Comparative Analysis of Joint Venture and Production Sharing New Contractual System in Nigeria

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Abstract - The Petroleum industry is not static but dynamic, defined by large capital investment with a low probability of commercial discovery, but with considerable financial returns when successful. Globally, there are constant modifications in the fiscal frame work to adjust to varying goals of the government and multinationals. Nigeria is not left out in these modifications since government wants to allure additional proceeds from the growth of its petroleum reserves. Joint venture began in Nigeria in 1971 attributable to the directive given by OPEC to its members in 1968 to be vigorously involved in the petroleum industry and also the fast growth in the request for oil globally and the increase in the income from oil. In 2017, the National Petroleum Policy announced a modification in its fiscal frame work from JVs to IJVs and PSCs. This research compares joint venture and production sharing new contractual system in Nigeria using the fiscal terms of PIFB 2018. The research used deterministic models and Monte Carlo simulation to analyze the JV and the production sharing new contractual system incorporating the fiscal terms of PIFB 2018, applying economic indicators like NPV, IRR, DPO and discounted take statistics. The deterministic model result for the JV had a government NPV of $461.19MM and discounted take of 72%, while the government NPV was $827.89MM and the discounted take was 73% for the production sharing new contractual system. Since, the Nigerian government is defaulting in its monetary duties and the result obtained from this research work yielded a higher government NPV in the production sharing new contractual system, it is recommended that the production sharing new contractual system be applicable in the petroleum industry for subsequent contracts in Nigeria.

Index Terms – Nigeria, Joint venture, Production Sharing Contract, Petroleum Industry Fiscal Bill (PIFB)

1 INTRODUCTION

Petroleum is of monumental interest in revenue generation for most oil producing and dependent countries globally like Nigeria. Statistics by BP in 2018 on Review of World Energy gives Nigeria's proven gas reserve as 183.7 trillion SCF and her proven oil reserve as 37.5 billion barrels making her the second largest crude reserve in Africa after Libya. Nigeria is a mono economy nation that is highly dependent on revenue from petroleum through its petroleum fiscal arrangements. Nigeria depends mainly on export of crude and import of finished product [1]. The upstream sector of the petroleum industry is pivotal to the Nigerian economy accounting for close to 90% of the country's trade and estimates of 70% - 80% of the government income [2]. The petroleum fiscal systems arrangement dominant in Nigeria are production sharing, joint venture, sole service concessions and risk service [3]. Joint Venture is a plan amid the government and the multinationals, where the host government contributes its share through monetary duties while the multinationals provide technology, expertise and the remaining fund required on the basis of their respective equity in a joint operating agreement. Nigeria operates six joint ventures with multinationals such as Chevron, Phillips, AGIP, Total E&P, Texaco, Mobil and Shell. Petroleum fiscal system as petroleum taxation and contract that exist within a countryc[4]. The arrangement could be between a multinational, National Oil Company (NOC), indigenous or sole risk, and marginal field operators [5]. It began to avoid conflicting interest amongst the government with aim of maximization of its oil revenue, increase its reserve and production potential, and the multinationals, with aim of efficient use of its proceeds and quick and fair return on investment. The design of an efficient fiscal system is of paramount importance to the government and the multinational which depends on the country. It should consider such factors as terrain, changeability of oil price, and fund required in exploration and development in each terrain. An efficient fiscal system is one that presents a win-win situation to both the government and multinational [3]. An efficient fiscal system is characterized by; ensuring equal risk and reward for the government and investor, refrains from complications and reduces responsibility on the management, dissuades excessive assumptions, guarantees a firm atmosphere for the business and reduces pre dominant threat, advance robust contest and the effectiveness of the market for the petroleum. Moreover, the components of an efficient fiscal system design are allocation of fields which could be done using sealed competitive bid from governments view or negotiations from the investors view, program involved in the work, number of years for exploration, production and to

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cede the field, types of bonuses that would apply (signature and production), royalty which should be sliding and not fixed to ensure progressivity, a limit on how much the investor is allowed to recover to recoup his investment, split of profit oil which should be biddable to ensure efficiency, taxes and participation of the government to have a small working interest [6]. However, some fiscal systems are ill designed and they have some marks such as, fiscal terms are not progressive, system without royalty to guarantee an income to the government or without cost recovery limit to allow the investor recoup some of his investment, a system that does not take into account all the variables that make up an efficient system but uses only one or two terms and where there is no negotiation of some terms in the contract [6].

