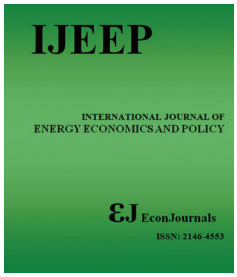


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# Nigeria Deep Offshore Inland Basin Production Sharing Contract Acts: Evaluating Contractor's Take

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**ABSTRACT**

Value-focused thinking is often designed to focus decisions on the essential activities that must occur prior to solving a decision problem. This approach was adopted by the Nigerian government in the fiscal legislation for Deep Offshore and Inland Basin Production Sharing Contract (DOIBPSC) Act enacted in 1999 and the subsequent amendment of 2020 version. One major item of interest in the amended Act is the introduction of royalty by price to enable the government to capture windfall in high oil price spike. This study evaluates the new fiscal regime to ascertain its attractiveness and impact on contractor take. Four features (royalty, cost recovery, tax oil, and profit oil) of the PSC contract terms were used to determine contractor and government takes from the transactions. This study adopted the full range of oil prices captured in the amended DOIBPSC Act in addition to the current market price of oil estimation. Six ranges of oil price ($20/bbl, $ 0/bbl, $0/bbl, $0/bbl, $20/bbl, $160/bbl) were used to cover the five royalty sliding scales adopted in the amended DOIBPSC and the current oil price, which is ≤ $20/bbl. From the econometric analysis, estimates from the unit root tests revealed that the time series data on of the I(0) and I(1) series. The ARDL/bound cointegration test result shows that all the integrated variables are cointegrated at a 5% level. Analysis of the impact of the price sliding royalty regime on the contractors' take shows that in both the long run and the short run, the price sliding (royalty by price) regime had a negative impact on the contractors' take. The short-run impact of the royalty level and the regime change on the contractor's take is high and significantly negative. This is expected as the design of the royalty regime is based on long term benefits.

**Keywords:** Deepwater Fiscal System, Royalty Regimes, Production Sharing Contract, Oil and Gas, Long and Short Run
**JEL Classifications:** P28, O22, O38

## 1. INTRODUCTION

In Africa, Nigeria and Angola are the largest crude oil producers, accounting for 65-75% of total crude oil production, with a combined total output of about 3.35 million barrels of oil per day (OPEC, 2020). Both countries are members of the Organization of Petroleum Exporting Countries (OPEC) and are stiff competitors in attracting investments for upstream oil and gas exploration and exploitation in Africa (African Development Bank, 2009). However, in recent times, production capacities and upstream petroleum investments in both countries have declined. One key instrument that arguably has a direct correlation to production capacity and investment is the prevailing fiscal regime governing the jurisdiction (Kantorowicz and Turyna, 2019). A progressive fiscal regime is greatly perceived to attract investment for exploratory and exploitation activities thereby increasing opportunities for production capacity while a repressive fiscal regime may achieve the opposite.

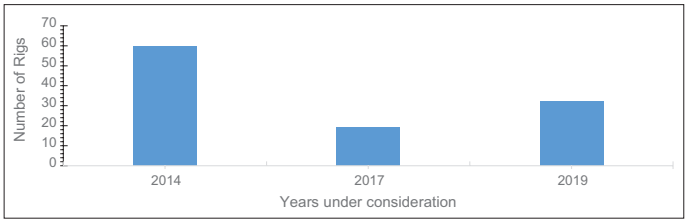
Production in Nigeria has reduced due to instability, though marginal recovery was experienced in 2019 and it is expected to

attain an average of 2.2 million barrels per day in 2020 (Adubisi et al., 2020). Also, oil production in Angola has declined, and it is projected that this trend will continue over the next 5 years. Statistics shows that production from block 17 in Dalia, Angola's largest oil field, fell by approximately 50% in 2019 (Eregha and Mesagan, 2020). However, the approvals of Mafumeira Sul which started production in 2016 and Kaombo projects are expected to improve the country's production capacity. This expectation could be short-lived with little or no new major projects springing up to boost production capacity. Likewise, upstream petroleum investments in Nigeria have greatly declined, no thanks to the huge uncertainty in fiscal propositions. According to Rystad Energy (2019), in Africa generally, investments fell by approximately 65%, from a peak of around $48 billion in 2014 to $17 billion in 2018. Approximately 80% of these investments were directed to Nigeria and Angola in 2019. Another indicator of decline in oil and gas projects in Sub-Sahara Africa (SSA) is the level of activity reflected in the number of drilling rigs operating in the region. This is also a measure of exploration and exploitation investment in the oil and gas industry. Figure 1 shows the number of mobile drilling units in operation between 2014 and 2019.

In January 2019, 32 platforms operated in the region, compared to 19 in 2017. Despite the increase in the number of mobile drilling units, it is only half the number of the active drilling rigs in January 2014, when 60 mobile drilling rigs were operating in the region (Zaidi et al., 2020). The overall utilization of vessels in West Africa was about 40% in 2017 and 80% in 2018. In general, about 110 vessels were active in the region as at January 2019 with utilization rate of 62-68%, while the utilization rate of 130 active vessels as at January 2014 was about 88%. Of the fifteen floating production storage and offloading (FPSO) in Nigeria, seven are involved in deepwater operations (Okoro et al., 2017; Ali et al., 2019). Presently, Nigeria ranks second in Africa's deepwater business after Angola in terms of FPSO deployment.

