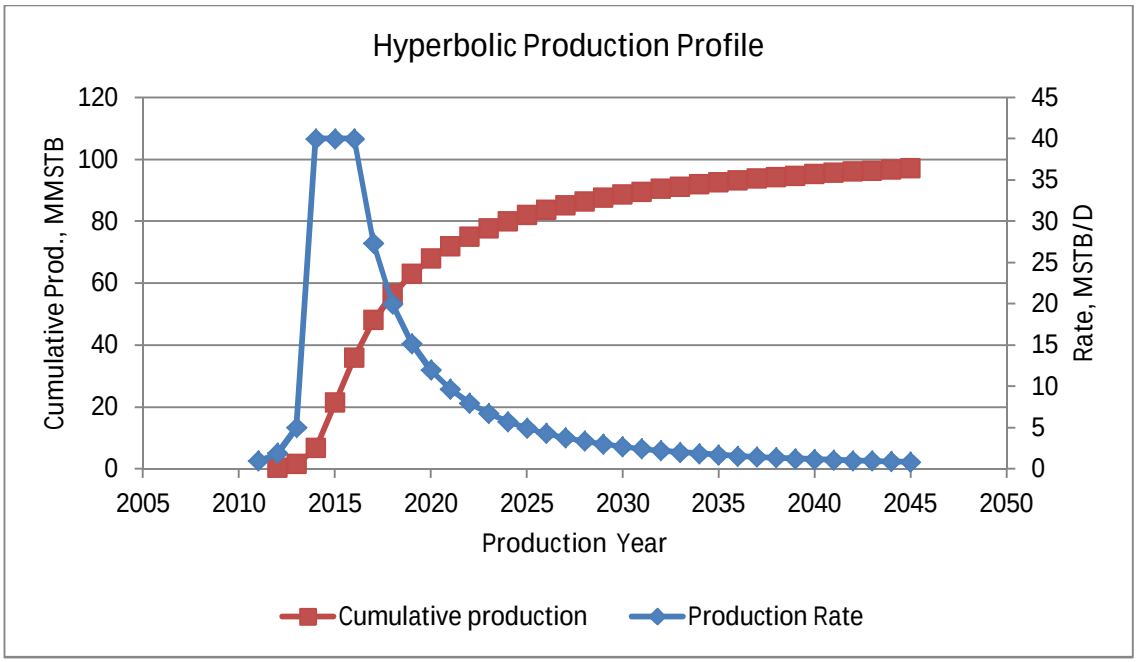


Fig A2 - HYPERBOLIC PRODUCTION FORECAST

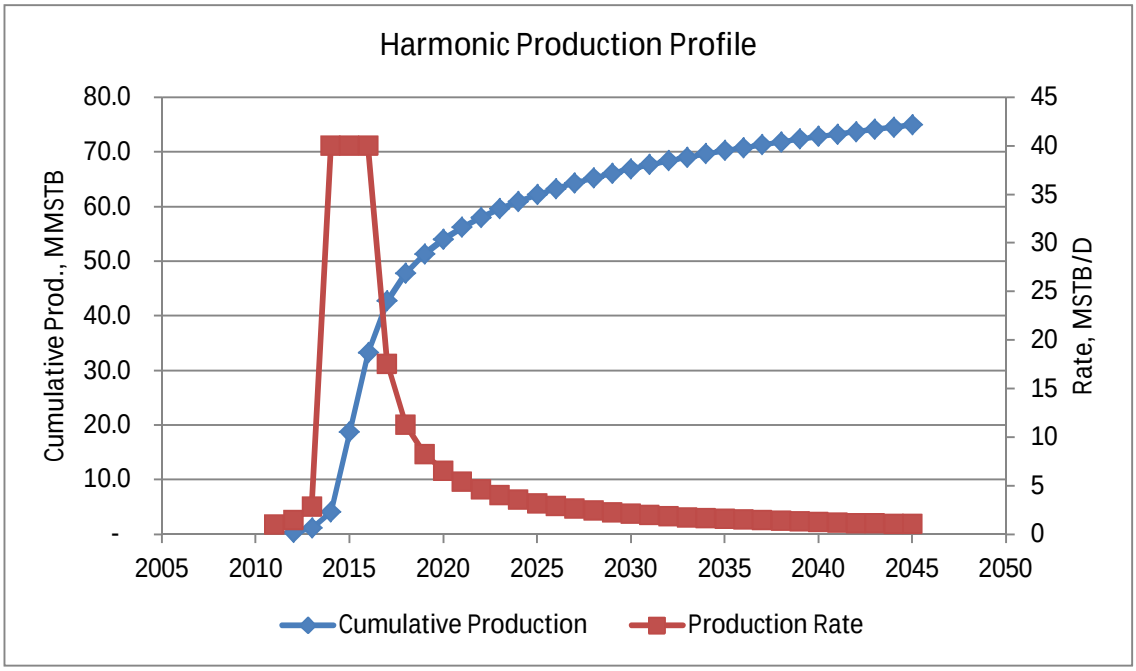


Fig A3 - HARMONIC PRODUCTION FORECAST

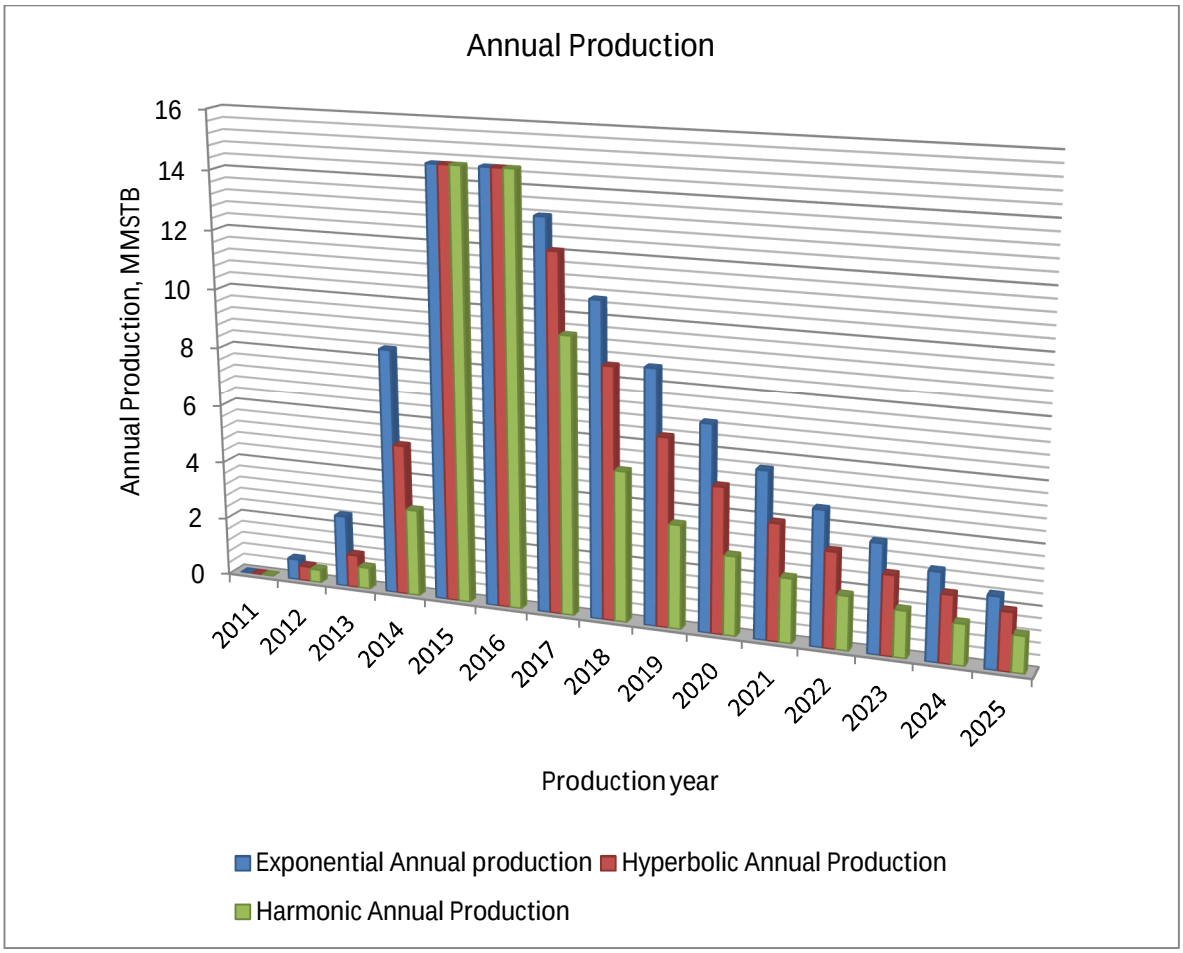


