KENYA OIL & GAS FISCAL REGIME: AN ECONOMIC ANALYSIS ON ATTAINMENT OF THE GOVERNMENT OBJECTIVES

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ABSTRACT: *The recent discoveries of oil and gas in East Africa's neighbouring countries have drawn attention to the Kenya Oil & Gas Fiscal Regime. Despite the marginality of Kenya's hydrocarbons, the Government of Kenya has signed 16 Production Sharing Contracts (PSCs) and are now planning a licensing round for the remaining 20. The division of profits under the Kenya system has been based on daily production since the embedment of the Model PSC in the Petroleum (Exploration and Production) Act, Cap 308 in 1982. Using a quantitative approach, the paper aims to determine whether the current system facilitates the attainment of the Government of Kenya (GoK) objectives. The methodology employed allows the paper to critically test the system under high and low oil price and costs and establish its degree of flexibility to this changes. The conclusion ascertains that the system is regressive through the interpretation of key results such as Undiscounted Government Take, Net Present Value of project cash flows, Internal Rate of Return, Saving Index, Access to Gross Revenues and Effective Royalty Rate.*

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LIST OF ABBREVIATIONS

AGR	**Access to Gross Revenues**
BOPD	**Barrels of Oil per Day**
CAPEX	**Capital Costs**
EIA	**Energy International Agency**
ERR	**Effective Royalty Rate**
FRS	**Financial Reporting System**
GDP	**Gross Domestic Product**
GOK	**Government of Kenya**
GoK	**Government of Kenya**
GT	**Undiscounted Government Take**
HG	**Host Government**
IOC	**International Oil Company**
IRR	**Internal Rate of Return**
MMBBLS	**Millions of Barrels**
NEP	**National Energy Policy**
OL	**Operating Leverage**
OPEX	**Operating Costs**
PPP	**Purchasing Power Parity**
PSC	**Production Sharing Contract**
ROR	**Rate of Return**
SI	**Saving Index**
US$	**US Dollar**
US$M	**Millions of US Dollars**
WTI	**West Texas Intermediate**

LIST OF FIGURES

LIST OF TABLES

1. INTRODUCTION

Petroleum fuels are the main source of commercial energy in Kenya and are mainly used in the transport, commercial and industrial sector. In 2007 the consumption of petroleum fuels in Kenya was 65,530bbl/day, all imported from the Middle East[1]. Kenya has a Gross Domestic Product (GDP) of US$25.20 billion and highly dependent on tourism and agriculture as its main source of government revenues. Kenya's search for oil and gas has been unsuccessful even though some of the 34 wells drilled since 1954 within its four sedimentary basins showed traces of oil and gas which was not commercially viable. Despite this hydrocarbon marginality, the country has signed production sharing contracts (PSC) for 16 blocks while the remaining 20 blocks are being considered for a licensing round. The government's optimism of attracting reputable International Oil Companies (IOC) to the licensing round would highly depend on the attractiveness of the fiscal regime taking into consideration the geological and political risk of the country. The Kenya fiscal system employs a sliding scale linked to daily production targets to determine the profit oil split between the IOC and Government of Kenya (GoK), where the latter expects a sustainable fair share of return upon discovery of commercial quantities of hydrocarbons.

This paper intends to provide an economic analysis of the current Kenya Oil and Gas Fiscal Regime and determine whether it facilitates the achievement of the GoK's objectives. Chapter 2 presents an overview of petroleum fiscal systems by describing the concept of economic rent, and classification of the fiscal regimes. A short review of Kenya's fiscal regime and the GoK's objectives are discussed in Chapter 3, while Chapter 4 outlines the production and economic assumptions made in developing a stand alone cash flow model. Chapter 5 provides an analysis of the system under different scenarios of high and low oil prices and costs. The results are measured in terms of Undiscounted Government Take

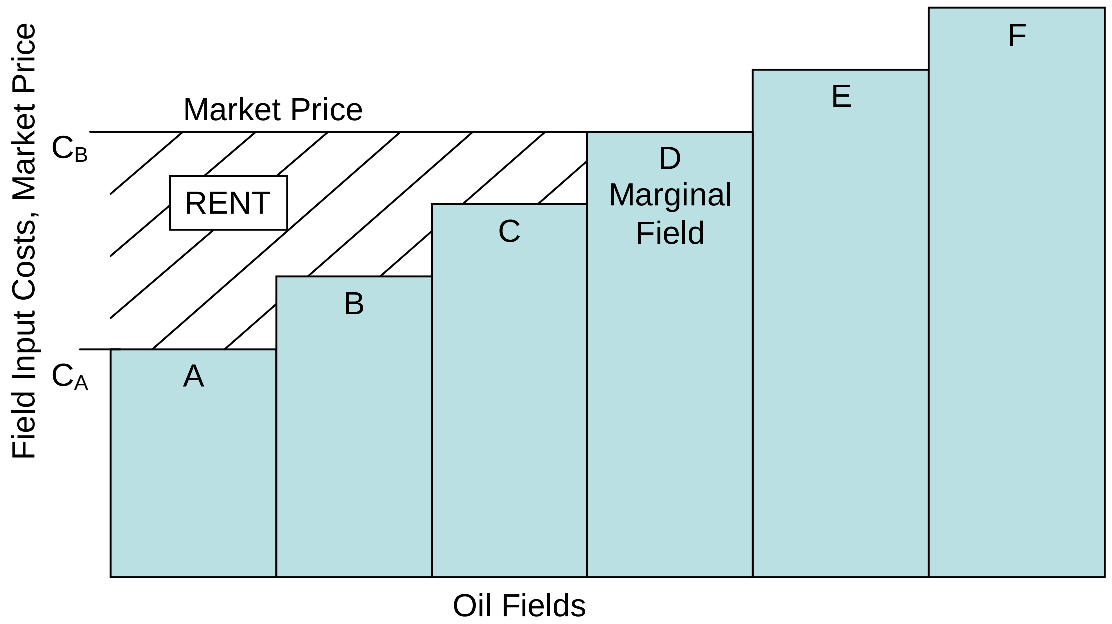
[1] Central Intelligence Agency "*Fact Book*" at https://www.cia.gov/library/publications/the-world-factbook/geos/ke.html (Last visited on Jan 10th, 2009)

(GT), Effective Royalty Rate (ERR), Saving Index (SI), Internal Rate of Return (IRR), Net Present Value (NPV), Access to Gross Revenues (AGR) and Operating Leverage (OL). Finally Chapter 6 concludes whether the economic analysis of the system enables the GoK achieve objectives set out under its National Energy Policy (NEP).

2. PETROLEUM FISCAL SYSTEMS

The concept of economic rent originates from the fundamentals of economic theory and the produce of the earth that is derived from the factors of production namely labour, capital and machinery[2]. It represents the surplus revenue realised after accounting for the all the costs incurred by these factors of production[3]. There are several types of economic rent i.e. the Scarcity rent[4], Differential or Ricardian rent[5] and the Quasi rent[6]. The Differential rent is generally used in the oil and gas industry because extraction costs typically depend on differences in the quality of the resource and location of the hydrocarbons[7]. (Figure 1)

Figure 1: Oil field Ricardian Rent



Source: Adapted from Nakhle (2008)

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[2] Johnston. D., The International Exploration Economics Risk, and Contract Analysis, (USA, Tulsa, Oklahoma: PennWell, 2003)

[3] Nakhle. C., Petroleum Taxation: Sharing the oil wealth – A study of petroleum taxation yesterday, today and tomorrow, (USA, New York: Routledge, 2008).

[4] Scarcity rent is the rent derived from the natural scarcity of a resource thus available output is limited.

[5] Differential or Ricardian rent named after the British economist David Ricardo, is the value of the difference in productivity between a given piece of land and the poorest, most costly piece of land producing the same goods under the same conditions (of labour, capital, technology, etc.). at http://eh.net/coursesyllabi/syllabi/munro/ECONRENT.htm (last visited on Jan 14th ,2009)

