European Journal of Research Development and Sustainability (EJRDS)
Available Online at: https://www.scholarzest.com
Vol. 5 No. 2, February 2024
ISSN: 2660-5570

THE REVIEW OF DEEP OFFSHORE POLICY IN THE OIL INDUSTRY AND IMPACT ON ATTRACTING FOREIGN INVESTMENTS

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Article history:

Received 14th December 2023
Accepted: 10th January 2024
Published: 20th February 2024

Abstract:

As onshore field reserves get depleted, upstream activities have begun delving into new frontiers for exploration especially in deep offshore environment. The petroleum fiscal system (PFS) plays a key role in investment decision in the exploration and production (E&P) of oil and gas. It provides a synopsis of the relationship between the host government, the investors, and the community stakeholders with regards to the equitable recovery of costs and distribution of profits. Governments design fiscal systems to entice investment and collect as much economic rent as possible from their petroleum acreage, which is determined by factors such as its geological endowment. In deep offshore environments, governments are often faced with the difficult task of finding a balance between making money and attracting foreign investment. A detailed review of deep offshore fiscal regimes becomes imperative because it affects different stakeholders in making informed decisions on the petroleum business investments worldwide. This paper highlights deep offshore fiscal policy in seven different countries scattered across the globe and demonstrates the impact, they had in attracting foreign investment.

Keywords: Deep offshore, fiscal policy, foreign investment, Economic rent, Petroleum exploration and production (E&P)

INTRODUCTION

For the development of hydrocarbon resources to be sustainable, there need to be policies, principles, and practices that encourage using these resources in a way that doesn't stop future generations from using them. International oil companies (IOC) are on the search for countries with promising and attractive fiscal regimes because exploration in new frontier areas is associated with high risk and cost outlay. Deepwater frontier exploration and production is associated with enormous risk and high capital investment in challenging offshore environment. Investors in Deepwater frontiers deserve lucrative tax structures in exchange for their risk. As a direct result, governments in a number of countries have instituted more competitive fiscal policies in an effort to attract foreign investments. Offshore activities in these countries opt to have a lower government take to attract investment from international oil and gas firms, in contrast to onshore operations in the same countries. This phenomenon has increased the allure of high-prospect, deep-water offshore locales like the Gulf of Mexico and West Africa. Fiscal regimes come along with varied degrees of uncertainties which must be juxtaposed against peers in other regions and benchmarks (Echendu et al., 2015).

Foreign direct investment (FDI) has been a major focus for developing nations (Kimiagari et al., 2023; Asiedu and Lien 2011). FDI started to influence capital flows on a worldwide scale in 2005 (worldwide Development Finance, 2005). The economic benefits of oil and gas exploration and production are governed by fiscal regimes, which are a body of laws, regulations, and agreements. It contains clauses like these that control the project's economics for exploitation of petroleum. It has many parts, including domestic market requirements, host nation equity, cost recovery caps, profit oil distribution percentages, corporate income tax rates, bonuses, bonus recoveries, losses carried over, and more. From the government's perspective, a fiscal system's goals are to attract investment and to take the most economic rent possible given the geologic endowment of the petroleum area under their jurisdiction. Governments all over the world are faced with the difficult task of finding a balance between their goals of attracting investment and making money. Production service contracts (PSCs) are the most common way that governments handle deep-water blocks' finances (Atinuke et al., 2019). With the exception of Ghana in West Africa which uses Royalty-Tax system. PSCs are a particular kind of contract used in the search and development of petroleum. The

State, as the rightful owner of the mineral resources, will contract with a third party to carry out exploration and development. Both endeavors will make use of these offerings. According to some, PSCs were first used in oil exploration and development contracts in Indonesia. PSCs set themselves apart from other contract types with the help of two features. First off, the contractor is accountable for all exploration risk. The contractor assumes the role of contractor without taking any ownership stake in the asset. Under national supervision, the contractor assumes full responsibility for the activity and all related risks and costs. Second, the facilities and the underlying mineral deposit are government property (Atinuke et al., 2019).