Fiscal regimes correlate positively with production capacity. On the other hand, production capacity greatly influences what the parties (the government and contractors) get in revenue, as specified in the production sharing contracts (PSCs) (Cendrero and Paz, 2017; Mariano et al., 2018). By the amended PSC Act, Nigeria operates a royalty regime that is sensitive to price changes. One striking element in the Act is that at lower price levels, contractors earn more revenue than the concessionaire. However, government-take from the contract is progressive as oil price ramps up. To ascertain the respective positions of the government and contractor under the amended Act, this study examined the financial implications of the royalty by price regime for the contractor. Royalty, cost recovery, tax oil and profit oil were the four PSC contract terms selected, for the investigation, and the range of oil prices ($20/bbl, $30/bbl, $40/bbl, $80/bbl, $120/bbl, and $160/bbl) selected cover the five royalty sliding scales adopted in the amended DOIBPSC and the current oil price. This study also provides insight on price-based royalty under crude oil price uncertainty.

**Figure 1:** Number of mobile drilling units operating in Sub-Sahara Africa




## 2. PETROLEUM FISCAL SYSTEMS IN DEEPWATER OPERATIONS

Generally, there are two broad petroleum fiscal systems: Concessionary and Contractual systems. A fundamental difference between the systems is in the structure of ownership of petroleum resources and the methodology for cost recovery with limitations that may be imposed (Blake and Roberts, 2006; Weijermars et al., 2017). Though, concessionary petroleum fiscal system has evolved over the years, it is mainly characterized with transfer of petroleum resource ownership from the mineral owner to the investor; while the contractual petroleum fiscal system is characterized by retention of petroleum ownership by the mineral owner. Johnston (1994) alluded that there are more petroleum fiscal systems in the world than there are more countries, because of the varying terms and modifications being agreed upon. Therefore, a contractor may have conditions different from another contractor in the same country. In Nigeria, as a result of the evolution of the petroleum fiscal system, numerous contracts are in effect at any given time. They include joint venture (JV) agreements, production sharing contracts (PSC), service contracts (SC), sole risk (SR) and marginal field (MF) operations (Ovadia, 2014). Except for the PSC and SC that are forms of contractual systems, the other arrangements are forms of the concessionary systems. Regardless of the system in place, the crux is on how to recover costs and share benefits, hence the need to introduce the term "Economic Rent" which is the difference between the value of production and the cost of extraction.

According to Johnston (1994), one of the absolute things that investors in petroleum resources face internationally is diversity of fiscal system. Most countries have their unique form of tax structure; though governments cannot control the gifts of nature, they can manage accruable economic rents in the form of taxes. Accordingly, PSCs vary considerably, and countries seldom follow the same pattern. The variations have arisen as a result of the challenge in obtaining a fair deal in the economic rent split (Yusgiantoro and Hsiao, 1993; Feng et al., 2014). Consequently, governments have designed numerous frameworks for the extraction of economic rents from the petroleum sector. The end-product of the prevailing frameworks has shown some of the fiscals to be more efficient and better balanced than others with a few complexities.

In Nigeria, the deep water operations are mainly governed by the production sharing contracts. Some of the reasons why this is adopted could be ascribed to government's funding constraints; retention of concessions while the International Oil Companies (IOC) act as the contractor and; limited technical know-how in the highly risky deep-water operations. However, the benefits of

deep-water projects and operations in Nigeria have been viewed from different perspectives (Nwachukwu and Mbachu, 2018). Stakeholders, especially civil society organizations, have subjected the deep-water operations to series of agitations and calling for a review of the PSC Act. Obviously, the yearning for a review is to increase government's economic rent. The focus of this study is to investigate the deep-water fiscal system in operation in Nigeria and to outline possible concerns in the dynamics of international negotiations.

### 2.1. Deepwater Fiscal System Instruments in Nigeria

The government is committed to ensuring that the hydrocarbon resources are developed in a manner that will be of maximum benefit to the nation whicle bearing in mind the imperative to maintain clear and competitive regulatory and royalty regimes in order to continue to attract new investments in the industry (Kanshio, 2020; Dagoumas et al., 2020). The contractual production sharing systems applies in Nigeria's deep-water operations. The PSCs provide a unique arrangement between exploration and production companies and oil producing countries such as Nigeria. The fiscal legislation in Nigeria is the Deep Offshore and Inland Basin Production Sharing Contract (DOIBPSC) Act enacted in 1999 and amended in 2020.

Historically, Nigeria's deep-water asset licenses were first issued in the mid-1990s. Majority of the assets initially operated as production sharing contracts (PSC) while a few were on a sole risk license basis. However, the promulgation of the Deep Offshore Inland Basin Production Sharing Contract (DOIBPSC) Act of 1999 converted all licenses in deep-water operations beyond 200 metre water depth to become a deep offshore asset. It is interesting to note that this Act was backdated to 1993 to cover assets whose licenses were issued in the period. Prior to the amendment of the DOIBPSC Act in Nigeria, the governing royalty schemes for deep offshore assets progress with water depth. The Act stipulates a fixed royalty rate of 12% for assets producing at a water depth range of 201-500 m; 8% fixed royalty rate for assets in water depth between 501 and 800 m; 4% flat royalty rate for oil production from assets operating in 801-1000 m water depth; and no royalty payment for assets in water depth greater than 1000 m. The fixed royalty rate implies that the charged rate is constant irrespective of the production volume from the asset in the water depth (Clancy, 2007). Also, the previous DOIBPSC Act had no royalty by price provisions though there exists a clause that could trigger a windfall profit capture on the economic rent. However, with the amendment, the DOIBPSC Act stipulates a 10% fixed royalty rate for all deep offshore production in water depth that exceeds 200 m. As a result, many of the prolific deep offshore assets operating at water depths above 1000 m are now subjected to the royalty provisions. It is interesting to note that the current production capacity in Nigeria is majorly driven by the prolific deep offshore assets such as the BONGA, EGINA, AKPO, and AGBAMI to mention a few. This bold amendment is anticipated to boost the government's economic rent.

