



Economic and Risk Analysis to Deep Water Operations

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Authors' contributions

This work was carried out in collaboration between both authors. Author CEU designed the study, designed the methodology and carried out the economic and risk analysis. Author AOO wrote the introduction, literature review and the conclusion. Both authors wrote the results and discussion. Both authors read and approved the final manuscript.

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ABSTRACT

The exploration and production (E&P) operations of oil and gas project in deep waters, is associated with risks. These risks affects return on investment if they are not identified and analyzed to reduce their impact on the project. This study seek to apply Discounted Cash Flow (DCF) analysis, Monte Carlo Simulation and Sensitivity analysis, to an existing field in the Niger Delta region in Nigeria, to ascertain the viability of deepwater project when it is affected by government fiscal terms and technical terms. Economic and risk models were developed to determine profitability indicators and risk associated with the project. Risk simulator software was used to carry out Monte Carlo simulation and the sensitivity analysis. Results obtained showed that the project was economically viable with a Net Present Value (NPV) of \$1,621.8 million and Internal Rate of Return (IRR) of 34%. The Monte Carlo Simulation and the sensitivity analysis showed that the Contractor's NPV and percentage take were most sensitive to tax (under the fiscal terms) with an range of \$639.27 million for a variation of by +/- 10% and crude price (under the technical term). The model developed can easily be applied in investment selections and decision makers should make decision based on the outcome of both economic model (cash flow analysis) and the risk model (Monte Carlo Simulation).

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1. INTRODUCTION

Petroleum is one of the most important raw materials to solve the energy problem facing the world. Its impact in everyday life is highlighted by the fact that the smallest of articles such as the plastic bags, cups have their basis from fossil fuels. Faced with an ever-increasing demand for petroleum-based products, the oil companies have had to extend the search for oil and gas to offshore fields. However, the challenges in terms of technology and terrain, poses a lot of uncertainty and risk in exploring for oil and gas in the offshore environment.

Offshore field has been classified into three categories: (1) Shallow offshore, - This is defined as water depths below 400 m, (2) Deepwater offshore - water depths between 400 m to 1000 m, and (3) Ultra-Deepwater – water depths greater than 1000 m.

The uncertainties and risk involve in exploring and producing hydrocarbon in deep offshore are more involved as water depths increase, unpredictable weather such as tornadoes, storms tsunamis are encountered. In addition, uncertainties in forecasts of product prices, expenses, future investments and tax laws, add to the burden of risk in deep offshore operations. Therefore, the success of in exploring and exploiting hydrocarbon in deep offshore is highly dependent on understanding the dynamics of risk involved in the oil and gas business [1,2].

The fundamental question in making an investment decision is whether the return on the investment will commensurate with the risk involve. In business, big decisions about large and risky investments are made every day; however, the outcome of these decisions is further improved by carrying out risk analysis, by the use of numerical probability or risk analysis.

In risk analysis, the uncertainties of a project are quantified using numeric probabilities. These are then applied to cash flows. The resulting risk-weighted economic yardsticks are used directly in the decision-making process. This inclusion of risk directly into the decision allows a normalized, meaningful comparison among projects with different levels of risk [3].

The profitability of the project is measured by various profit indicators: The Net Cash Flow,

payout time, profit per dollar invested, net present value, discounted cash flow rate of return (DCFROR), discounted payback period and the discounted profit to investment ratio.

1.1 Offshore Development/Operation around the World

The early period of 1970, saw the production of hydrocarbon in the deep water of Gulf of Guinea, in the coast of Nigeria, Angola, and the Republic of Congo. The main resources of the region is located in the deep water of the Gulf of Guinea and on the Niger Delta's coastal areas. However, one in every four barrels of crude oil sold in the world comes from the Gulf of Guinea, with exclusion of the Persian Gulf. The Gulf of Mexico and Brazil's Campos Basin are two other important deep offshore with vast deposit of hydrocarbon [4].

For Nigeria, the journey into offshore operations started with Chevron's (Operator of the NNPC/Chevron Joint Venture) discovery of its first offshore fields in 1963 – the Koluama and Okan fields. On April 8, 2003, ENI through its subsidiary Nigerian Agip Exploration (NAE) commenced oil production from its deep offshore Abo Central Field. The development of the Abo field marked the first oil production from deep offshore in Nigeria.