Supporters of foreign direct investment believe that using it to finance the growth of the oil and gas sector will accelerate the nation's achievement of the oil production target earlier than expected. Prior to 2035. (Timilsina et al., 2005). Many oil and gas rich Countries have made several concerted efforts to design policy and fiscal system to attract foreign investment into the deep offshore terrain for exploration and production activities. They aim to maximize economic rent from oil production in the country owing to the fact that most of these countries depend on revenue from oil to fund the national budget and carry out capital projects. The big question now is; "Are these policies and fiscal system capable of meeting the host government objectives of maximizing economic rent? Do these policies position the country as an attractive destination for foreign investment in deep offshore?" These questions are the main thrust of this paper; to review and evaluate the fiscal attractiveness of petroleum fiscal regimes in different parts of the world that compete for upstream investment in deep offshore. This paper also attempts to review the evolution of Nigeria deep water fiscal policy across the years and describe the 2019 Deep water and Inland Basin Production Sharing Contract Amendment and its economic impact and effectiveness in attracting capital investment Kenneth et al., (2019).

OVERVIEW OF DEEPWATER FISCAL SYSTEM ACROSS THE WORLD

Although the contractor assumes the role of contractor, they do not take title to the asset. Under national supervision, the contractor assumes full responsibility for the action and all associated risks and expenses. Second, the government owns both the surface infrastructure and the underlying mineral deposit. The governments of oil-rich nations are interested in assessing the attractiveness of their oil and gas exploration and production investment climate in order to implement proactive policy changes. This is imperative because International Oil Companies and big portfolio investors are constantly evaluating and juxtaposing petroleum fiscal policies across countries to make investment decisions (Echendu et al., 2015). There was popular anxiety over whether the government should permit foreign investors to profit more from the oil sands investment than Canadians due to the large influx of capital. The development saw the Canadian government introduce new rules on state-owned company investments in the oil sands in 2012 in response to the Chinese state-owned businesses China National Offshore Oil Corporation's acquisition of Nexen Energy. The onus of proof was shifted to foreign investors by the government to show how their money will benefit Canada overall (Beaulieu and Saunders 2014).

CHINA FISCAL SYSTEM FOR DEEPWATER OIL AND GAS DEVELOPMENT

China has an estimated proven reserves of 25.9 billion BBL and total daily production of 3.8 million BOPD as at end of 2018 (BP 2019 Statistics). South China Sea has tremendous oil and gas resources. The contractor acts in the role of contractor without ever acquiring legal ownership of the asset. While operating under national supervision, the contractor assumes full accountability for the action and all associated costs and risks. Second, the government owns both the above-ground infrastructure and the underlying mineral resource.

- Special oil gain levy: This is calculated by a formula when the monthly average weighted price per barrel of crude oil sold is more than US$40 per barrel before 1 November 2011, US$55 per barrel before 1 January 2015, and US$65 per barrel after 1 January 2015.
- Royalties: This between 0 percent to 12.5 percent, not applicable to PSCs concluded after 1 November 2011
- Bonuses: It is defined in the PSC and take into account the volume of petroleum resources and the economic value of the field
- Production shares are based on how much is made.
- Income tax rate is 25 percent
- The general rate of the value-added tax is 17 percent.
- The corporate tax is based on the amounts and types of taxable petroleum products.
- As of December 1, 2014, the resource tax is 6 percent of the sales price.
- As of December 1, 2014, the mineral resources compensation fee is 0 percent of the sales revenue from oil and gas production.
- The EPT is based on the amount and type of pollution released.
- Investment incentives are based on qualified research. and development (R&D) expenditure, which can be deducted at 150% of the actual expenses.

FOREIGN INVESTMENT IN CHINA UPSTREAM OIL AND GAS SECTOR

The contractor performs the work required of them without ever becoming the owner of the asset. The contractor bears all risks and costs, as well as all responsibility for the activity itself, while working under national supervision.