Additionally, the amendment makes provision for an extra royalty known as "Royalty by Price." A "royalty by price" structure was introduced to provide royalty flexibility based on changes in the prices of crude oil, condensate and natural gas. This royalty is paid in addition to fixed water depth royalties. This implies a royalty regime made up of fixed and variable components. The additional royalty by price is triggered when oil price is greater than USD 20 per barrel and it is implemented on the incremental oil price value above USD 20 per barrel. In the stipulation, the royalty by price is tranche (Table 1). If prevailing oil price is USD 20 per barrel or less, there would be no royalty by price payment. However, when prevailing oil price is greater than USD 20 per barrel but not more than USD 60 per barrel, a 2.5% charge on the incremental oil price value above USD 20 per barrel is applied. Likewise, when prevailing oil price is within the range of USD 60-100 per barrel, a 4% rate on the incremental oil price value is charged. For oil price above USD 100 per barrel and not more than USD 150 per barrel, 8% rate on the incremental price value above USD 20 per barrel is charged. Finally, a flat 10% rate on the incremental price value applies when prevailing oil price is above USD 150 per barrel.

The cost recovery and the profit oil share, as in many jurisdictions, are usually not legislated. In Nigeria, the methodology for allocation of cost oil for recovery of expended costs are mostly in contract specific terms in the production sharing contracts (PSC). Most of the producing deep offshore assets belong to the 1993 PSCs where there is a 100% cost recovery eligibility including a 50% investment tax credit (ITC). The impact of the ITC on economic rent to the government has generally not been favourable. As a result of the adverse ITC impact, the government changed subsequent PSCs' investment incentives to be investment tax allowance (ITA) at the same 50% rate previously applied to ITC (Graham and Ovadia, 2019).

Similarly, the allocation of profit oil, being the balance of available crude oil after deducting royalty oil, tax oil and cost oil, are also contract specific in accordance with the terms of the PSC. In many instances, the profit oil share is a sliding split between the national oil company and the contractor (Majd and Myers, 1985). The profit oil split is typically tied to cumulative production. At the early stage of production, the contractor usually enjoys more percentage share than the concessionaire but this changes as production ramps up in favour of the concessionaire. Typically, the split ranges from 90 to 40%, in favour of the contractor, as cumulative production level ramps up.

### 2.2. Alignment of Fiscal Terms Features in Nigeria PSCs with International Practice

There is no universal template or standard PSC, but each country has developed its variation of contract terms over the years through some modifications and amendments. Globally, there is

**Table 1: Royalty Regimes in DOIBPSC**

| Fixed Water Depth | Royalty | Prices per Barrel (US$) | Royalty by Price (%) |
|---|---|---|---|
| Above 200 m | 10% | $0-$20 | 0 |
| | | Above $20-$60 | 2.5 |
| | | Above $60-$100 | 4 |
| | | Above $100-$150 | 8 |
| | | Above $150 | 10 |

a call for change in economic perspectives, since the exploration, development and production phases can be quite different (Van Meurs, 1997). Johnston (1994) showed the aspects that are subject to change and how they should be viewed. Many production sharing agreements have common elements, for which an essential feature is the host government ownership of the resource. The contractor receives the share of the produced resources for the service performed. Selected fiscal terms in Nigeria's current PSC will be compared with international best practices. According to Zhen et al. (2010), the elements that affect PSC economics mainly include royalty, cost oil, profit oil as well as income tax. Some of these elements will be discussed with emphasis on Nigeria's PSC agreement. Interestingly, most of Nigeria's PSC are within the offshore terrain with majority as deep offshore assets. This study will focus on the first three elements listed.

### *2.2.1. Royalty rate*

Royalty directly depends on the total income, but some systems allow return of shipping costs. The latter occurs when there is a difference between the valuation points for calculating royalties and points of sale. Transportation costs from the valuation point to the point of sale are deducted (returned). Many PSCs, in other jurisdiction, do not have royalties because the national oil companies are the concessionaire. In Nigeria, the deep offshore assets do have floating production, storage and offloading (FPSO) vessels and as a result do not incur transportation costs. The application of royalty could be a fixed rate or a graduated scale which could be jumping or sliding (Mamudu et al., 2019). The sliding scale is a step-by-step approach based majorly on average daily production. The following example shows royalty on a sliding scale, which increases from 5% to 15% on 10,000 BOPD tranches of production as seen in Table 2.

The terms used as basis for the sliding scale system must be carefully selected, because if the rate is too high, the system has virtually no flexible sliding scale. A good PSC has the best combination of parameters (Kankam and Ackah, 2014). Therefore, in order to determine the correct combination of these PSC parameters, one must be fully aware of the impact and importance of each of these parameters on the PSC. Its contribution to the national oil strategy is of great importance (Keeney, 1992). For example, if the government is interested in obtaining guaranteed cash flow, regardless of the profitability of the project, the royalty could be high. On the other hand, if the government is seeking high potential returns, then higher benefits from taxes are required (Yassine et al., 2013). Figure 2 shows the effect of certain range of royalties for different oil prices, because royalties are deducted first by the Government before other deductions such as: cost recovery, profit share, tax and so on. Practically, countries with unproven reserves for deep water operations at the time of PSC signature often have 0% royalty to make their PSCs attractive for International Oil Companies (IOCs).