1.2 Oil and Gas Investment in Nigeria: From Joint Operating Agreement to Production Sharing Contract

The emergence of offshore oil and gas operations and the granting of deep-water acreages to the oil producing companies have however witnessed a shift from Joint Operating Agreement (JOA) regimes to Production Sharing Contracts (PSCs), with implications for the operation and regulation of the oil industry in Nigeria. This shift is attributable to a number of factors ranging from the complexity of operations in the offshore terrain, (which makes regulation under a JOA more difficult), to dwindling resources of the country, (which makes funding under the JOAs precarious for the government).

Modelled after partnership agreements, the JOA operates as a form of partnership between the joint venture partners, spelt out the participatory

interest of each of the partners and also designates one of the partners as the operator of the venture. In Nigeria, the NNPC represents the interest of the government in the joint ventures, whereas the respective MNOCs operate the different ventures with varying participatory interests. The JOA governs the relationship between the parties, including budget approval and supervision, crude oil lifting and sale in proportion to equity, and funding by the partners. In addition to the JOA, a Memorandum of Understanding (MOU) governs the manner in which revenues from the venture are allocated between the partners, including payment of taxes, royalties and industry margin.

Some of the constraints associated with the JOA include poor funding, due mainly to the imbalance in the financial capacity of the different joint venture partners, especially the government that has other pressures on its resources, leading often to reduction in operations and consequential loss in revenue. JOA is also constrained by allegations of gold plating of operating costs by the non-operators of the venture, which often leads to mutual suspicion between the parties, and the rather unfair distribution of revenues, especially in the situation of upsides from high oil prices.

As the name implies, Production Sharing Contract (PSCs) focuses on the sharing of the output of oil and gas operations in agreed proportions between the Oil Company, as a contractor to the government, and the NOC, as the representative of government interests in the venture. Under a PSC, the contractor, usually a foreign oil company bears the entire cost and risk of exploration activities, and only reaps the rewards after a commercial finding of hydrocarbon. In the event of a commercial discovery, the contractor recovers its costs fully from allocation of oil, referred to as 'Cost Oil (CO). Cost Oil is a percentage of the difference between Gross revenue from Production after Royalty has been deducted. Allowances also made from production for royalties, after which the remainder of the production, called 'Profit Oil (PO), is shared in agreed proportions between the company and the government as represented by the NOC.

It provides for payment of a flat rate of 50% tax on petroleum profits by PSC operators, and sets different royalty regimes, depending on the water depth in which the operation is carried out, ranging from 12% for water depths of 200-500 m,

to 0% for water depths in excess of 1,000 m. PSCs in inland basins attract a flat royalty of 10%.

In [5], the author stated and analysed five risk analysis models: Starting from a simple two outcome analysis which he referred to as level 1 and concluding with the Monte Carlo simulation which he referred to as Level 5.

According to [6], the economics of the WOMBAT field was most sensitive to changes in the project CAPEX by using the Expectation curve method of risk analysis.

The article by [7], showed how Value of Information (VOI) could be used as a ranking tool in a portfolio or subsurface appraisal.

The author in [8], performed risk analysis to investigate the economic feasibility of an offshore exploration prospect using PetroVR. To perform the sensitivity analysis of the project, they divided the key drivers into commercial and technical terms. Their study showed that technical terms had more impact than the commercial terms of the contract.

The utilization of expected value method, showed that for an offshore field, the parameters were most sensitive to tax rate [9].

Work on the Sensitivity of the Production Sharing Contract was carried out by [10], using simulation method. Their study compared the impact of fiscal terms on the economics of deepwater opportunities in three countries: Equatorial Guinea, Angola and Egypt. Each of the three countries had different production sharing formula. He showed that the Angolan Profit split although it does not protect against downside risk, however seems a fair mechanism, for countries to use in limiting their exposure to lost profits.