Fig A4 – COMPARATIVE ANNUAL PRODUCTION

APPENDIX B

DETERMINISTIC CASH FLOW ANALYSIS (EXTRA)

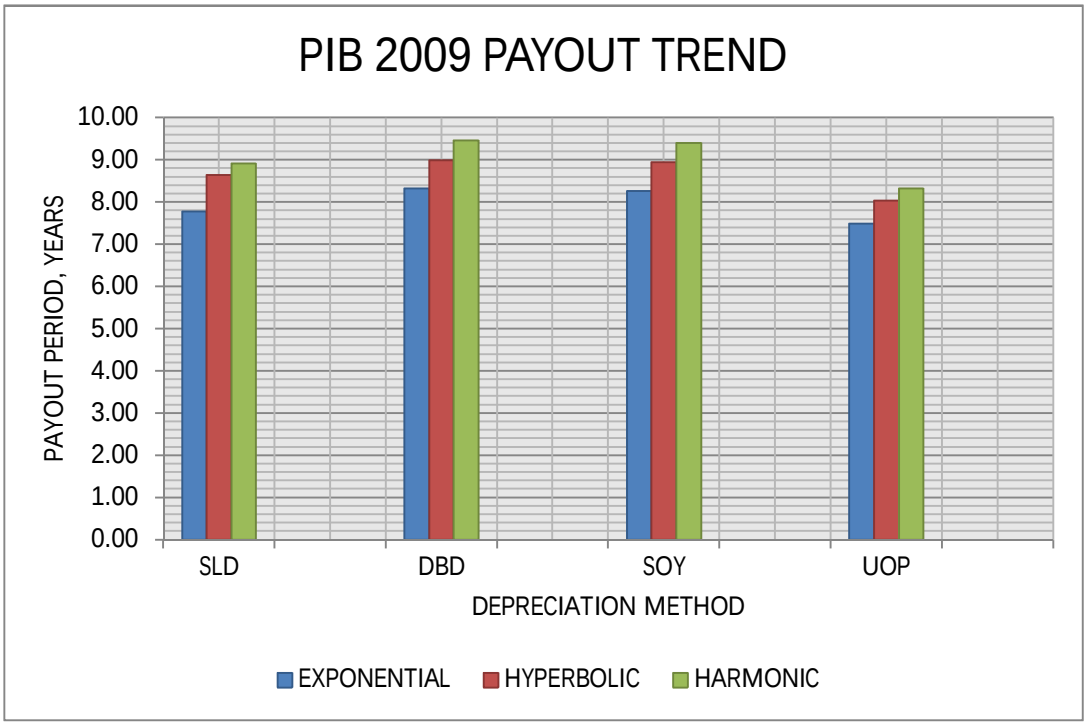


Fig B1: Histogram of PIB 2009 Payout trend.