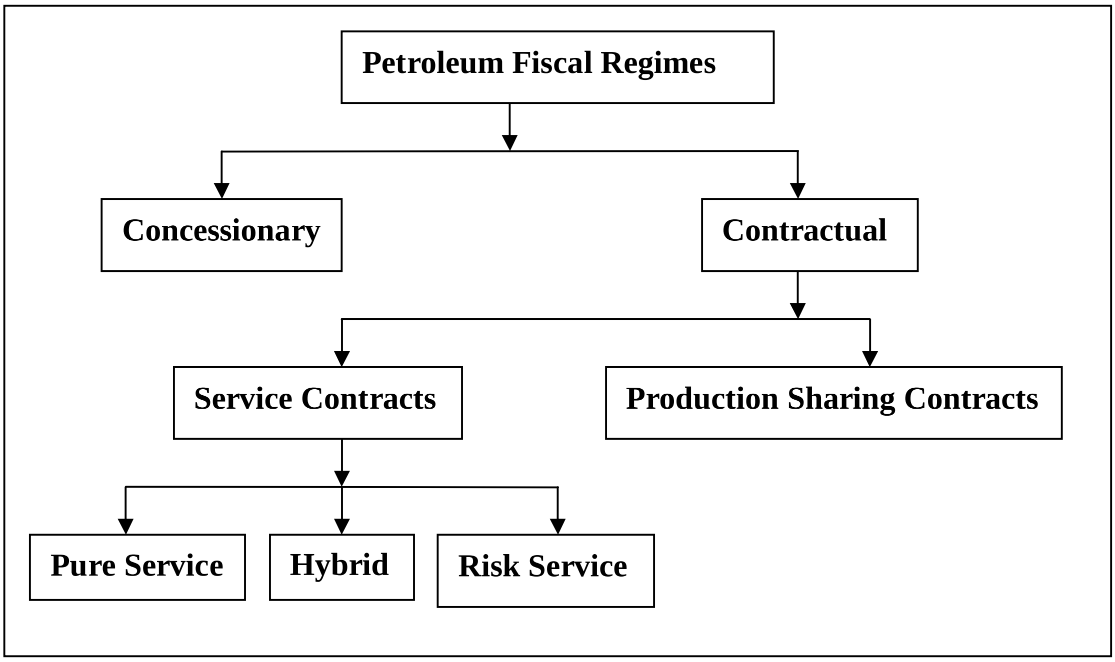
[6] Quasi rent represents the returns that accrue to firms as a result of changes in the market in the short run

[7] *See* Nakhale *Supra* note 3

2.1 Classification of Fiscal Regimes

In the global oil and gas industry, host governments (HG) seek economic rent on their resources through the enactment of a hydrocarbon law that establishes the legal and fiscal basis of granting exploration, development and production rights in particular areas or blocks by means of concessions or contracts[8]. The development of these legal and fiscal systems is essential because they address the rights and obligations of the (HG) and the IOC[9]. The fiscal regimes are typically grouped into two main families i.e. "contractual based" systems and "concessionary" systems[10]. Figure 2 illustrates the classification of petroleum fiscal regimes

Figure 2: Classification of Petroleum Fiscal Regimes



Source: Adapted from Johnson (1994)

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[8] Tordo. S., Fiscal Systems for Hydrocarbons- Design Issues, (USA ,Washington D.C: World Bank Working Paper No 123,,August 2007)
[9] *Ibid*
[10] Johnson. D., International Fiscal Systems and Production Sharing Contracts (USA, Tulsa, PennWell:Oklahoma, 1994)

2.1.1 Concession Systems

Concessions were the first systems used in petroleum agreements worldwide and originated from the Greek silver mining operations in 480 B.C.[11]

Under a concessionary system (also referred to as royalty/tax system), the land owner normally transfers title of the minerals to the IOC at the well head and in return the IOC pays royalties and taxes specified in the HG's state legislation[12]. However, upon termination or expiry of the concession, the title and ownership of the equipment and permanent installations used for exploration and production of oil and gas, reverts back to the state while the contractor is responsible for decommissioning[13]. The royalty calculation is based on a percentage applied to the gross revenues of the recovered hydrocarbon resources and payable by the IOC in form of "cash" or "in kind"[14].

2.1.2 Contractual Systems

Contractual systems originated from the Napoleonic era and were based on the French legal concept that all mineral resources are owned by the HG for the benefit of all its citizens[15].

Under a contractual systems, the HG transfers title of the mineral resource to the IOC at the delivery point. However, the ownership of the exploration and production equipment reverts to the HG immediately and as a result; the HG becomes responsible for decommissioning or abandonment of the block areas[16]. The "contractual based systems" include both the PSCs and service contracts where the latter consists of risk service contracts, pure service contracts and hybrid contracts.

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[11] Anderson, O.L., *Royalty valuation: Should royalty obligations be determined intrinsically, theoretically, or realistically?* Natural Resources Law Journal 37:611, 1998

[12] Kaiser. M, ,Pulsipher. A.G, *Fiscal System Analysis: Concessionary and Contractual Systems Used in Offshore Petroleum Arrangements.* US Department of the Interior, Minerals Management Service, Gulf of Mexico OCS, New Orleans, La. OCS Study MMS 2004-016. 78pp

[13]*See* Tordo *Supra* note 8

[14] Gallun. R. A, Wright. C. J., Nichols. L. M, Stevenson J. W, Fundamentals of Oil & Gas Accounting, 5th (USA, Tulsa, Oklahoma: Edition, PennWell, 2005)

[15]*See* Johnston *Supra* note 10

[16] *See* Tordo, *Supra* note 8

The PSC is a contractual agreement between the HG and IOC whereby the contractor bears all the costs and risks of exploration, development and production in return for a specified split of the production[17].

2.1.3 Fiscal Components of Contractual Systems

2.1.3.1 Royalty

It is a payment to the HG calculated as a fixed percentage of gross revenue adjusted for the cost of transportation and basic processing[18]. PSCs typically contain royalty provisions that range from 0% - 15% and can either be "fixed" or based on a "sliding scale" attached to the production level of a field[19]. The formula below illustrates how a royalty is calculated[20];

$$\boxed{ROY = R*(Gr - Allow),}$$

Where

Roy	*= Royalty*
R	*= Royalty rate*
Gr	*= Gross Revenues*
Allow	*= Total allowance cost i.e. transport & basic processing*

2.1.3.2 Cost Recovery Limit

It is the means by which IOCs recover costs incurred in exploration, development and production from available gross revenues. Globally, most PSCs place a limit on the amount of costs the IOC can recover from the revenues. This limit also referred to as a "cost ceiling" typically ranges from 40% to 100%[21] and considered as one of the ways in which the HG is guaranteed a share of production in any given accounting period[22]. The

[17] *See* Johnston, *Supra* note 2
[18] *See* Gullan, *Supra* note 14
[19] *See* Johnston, *Supra* note 2
[20] *See* Kaiser, *Supra* note 12
[21] The world average for cost recovery limit is 65%
[22] *See* Johnston, *Supra* note 2

unrecovered costs are then carried forward and recouped the following accounting period in the order below[23];

- Unrecovered exploration expenditures
- Unrecovered development expenditures
- Current year operating costs
- Current year Depreciation
- Interest on financing (if allowed)
- Investment credit or capital uplift (defined later)
- Future abandonment cost fund

Approximately 85% of the cost recovery limits in the world are based on 'gross production or revenues' while the remaining 15% are based on 'net production' after deducting royalty. The most basic form of cost recovery is computed as follows[24] ;

$$\boxed{Cr = U + CAPEX / I + OPEX + DEP + INT + INV + DECOM,}$$

Where,
CR = Cost recovery in year t,
U = Unrecovered cost carried over from previous year,
CAPEX =/ I Intangible capital expenditures in year t,
DEP = Depreciation in current year
INT = Interest on financing in year t,
INV = Investment credits and uplift in year t,
DECOM= Abandonment cost recovery fund apportionment in year t.

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[23] *Ibid*

[24] *See* Kaiser, *Supra* note 12

2.1.3.3 Profit Oil

It is the amount of revenues or production that the government shares with the IOC after royalties and cost oil are recovered from the gross revenues.

$$\boxed{PO = GR - ROY - CO,}$$

Where,
PO = Profit Oil
GR = Gross Revenues
CO = Cost Oil

A study by Bidermann (1999) indicated that 45 of the 268 PSCs worldwide had a "fixed" profit oil share while the rest applied a "sliding scale" which was based on the oil production or rate of return (ROR)[25]. Table 1 illustrates the profit oil for IOCs

Table 1: Profit Oil for IOCs

	Average Pofit Oil (%)		Max Profit Oil (%)		Min Profit Oil (%)	
	Max	Min	Highest	Lowest	Highest	Lowest
Asia	44.15	28.51	100.00	15.00	60.00	10.00
Centra America	64.71	36.57	95.00	40.00	85.00	20.00
South America	48.00	38.38	50.00	40.00	50.00	30.00
Europe	51.93	37.00	80.00	40.00	60.00	10.00
Middle East	27.80	15.75	60.00	11.80	40.00	7.50
North Africa	38.67	18.00	100.00	19.00	50.00	10.00
South & Central Africa	55.69	29.17	100.00	15.00	75.00	5.00

Source: Adapted from Bidermann (1999)

Out of the PSCs based on sliding scales, 75% have a production-based sliding scale while the remaining 25% are based on the ROR or R factor[26]. The production-based sliding scales are typically popular with the HG because they offer a greater share of profit oil at higher rates of production. However, these sliding scales (unlike the R factor and ROR systems[27]) are totally insensitive to fluctuations of oil prices[28].