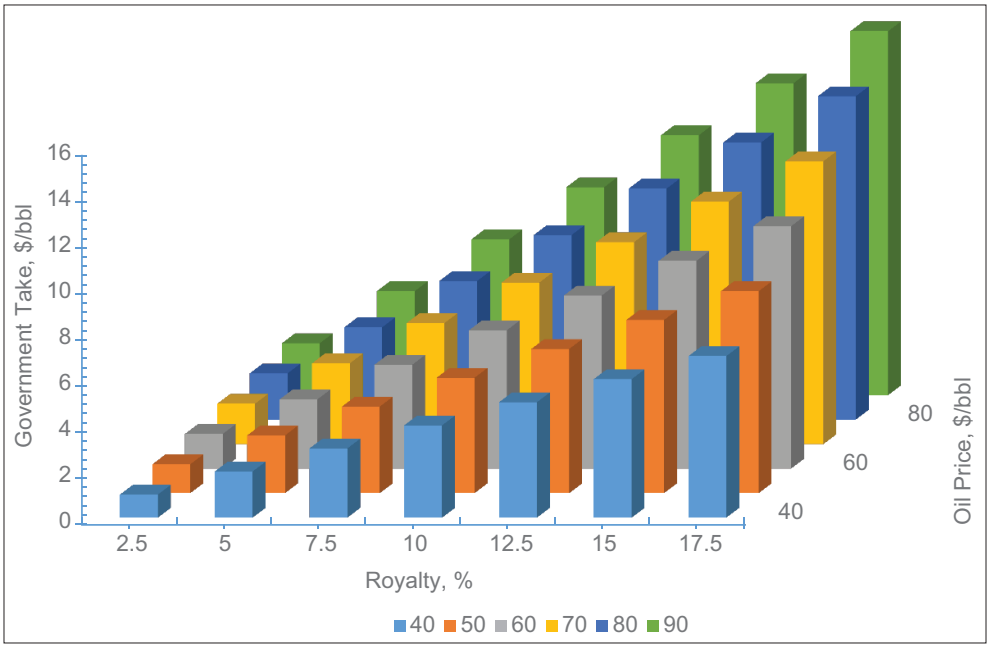
### *2.2.2. Cost recovery*

Before production sharing, PSC allows contractors to offset the costs of exploration, development and operation with a given percentage of production (cost oil). The contractor's costs are recovered from the cost recovery portion. Most contracts have a cost recovery limit, which in some cases can be approximately 50% of production, but unrecovered costs can be carried forward to the next period (Zhen et al., 2010). According to Yassine et al. (2013), few oil producing countries have adopted sliding scale cost recovery in their PSC agreements. The reason being that cost recovery is a function of costs paid and not a function of the gross production. It must be clearly specified in the agreements as

**Table 2: Tranches of Production Royalty Sliding Scales (Johnston, 1994)**

| Average | Daily production | Royalty (%) |
|---|---|---|
| First tranche | Up to 10, 000 BOPD | 5 |
| Second tranche | 10, 001 TO 20, 000 BOPD | 10 |
| Third tranche | Above 20, 000 BOPD | 15 |

**Figure 2:** Government take for different range of royalty rate and oil price



what should be included in the contractor's costs. Unfortunately, exploration information is characterized by lack of information and uncertainty.

Most PSCs have one or more combinations of the following features in cost recovery mechanics (Mudford and Stegemeier, 2003). The first feature is the upper limit of cost recovery which defines the portion of the total revenues, either before or after the payment of royalties that can be used to recover costs over a specified period. The second feature is the order in which costs can be reimbursed. Typically, costs are divided into several groups, and these cost groups must be recovered in a specific order. The third characteristic is that some of the costs in some pools should be reimbursed on a depreciated basis. The fourth feature is that the uplift can be applied against the unrecovered costs of a certain group or to current capital in the pool. The fourth feature is not common or found in some PSCs. This feature will usually vary depending on the country and or the characteristics of the field of reference. Literature has viewed cost recovery as the most attractive way for IOCs to mitigate their investment risk and thus, has largely been accepted in most current PSC agreements. Cost recovery is unique because it mainly comprises one of two ways that determine the share of contractors. However, during exploration of risky deposits (deep water exploration), contractors (mainly IOCs) seek additional guarantees, and cost recovery alone may not be enough for such prospects (Al-Kasim et al., 2013). Cost recovery seems attractive, primarily because of the inclusion of profit oil for the IOCs, which has led to some recent efforts by host governments to reduce cost recovery.

#### *2.2.3. Profit oil*

Profit oil is the remainder after accounting for royalty and cost recovery. This is often split between the IOCs and the National Oil Company (NOC) at an agreed percentage. It can also be defined as the amount of production, after deducting cost oil production allocated to costs and expenses, which will be divided between the IOCs and the host government in line with the production sharing contract. According to Mian (2011), it is negotiated before the contract is signed and it is dependent on political stability, cost, infrastructure and any other key factor that can influence business decisions. In 2019, Nigeria demanded $62 billion from oil majors for past profits. This claim was based on the 1993 contract-law, which stated that the host country (Nigeria) will receive a greater share of revenue when the oil price exceeds $20 per barrel. The IOCs attested to the claim but argued that the Act did not provide for payment of arrears.