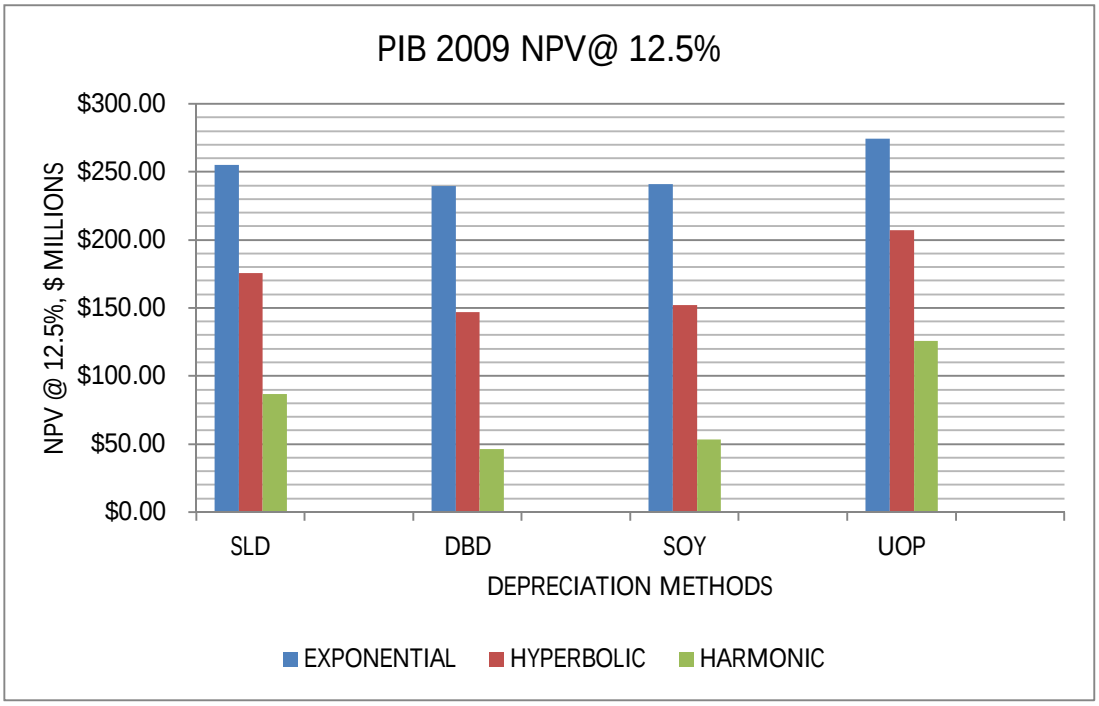


Fig B2: Histogram of PIB 2009 NPV@12.5%

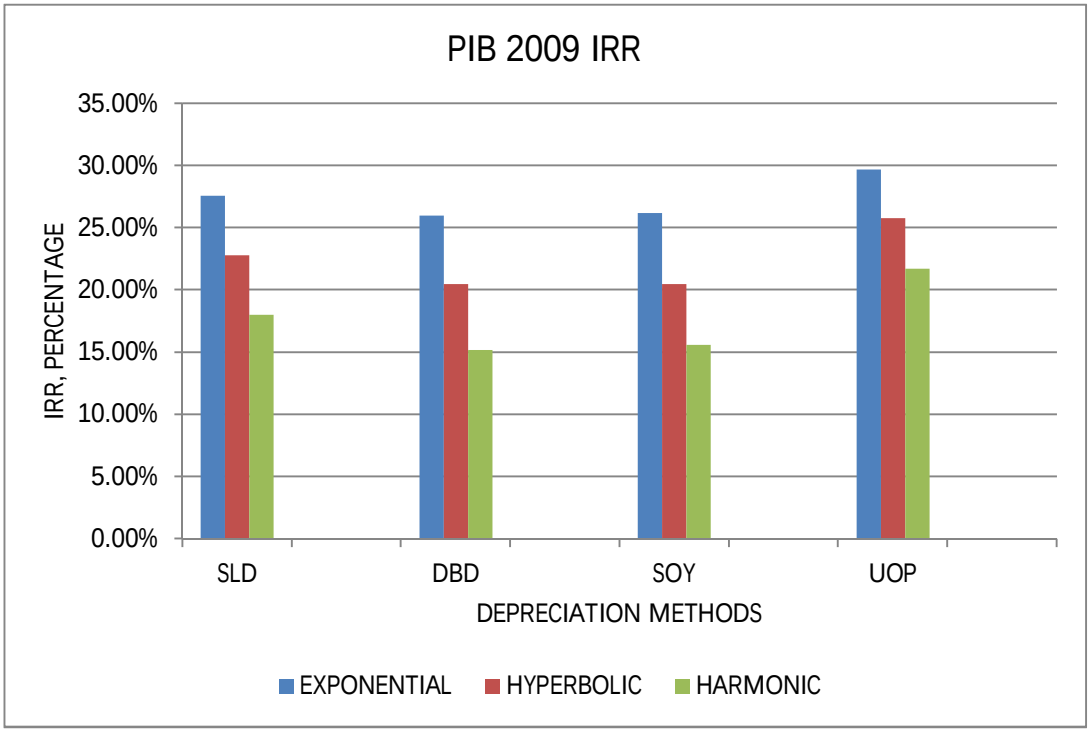


Fig B3: Histogram of PIB 2009 IRR

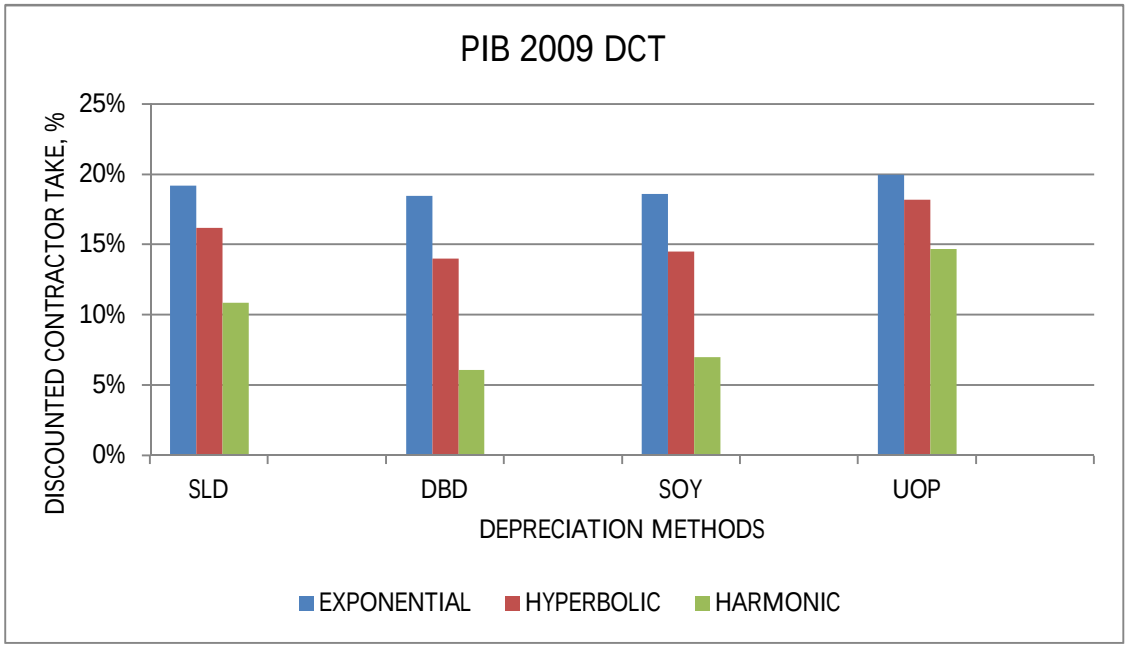


Fig B4: Histogram of PIB 2009 Discounted Contractor Take.