[25] Bindemann. K., Production Sharing Agreements : An Economic Analysis (UK, Oxford,:Oxford Institute for Energy Studies, 1999)
[26] Johnston, D. Economic Modelling and Risk Analysis Handbook (UK, University of Dundee, Dundee,2002)
[27] The R Factor, ROR systems divide 'profit oil' based on a profit-based mechanism tied to a payout formula or internal rate of return threshold.
[28] See Johnston Supra note 26

2.1.3.4 Government Participation

PSCs provide an option for the state-owned oil company to participate in development of the oil project. While the contractor bears the cost and risk of exploration, the government through the national oil company can elect to participate at a level of working interest up to a maximum of 51% upon the discovery of oil and gas. Normally, the government participation is automatically assumed whenever a percentage of it is quoted, although some key aspects of it should be first determined i.e.[29].

- The point at which the government backs in (usually at commerciality)
- The scale of participation in management of the venture (large range)
- The costs to be bore by the government (usually prorated share of development costs)
- The ways of funding the government portion of costs (often out of production) split

2.1.3.5 Others Fiscal Instruments

A number of PSCs have several other fiscal instruments like bonuses[30], investment credits[31], tax holidays[32], income tax and domestic market obligations[33].

[29] Ibid
[30] These are up front monies paid by the IOC to the government for signing the PSC agreement
[31] Investment credits encourage the oil companies to recover an additional percentage of capital expenditure over and above the actual amounts spent.
[32] Tax holidays are used by governments to attract additional investment thus encouraging IOCs to maximize investments in the early years of production.
[33] The DMO would normally be included where the demand for crude oil in the country is greater than the government's share of production consequently reducing the shortfall and decreasing the government's need to import oil.

3. AN OVERVIEW OF KENYA

3.1 Background

3.1.1 Economy

In 2007, Kenya's GDP was approximately US$25.20 billion with a per capita GDP in purchasing power parity (PPP) terms of $1,700 the same year[34]. The economy comprises of 16.7% agriculture, 23.8% industry and 59.5% services sector although highly dependent on tourism and agriculture as the main source of government revenues[35].

3.1.2 Geology & Hydrocarbon Development

Geologically, the country has four sedimentary basins; Anza, Mandera, Tertiary Rift and Lamu which measure 94 200 km², 51 920 km², 40 000 km² and 132 720 km² respectively[36]. Petroleum exploration in Kenya began in 1954 and since then thirty four (34) wells have been drilled within the four sedimentary basins. Traces of oil and gas were encountered but none was commercially viable.

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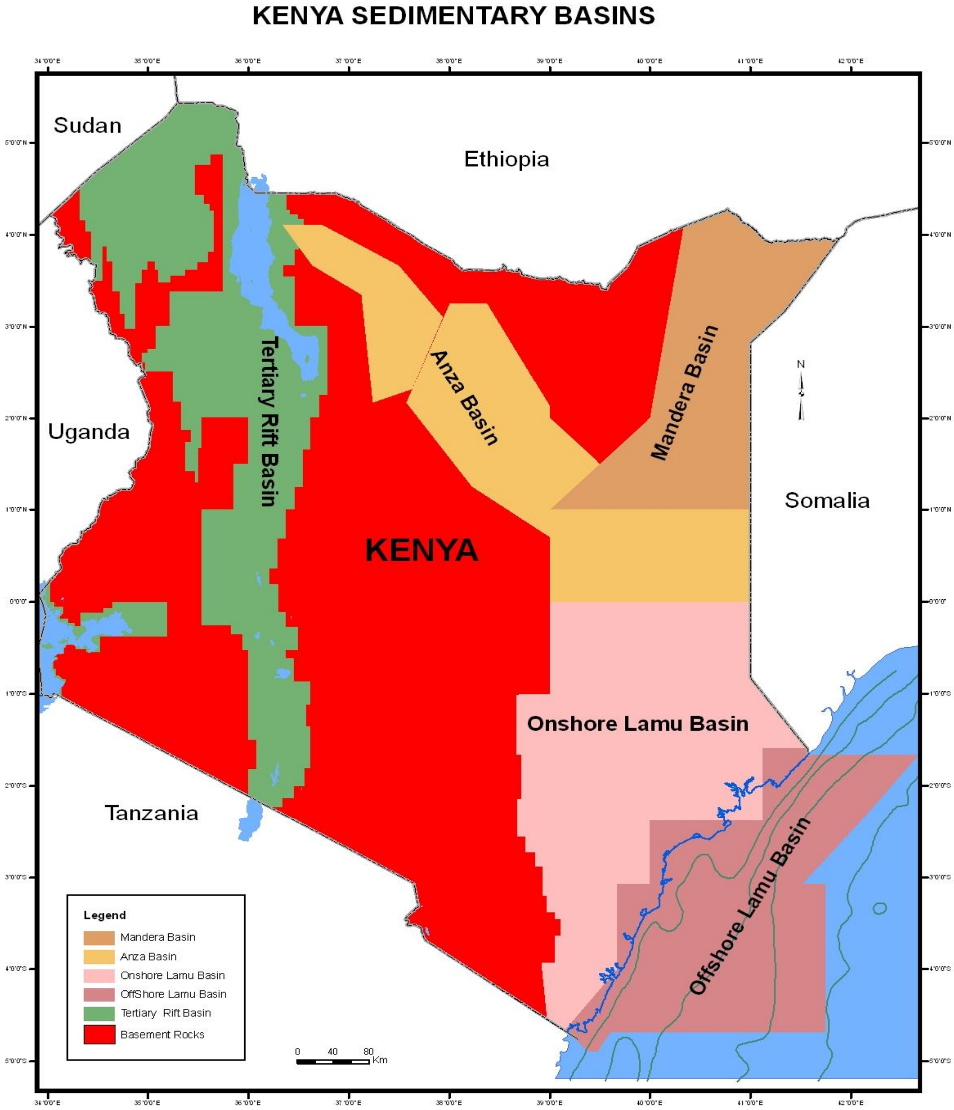
[34] Central Bank of Kenya, *Monthly Economic Review* , November 2008 at http://www.centralbank.go.ke/downloads/publications/mer/nov08.pdf (last visited on jan 10th, 2009)
[35] Central Intelligence Agency *Fact Book* at https://www.cia.gov/library/publications/the-world-factbook/geos/ke.html (Last visited on Jan 10th, 2009)
[36] National Oil Corporation of Kenya website at www.nockenya.co.ke (last visited on Jan 26th, 2009)

Figure 3: Kenya Sedimentary Basins



3.1.3 Petroleum (Exploration and Production) Act Cap 308

Petroleum exploration and production in Kenya is governed by the Petroleum (Exploration & Production) Act, Cap 308 enacted in 1982 and further revised in 1986 to regulate the negotiation and conclusion of petroleum agreements by GoK[37].

3.2 Model Production Sharing Contract

Prior to 1981, exploration and production was carried out under a Royalty/Tax based system that was provided for under the Mining Act, Cap 306. However, Kenya changed to

[37]Republic of Kenya, Ministry of Energy, Petroleum (Exploration and Production) Cap 308 www.energy.go.ke (last visited on Jan 16th, 2009).

a PSC based system after the enactment of the Petroleum Exploration and Production Act in 1982[38].

3.2.1 *Fiscal Instruments*

Kenya is considered to have one of the toughest fiscal regimes in Africa because of its high government take and its classification as a frontier area where no commercial discoveries are yet to be made[39].

3.2.1.1 Profit Oil Split

The division of profits is centred on a daily production-based sliding scale system which assumes the first tranche at 20000 barrels of oil per day (BOPD) whilst the last tranche being 100,000 BOPD. The profit splits are **negotiable** at each tranche as shown below[40]

Increments of Profit Oil	*Government share*	*Contractors share*
First 20,000 BOPD	%	%
Next 30,000 BOPD	%	%
Next 50.000 BOPD	%	%
Over 100,000 BOPD	%	%

3.2.1.2 Cost Recovery

The cost recovery limit is negotiable under the Kenya model PSC although some of the PSCs have been signed at a cost recovery limit of 75%[41].

3.2.1.3 Government Participation

Under the Kenya model PSC, the Government may elect to participate in the petroleum operations in any development area and acquire an interest of up to certain **negotiable**

[38] Republic of Kenya , Ministry of Energy (MOE), National Energy Policy Sessional Paper No. 4 of 2004 on Energy, October 2004 Republic of Kenya
[39] Barrows, G.H., World Fiscal Systems for Oil, Van Meurs & Associates Limited, Calgary, Alberta, 1997
[40] See MOE *Supra* note 37
[41] Conversation with Lois Allela ,Legal Officer, National Oil Corporation of Kenya

participating interest. The GoK can participate directly or through a wholly owned body corporate appointed by the state[42].