Deepwater development/operations require a large investment of capital due to their size, locations, deep water completions and logistical support requirements. According to Behrenbruch, [6], a typical large field development can have costs exceeding \$3 billion dollars. Flow assurance issues, caused by paraffins and asphathene deposition, may escalate operating cost. Finding and Development (F&D) cost has fluctuated between \$4/bbl and \$8/bbl, which pose a lot of risk in deep offshore operation. A proper understanding of these problem will minimize risk and increase investor's confidence.

2. MATERIALS AND METHODS

Two major software for handling economic model and risk analysis: Excel spreadsheet and Risk Simulator, where employed to develop an economic model and carry out a risk analysis, due to the nature and computation involves in handling the data from deep offshore operation.

An economic model for PSC was developed using Excel Spreadsheet and Cash flow parameters were programmed into the model to estimate profitability indicators.

Equations 1 and 2, was used to calculate the Gross and Net Revenue.

$$GR = \text{Annual Production (bbl)} \times \text{Oil Price (\$/bbl)} \quad (1)$$

$$NR = GR - \text{Royalty (bbl)} \quad (2)$$

Where Royalty is paid on Gross Revenue.

Other taxes which are part of the model are: NDDC (3% of Companies Budget for each year). In this model, the operator's budget for the year comprises solely of the total operating expenses and thus;

The NDDC provision for the year is then determined using:

$$\text{NDDC provision} = \frac{3 \times \text{OPEX}}{97} \quad (3)$$

The cost and profit oil (for each participant) sharing are calculated as follows:

$$\text{Cost to Recover} = \text{CAPEX} - \text{OPEX} \quad (4)$$

$$\text{\%Cost - Recover} = \frac{(\text{Gross Revenue} - \text{Royalty})}{\text{Cost to Recover}} \quad (5)$$

$$\text{\%Profit Oil} = \frac{(\text{Gross Revenue} - \text{Royalty} - \text{CO})}{\text{Profit Oil}} \quad (6)$$

The stake holder's Net Revenue (taxable income for the contractor) are calculated as follows

$$\text{Contractor's Net Revenue} = \text{CR} + \text{Contractor's Profit Oil Share} + \text{Investment Tax Credit (ITC)} + \text{Contractor's Share} - \text{Bonus} - \text{NDDC} - \text{CAPEX} - \text{OPEX} \quad (7)$$

The Net Cash flow for the contractor is then calculated with the Equation

$$NCF_C = \text{Net Revenue} - \text{Taxes} \quad (8a)$$

$$NCF_G = \text{Net Revenue} + \text{Taxes} \quad (8b)$$

Contractor and Government take are determined thereafter

$$\text{Contractor Take} = \frac{\text{Contractor's NCF}}{\text{Government's NCF} + \text{Contractor's NCF}} \quad (9a)$$

$$\text{Government's Take} = 1 - \text{Contractor's NCF} \quad (9b)$$

The sensitivity analyses were carried out to determine the parameter which most impacts the project using Monte Carlo Simulation built into the Risk Simulator.

The sensitivity analysis involves three (3) phases. Phase one (1) investigated the impact of the most influential of the drivers governed by the fiscal terms (also known as commercial terms), phase two (2) and three (3) addressed the impacts of technical terms and a combination of both fiscal as well as commercial terms respectively.

Fiscal associated with the operations are: Cost Oil – 64%, Profit Oil – 40/60 in favour of Government, Royalty Rate – 8%, Investment tax Allowance – 50%, discount rate – 15%, Oil price: \$45/bbl.

3. RESULTS AND DISCUSSION

Oil and gas project of this type, requires estimation of the minimum oil price (Break even oil price - below which the project starts generating loss – negative NPV) at which the project will remain profitable. The minimum oil price was determined from the cash flow via NPV profiles to be \$21.93/bbl. The project remains profitable as long as crude oil price is above the minimum price.

The results obtained from the NCF analysis are presented in the table below

Table 1. Estimated managerial indicators

Economic indicators	Value obtained
NPV@15%	\$1,621.80M
IRR	34%
Profitability Index	1.43
Payback Period	4.89
Unit Technical Cost (UTC)	\$11.2
Contractor's Take	18%

The values in Table 1 shows that the investment is profitable, since NPV for the project remains positive, IRR is more than 2 times the cut-off limit (15%) and UTC (which is the cost required to produce 1 bbl of crude oil) is at a value lower than the minimum oil price (\$21.93/bbl).