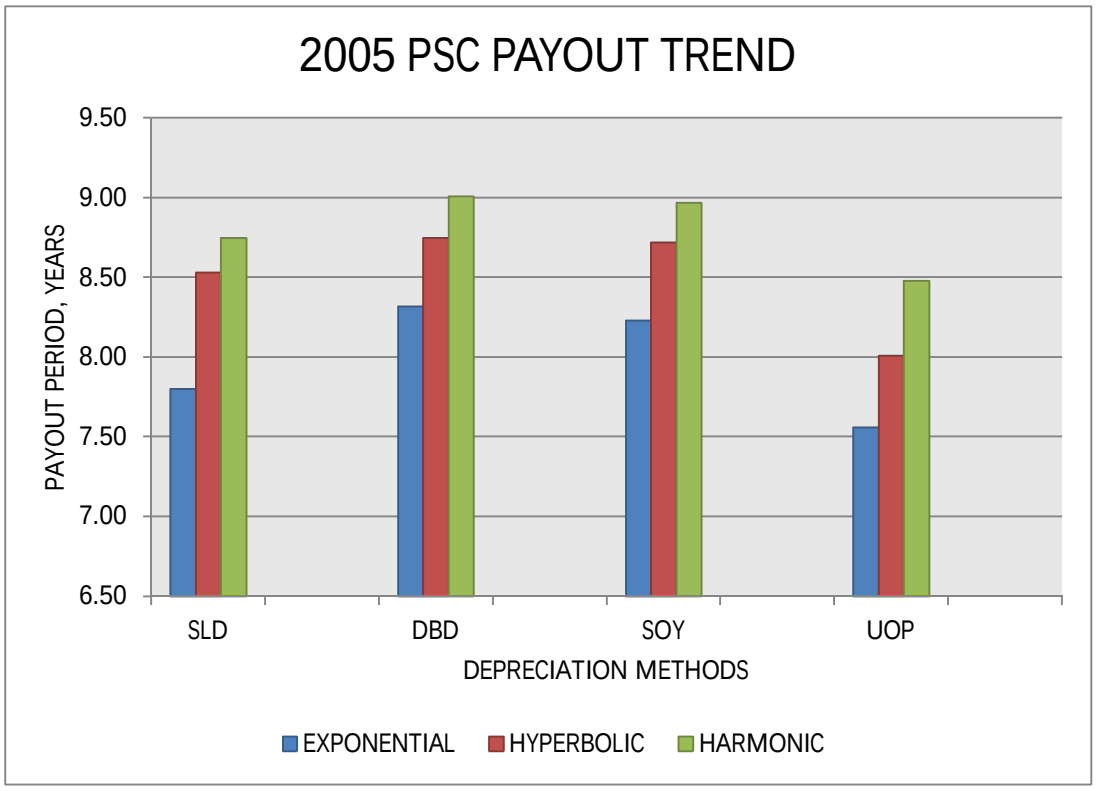


Fig B5: Histogram of 2005 PSC payout trend.