3.3 Government Objectives

3.3.1 Attract Foreign Direct Investments

The commercial energy sector in Kenya is dominated by petroleum and electricity as the prime movers of the modern sector of the economy. The accelerated search for hydrocarbons and potential success is seen as one of the solutions that can mitigate the adverse effects of oil importation on the Kenya economy. For this reason, the NEP states that the GoK objective as regards hydrocarbons is "*to enhance an enabling environment through which petroleum exploration and associated resource development activities can be undertaken*"[43]. This means stimulating exploration activities in the country by providing favourable fiscal terms to the IOCs while taking into consideration the geological uncertainty of the country. In addition, the NEP strategy on how to enhance the enabling environment involves:

- Collection and analysis of primary data in areas designated for licensing through service contracts so as to reduce the exploration risk undertaken by the IOCs.
- Reducing the size of exploration blocks in order to attract domestic and small IOCs.
- Enhance the regional cooperation in data acquisition and exchange so as to reduce the exploration cost.
- Building local content internally to undertake exploration so as to complement external efforts by the IOCs.

[42] See MOE Supra note 37
[43] ibid

Countries like Kenya however, have a limited leeway in attracting IOCs to undertake exploration activities because they have no commercially proven reserves of hydrocarbons [44].

3.3.2 Fair Share of Return

> *'The art of taxation consists of plucking the goose so as to obtain the largest amount of feathers with the least possible amount of hissing'*
>
> Loius XIV's Controller-General of Finance, J.B.Colbert (1619- 1683)[45]:

True to the statement above, the GoK should strive to ensure that the current fiscal regime responds to its intended objectives as well as the IOC's in a 'fair and equitable way'. This means that the GoK should seek to maximize the wealth from its natural resources and attract foreign direct investments at the same time.

Therefore, if the first NEP objective is achieved, the GoK is expected to have negotiated the fiscal terms on assumption that the project would go into production. The next objective would be to ensure that the Kenya fiscal regime appropriately provides a fair share of return from successful exploration once production commences. This is achieved by adjusting the GoK share of fiscal benefits to changes in market conditions. Consequently, undiscounted government "take" would rise or fall to correspond to changes in the levels of profitability actually achieved.

[44] *See* Johnston *Supra* note 26
[45] *ibid*

4. MODEL ASSUMPTIONS

The methodology applied in the paper is quantitative and intends to use a Model Cash Flow based on different production and economic assumptions. The Kenya fiscal system was subjected to two development scenarios of high and low oil price and cost environments to assess whether it attained the GoK objectives. The results were measured in terms of Undiscounted Government Take (GT)[46], Net Present Value (NPV) of the project's cash flow[47], Internal Rate of Return (IRR)[48], Operating Leverage[49], and Saving Index (SI)[50].

4.1 Production Assumptions

4.1.1 Production Profile

The model assumes a production profile of 25 years with a peak production of 10% in the third year after production starts followed by an exponential decline rate of 10% over the life of the project[51].

4.1.2 Production Profile

Different sizes of fields generate different levels of profitability. The classification of three generic **offshore** fields was based on literature by Nakhle (2008) reflecting different field sizes. The recoverable oil field size assumed in the model would range from 100MMBBLS

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[46] Government Take is the government share of gross cash flow from royalties, taxes, bonuses and profit oil

[47] The Net Present Value (NPV) is the sum of net cash flow stream when discounted at a specified rate which equates to the company's cost of capital. Decision rule is that if NPV is positive the project is accepted and vice versa.

[48] The Internal Rate of Return (IRR) is the percentage rate that will discount a net cash flow stream to a cumulative present value of zero. It is a prime indicator of a project's attractiveness

[49] The operating leverage is the ratio of the net present value of total cost to the net value of gross income. The higher the operating leverage, the more exposed the project profitability is likely to be to a drop in oil prices.

[50] The Saving Index (SI) is a measure (from an undiscounted point of view) of how much a company gets to keep if it saves one dollar. It quantifies the incentives companies get to keep costs down.

[51] See Johnston Supra note 27

to 400MMBBLS. The base case was 200MMBBLS[52]. Table 2 illustrates the classification of field size

Table 2: Classification of Field Size

Field Size	Recoverable Reserves mmbbls
Very Small	< 100
Small	100-200
Medium	200-400
Large	400-500
Very Large	> 500

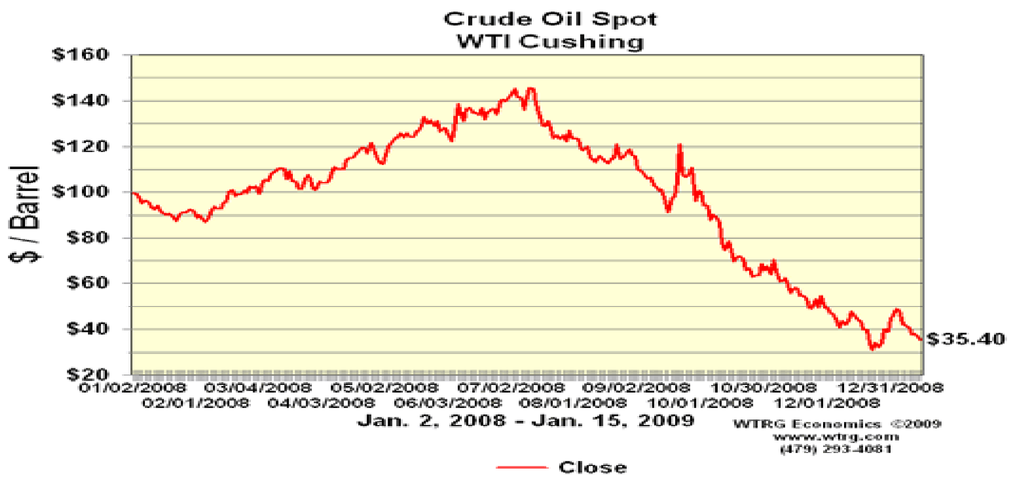
Source: Adapted from Nakhle (2008)

4.2 Economic Assumptions

4.2.1 Oil Price

The model assumes crude oil spot price range between US$20 and US$160 per barrel based on the West Texas Intermediate (WTI). The base case is US$80 per barrel. Figure 4 illustrates the movement of WTI crude price in 2008.

Figure 4: Crude Oil Spot Price (WTI)



Source: WRTG Economics

[52] *See* Nakhle *Supra* note 3

4.2.2 *Capital and Operating Expenditure*

The capital expenditure (CAPEX) represents costs related to drilling development wells, building subsea structures and production facilities, whilst the operating expenditure (OPEX) represented costs of maintaining the wells and production facilities.[53]

The model assumes total costs per barrel ranging from US$12 to $40 based on a discussion document by Dr. Pedro Van Meurs[54]. These costs per barrel are split into 46% and 54% for OPEX per barrel and CAPEX per barrel respectively based on the Energy Information Administration (EIA) Form EIA-28 (Financial Reporting System)[55]. Therefore the OPEX range from US$5.52 to US$18.40 and a base cost of US$11.50 per barrel. The CAPEX range from US$6.48 to US$21.60 per barrel and a base cost of US$13.50 per barrel. The model further assumed that the CAPEX consisted of 18% intangible assets and 82% tangible assets. The intangible assets were expensed in the year they incurred, while the tangible assets were depreciated using straight line over 5 years. The total CAPEX was also distributed as (20%, 13%, 43% and 25%) over the first 4 years of the project[56].

Table 3: Total CAPEX & OPEX per barrel

Cost Environments (CAPEX plus OPEX $ per barrel) for oil and gas fields		
	Low	High
Large onshore fields in Middle East and North Africa	$ 2.00	$ 8.00
Onshore oil and gas fields in other parts of the world	$ 4.00	$ 24.00
Onshore heavy oil fields (no major upgrading)	$ 8.00	$ 28.00
Shallow water oil and gas fields	$ 10.00	$ 30.00
Individual oil and gas wells in North America	$ 12.00	$ 35.00
Deep water oil and gas fields	$ 12.00	$ 40.00
Oil sands (mines, SAGD) including upgrading	$ 18.00	$ 40.00

Source: Van Meurs Corporation

[53] See Johnston, Supra note 27
[54] Van Meurs, P., "*Maximizing the value of government revenues from upstream petroleum arrangements under high oil prices*", Van Meurs Corporation , 2008
[55] EIA, Performance Profiles of Major Energy Producers 2007 at http://www.eia.doe.gov/emeu/perfpro/t&f_financial.html (last visited on Jan 18th, 2009).
[56] *See* Kaiser *Supra* note 13

4.2.3 Other Assumptions

The model assumed a 35% p.a. corporate tax, 10% government participation and the profit oil split was based on the PSC signed between the Republic of Kenya and Amoco[57].

[57] See Barrows, Supra note 39

5. ANALYSIS & RESULTS[58]

5.1 Attract Foreign Direct Investments

Several key economic performance indicators were used to determine whether the Kenya Fiscal Regime is attractive to the IOCs. These are the Project NPV, the Project IRR, the Saving Index (SI), Operating Leverage and Access to Gross Revenues (AGR).

Based on the assumptions stated in Chapter 4, the Kenya "BOPD based" system produced the following results from an investor's perspective on the attractiveness of the system under the base scenario[59].