Second, the government owns both the surface infrastructure and the underlying mineral resource. Investing abroad is subject to a wide variety of regulations and prohibitions, all of which are detailed in The Negative Lists. With these changes, China is opening up a wider range of sectors to foreign investment. The upstream petroleum industry is one such area. The condition that foreign investment in upstream oil and gas exploration and exploitation be in the form of an equity joint venture (EJV) or a cooperative joint venture (CJV) has been eliminated as part of this year's update to the Negative List 2019. (CJV). Upstream oil and gas operations in China are currently open to 100% foreign ownership. According to Hebert, 2019 the financing and taxes method used by China's international cooperation is based on production sharing contracts, which include periods for development, production, and exploration. In general, the government's representative, China National Offshore Oil Corporation, is limited to obtaining interests and rights of up to 51% in the commercial discovery of offshore oil and gas. All exploration costs and associated risks should be borne by contractors (Hao and Kaiser 2010). Foreign investors will have more opportunities to do business in a more investor-friendly environment thanks to China's continued opening and change signaled by the 2019 Negative List. Joint ventures are no longer required in the upstream oil and gas sector, demonstrating that China is opening up its energy sector to the market and attempting to attract foreign direct investment (FDI). Additional regulatory tweaks will be made to bolster the new system and provide the market with breathing room to respond to emerging opportunities. This will make the business climate more welcoming to international investors. The goal of these adjustments is to increase the number of opportunities available to foreign investors. As of right now (Hebert, 2019). The condition that foreign investment in upstream oil and gas exploration and exploitation take the form of an equity joint venture (EJV) or a cooperative joint venture (CJV) was eliminated as part of the update to the Negative List 2019 that was announced earlier this year (CJV). Upstream oil and gas operations in China can currently accept 100% foreign ownership. These test initiatives were carried out in Xinjiang Province.

North Sea deep offshore environment is a rapidly maturing oil and gas basins. The Government of United Kingdom (UK) and Norway are principally the regulators of Oil and Gas Activities in the North Sea. They are currently challenged with maintaining a competitive level of government take whilst balancing the need to incentivize further investment. The fiscal terms offered by each country are different, and this impacts on the attractiveness to foreign and local potential investors. UK fiscal policies have evolved with many amendments over the years, whilst Norway has remained relatively stable. The structure of these fiscal changes have ranged from windfall taxation to investor incentivization. UK Continental Shelf (UKCS) is arguably a more mature basin when compared to the Norwegian Continental Shelf (NCS). As a result, the UK government has adopted several strategies to attract investors and has continued to offer incentives targeting the development of remaining resources. In Norway, however, the nature of fiscal incentives focus more on the exploration and appraisal phase of early field development (Agha, 2014).

UNITED KINGDOM FISCAL SYSTEM FOR DEEPWATER OIL AND GAS DEVELOPMENT

United Kingdom has an estimated proven reserves of 2.5 billion BBL and total daily production of 1.08 million BOPD as at end of 2018 (BP, 2019). The United Kingdom uses what is known as a concessionary system (also known as a royalty/tax system) to collect revenue. In West Africa, in the country of Ghana, the same system can be implemented. At present, a field's tax liability is determined primarily by the date on which development approval was granted. Royalty payments ceased in 2001. E&P firms typically foot the bill for the Petroleum Revenue Tax (PRT), Ring Fence Corporation Tax (RFCT), and Supplemental Charge Tax (SCT) (SCT). Currently, all businesses must pay a 30% RFCT, which is a broad corporate tax. However, the RFCT is typically only used for E&P activities, and different fields have varying approaches to loss. The SCT is a tax with a rate of 32% that is applied to all profits. It follows the same methodology as the RFCT calculation, minus the inclusion of financing fees. In addition, fields for which development permission was granted prior to March 1993 are subject to a 50% Petroleum Revenue Tax (PRT). Thus, given the current rates, the marginal tax payable for a new field in the UKCS is 62% whilst PRT fields pay 81% (Agha, 2014).