Pay-back period of 4.89 years for the project is satisfactory since within this period, production is still building-up.

For the sensitivity analysis, the input parameters were classed into commercial and technical terms. The Table 2 illustrates the distributions.

Table 2. Distribution of parameters

Commercial	Technical
Tax rate	CAPEX
Signature Bonus	Fixed OPEX
CO	Variable OPEX
PO	
Royalty	

A tornado chart of the sensitivity analysis is shown in Fig. 1. Green bars in the chart indicate a positive effect while the red bars indicate a negative effect. Tax has the higher negative impact on the NPV, indicating that, the higher the tax, the lesser the NPV. OPEX, Royalty and signature bonus have minimal negative impact on the NPV and thus the effect can be ignored, since their contribution to uncertainty is minimal. Crude Price, Profit Oil (PO) and Investment Tax Credits (ITC) have high positive impact on the NPV, indicating that these parameters and NPV has positive correlation.

A similar analysis applied to %CT (Fig. 2), tax has the higher negative impact on the Contractor's Take, while Profit Oil and investment Tax Credit, has higher positive impact on the Contractor's Take. In addition, the percentage variation explained (Fig. 2), shows that 64.17% of the variation in %CT is accounted for by Tax, 28.91% by Profit Oil and 1.99% by ITC.



Fig. 1. Tornado and percentage variation on NPV

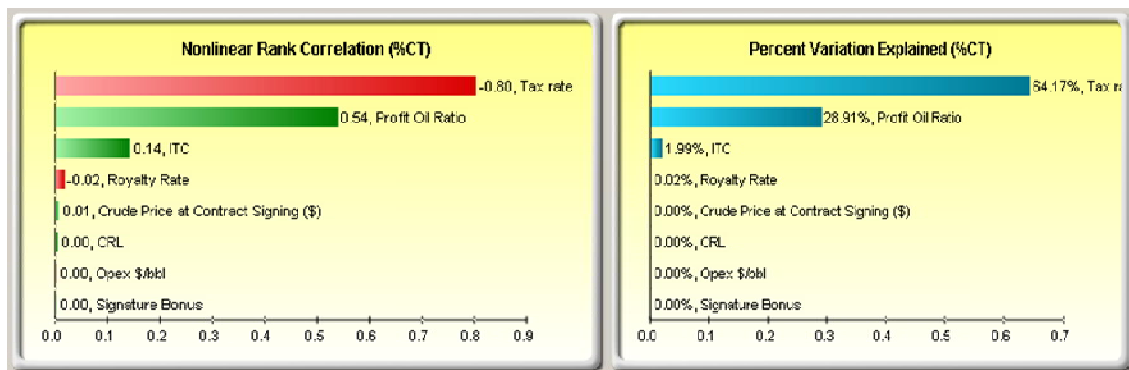


Fig. 2. Tornado and percentage variation on %CT

In both, NPV and %CT, the effect of tax is most significant, since increased tax rate will affect the profitability of the project and reduced tax will favour of the Contractor. However, where there is need to improve the %CT, it is possible to implement that by negotiating strongly for a higher PO ratio and possibly revision of ITC upwards.

4. CONCLUSION

Deep water development and operation in Nigeria is capital intensive and as such investors must be well informed on the risk and uncertainty associated with the project before making investment decision. This project examined the impact of fiscal terms and technical terms on the profitability of a Deepwater development/operation under Nigeria's PSC. The Fiscal Terms have more impact on profitability of Deepwater development in Nigeria than the technical terms of the project. Tax which is component of the fiscal terms, negatively impact more on the project profitability indicators (Net Present Value – NPV and Contractor's Take), indicating that the project is most sensitive to changes in tax. Crude oil price, profit oil and investment tax credit, positively impact more on the profitability indicators, indicating that the higher these parameters, the higher the NPV and contractor's take.

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COMPETING INTERESTS

Authors have declared that no competing interests exist.

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