## 3. ASSESSMENTS OF NIGERIA DEEPWATER PSCS

The deep-water operations in Nigeria have shown that the Bonga oil field is fertile being the first commercial discovery in deep-water areas (OML118) and has produced over 700 million barrels of oil since inception. Bonga FPSO has contributed 10% increment in Nigeria's oil production capacity since 2005. Thus, the incentives that led to significant investment among the IOCs allowed oil reserves in Nigeria to increase to about 36 billion barrels as of June 2019. The summary of the deep water operation procedures is:

1. IOC bids the contract and is awarded rights to explore (OPL) and produce oil and gas (OML) for a specified period as a Contractor.
2. IOC operates subject to laws (Petroleum Act) and regulations of State Regulatory Authority (DPR)
3. IOC funds all exploration, development and operations expense.
    - In the PSC, assets are installed by IOC but owned by the State.
    - The PSC defines an order of allocation of proceeds between the parties: (1) Royalty Oil (2) Cost Oil (3) Tax Oil, (4) Profit Oil. Profit Oil is shared on a pre-determined split between IOC and NOC based on cumulative production.
    - For risk sharing, the Contractor entity may be more than one IOC. In which case they would have signed a Joint Operating Agreement to regulate their working relationship. The Lead Contractor or Operator serves in the Management Committee (MACOM), and Technical Committees (TECOM) which the National Oil Company chairs.
4. If exploration is successful and production is initiated, IOC recovers cost. After cost recovery and tax oil is lifted, profit oil is shared among the parties.
5. In Nigeria, IOC tax is paid on behalf of IOC by the National Oil Company through Tax Oil.
6. IOC compensation is directly tied to exploration and production success; and is subject to petroleum prices.
7. IOC receives a share of production (Cost Oil + Profit Oil) and can book reserves.

The problem for governments in deciding how to effectively generate revenue in the oil and gas sector is the high rate of unsuccessful exploration activities, and the low economic rent (income) which is the difference between the value of production and the cost of extracting it (Playfoot et al., 2015). This important risk component during the exploration phase strongly characterizes the upstream portion of the oil industry. The development of fiscal system that can generate enough potential rewards for exploration efforts should take this risk into account (Da Hora et al., 2019). This is not easy, and one cannot guarantee a unique solution for each specific case.

Despite the attractiveness of PSC agreement, this does not relieve some of the faults. Some of the drawbacks are (Ogunleye, 2015):

1. Contractors can earn the so-called "windfall profits" that arise when crude oil prices rise significantly, thus, the contractor earns a greater share of revenue than would usually have been allowed,
2. The contractor knowing that their expenses are fully covered, can make extravagant decisions in field development, which is clearly a disadvantage for the host country, and
3. Contractors can focus on developing and producing a profitable field thus, slowing down exploration work in other areas with potential risks.

The "windfall profit" has been viewed by many non-governmental organizations as the greatest leakages in Nigeria's crude oil production sharing contract. The purpose of tax and fiscal structuring for a country like Nigeria is to capture every possible economic rent from the oil and gas industry which is the main mainstay of the economy. This is consistent with the fact that the industry receives a reasonable share of the profits. The industry profit margins should be fair and reasonable but should not exceed that of the host government whose objective is to maximize wealth from its natural resources (Majd and Myers, 1986). Profit sharing is the basis of contract/license negotiations. The development of an effective fiscal system should take into account not only political and geological risks, but also benefits. The success of the deepwater operations in Nigeria's Gulf of Guinea has gained more bargaining power for the government and this is evidenced in the new 2019 PSC Amended Acts. The government has also added additional tax to capture excess profits from unexpected high oil prices.

### 3.1. Summary Assessments of Nigerian Deepwater PSCs

1. Robust terms for Contractors
2. Non progressive system
3. The 1993/2000 model does not respond to windfall profits
4. Contain ambiguous terms
5. Potential for Zero Government take.

### 3.2. Key Deepwater PSC Milestones in Nigeria

1. Exploration commenced 1994
2. Major discoveries were announced in 1998
3. Abo first oil exploration activity was in 2003
4. Bonga first oil exploration activity was in 2005
5. Erha first oil exploration activity was in 2006
6. Agbami first oil exploration activity was in 2008
7. Akpo first oil exploration activity was in 2009
8. Usan first oil exploration activity was in 2012.

### 3.3. Issues and Challenges of Nigeria Deepwater PSCs

1. Contract clarity and Conflict with legislations
   - Interpreting Disputes between Govt. and IOCs
   - Divergent entitlement claims
2. Rising Production with declining Government-take
   - Potential Zero Government-take
3. High Technical Cost
4. Weak accounting procedures
5. Stability clauses.

Figure 3 shows a comparison of terms such as contractor-take and cost recovery limit for Nigeria and other selected countries.

## 4. NUMERIC ANALYSIS ON THE CURRENT DOIBPSC

The effect of taxation on government revenue depends mainly on the contract terms. If government receives large amounts of concession payments and a large share of profit oil, there will be very little left for the IOCs as taxable income. This can be a major disincentive or an obstacle to investments. If the government-take is huge, the less likely it is that the IOC will respond to the project. The effect of the royalty regimes (royalty by oil price) and petroleum profit tax was analyzed to establish the IOCs and host goverment-takes. Royalty in this discussion means the amount of any rent as to which there is provision for its deduction from the amount of any royalties under an oil prospecting licence or oil mining lease to the extent that such rent is so deducted, and the amount of any royalty's payable under any such licence or lease less any such rent deducted from those royalties (Manaf et al., 2016). The cost recovery oil allocated to the IOC to enable it to recover all its operating costs is capped at 50%.