2 Upstream Petroleum Fiscal System Arrangement in Nigeria

The two broad categories of petroleum fiscal regimes exist in Nigeria; concessionary and the contractual systems [7], [8]. The concessionary system was preeminent in the petroleum industry for many years when concession was given to Shell D' Arcy which later became Shell B P [9]

2.1 Joint Venture (JV)

It is a royalty and tax system with the involvement of the government. It designates the multinational the right to conduct a systematic search for petroleum. The produced petroleum belongs to the multinational while royalties and tax payments are made to the government. It is modified to adapt to increasing or decreasing prices and serves as a safe haven for multinationals.

2.2 Production Sharing Contract

The discovery of petroleum offshore in 1973 brought about the production sharing contract. [10] noted that the multinationals has full right to cost oil and equity oil and can help dispose of tax oil on NNPC's behalf. The basic terms of a PSC is usually determined through legislation but can also be negotiated due to political and economic conditions or when more information becomes available. PSC has four basic components namely: royalty, cost recovery, profit oil and tax oil [11].

1. Royalty: Percentage of gross revenue after selling petroleum. It is being proposed as a sliding scale in Nigeria.
2. Cost recovery: The multinationals are allowed to recoup part of the cost that they spent known as capital expenses and operating expenses. The cost recovery limit is fixed at 80%.
3. Profit oil: The remainder after removal of royalty and cost recouped from the gross revenue which is divided between the host government and the multinationals.
4. Tax oil: It is this portion that the multinationals apply in the payment of taxes

Table 1 shows how the different petroleum fiscal systems compare in terms of risk and reward by Mian (2002), and Bindemann (1999)

Table 1: Comparative Analysis of Petroleum Fiscal Systems (Mian (2002) and Bindemann (1999))

Type of Contract	Contractor	Host Government
Concession or royalty/tax	• Assume all risk • Take part in reward	Reward will depend on production and oil price
Production sharing contract	• Assume exploration risks • Share reward	• Share in reward of oil • Share in reward from price through taxation
Joint venture	• Share in risk in exploration, production • Share in reward	• Share in risk of business • Share in reward
Pure service contract	No risk for contract because payment is under contract	• All risk from exploration and production • All reward from production, price

3 METHODOLOGY

Two deterministic models were built using an estimated field reserves size of 35MMBBl produced for 21 years. The data applied in this study to compare the joint venture and the production sharing new contractual system include production data for a theoretical field and fiscal terms which is the Petroleum Industry Fiscal Bill (PIFB) 2018. See Table 2 and 3.

Table 2: Key Fiscal Terms for Onshore terrain (PIFB 2018)

Fiscal Terms	Value
Royalty Rate by Daily Production (%)	• 0>q<=2500 2.5 • 2500<q>=10000 7.5 • 10000>q<=20000 15 • Above 20000 20
Petroleum Income Tax (PIT)	65%
Additional Petroleum Income Tax	0.5% per $1 increase in oil price above $60
Production Allowance	30% of the official selling price of crude
Depreciation	Straight line, 1st 4years (20%), 5th year (19%, 1%)
Education Tax	2% of assessable profit
NDDC Levy	3% of the total budget
Profit Oil	• 70% to the government • 30% to the contractor
Cost Recovery Limit (CRL)	80% of the net revenue

Table 3: Oil Field Development Plan

Reserves	35	MMBBL
Exploration period	2	Years
Development period	2	Years
Time to build up	4	Years
Build up rate	5000	Bopd
Plateau rate	12000	Bopd
Build up duration	3	Years
Plateau starts at	4	Years
Plateau ends at	7	Years
Decline factor	0.524	Fraction
Production life	21	Years
Duration of decline	14.84	Years

The plateau rate is reached after 4 years of the beginning of production. Build up is linear with an instant production rate of 5000bopd based on typical exploration and production project under joint venture agreement in the Niger Delta basin. The plateau rate remains constant at 12000bopd for 3 years after the beginning of production and ends at year 7. At the phase of build-up, about 8.7 MMbbl of oil had been produced and about13 MMbbl of oil during 7 years at the plateau with a plateau rate of 12000bopd. Decline factor is obtained using the remaining reserve of 8.1 MMbbl to produce a rate of 0.524. The total time to economically produce the 35MMBBL field is 21 years.

3.1 Production Profile

It was forecasted by assuming an initial production of 5000 BOPD. The annual production was obtained using equation 2 below, while the cumulative production was obtained by adding the previous annual production to the present annual production for each year. Most deterministic models that were built by researchers in energy economics, applied production forecast using exponential decline for cash flows such as [13], [14], [15], [16] as it does not require much effort to decipher.