The unique element of the recent UK tax regime is a set of tax allowances, applicable to fields which fulfill a set of qualifying criteria. For the purpose of simplification, New and currently producing fields can be broadly split into three categories; PRT paying fields, which were approved prior to 1993 and are eligible to pay all three taxes i.e. PRT, RFCT and SCT thus attracting a maximum tax rate of 81%, Non-PRT and no allowance fields, which pay only the RFCT and SCT and get no tax allowance under the current fiscal system and pay at marginal tax rate of 62%, and lastly fields qualifying for allowance, which pay the RFCT and a reduced SCT ranging from 0 to 32% making their marginal tax rate between 30 to 62%.

IMPACT ON ATTRACTING FOREIGN INVESTMENTS AND UK ECONOMY

The positive economic impact on deep offshore projects can be seen by the increased usage of the field allowances, from just 2 fields in 2009 to 27 fields in 2013. Moreover, of the fields approved for development since 2009, the share of field with allowances has increased over time, as a result of which increasing number of qualifying projects have taken FID (Agha, 2014). The increase in FDI results in a corresponding increase in economic growth. This is brought about by the influx of capital as well as a larger tax collection pool for the host government according to Aswathappa et al., (2010).

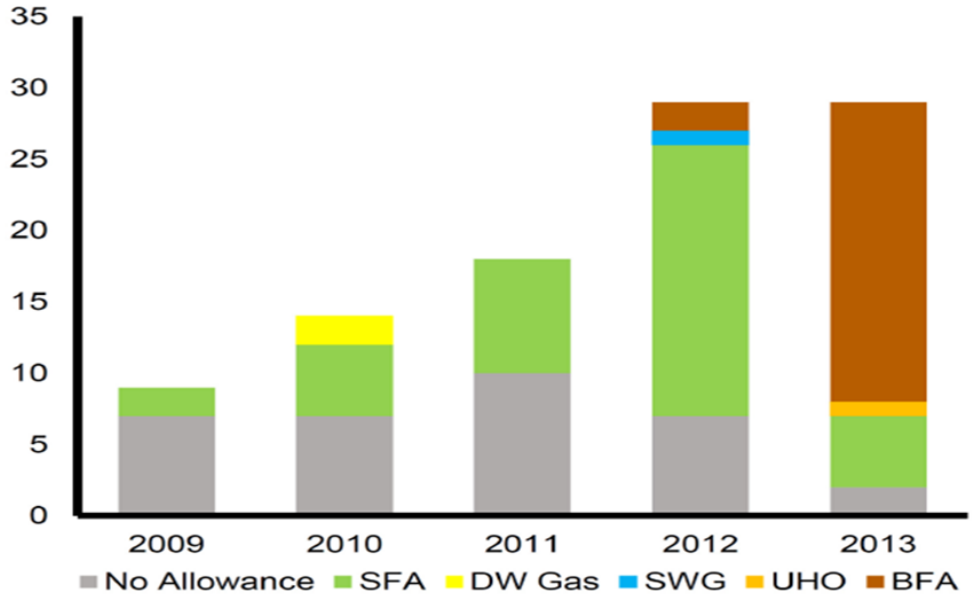

Figure 1- Field Development Approvals Qualifying for Field Allowance (Source: Agha Saad 2014)

Figure 1 indicates that amongst the available allowances, the most utilized are the Small Field Allowance and Brown Field Allowance.