Table 4: Base Case Scenario Investor Results

Investor Results

NPV US$M	Project IRR	AGR	Operating Leverage	Saving Index US cents
727.32	16.32%	62.98%	0.36	0.42

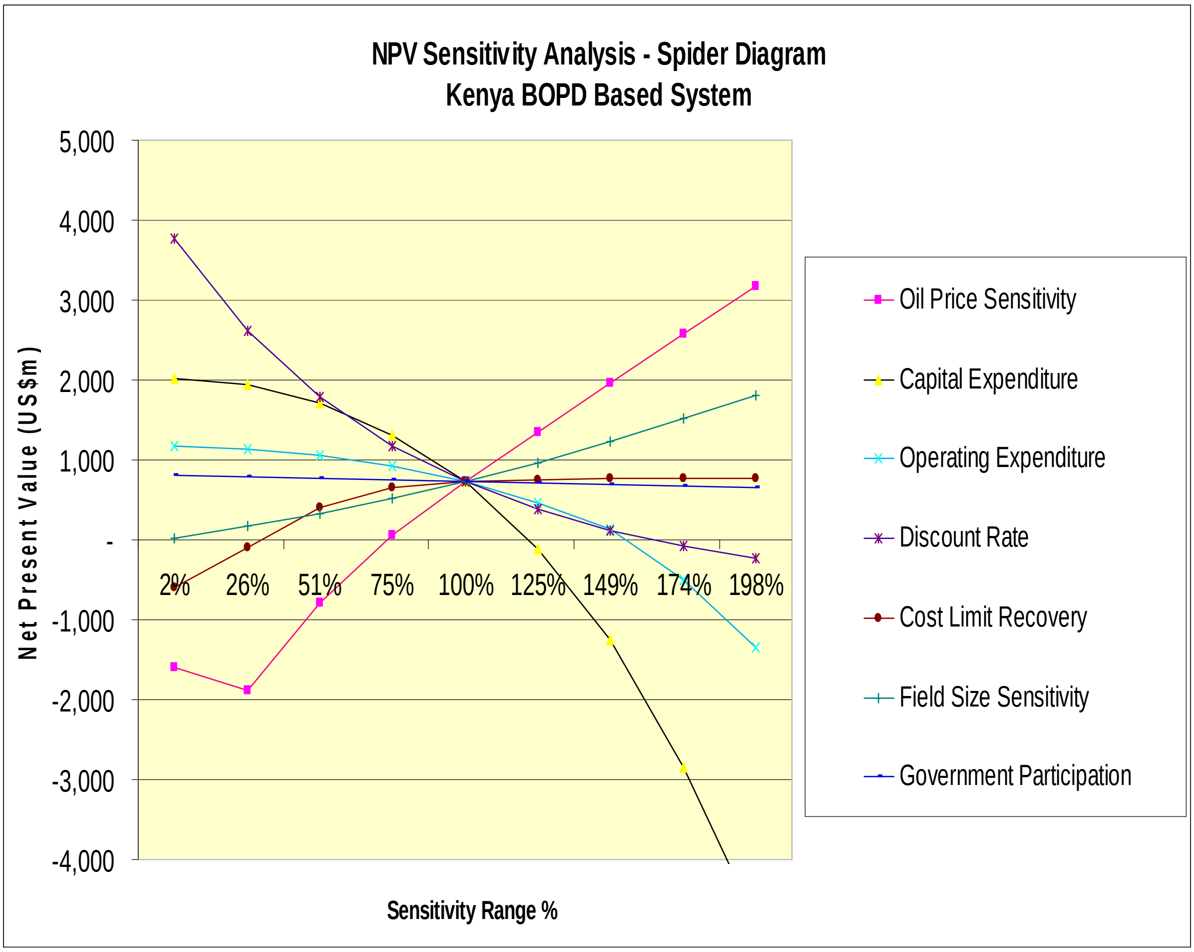
A sensitivity analysis addressing variations of crude oil price, CAPEX per barrel and OPEX per barrel was conducted on the above mentioned results.

5.1.1 NPV Sensitivity Analysis

The spider diagram represents the different sensitivity scenarios that were developed to evaluate how the NPV under the Kenya BOPD based system varies with changes in the various economic parameters. This will also provide an in-depth understanding of the different variables that significantly affect the reported NPV of US$ 273.81M.

[58] See appendices for the spreadsheets
[59] Please note that in the event of a dry hole, the contractor will bear the risks and costs of exploration.

Figure 5: NPV Sensitivity Analysis – Spider Diagram



Source: Author's Computation

The sensitivity scenarios results were as follows

The **crude oil price** reflected the second strongest relationship with the NPV whereby, a 25% increase in the base crude oil price of US$80 per barrel represented an 86% increase in the NPV from US$ 273.81M to US$ 687.51M. Conversely, a crude price of US$20 per barrel returned a negative NPV of US$ 1878.34M.

The **CAPEX sensitivity** showed that a 12.5% reduction in the prevailing CAPEX per barrel of US$13.50 per barrel resulted to an NPV of US$ 510.68M

The NPV was equally sensitive to the **OPEX** whereby a 1% increase in the base OPEX of US$ 11.50 per barrel resulted to a decrease in the NPV by US$13.52M.

The NPV was not as sensitive to the **field size** as the variables mentioned above but the discovery of a field that is 50% larger than the base case of 200MMBBLS would result to an NPV of US$505.89M

The NPV was similarly sensitive to the **discount rate** whereby a 1% increase in the base discount rate of 10% resulted to a decrease in the NPV by US$9.96M

The variable that least affected the NPV was the **cost recovery limit** where an increase in the recovery limit from the base 65% to 100% would only reflect an NPV of US$310.55M

Table 5 illustrates the sensitivity scenarios on the NPV.

Table 5: Sensitivity Scenarios on Net Present Value

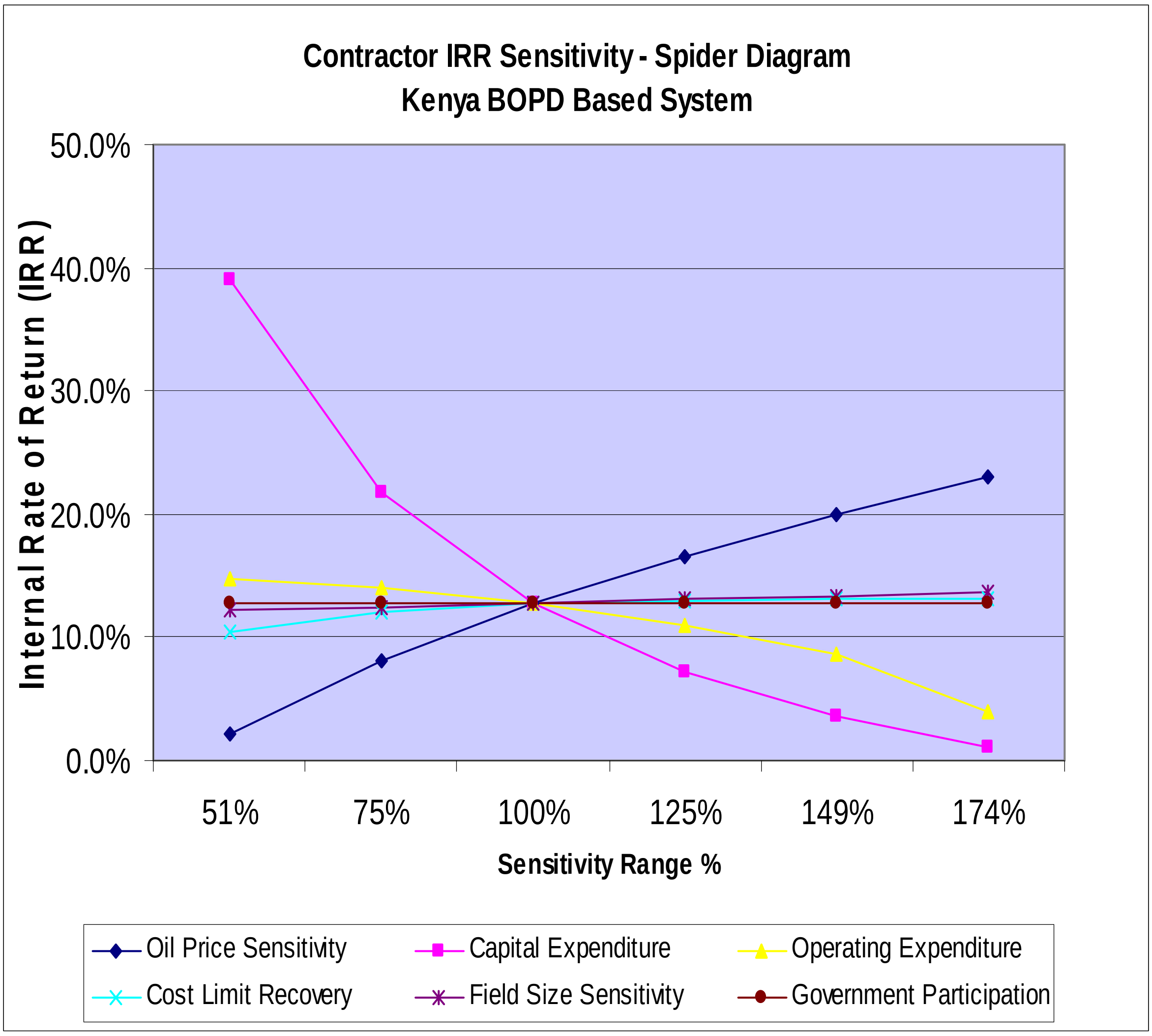
Net Present Value									
Sensitivity	2%	26%	51%	75%	100%	125%	149%	174%	198%
Oil Price Sensitivity	(1,599.31)	(1,878.34)	(822.56)	(186.52)	273.81	687.51	1,091.68	1,490.91	1,884.45
Capital Expenditure	1,311.36	1,244.98	1,062.99	747.55	273.81	(432.83)	(1,446.89)	(2,890.93)	(4,768.47)
Operating Expenditure	566.72	546.82	491.79	401.97	273.81	98.18	(143.66)	(592.43)	(1,349.35)
Discount Rate	2,441.69	1,627.52	1,037.30	601.18	273.81	24.92	(166.17)	(313.97)	(428.83)
Cost Limit Recovery	(672.07)	(306.10)	44.33	220.21	273.81	296.78	310.55	310.55	310.55
Field Size Sensitivity	4.28	56.67	112.02	183.29	273.81	382.86	505.89	638.81	777.82
Government Participation	303.62	296.17	288.71	281.26	273.81	266.35	258.90	251.45	243.99