The production rate at time t is calculated by

$$q_t = q_i \mathrm{EXP}^{-at} \tag{1}$$

$$\Delta N_P = \frac{(q_i - q_t)\times 365}{a} \tag{2}$$

Annual production ΔN_P time is expressed by applying Equation 3.3.

$$T = \frac{\ln(\frac{q_i}{q_t})}{a} \tag{3}$$

Where; q_t, rate at any time t of production,bop; q_i,initial rate of production,bopd; t, time period between q_i and q_t, years; a, nominal decline rate,fraction/year; ΔNp, cumulative production,stb. There are typically three phases during the production for the reservoir according to Iledare [17], the Development Phase or Buildup, Plateau Phase, and the Decline Phase. The production life for this study using exponential decline is 21 years.

3.2 Building of the Model

The spread sheet modelling approach comparable to that adopted by Mian (2002), Johnston (2003), and Iledare (2010) is applicable. The cash flow is the cash expended over a time frame, usually, one year which starts with a forecast of production profile, after which the revenue generated and cash spent each year is obtained. Net cash flow (NCF) is the cash received minus the cash spent.

3.2.1 Components of Cash Flow

The components that make up the cash flow include; Annual Production, Gross Revenue, Oil Price [18], Net Revenue, Abandonment Provisions, Royalty, NDDC Levy, Education Tax, Rental, Petroleum Income Tax (PIT), Additional Petroleum Income Tax, Value Added Tax (VAT), Signature Bonus, Profit oil, Cost Recovery. Other components of the cash flow include Technical costs and Production allowance which are discussed in details in the sections below as deem important for this study.

3.2.1.1 Technical Costs [capital expenditure (CAPEX) and operating expenditure (OPEX)]

The two costs associated with exploration, development and production on any oil field, are capital expenditure (CAPEX) and operating expenditure (OPEX).

1. CAPEX: They are incurred at the beginning of the project required to exploit and produce petroleum. The fund to be spent on CAPEX is hinged on the terrain, implying that for an onshore field, the CAPEX is lower when placed side by side

with shallow water or deep offshore. They are either tangible (capitalized and depreciated) or intangible (expensed). The tangible CAPEX are deducted in calculating taxable income and therefore, income tax. Straight line depreciation was applied in depreciating the tangible CAPEX as legislated by the Nigerian government.

For an Onshore field,

Cost of drilling one well = $ 20 MM

Plateau Rate = 12 000 BOPD

(field development plan in the model)

Number of Wells = 6 Wells

Experience shows that production from an onshore field should be between 1500bopd-3000bopd. Assuming 2000bopd which is in the range, based on the peak production of 12000bopd, the number of wells will be:

$$Number\ of\ wells = \frac{12000bopd}{2000bopd} = 6\ wells \qquad (4)$$

Therefore, the cost of drilling 6 wells = cost of drilling one well * the number of wells which is $120MM.

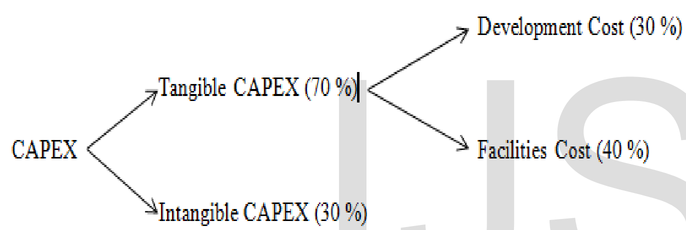

Fig 3.3: Breakdown of CAPEX (Mian, 2002)

$ 120 MM = 30 % of Total CAPEX

$$Total\ CAPEX = \frac{\$120\ MM}{0.3} = \$400\ MM \qquad (5)$$

From the total CAPEX, 30% is expensed while 70% is capitalized and applied for the depreciation using straight line for 5 years as presented in table 4 below.

Table 4: straight line depreciation

YEAR BEGIN	TIME T	CAPEX (MM$)	EXPENSED CAPEX (MM$)	CAPITALIZED CAPEX (MM$)	SLD	DEPRECIATION				TOTAL DEPRECIATION (MM$)	ABANDONMENT COST (MM$)
2016	0										
2017	1	100	30	70	0.2						
2018	2	100	30	70	0.2						
2019	3	100	30	70	0.2						
2020	4	100	30	70	0.2						
2021	5				0.19	14				14	
2022	6				1	14	14			28	
2023	7					14	14	14		42	
2024	8					14	14	14	14	56	
2025	9					13.3	14	14	14	55.3	
2026	10						13.3	14	14	41.3	0.7
2027	11							13.3	14	27.3	0.7
2028	12								13.3	13.3	0.7
2029	13										0.7
2030	14										

2. OPEX: These are direct funds involved in production from a field such as production costs, overheads, management fees, lifting costs, environmental costs and community settlements. They could either be fixed or variable costs. Fixed cost is not hinged on the yield from petroleum and is highly susceptible to diminished unit cost and heightened output while variable cost is hinged on the yield from production. Rule of thumb specifies the fixed OPEX to be 4% or 5% of the total CAPEX while the variable OPEX is applied as 15% of net revenue.