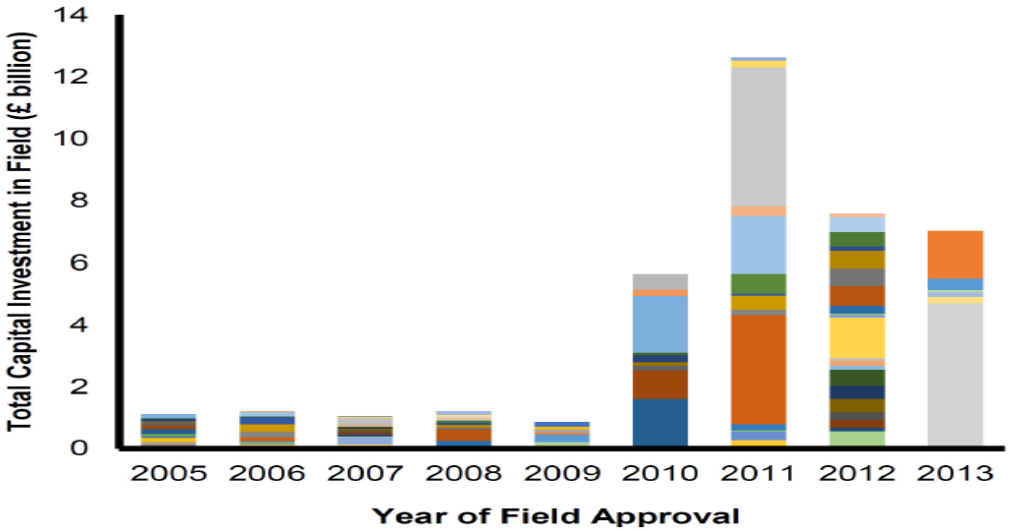

Figure 2- Total Field Investment by Year of Approval, 2005 - 2013 (Source: Agha Saad 2014)

There is also a ramp up in capital investment figures, Figure 2 shows a large ramp up in committed capital in individual fields following the introduction of allowances. The graph also shows the record low investment between 2005 and 2009 as investor confidence was low. A closer look at the £22 billion sanctioned in 2011 and 2012, some 45 new and brownfield projects are being developed would add a daily production of 500, 000 barrels by 2017. According to OGUK, over the long term, these investments is expected to generate two billion boe in production and more than £25 billion in production tax, helping the UK Government improve their revenue base and reduce importation of hydrocarbon. It is pertinent to note, that the capital being invested in United Kingdom Continental Shelf (UKCS) is still competing against other world class basins and the rise in development costs is a concern to the global oil and gas industry. Thus, the fact that foreign investors have chosen to sanction large projects in UKCS is evidence enough that they see valuable returns in the near future.

NORWEGIAN FISCAL SYSTEM FOR DEEPWATER OIL AND GAS DEVELOPMENT

Norway has an estimated proven reserves of 8.6 billion BBL and total daily production of 1.84 million BOPD as at end of 2018 (BP, 2019). The Norwegian Continental Shelf (NCS) is less mature basin when compared to the UKCS. Norwegian government incentivizes exploration activities in the North Sea enticing companies to look for the big find. The Fiscal policy is a relatively simple but high tax system with a corporate tax at 27%, and a Special Petroleum Tax (SPT) payable at 51% bringing the overall tax rate to 78%. There are no field allowances or special provisions for individual developments. Nonetheless, an exploration tax refund and capex uplift are available, targeting exploration

activity. A concessionary system, also known as a royalty/tax system, is one source of revenue for the United Kingdom. The West African nation of Ghana is also capable of using this method. At present, the date on which development approval was granted is the primary factor in determining whether or not a given field is subject to taxation. The final royalty payment was made in 2001. E&P firms typically must pay the Petroleum Revenue Tax (PRT), the Ring Fence Corporation Tax (RFCT), and the Supplemental Charge Tax (SCT) (SCT). Currently, all corporations are subject to a 30% Regular Federal Corporate Tax (RFCT). However, the RFCT is typically applied only to exploration and production tasks, and the concept of loss is viewed differently across disciplines. All profits are subject to a 32 percent tax rate under the Specialty Commodities Tax. The method used is identical to that used for the RFCT, with the exception that financing costs are ignored. Additionally, a 50% tax on oil production gross profits applies to all fields granted development permits prior to March 1993. (PRT).