Source: Author's Computation

5.1.2 IRR Sensitivity Analysis

The Internal Rate of Return is a widely used economic indicator that assesses the performance and attractiveness of a project. Projects that return higher IRR are normally preferred thus a sensitivity analysis on the IRR with respect to the Kenya BOPD system was conducted and the results were as follows. The following spider diagram represents the different sensitivity scenarios that were developed (Figure 6).

Figure 6: Contractor IRR Sensitivity – Spider Diagram



Source: Author's Computation

The CAPEX demonstrated a considerable correlation to the IRR whereby, a 25% decrease in the base CAPEX (US$13.50 per barrel) resulted to a significant increase in IRR from 12.7% to 21.7%. However, the same increase in CAPEX only resulted to a decrease in IRR from 12.7% to 7.2%.

The oil price sensitivity disclosed an equally strong relationship to the IRR although a 25% increase in the base oil price (US$80 per barrel) reflected a 30% increase in IRR from 12.7% (base) to 16.6%.

Nonetheless, the other sensitivity scenarios particularly the field size, OPEX and discount rate did not significantly shift the IRR. Table 6 illustrates sensitivity of the IRR to the different economic parameters

Table 6: Sensitivity Scenarios on IRR

Contractor IRR									
Sensitivity	2%	26%	51%	75%	100%	125%	149%	174%	198%
Oil Price Sensitivity	0.0%	0.0%	2.1%	8.1%	12.7%	16.6%	20.0%	23.0%	25.8%
Capital Expenditure	717.9%	84.3%	39.0%	21.7%	12.7%	7.2%	3.7%	1.0%	-1.5%
Operating Expenditure	15.5%	15.3%	14.8%	14.0%	12.7%	11.0%	8.6%	4.0%	-8.7%
Cost Limit Recovery	3.4%	7.1%	10.4%	12.1%	12.7%	13.0%	13.2%	13.2%	13.2%
Field Size Sensitivity	12.2%	12.2%	12.2%	12.4%	12.7%	13.1%	13.3%	13.6%	13.8%
Government Participation	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%	12.7%

Source: Author's Computation

5.1.3 Other Sensitivity Analysis

The SI, Operating Leverage and AGR results were subjected to a sensitivity analysis that took into consideration the changes in oil price, OPEX, CAPEX, field size, cost recovery limit and government participation and the following results were achieved. (Table 7)

Table 7: Sensitivity Scenarios on Saving Index

Saving Index									
Sensitivity	2%	26%	51%	75%	100%	125%	149%	174%	198%
Oil Price Sensitivity	0.28	0.28	0.28	0.27	0.27	0.28	0.28	0.28	0.28
Capital Expenditure	0.28	0.28	0.28	0.28	0.27	0.27	0.27	0.28	0.28
Operating Expenditure	0.27	0.27	0.27	0.27	0.27	0.27	0.28	0.28	0.28
Cost Limit Recovery	0.28	0.28	0.28	0.27	0.27	0.27	0.27	0.27	0.27
Field Size Sensitivity	0.26	0.26	0.26	0.27	0.27	0.28	0.29	0.30	0.31
Government Participation	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27

Source: Author's Computation

The SI only responded to the field size whereby as the size of the field increased, the IOC was bound to save more from every dollar spent on the project. This is as a result of the economies of scale that is characterized in oil projects because of their capital intensity nature. Table 8

Table 8: Sensitivity Scenarios on Operating Leverage

Operating Leverage									
Sensitivity	0.02	0.26	0.51	0.75	1.00	1.25	1.49	1.74	1.98
Oil Price Sensitivity	32.50	2.45	1.27	0.63	0.36	0.23	0.16	0.12	0.09
Capital Expenditure	0.18	0.19	0.23	0.28	0.36	0.46	0.58	0.65	0.65
Operating Expenditure	0.18	0.19	0.23	0.28	0.36	0.46	0.58	0.65	0.65
Cost Limit Recovery	0.01	0.17	0.33	0.36	0.36	0.36	0.36	0.36	0.36
Field Size Sensitivity	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36
Government Participation	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36	0.36

Source: Author's Computation

The operating leverage was highly sensitive to the volatility of the oil price whereby a 25% decrease in the oil price resulted to a 75% increase in the operating leverage from the base 0.36 to 1.27. Therefore the project profitability is highly exposed to a drop in crude oil prices under the Kenya BOPD based system.

Table 9: Sensitivity Scenarios on AGR

AGR									
Sensitivity	0.02	0.26	0.51	0.75	1.00	1.25	1.49	1.74	1.98
Oil Price Sensitivity	3997.6%	301.7%	156.8%	92.3%	63.0%	47.4%	37.8%	31.4%	26.8%
Capital Expenditure	53.0%	53.7%	55.7%	58.8%	63.0%	68.7%	75.9%	80.0%	80.0%
Operating Expenditure	52.7%	53.4%	55.4%	58.6%	63.0%	68.7%	75.7%	80.0%	80.0%
Cost Limit Recovery	43.5%	52.6%	61.7%	63.1%	63.0%	63.0%	63.1%	63.1%	63.1%
Field Size Sensitivity	61.6%	61.6%	61.7%	62.2%	63.0%	63.8%	64.7%	65.5%	66.2%
Government Participation	63.0%	63.0%	63.0%	63.0%	63.0%	63.0%	63.0%	63.0%	63.0%

Source: Author's Computation

The Access to Gross Revenues (AGR) for the IOC increased from the base 63% to 92.3% following a drop in prices from US$80 per barrel (Base) to US$60 per barrel based on the assumption that the recovery of OPEX and CAPEX in a given accounting period relative to gross revenues is unlimited.

5.2 Fair Share of Return

If Kenya discovers hydrocarbons, it would be in the best interest for the government to secure a fair share of return from the discovery. Therefore, several key economic indicators were used to determine whether the Kenya Fiscal Regime meets this objective in the event of a discovery of oil and gas. They are the Government Take and the Effective Royalty Rate (ERR)

The Kenya BOPD based system generated the following results from the government's perspective in achieving a fair share of return.

Government Results

Govt Take Undiscounted	ERR
75.36%	37.02%

A similar sensitivity analysis addressing variations of crude oil price, CAPEX, OPEX was conducted on the above mentioned results. The sensitivity sole aim was to determine how the Kenya BOPD based system would under the conditions mentioned and if at all the government objective of a fair share of return was achieved.

5.2.1 Undiscounted Government Take – High and Low Oil Prices

The graph below represents the sensitivity of the undiscounted government take to fluctuations of the oil price. It was observed that a 50% increase in the base crude oil price US$80 per barrel to US$120 per barrel insignificantly reduced the undiscounted government take from 75.36% to 75.15%. However, a decrease in oil prices increased the government take from 75.36% to 81.50%. This result demonstrated that the undiscounted government take under the Kenya BOPD based system does not correspond to movements in the oil prices. This can be attributed to the fact that the fiscal regime is solely dependent on production in determining the undiscounted government take.