3.2.1.2 Production Allowance

The production allowance is dependent on the crude the multinational is permitted to claim which can be demanded on its cost efficiency using the cost efficiency factor. The Cost Efficiency Factor (CEF), can be described as a proportion of 20% of the entire revenue to the entire operating cost. It is expressed mathematically as:

$$CEF = \frac{20\%\ of\ Revenue}{Total\ OPEX} \qquad (6)$$

The cost efficiency Factor that is applicable is shown in the table 5.

Table 5 Cost Efficiency Factor Applicable for Production Allowance (PIFB 2018)

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Cost Efficiency Factor	Production Allowance
CEF<=0.5	50%
0.5<CEF<1.2	50% to 120%
CEF>=1.2	120%

The multinational is entitled to additional production allowance that is secured to the Reserve Replacement Ratio (RRR) as presented in the table 6 below:

Table 6 Reserve Replacement Ratio Applicable for Additional Production Allowance (PIFB 2018)

RRR Range	Additional Production Allowance
RRR=1	50%
1<RRR<1.25	75%
1.25<RRR<1.5	100%
RRR>=1.5	125%

3.4 Analysis of Cash Flow

The net cash flow (NCF) is the net annual expenditure that is deducted from the net annual revenue annually. It is computed as:

NCF = Net Annual Revenue- Net Annual Expenditure (7)

Mian (2002), gives the general expression for NCF governing any field in year t operating the joint venture and production sharing contract as

$$NCF_t = GRR_t - ROY_t - CAPEX_t - OPEX_t - BONUS_t - TAX_t - OTHERS_t \quad (8)$$

$$NCF_t = GRR_t - ROY_t - CAPEX_t - OPEX_t - BONUS_t - PO/G_t - TAX_t - OTHERS_t \quad (9)$$

3.6 Measures of Profitability

The measures for the comparative analysis are: Discounted take statistics, Net Present Value (NPV), Internal Rate of Return (IRR), and Pay out Period.

The screening criteria applied in this study, is as shown in table 7 below as adapted by Mian (2002).

Table 7: Capital Budgeting Techniques Rules (Mian, 2002)

Measure of profitability	Accept	Reject
NPV	>0	<0
IRR	>r	<r
DPO	≤ desired	≥desired

Where, r = discount rate

RESULTS

A presentation of the result realised from the comparative analysis of joint venture and production sharing new contractual system in Nigeria using the fiscal terms of PIFB 2018 are analysed here.

4.2 Decision Analysis Guide

In the analysis carried out, some common economic measures were employed such as Net Present Value (NPV), Internal Rate of Return (IRR), Pay out period (DPO), the government and contractor take (discounted and undiscounted). The decision rules that apply to them are seen in table 7.

The deterministic results obtained for the joint venture and the production sharing new contractual system in Nigeria is as displayed in Table 7 and Table 8

Table 8: Deterministic model result for joint venture in Nigeria using PIFB 2018

Economic measures	Host government	Contractor
Net Present Value (NPV)$MM	461.19	183.53
Undiscounted take statistics	62%	38%
Discounted take statistics	72%	28%
IRR discounted		25%
IRR undiscounted		44%
Discounted Payout Period		6.9Years

Table 9 Deterministic model result for PS new contractual system in Nigeria

Economic measures	Host government	Contractor
Net Present Value(NPV) $MM	827.89	304.73
Undiscounted take statistics	70%	30%
Discounted take statistics	73%	27%
IRR undiscounted		54%
IRR discounted		34%
Discounted Payout Period		5.5 Years

Applying the profitability measures mentioned in Table 3.6 and the base case of Table 8 and Table 9, a comparative analysis of the joint venture and production sharing new contractual system in Nigeria using the fiscal terms of PIFB 2018 will be evaluated. For the joint venture in Nigeria, it produced a discounted take 72%, yielding an NPV of $461.19 million while the new contractual system has a discounted take of 73% yielding an NPV of $827.89 million. The NPV generated were positive showing that the ventures are profitable. The joint venture yielded a discounted IRR of 25% while the production sharing new contractual system yielded a discounted IRR of 34% for the contractor which is higher than the hurdle rate of 15%, implying that the ventures are profitable. From the analysis above, the production sharing new contractual system generated more government NPV and Discounted take than the joint venture.

Conclusion

The production sharing new contractual and joint venture systems are profitable but the production sharing new contractual system yielded a higher government take. Since, the Nigerian government is defaulting in its monetary duties and the result obtained from this research work yielded a higher government NPV in the production sharing new contractual system, it is recommended that the production sharing new contractual system be applicable in the petroleum industry for subsequent contracts in Nigeria.

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