IMPACT ON ATTRACTING FOREIGN INVESTMENTS AND NORWEGIAN ECONOMY

The diversity of the participants and the near doubling of their numbers over the past decade are both indications of the policy's positive impact on the economy. This has prompted extensive investigation over a long period of time, yielding a wealth of newly discovered data.

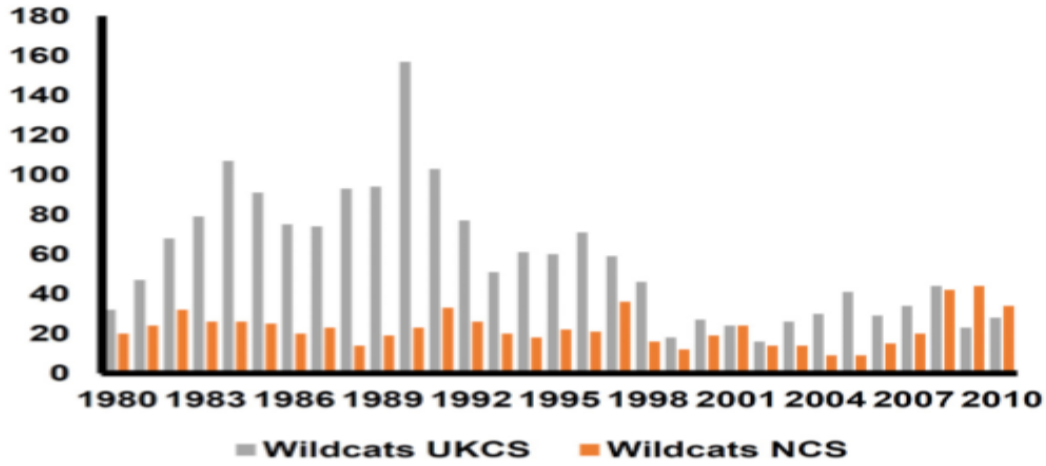

Figure 3- Exploration Wells Drilled in NCS and UKCs 1980 – 2010 (Source: Oil and Gas, UK)

Figure 3 shows the total number of wildcat wells drilled in the UKCS and Norway. It clearly shows reversal of activity from the UKCS in the 1990s to early 2000 to the NCS more recently. In fact, over the last few years, the number of exploration wells drilled in Norway has over taken that in UKCS and is becoming of great concern for UK, as sustained exploration is the key to maximizing recovery from the basin. The policy's positive effects on the economy can be seen in the varied range of participants and the nearly doubling of their number over the past decade. As a result, the investigation has been going on for quite some time and has yielded a wealth of previously undiscovered data. Thus, the Norwegian exploration led policy has proven to be a success story and continues to attract foreign investors.

BRAZIL FISCAL SYSTEM FOR DEEPWATER OIL AND GAS DEVELOPMENT

Brazil has an estimated proven reserves of 13.4 billion BBL and total daily production of 2.68 million BOPD as at end of 2018 (BP, 2019). Brazil has a significant presence in the international and Latin American oil and gas markets. Brazil discovered a reservoir of hydrocarbons in the pre-salt formation after drilling exploration wells at Parati and Tupi in 2005 and 2006. Pre-salt accounts for over 40% of total output, and fields like Lula, Jubarte, and Baleia Azul are seeing significant increases in output. Petrobras, a government-owned company, produces the vast majority of Brazil's crude oil. The upstream sector of Brazil's economy is dominated by legally sanctioned enterprises and is governed by a tangled web of tax breaks. Since October 2013, pre-salt and other strategic areas have been developed using profit sharing contracts (PSC). The licensing process occurs in predetermined waves. The concession entails a 34% tax on corporate profits in addition to a 10% royalty and a special participation tax that varies from 10% to 40% depending on time of year, location, and volume of production. A 15 percent royalty, an 80 percent cost recovery cap, and a biddable profit share with the government are all part of the PSC's terms. The latter is modified based on modifications to both output and prices. The concepts behind tax breaks for corporations and the corporate income tax are identical. The overall investment and expenditure amount for the project increases by about 15% - 20% as a result of these taxes.