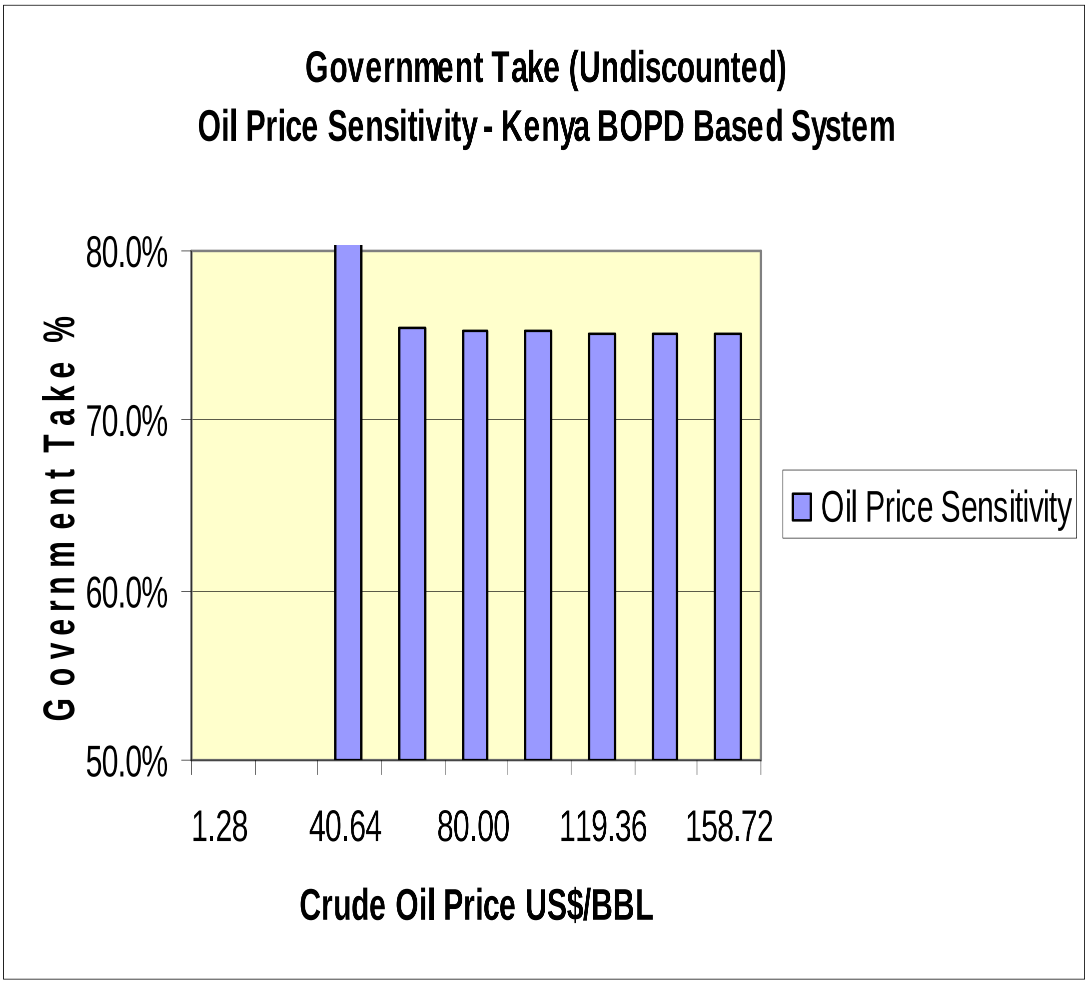


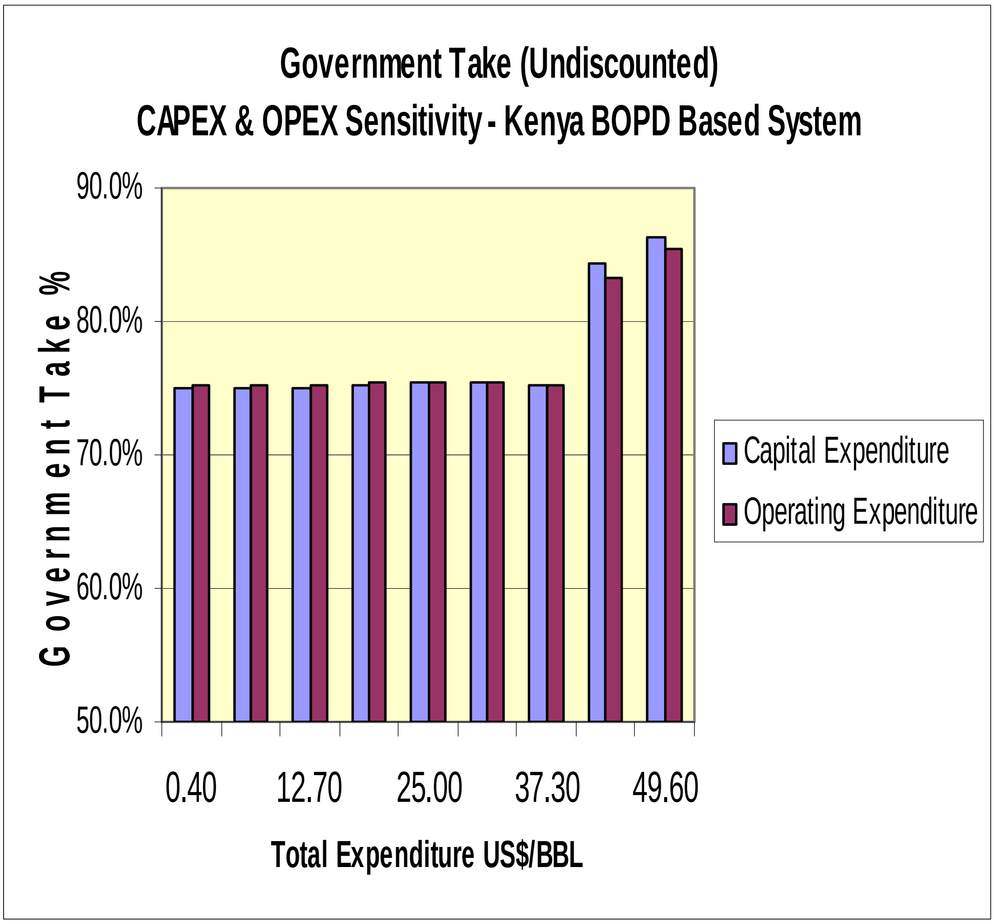
Figure 6: Undiscounted Government Take Sensitivity to High and Low Oil Prices

Source: Author's Computation

5.2.2 Undiscounted Government Take – High and Low CAPEX & OPEX

The GT was similarly insensitive to the fluctuation of both the OPEX and CAPEX per barrel. However, a 75 % increase in both the OPEX and CAPEX per barrel resulted to an undiscounted government take increase of 83.35% and 84.28% respectively.

Figure 7: GT under High and Low CAPEX & OPEX



Source: Author's Computation

5.2.3 *Undiscounted Government Take – Field Size Sensitivity*

It was observed that the GT illustrated the strongest relationship with the increase or decrease of field size although, the bigger the field, the lower the GT.

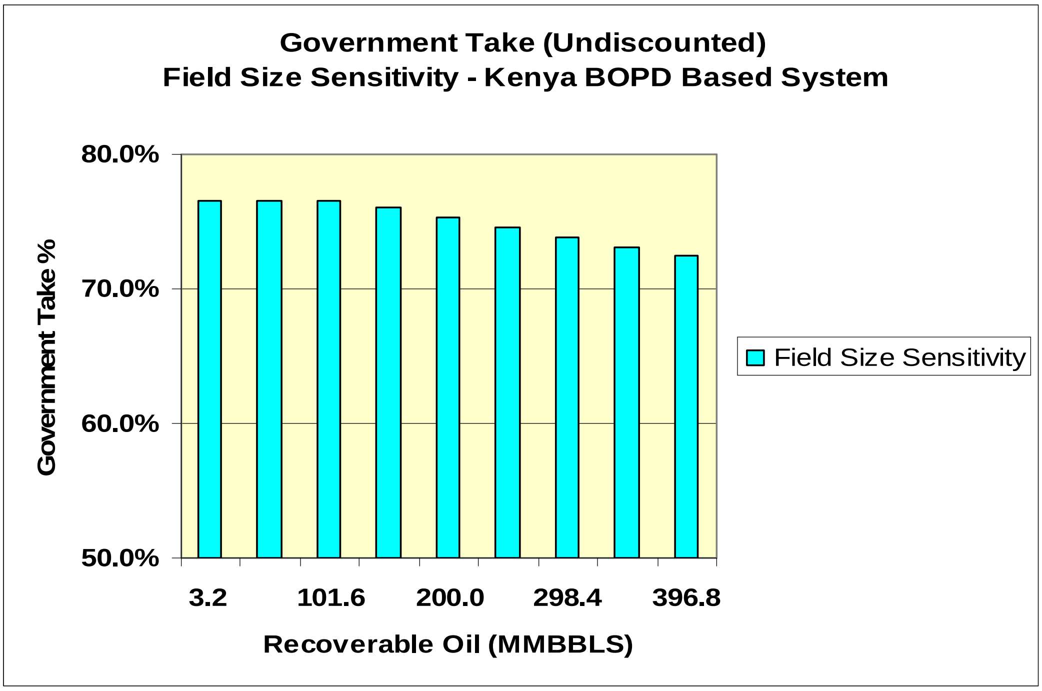


Figure 8: GT under Field Size Sensitivity

Source: Author's Computation

The other sensitivity scenarios are reflected below.