The operating costs are recovered in the year of expenditure while capital costs are recoverable in equal installments over a period, though it can be contract specific. The next portion is tax oil which is the quantum allocated to the NOC to pay on behalf of itself and the IOC. The Petroleum Profits Tax applicable to deep offshore contract areas is 50% flat rate of chargeable profits for the duration of the contract. Profit oil is shared between the NOC and the IOC in accordance to an agreed profit split based on cumulative levels of production. In this study, 35%/65% for IOC/NOC respectively were used for the analysis. Four features (royalty, cost recovery, tax oil and profit oil) were the only PSC contract terms used to determine contractor and government-takes. It is important to note that companies are allowed to recover their capital and operational costs before profit oils are shared. Six of oil price ($20/bbl, $30/bbl, $40/bbl, $80/bbl, $120/bbl, and $160/bbl) were used so as to cover the five royalty sliding scales adopted in the new DOIBPSC and the current oil price during this study which is ≤ $ 20/bbl.

Table 3 shows the estimated average cash flow for each royalty by oil price and the take each party will receive for a particular range of oil price for one barrel of oil produced. The division of net

**Figure 3:** Comparison of Fiscal Terms for Nigeria and selected Countries

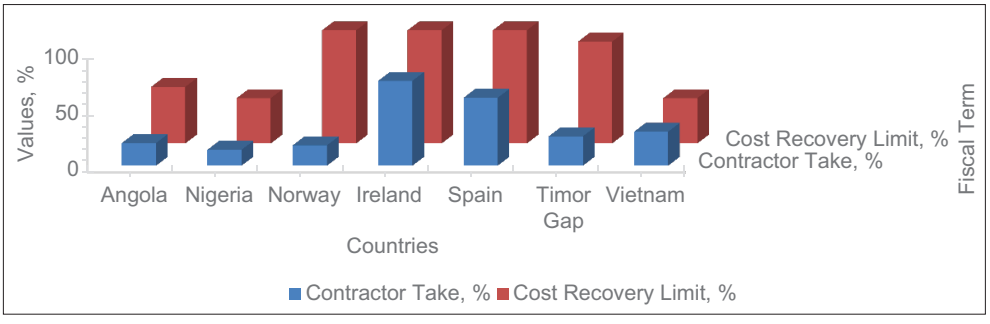


**Table 3: Impact of the Royalty by Crude Oil Price on the Host Government (HG) and IOC**

| Parameters | Oil price, $ 20 | | Parameters | Oil price, $ 30 | | Parameters | Oil price, $ 40 | |
|---|---|---|---|---|---|---|---|---|
| | IOC ($) | HG ($) | | IOC ($) | HG ($) | | IOC ($) | HG ($) |
| Royalty (0%) | 0 | 0 | Royalty (0%) | 0 | 0 | Royalty (0%) | 0 | 1 |
| Cost recovery (50%) | 10 | 0 | Cost recovery (50%) | 10 | 0 | Cost recovery (50%) | 19.5 | 0 |
| Profit Oil, 35/65% | 3.5 | 6.5 | Profit oil, 35/65% | 3.5 | 6.5 | Profit oil, 35/65% | 6.83 | 12.68 |
| Tax Oil (50%) | (1.75) | 1.75 | Tax oil (50%) | (1.750 | 1.75 | Tax oil (50%) | (3.41) | 3.41 |
| Gross revenue | 11.75 | 8.25 | Gross revenue | 11.75 | 8.25 | Gross revenue | 22.92 | 17.09 |
| Net cash flow | 1.75 | 8.25 | Net cash flow | 1.75 | 8.25 | Net cash flow | 3.42 | 17.09 |
| **Parameters** | **Oil price, $ 80** | | **Parameters** | **Oil price, $ 110** | | **Parameters** | **Oil price, $ 160** | |
| | IOC ($) | HG ($) | | IOC ($) | HG ($) | | IOC ($) | HG ($) |
| Royalty (0%) | 0 | 3.2 | Royalty (0%) | 0 | 8.8 | Royalty (0%) | Oil price, $ 160 | 16 |
| Cost recovery (50%) | 38.4 | 0 | Cost recovery (50%) | 50.6 | 0 | Cost recovery (50%) | 72 | 0 |
| Profit oil, 35/65% | 13.44 | 24.96 | Profit oil, 35/65% | 17.71 | 32.89 | Profit oil, 35/65% | 25.2 | 46.8 |
| Tax oil (50%) | (6.72) | 6.72 | Tax oil (50%) | (8.86) | 8.86 | Tax oil (50%) | (12.6) | 12.6 |
| Gross revenue | 45.12 | 34.88 | Gross revenue | 59.45 | 50.55 | Gross revenue | 84.6 | 75.4 |
| Net cash flow | 6.72 | 34.88 | Net cash flow | 8.85 | 50.55 | Net cash flow | 12.6 | 75.4 |

cash flow between the contractor (IOC) and the host government is called contractor take and government take respectively. If the market price is $20/bbl, the IOC will not pay any royalty by price to the government, thus, the $20 is used by the IOC to cover its costs. The average cost of oil is 50%, which is the maximum from literature. The IOC then receives 35% of the $10 left while the government obtains 65%. The latter is also entitled to 50% tax on the IOC share of profit oil. Consequently, the gross revenue for the government is $8.25 of the $20/bbl, and the IOC settles for $11.75. The key figures are the net cash flow, and it should be noted that the IOC cost recovery will not be captured as cash flow, because it is considered as reimbursement of expenditures. Thus, the aggregate net cash flow for the first case study is $10 from which the government takes 82.5% ($ 8.25), and the IOC 17.5% ($ 1.75).