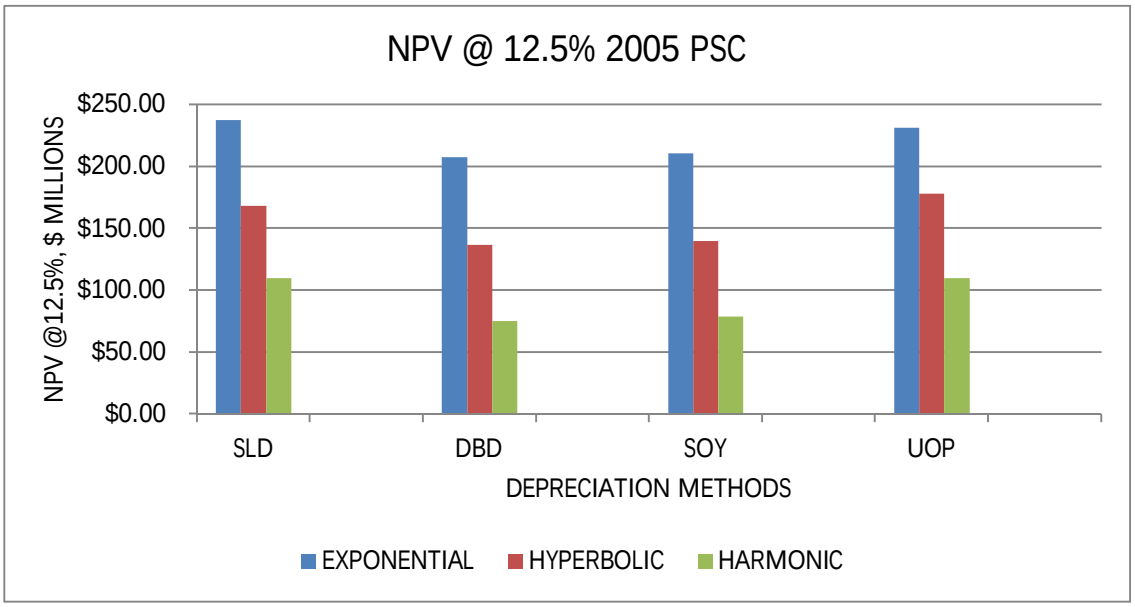


Fig B6: Histogram of 2005 PSC NPV@12.5

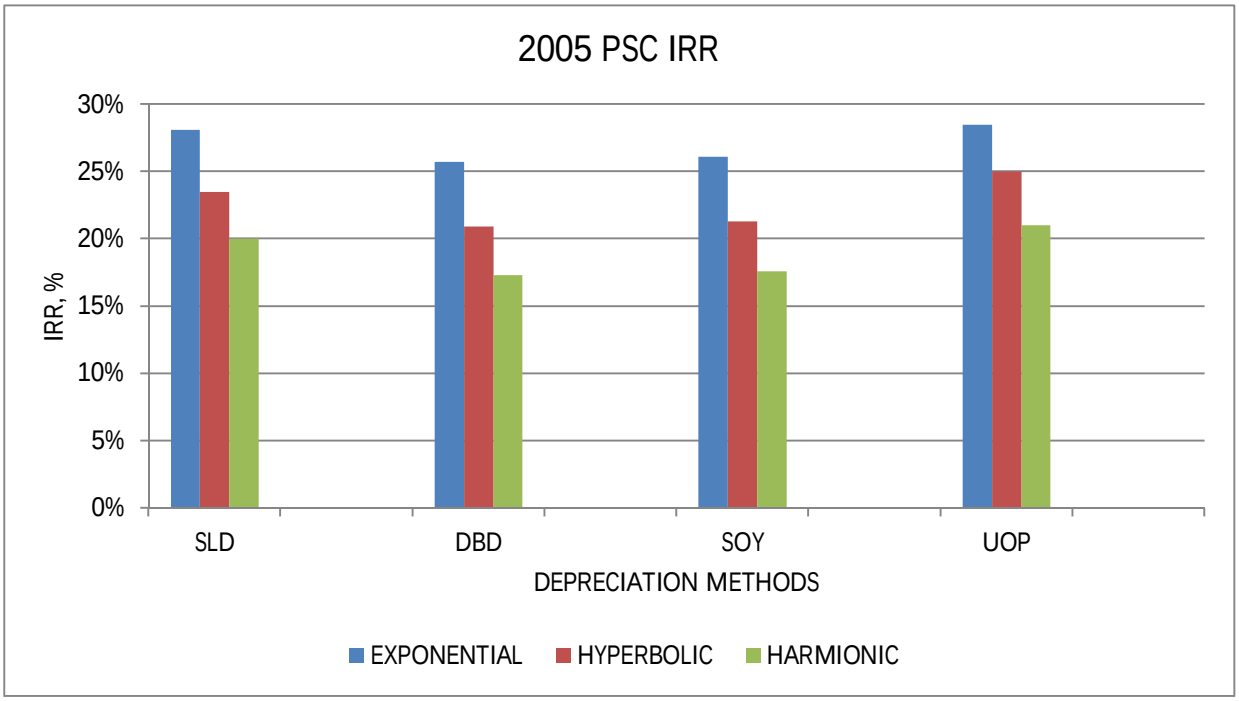


Fig B7: Histogram of 2005 PSC IRR.

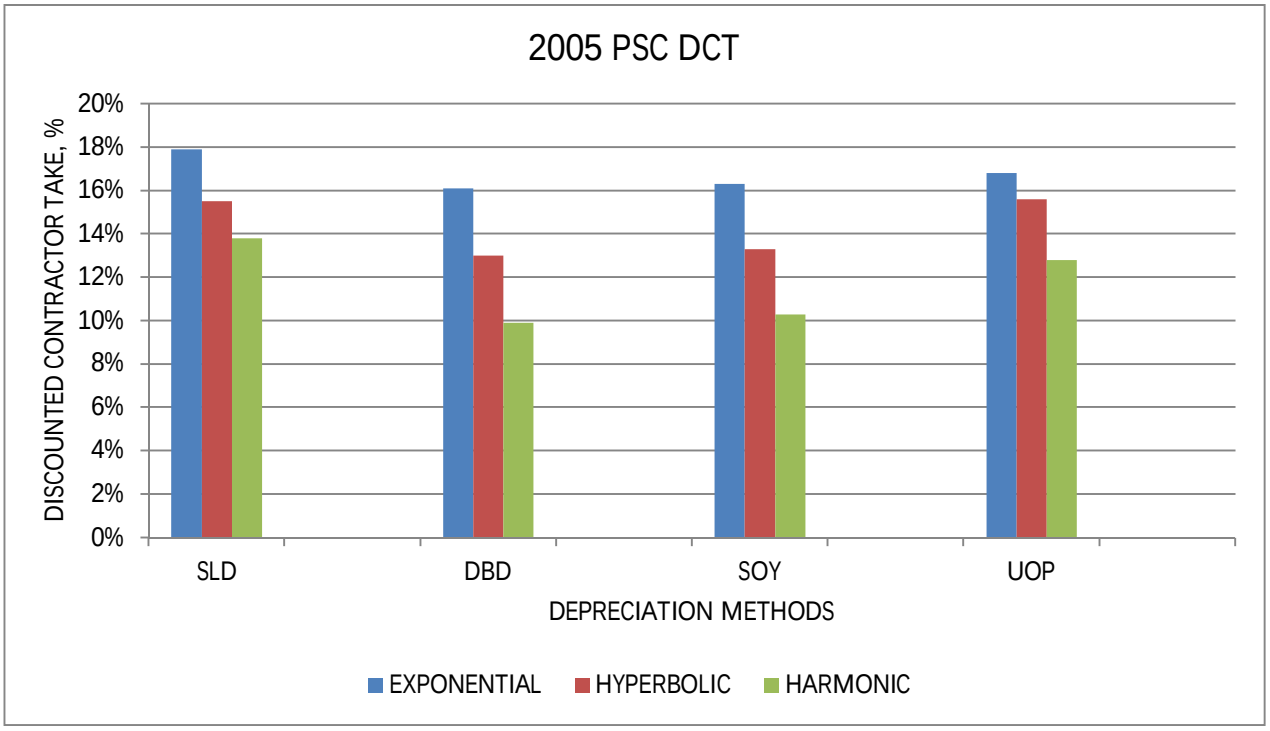


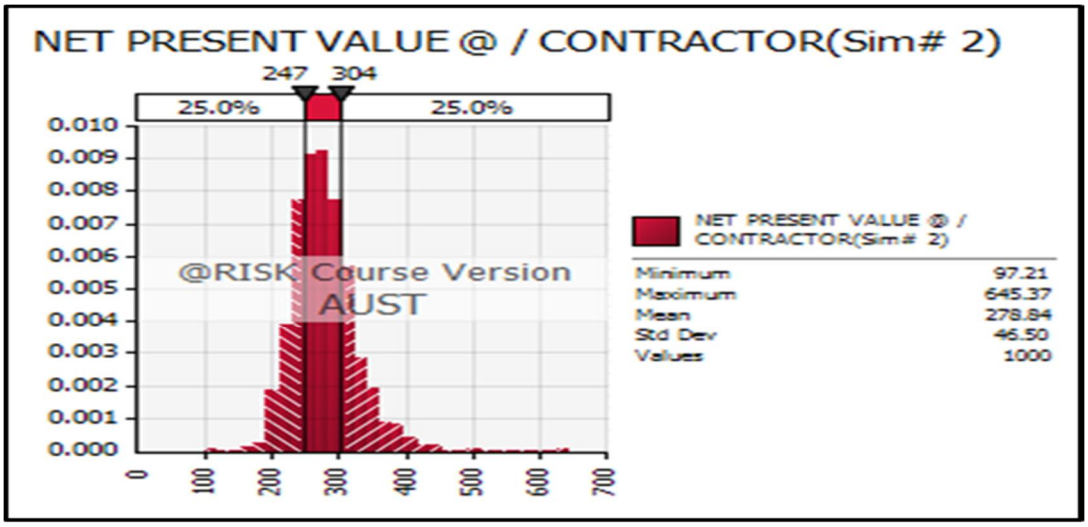
Fig B8: Histogram of 2005 PSC Discounted Contractor Take.