Undiscounted Government Take									
Sensitivity	2%	26%	51%	75%	100%	125%	149%	174%	198%
Oil Price Sensitivity	7.172%	-40.675%	81.508%	75.423%	75.361%	75.249%	75.158%	75.099%	75.074%
Capital Expenditure	75.0%	75.0%	75.0%	75.1%	75.4%	75.5%	75.3%	84.28%	86.28%
Operating Expenditure	75.3%	75.3%	75.3%	75.3%	75.4%	75.4%	75.2%	83.35%	85.35%
Cost Limit Recovery	93.2%	84.9%	76.5%	75.3%	75.4%	75.3%	75.3%	75.3%	75.3%
Field Size Sensitivity	76.6%	76.6%	76.5%	76.0%	75.4%	74.6%	73.8%	73.1%	72.5%
Government Participation	72.7%	73.3%	74.0%	74.7%	75.4%	76.0%	76.7%	77.4%	78.0%

6. CONCLUSION

Recent discovery of oil and gas in the East Africa region (Uganda and Tanzania) has put the Kenya Fiscal Regime on the spotlight. The statistical results demonstrated that the system attractiveness is doubtful because of its failure to effectively adjust to the ebb and flow of oil prices and costs. Evidently, in the low oil price era, the IRR and project NPV decrease although the GT comparatively remains the same and vice versa. This is because the division of profits is entirely based on **daily oil production** instead of linking aspects of the profit-sharing mechanism to **profitability** of the project through **oil prices** or **ROR**.

Therefore, the overall conclusion is that the Kenya Fiscal Regime does not meet the GoK objectives because it is **regressive** and **inflexible** to fluctuations of oil prices and costs. It is recommended that revision of the system is done to include sensitivity to oil prices and costs hence avoid issues of alignment of interests that lead to renegotiation of existing contracts in the future upon discovery of commercial quantities of oil and gas.

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APPENDICES

Field Cash flow Model – Kenya "BOPD based" system

KENYA "BOPD BASED" SYSTEM

Yr	Oil Production	OIL Price	Gross Revenues	Royalty	Net Revenue	Capital Costs	Operating Costs	Deprn & Ammortn	Unrecovrd. Costs C/Fwd	Company Cost Recovery	Company Profit Oil	Govt Participation 10%	Govt Profit Oil	Company Taxable Income	Income Taxes	Government Take Cash Flow Net After-Tax	Government Take Cash Flow DCF 10.0%	Contractor Group Cash Flow Net After-Tax	Contractor Group Cash Flow DCF 10.0%
Yr	(MBBLS)	$/bbl	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m	US$m
																			1
1	-	$80.00	-	-	-	540,000	-	-	-	-	-	-54,000	-	-97,200	-	**-54,000**	**-51,487**	**-486,000**	**-463,383**
2	-	$80.00	-	-	-	358,020	-	-	97,200	-	-	-35,802	-	-161,644	-	**-35,802**	**-31,033**	**-322,218**	**-279,293**
3	-	$80.00	-	-	-	1,207,904	-	-	161,644	-	-	-120,790	-	-379,066	-	**-120,790**	**-95,181**	**-1,087,114**	**-856,630**
4	5,429	$80.00	434,322	-	434,322	802,273	66,255	476,944	379,066	282,309	60,805	-52,541	91,208	-723,561	-	**38,666**	**27,699**	**-472,873**	**-338,743**
5	12,668	$80.00	1,013,418	-	1,013,418	-	157,687	476,944	784,366	658,722	151,798	65,283	202,898	-547,673	-	**268,181**	**174,647**	**587,549**	**382,628**
6	20,000	$80.00	1,600,000	-	1,600,000	-	253,939	476,944	760,276	1,040,000	264,460	104,145	295,540	25,904	9,066	**408,752**	**241,991**	**937,309**	**554,911**
7	18,097	$80.00	1,447,740	-	1,447,740	-	234,369	476,944	451,159	941,031	232,700	77,752	274,009	462,418	161,846	**513,607**	**276,426**	**699,764**	**376,617**
8	16,375	$80.00	1,309,969	-	1,309,969	-	216,307	476,944	221,441	851,480	206,179	71,381	252,310	364,408	127,543	**451,234**	**220,778**	**642,429**	**314,326**
9	14,816	$80.00	1,185,309	-	1,185,309	-	199,637	-	63,212	262,849	405,092	30,440	517,368	468,304	163,906	**711,714**	**316,569**	**273,958**	**121,856**
10	13,406	$80.00	1,072,512	-	1,072,512	-	184,252	-	-	184,252	383,671	24,939	504,589	383,671	134,285	**663,813**	**268,420**	**224,448**	**90,758**
11	12,131	$80.00	970,449	-	970,449	-	170,052	-	-	170,052	339,990	22,099	460,407	339,990	118,997	**601,503**	**221,113**	**198,894**	**73,114**
12	10,976	$80.00	878,099	-	878,099	-	156,947	-	-	156,947	300,623	19,541	420,528	300,623	105,218	**545,287**	**182,226**	**175,865**	**58,771**
13	9,932	$80.00	794,536	-	794,536	-	144,852	-	-	144,852	268,482	17,451	381,203	268,482	93,969	**492,623**	**149,660**	**157,062**	**47,716**
14	8,987	$80.00	718,926	-	718,926	-	133,689	-	-	133,689	239,587	15,573	345,651	239,587	83,855	**445,079**	**122,924**	**140,158**	**38,710**
15	8,131	$80.00	650,511	-	650,511	-	123,386	-	-	123,386	213,545	13,880	313,581	213,545	74,741	**402,202**	**100,983**	**124,924**	**31,365**
16	7,358	$80.00	588,607	-	588,607	-	113,877	-	-	113,877	190,078	12,355	284,652	190,078	66,527	**363,535**	**82,977**	**111,196**	**25,381**
17	6,657	$80.00	532,594	-	532,594	-	105,101	-	-	105,101	170,997	11,115	256,496	170,997	59,849	**327,459**	**67,948**	**100,033**	**20,757**
18	6,024	$80.00	481,911	-	481,911	-	97,001	-	-	97,001	153,964	10,008	230,946	153,964	53,887	**294,841**	**55,618**	**90,069**	**16,990**
19	5,451	$80.00	436,051	-	436,051	-	89,526	-	-	89,526	138,610	9,010	207,915	138,610	48,514	**265,438**	**45,520**	**81,087**	**13,905**
20	4,932	$80.00	394,555	-	394,555	-	82,626	-	-	82,626	124,771	8,110	187,157	124,771	43,670	**238,937**	**37,250**	**72,991**	**11,379**
21	4,463	$80.00	357,008	-	357,008	-	76,259	-	-	76,259	112,300	7,299	168,450	112,300	39,305	**215,054**	**30,479**	**65,695**	**9,311**
22	4,038	$80.00	323,034	-	323,034	-	70,382	-	-	70,382	101,061	6,569	151,592	101,061	35,371	**193,532**	**24,935**	**59,121**	**7,617**
23	3,654	$80.00	292,294	-	292,294	-	64,958	-	-	64,958	90,934	5,911	136,402	90,934	31,827	**174,139**	**20,397**	**53,197**	**6,231**
24	3,306	$80.00	264,478	-	264,478	-	59,952	-	-	59,952	81,811	5,318	122,716	81,811	28,634	**156,667**	**16,682**	**47,859**	**5,096**
25	3,171	$80.00	253,676	-	253,676	-	58,653	-	-	58,653	78,009	5,071	117,014	78,009	27,303	**149,387**	**14,461**	**45,635**	**4,418**
	200,000		16,000,000	-	16,000,000	2,908,198	2,859,705	2,384,722	2,918,365	5,767,903	4,309,467	280,115	5,922,630	2,400,324	1,508,314	**7,711,059**	**2,522,002**	**2,521,038**	**273,806**

Undiscounted	Take	US$m
Contractor Group	24.6%	2,521,038
Government	75.4%	7,711,059
Total	100%	10,232,097

Internal Rate of Return	12.7%

Investor Results				
NPV US$m	Project IRR	Access to Gross Revenues	Operating Leverage	Saving Index US cents
273.81	12.74%	62.98%	0.36	0.27

Government Results	
Govt Take Undiscounted	ERR
75.36%	37.02%

Profit Oil Split Assumptions		
Bopd	Govt	Contractor
First 20000	60%	40%
Next 30000	55%	45%
Next 40000	50%	50%
Next 50000	45%	55%
Over 100000	40%	60%

Assumptions (Base Case)					
Production Assumptions		Economic Assumptions		Fiscal Terms	
Field Size	200mbbls	Currency	US $	Cost Oil	65%
Peak Prod.	10%	Oil Price $	80.00	Inc Tax	35%
Decline Rate	10%	Capex $/bbl	13.50	Govt Part	10%
		Opex $/bbl	11.50		