In this case study, the government has two sources of revenue: its share of profit and tax. It should also be noted that the IOC recovers an additional percentage for capital cost. In reality PSCs have a much larger number of variables, apart from the four considered in this analysis. In addition, certain qualifying operating or capital costs incurred by the IOC are taken into account and are deducted when calculating chargeable profits for the purposes of petroleum profits tax, in accordance with the Petroleum Profit Tax Act. From Table 3, it can be deduced that as the crude oil price increases from $20/bbl to $160/bbl, government-take increases from 82.50% to 85.68%, while the IOC-take decreases from 17.50% to 14.32%. This confirms that the aim of the government which is to ensure that additional revenue becomes economically beneficial to the federal government anytime there is increase in crude oil price was achieved with this new crude oil price-based royalty. Crude oil trading offers excellent opportunities and profit in nearly all market conditions due to its unique standing within the world's economy (Mommer, 1999; Nakhle, 2008). Market participants often fail to take full advantage of crude oil fluctuations, either because they have not learned the unique characteristics of these markets or because they are unaware of the hidden pitfalls that can eat into earnings (Obi, 2014). In addition, not all energy-focused financial instruments are created equally, with a subset of these securities more likely to produce positive results.

## 5. ECONOMETRIC MODEL DEVELOPMENT FOR CONTRACTOR TAKE

The empirical relationship between the Contractor take (IOC) and the Deep Offshore Inland Basin Production Sharing Contract royalty regime is expressed as follow:

$$NPIOC_i = f\left(OO, OP, PV, RYT\right) \quad (1)$$

Where $NPIOC_i$ is the net profit per barrel for the contractor take, OO is the oil output, OP is the oil price, RYT is the royalty level per price, and PV is the royalty regime (a policy variable for the study). This implicit model (equation 1) was transformed into equation (2), which is an explicit econometric model:

$$NPIOC_i = \aleph_0 + \aleph_1 OO_i + \aleph_2 OP_i + \aleph_3 PV_i + \aleph_4 RYT_i + \mu_i \quad (2)$$

Where, $\aleph_0$ is a constant term, $\aleph_1$, $\aleph_2$, $\aleph_3$,

$\aleph_4$ are coefficient of the variables which measure the marginal effect of the oil output, oil price, and the royalty regime respectively.

The effect of contractor's output was investigated using three fiscal performance indicators. These are the government expenditure, oil revenue and deficit-GDP ratio (Andarge and Lichtenberg, 2020). The empirical model for the effect of the royalty regime on the contractor performance is stated explicitly as:

$$OO_i = \gamma_0 + \gamma_1 NPIOC_i + \gamma_2 OP_i + \gamma_3 PV_i + \gamma_4 RYT_i \varepsilon_I \quad (3)$$

Data for the analysis are secondary in nature and consists of annual time series of the variables in the model, these data were collected from 1980 to 2019. Data oil price, and oil output were collected from the OPEC Annual Statistical bulletin (various issues) and BP Statistical Review of World Energy June 2019. Contractors' take was calculated as 35% of profit oil. The study adopted the Auto-Regressive Distributed Lag (ARDL) econometrics regression

techniques developed by Pesaran, Shin and Smith (2001) to analyse the data.

### 5.1. ARDL/Bound Cointegration Test

The ARDL/Bound cointegration testing model for the study can be specified compactly as follows:

$$\Delta X_i = \alpha_0 + \sum_{i=1}^{i=n} \eta_i \Delta Y_{it-1} + \sum_{i=1}^{i=m} \theta_i Y_{it-1} + V_i \quad (4)$$

Where $\Delta X$ is the first difference operator of dependent variable, and $\Delta Y_{it-1}$ is column vector of the lag of the first difference of the independent variables, i=1…4, $\eta_i$ is a row vector of the short run coefficients of the independent variables; while $Y_{it-1}$ is column vector of the lag of the independent variables, and $\theta_i$ is row vector of the variables long run parameters.

### 5.2. Empirical Results and Discussion

The results of the unit root test of the variables in the models for the level and the 1st difference of the Augmented Dickey-Fuller (ADF) and the Phillips- Perron results are presented in the Table 4.

Table 4 shows that the ADF unit root test indicated that fiscal deficit-GDP ratio (GD), government expenditure (GEXP) and contractors take (NPIOC) are stationary at level. Therefore, they are I (0) series. Oil price (OP), royalty (RYT), oil output (OO), and oil revenue (ORG) were not stationary at level, thus, they have unit root. However, they became stationary after 1st differencing (I (1) series). Phillips-Perron test indicated that only oil output (OO) and contractors take are stationary at level and other variables became stationary after 1st differencing.

Table 5 shows a sample of the ARDL/Bound test, and literature have shown that it is one of the most appropriate method for examining cointegration among the integrated series. The results show that all the models are cointegrated (other variables of the ARDL/Bound test are attached as supplementary file). This implies that there is a stable long run relationship among the variables in the model. Therefore, the relationship in the model can be expressed as an economically meaningful model.