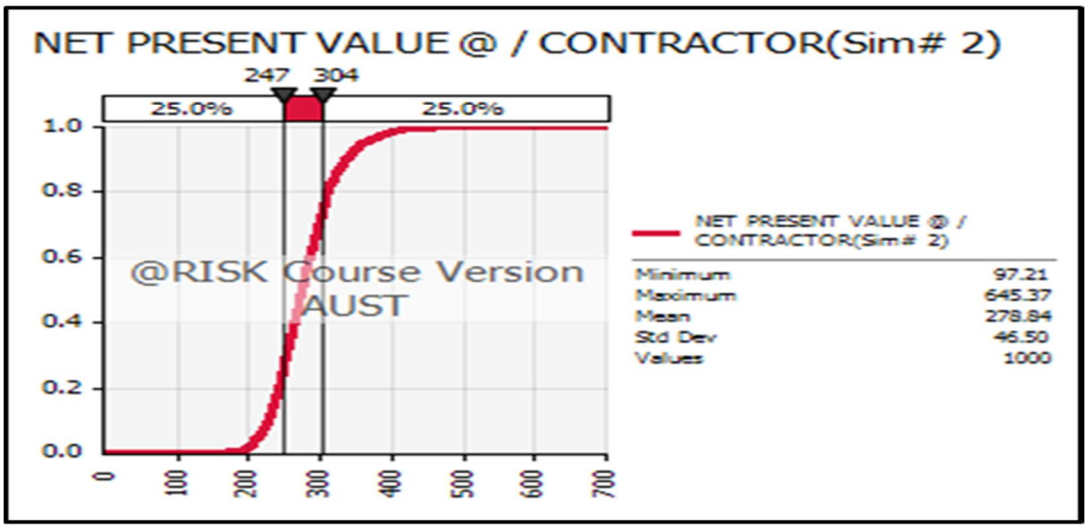
APPENDIX C

STOCHASTIC CASH FLOW ANALYSIS (EXTRA)

Table C1 - Output Summary for best scenario in PIB 2009

Name	Worksheet	Cell	Sim#	Graph	Min	Mean	Max	5%	95%	Errors
UNIT TECHNICAL COST, $/STB / PROJECT	METRIC MEASURES	J14	exponential UOP1	16 36	16.81	27.51	35.82	23.10	32.53	0
UNIT TECHNICAL COST, $/STB / PROJECT	METRIC MEASURES	J14	exponential UOP2	10 40	14.51	27.49	36.13	23.03	32.18	0
NET PRESENT VALUE @ / CONTRACTOR	METRIC MEASURES	M4	exponential UOP1	100 800	179.09	278.62	731.27	217.04	359.70	0
NET PRESENT VALUE @ / CONTRACTOR	METRIC MEASURES	M4	exponential UOP2	0 700	97.21	278.84	645.37	213.44	360.14	0
INTERNAL RATE OF RETURNS / CONTRACTOR	METRIC MEASURES	M5	exponential UOP1	20% 38%	21.2%	26.5%	37.5%	23.2%	30.0%	0
INTERNAL RATE OF RETURNS / CONTRACTOR	METRIC MEASURES	M5	exponential UOP2	20% 38%	20.8%	26.5%	36.8%	23.1%	30.1%	0
PROFITABILITY INDEX / CONTRACTOR	METRIC MEASURES	M7	exponential UOP1	110% 180%	1.16	1.30	1.78	1.21	1.40	0
PROFITABILITY INDEX / CONTRACTOR	METRIC MEASURES	M7	exponential UOP2	110% 180%	1.12	1.30	1.76	1.21	1.40	0
DISCOUNTED TAKE STATISTICS / CONTRACTOR	METRIC MEASURES	M9	exponential UOP1	10% 22%	11.3%	16.4%	21.4%	13.2%	19.3%	0
DISCOUNTED TAKE STATISTICS / CONTRACTOR	METRIC MEASURES	M9	exponential UOP2	8% 22%	9.9%	16.4%	21.6%	13.5%	19.4%	0
PAYOUT PERIOD, YEARS / CONTRACTOR	METRIC MEASURES	M10	exponential UOP1	710% 800%	7.18	7.69	7.92	7.52	7.84	0
PAYOUT PERIOD, YEARS / CONTRACTOR	METRIC MEASURES	M10	exponential UOP2	720% 800%	7.25	7.69	7.93	7.52	7.84	0