IMPACT ON ATTRACTING FOREIGN INVESTMENTS AND BRAZILIAN ECONOMY

The Brazilian Deepwater sedimentary basins have proven to be an excellent oil-producing region, garnering praise from governments and international organizations such as the International Energy Agency. These two factors may maintain Brazil's exploration and production industry's appeal. According to Deloitte (2018), Petrobas has consolidated its position as the dominant player in Brazil's oil and gas sector by merging with several other oligopolies. The collective has verified this data. Although Petrobras is the primary investor and operator, challenges such as deep

water, a lack of infrastructure, and challenging reservoir characteristics could delay the resource's full development. In addition, the business might not be able to proceed because it is saddled with too much debt and lacks the necessary operating capital. Current re-injection rates for natural gas are around 25%. This is due to a number of factors, the most significant of which is the lack of adequate infrastructure linking offshore fields to high-demand areas. Large capital projects have been conducted by Total, ExxonMobil, Chevron, Shell, and Statoil in the Miocene and Paleogene sub-salt Gulf of Mexico, as well as the pre-salt African Gulf of Guinea. Large, independent oil companies and IOCs appear to be the most prepared for the impending difficulties. Both Statoil and Total have funded projects to explore for pre-salt in remote areas of Brazil. It's likely that other businesses will follow Petrobras' lead and reduce operatorship requirements after seeing its success. More than half of the world's oil comes from other places, such as offshore post-salt fields, so concentrating solely on the pre-salt might not be the best strategy. At least two bid rounds in 2017 were successful under the concession regime. These engagements took place outside the established salt polygon. Smaller domestic players were very interested in one of them because it was focused on small accumulations in already developed basins. The second round of bidding resulted in the selection of 37 blocks. This time around was different than the last because seven of the winning companies were not American. The offer was the most lucrative the country had ever seen, and it included a $1.2 billion bonus for two blocks in the Campos basin. The development stages of both pre-salt and post-salt projects are not without risk. The thick layer of evaporated salt and greater water depths will likely be beyond the capabilities of all but a select few service providers. Because of this, fewer service providers will be able to meet the demands placed on them. To make mature basins and smaller discoveries profitable, international oil companies (IOCs) and local players in deep water environments would need to be extremely frugal and efficient in their operations. In addition to their extreme depth, these reservoirs are also offshore and relatively isolated. If operators are serious about profiting from the gas resource and maintaining its equilibrium, then a substantial network of new pipelines may be required in the not-too-distant future. Companies in the oilfield service, engineering, and procurement industries that have the expertise and political savvy to deal with above-ground risks and other regulations may stand to gain significantly from this development. This may present an opportunity for financial gain for these companies. Based on research conducted by Deloitte (2018).

GULF OF GUINEA

When it comes to raising capital for oil and gas projects, the Gulf of Guinea is often cited as a top contender. Equatorial Guinea, Gabon, Angola, and Nigeria hold the bulk of the Gulf of Guinea's oil reserves (Fig. 4). As of the end of 2013, these four countries accounted for 90% of Africa's reserves. The Petroleum Fiscal System is the single most important factor influencing foreign direct investment in the region's deep offshore areas. The only entity with the legal authority to make mineral claims in the Gulf of Guinea is the national government (the State). Licenses, leases, and contracts for Exploration and Production activities in a given contract area are typically issued by a National Oil Company or a Ministry on behalf of the national government. Any part of a contract can be modified in this way. The Petroleum Fiscal System of various countries in the Gulf of Guinea various considerably, countries rarely follow the same pattern.