Table 6 shows the impact of royalty by price regime on Contractor -take in the long and short run. The result of the analysis shows that there is a positive difference before royalty by price regime and after the introduction in the new policy. The positive sign of the policy variable coefficient (PV) indicates that the current regime is impacting more on the takes now than before they were introduced. However, the change in royalty regime is not significant for the contractor. The royalty payout by the IOC (RYT) has negative impact on the contractors take, but the impact is not significant in the long run. The short run impact of the royalty level and the regime change on the contractor's take is high and significantly negative. This is expected as the design of the royalty regime is based on long term benefits. The contractor in the long run will adjust and reduce some of the negative impact by restructuring, closing unproductive wells, and even divesting in some areas. This is why the short run impact is higher for the contractors than the long run impact. Oil price has higher impact on the contractor-take.

## 6. EFFECT OF PRICE ROYALTY SLIDING SCALES

According to Gowharzad and Al-Harthy (2011), many oil and gas companies have been affected by the fluctuation in prices of crude oil. This trend is well known, because with rise in oil prices comes an increase in investment, expansion and exploration. On the contrary, a decrease in crude oil prices does not encourage any of these three. In any case, oil companies are faced with investment decisions for projects that must meet rising and falling crude oil prices. The host government on the other hand is interested in making the highest available economic benefits through royalty and an agreed share of production as the owner of the subsurface resources. This is the case in this study.

Table 3 shows that an increase in oil price will favour the host government in terms of royalty and help capture windfall economic benefits that comes with sudden increment in price. The basic idea of a sliding scale is progressivity and to account for uncertainty during the project life. The contractor does get incentive of zero royalty payment from the host government when price falls below $20/barrel. The sliding scale that links production and royalty together has a higher rate as production increases, so the government benefits from increased production but gets lower royalty rates as production decreases so that the contractors will have an incentive to produce even with lower production rates. Literature has shown that this theoretically allows reasonable

**Table 4: The results from the Unit Root Analysis**

| Variable | Augmented Dickey-Fuller (ADF) | | Phillips-Perron (PP) | |
|---|---|---|---|---|
| | Level | First difference | Level | First difference |
| OPR | −2.312835 | −7.09558** | −2.250076 | −7.207769** |
| OO | −3.303501 | −5.678877** | −3.579678* | - |
| RTY | −2.390448 | −6.286575** | −2.320222 | −6.589332** |
| ORG | −1.892841 | −6.879179** | −1.983439 | −6.906524** |
| GD | −3.677331* | - | −3.439217 | 15.99685** |
| GEXP | −4.666724* | - | −3.12831 | −7.477777** |
| NPIOC | −5.284372* | - | −5.300562* | - |
| NPNOC | −2.287138 | −7.472131** | −2.198647 | −7.746986** |
| RESERV | −1.039973 | −4.702829** | −1.580249 | −4.778209** |

1%=−4.211868, 5%=−3.529758, 10%=−3.196411. Sources: E-view Computer output.
*Indicate significance at level. **Indicates significance at 1st difference

**Table 5: ARDL/Bound cointegration test analysis**

| Model | Equation | Sample size (n) | No. of variables (k) | F-Statistic | 5% Upper critical Bound | Remarks |
|---|---|---|---|---|---|---|
| NPIOC | 3.3 | 35 | 4 | 10.2041 | 4.544 | Cointegrated |
| OO | 3.5 | 37 | 4 | 5.9338 | 5.226 | Cointegrated |

**Table 6: Long and short run impact of royalty by price regime on contractor's take**

| Variable | Short run Contractor Impact coefficient | P-value | Long run Contractor Impact coefficient | P-Value |
|---|---|---|---|---|
| OPR | 0.322 | 0.0010 | 0.145* | 0.0043 |
| RTY | −12.729 | 0.0001 | −0.669 | 0.6546 |
| PV | −16.890 | 0.0033 | 0.710 | 0.8128 |
| OO | 0.022 | 0.0033 | −0.008* | 0.028 |

terms for the IOCs to develop both large and small fields; but, if the term is tied to the oil price, the IOC's-take is automatically adjusted when the price variations take place. Both production and price-based royalty restrict the IOCs from making excessive profits at the expense of the host government in case a larger than anticipated fields are encountered or during rapid and sustained product price increase.

## 7. CONCLUSION

In line with the objectives of the new DOIBPSC, the study assessed the attractiveness of the royalty by price regime to the contractor. The regime seeks to achieve a balance between the interests of the IOCs and the government. As private business entities, profit is key to the operations of the IOCs. Though royalty by price is value-focused, production royalty sliding scale also encourages the development of smaller fields by the IOCs. This study assessed the attractiveness of the new DOIBPSC royalty by price to the contractor. The government take increases at higher price levels while that of the IOC progressively diminishes. This may serve as disincentive for the contractors that invest in these deep-water projects, and also affects the development of small deep water fields.

Careful adoption of the underlying strength of the two approaches (production and price based royalty) can provide an extensive contractual framework tailored to the specific circumstances of the field in recovering these inconsistent economic benefits. This approach can be used to plug gaps such as early abandonment and delay in development of new fields in an overarching regulatory system, which can be particularly useful in Nigeria where the legal system is less developed. The most common criticism of PSC systems in the world is that the priority facilitation of the IOC-cost recovery can lead to IOCs inflating their costs (gold plating).

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