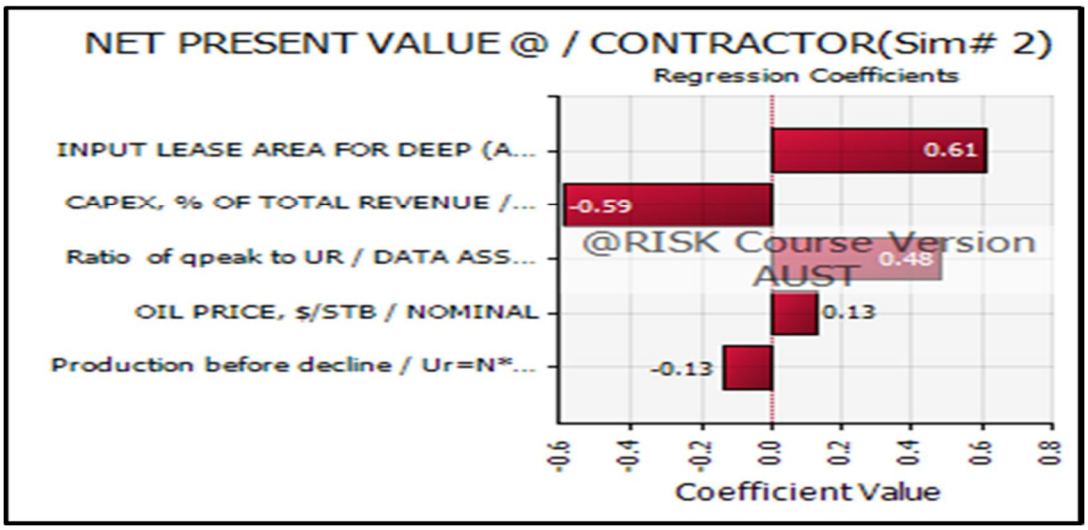
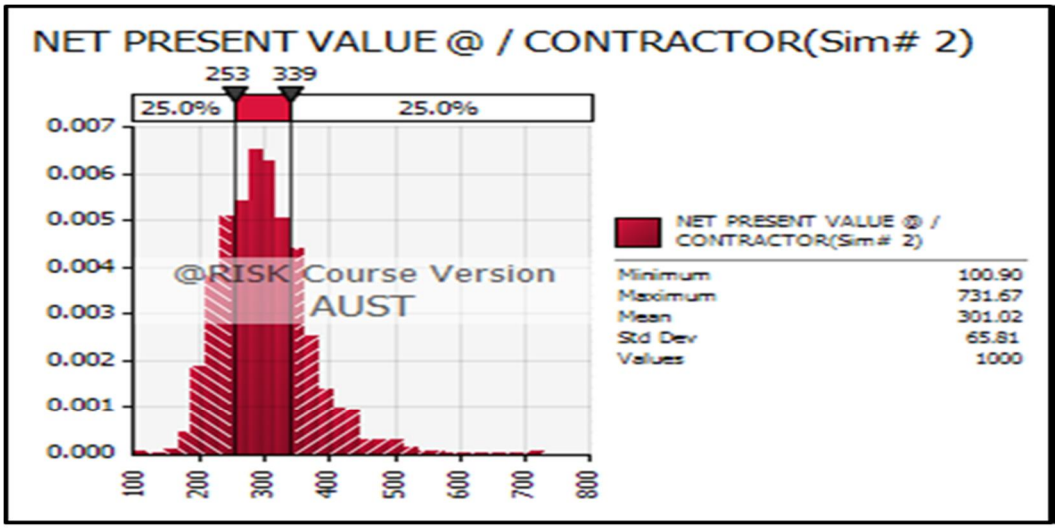
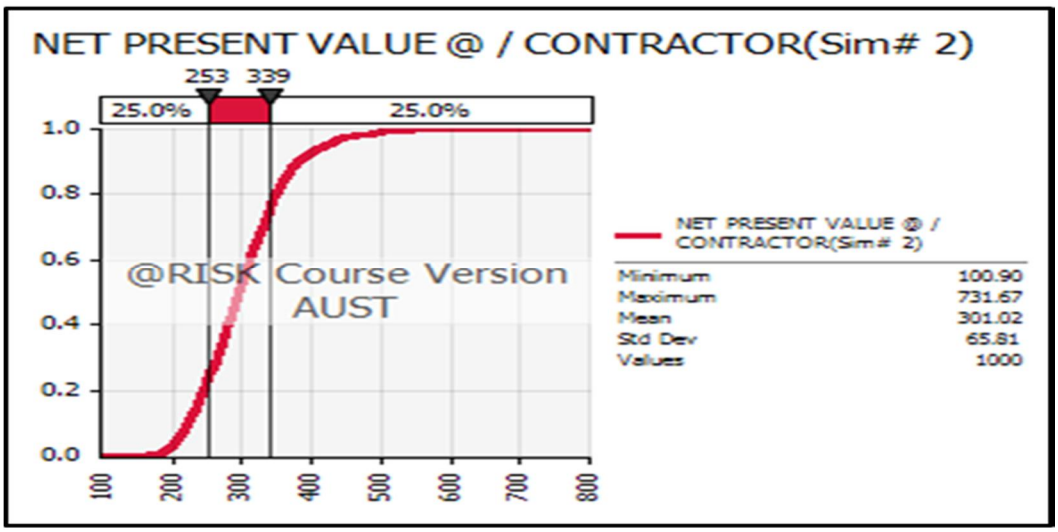


Fig C1: NPV@ 12.5% of the best scenario for PIB 2009 model

Table C2 - Output Summary for best scenario in 2005 PSC.

Name	Worksheet	Cell	Sim#	Graph	Min	Mean	Max	5%	95%	Errors
UNIT TECHNICAL COST, $/STB / PROJECT	METRIC MEASURES	J14	EXPONENTIAL SLD1	18 36	18.88	27.37	35.57	23.00	32.30	0
UNIT TECHNICAL COST, $/STB / PROJECT	METRIC MEASURES	J14	EXPONENTIAL SLD2	16 36	16.99	27.35	35.87	22.95	31.96	0
NET PRESENT VALUE @ / CONTRACTOR	METRIC MEASURES	M4	EXPONENTIAL SLD1	100 900	156.72	301.16	821.52	210.15	414.55	0
NET PRESENT VALUE @ / CONTRACTOR	METRIC MEASURES	M4	EXPONENTIAL SLD2	100 800	100.90	301.02	731.67	207.31	420.23	0
INTERNAL RATE OF RETURNS / CONTRACTOR	METRIC MEASURES	M5	EXPONENTIAL SLD1	0.20 0.36	21.0%	26.6%	34.1%	23.4%	30.1%	0
INTERNAL RATE OF RETURNS / CONTRACTOR	METRIC MEASURES	M5	EXPONENTIAL SLD2	0.20 0.36	20.7%	26.6%	34.3%	23.2%	30.3%	0
PROFITABILITY INDEX / CONTRACTOR	METRIC MEASURES	M7	EXPONENTIAL SLD1	1.15 1.60	1.16	1.29	1.59	1.21	1.39	0
PROFITABILITY INDEX / CONTRACTOR	METRIC MEASURES	M7	EXPONENTIAL SLD2	1.10 1.60	1.12	1.29	1.57	1.21	1.39	0
DISCOUNTED TAKE STATISTICS / CONTRACTOR	METRIC MEASURES	M9	EXPONENTIAL SLD1	0.14 0.24	14.4%	18.3%	23.6%	16.3%	20.9%	0
DISCOUNTED TAKE STATISTICS / CONTRACTOR	METRIC MEASURES	M9	EXPONENTIAL SLD2	0.12 0.24	13.0%	18.3%	23.9%	16.2%	20.9%	0
PAYOUT PERIOD, YEARS / CONTRACTOR	METRIC MEASURES	M10	EXPONENTIAL SLD1	7.5 8.5	7.50	8.00	8.44	7.76	8.27	0
PAYOUT PERIOD, YEARS / CONTRACTOR	METRIC MEASURES	M10	EXPONENTIAL SLD2	7.5 8.4	7.54	8.00	8.40	7.75	8.30	0





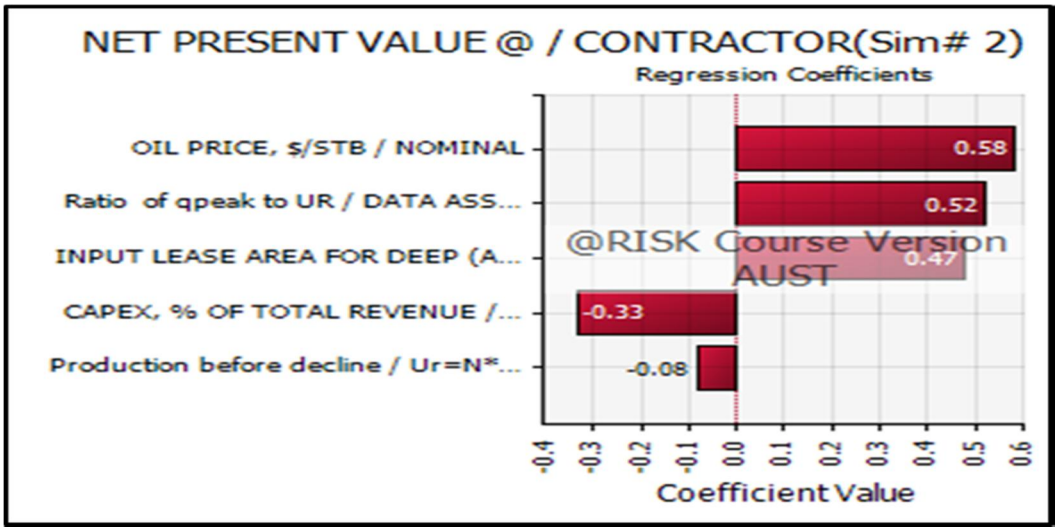


Fig C2: NPV@ 12.5% of the best scenario for 2005 PSC model.

APPENDIX D

SUMMARY OF THE FISCAL TERMS USED.

Table D1- Typical 2005 PSC stipulations (source: Nwonodi et al, 2008)

<table>
<tr><th>Fiscal Term</th><th>Description</th></tr>
<tr><td>Royalty</td><td>• Royalty rate for all produced crude oil is 18.5%</td></tr>
<tr><td>Cost Recovery</td><td>• 100% of Revenue after deducting Royalty is used for Cost Recovery.
• Unrecovered costs are carried forward indefinitely.
• Interests accrued on un-recovered balances of Dev capital , LIBOR + 3%
• Abandonment Costs are Expensed (Default) and cost recoverable
Operating, Exploration and Intangible Development Costs are expensed.</td></tr>
<tr><td>Education Tax</td><td>• Tax Rate: 2% based on Assessable Profit.
• Assessable Profit = Sales Revenue – Royalties – Op Costs – Exploration – Intangible Development.
(Note: Surface Rental is assumed to be a type of operating cost and thus is included as Op Costs)
• Loss can be carried forward indefinitely.</td></tr>
<tr><td>Niger Delta Development Commission (NDDC)</td><td>• NDDC Levy is incurred on annual costs (OPEX & CAPEX including Abandonment)
• NDDC Levy Rate: 3%</td></tr>
<tr><td>Petroleum Profit Tax</td><td><table><tr><th>Duration from Production Date</th><th>Tax Rate (%)</th></tr><tr><td>First five years</td><td>65.75</td></tr><tr><td>Subsequent years</td><td>85</td></tr></table>• All taxes applicable are chargeable on all profits for the duration of the contract.
• PPT Taxable Basis = Assessable Profit – Education Tax – Tangible Development Costs depreciation – Investment Tax Allowance
• Tangible Development Costs are depreciated over 5 years or remaining life time, whichever is less (Custom schedule) – 20%, 20%, 20%, 20%, 19%.
• Loss can be carried forward indefinitely.</td></tr>
<tr><td>Investment Tax Allowance</td><td><table><tr><th>Terrain (Meters)</th><th>Tax Rate (%)</th></tr><tr><td>Onshore</td><td>5</td></tr><tr><td><100</td><td>10</td></tr><tr><td>100 – 200</td><td>15</td></tr><tr><td>> 200</td><td>50</td></tr><tr><td>Inland Basin</td><td>50</td></tr></table>Use model scenarios for the Terrains.
ITA is based on Tangible Development costs. Used only for Tax calculations</td></tr>
</table>

Table D2- Typical Redraft PIB 2009 Stipulations Summary.

ROYALTY BY VOLUME					
	OIL			NATURAL GAS	
Area/Royalty	5%	12.50%	25%	5%	12.50%
Onshore	0 - 2Mb/d	2 - 5Mb/d	>5Mb/d	0 - 100MMcf/d	>100MMcf/d
Shallow water	0 - 5Mb/d	5 - 20Mb/d	>20Mb/d	0 - 200MMcf/d	>200MMcf/d
Deepwater	0 - 50Mb/d	50 -100Mb/d	>100Mb/d	0 - 500MMcf/d	>500MMcf/d

ROYALTY BY VALUE			
OIL PRICE PER BBL	ROYALTY %	GAS PRICE PER MMBTU	ROYALTY %
$0 - $70	0	$0 -$2	0
$70 - $100	0.4/$	$2 -$7	0.2/10cents
$100 - $140	12+0.2/$	$7 - $13	10+0.15/10cents
$140 - $190	20+0.1/$	$13 - $19	19+0.10/10cents

DEDUCTIBLE FOREXP	80%		
EXPENDITURE		CAPEX	OPEX
ACTUAL FOREIGN EXP		75%	50%
ALLOWABLE FOREIGN EXP		0.85	0.9
PRODUCTION ALLOWANCE PER STB			$ 7.00
ALLOWABLE PRICE LIMIT			30%
NIG. HC TAX (NHT)			30%
CITA			30%
EDUCATION TAX			2%
DISCOUNT RATE			12.5%
RIFT $/Bbl			0.50
NDDC			3%

SPECIAL PRODUCTION ALLOWANCES		
AREA	ALLOWANCE	CUM. PROD (MMBbl)
ONSHORE	min($30/Bbl, 30% of Price)	10
	min($12/Bbl, 30% of Price)	<75
SHALLOW WATER	min($30/Bbl, 30% of Price)	20
	min($12/Bbl, 30% of Price)	<150
DEEP WATER	min($ 7/Bbl, 30% of Price)	all prod. Levels

RENTALS			
	LICENSE ($/sqKM)		
YEAR	PEL	PPL	PML
1	10	100	1000
2	10	100	1000
3	10	300	1000
4	10	300	1000
5	10	500	1000

PROFIT SHARING				
Np (MMBbl)	750	1000	2000	>2000
% Share	20%	30%	40%	negotiable