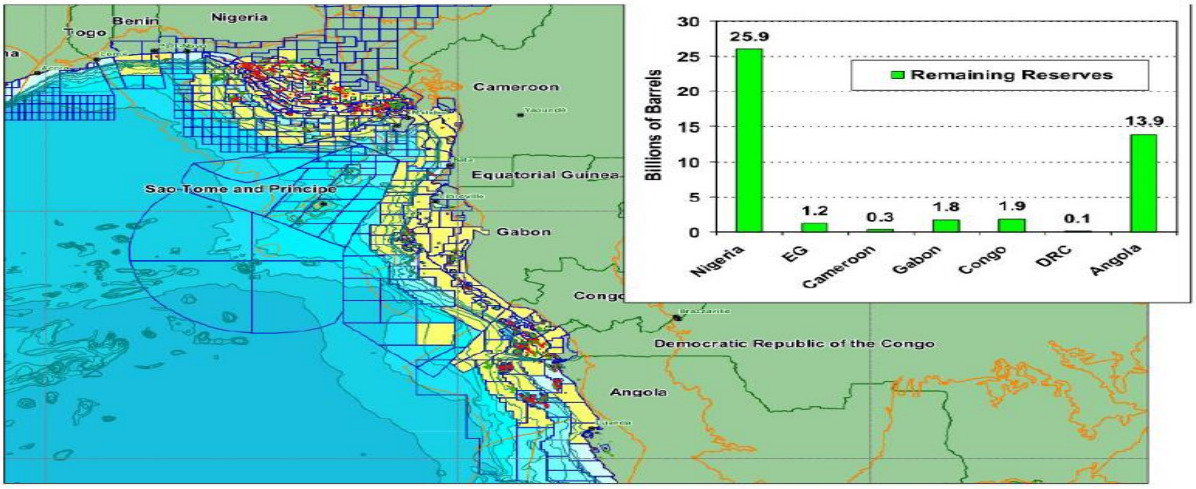

Figure 4- Gulf of Guinea Remaining Reserves as at 2005 (Source: Echendu et al., 2015)

ANGOLA FISCAL SYSTEM FOR DEEPWATER OIL AND GAS DEVELOPMENT

Angola has an estimated proven reserves of 8.4 billion BBL and total daily production of 1.53 million BOPD as at the end of 2018 (BP, 2019). China and United States are the major importers of Angola's crude oil. The Ministry of Petroleum in Angola is mandated with the coordination, oversights and regulation of Oil and gas sector as well as policy and guidelines formulation. The Petroleum Activities Law (PAL) No. 13 of 1978 provides the basic guidelines regulating the exploration and production of hydrocarbon post-independence years. Law No. 10 of 2004 sets the guidelines for the 2004 PSC.Angola PSCs provides for an initial exploration period of 4 years and an extension to a maximum of 2 additional years for deep offshore. The production period is 20 years from date of commercial

discovery and allows for relinquishment of all except development areas after 6 years. There is a negotiable exploration obligation in the PSC. There is no defined signature bonus in the Petroleum Activities Law (PAL), moreover, request for prospecting licenses activates payment of relevant fees paid under applicable law, as stipulated in Articles 37 and 38 of PAL 2004. According to Article 84 of the PAL, the National Concessionaire is required to remit to the State Treasury any bonuses it receives as a result of agreements it has reached with its business partners. There is no royalty definition in the 1990 and 2004 PSCs. There is a Domestic-Market Obligation (DMO) of up to 40% of production (Echendu et al., 2015). According to the PSC from 2004, depreciation for exploration and development expenses must be taken out over a six-year period at a constant rate of 16,66667 percent per year, or using the straight-line method of depreciation. The expenses caused by dry holes are included in this total. Production-related expenses are amortized over a four-year period at a flat rate of 25% per year. There is a maximum of 50% of annual gross production that can be used to recover costs, with an additional 40% of gross production added to the cost base for development. Companies involved in exploration and production in Angola are required to contribute to a training levy that will be used to fund educational opportunities for locals. Profit The contractor would receive 50-60% if the daily average output was 25MBOPD. The contractor takes roughly 10% of all production above 100MBOD. The average rate of production is used to allocate oil after deducting royalties and cost recoveries.

IMPACT ON ATTRACTING FOREIGN INVESTMENTS AND ANGOLA ECONOMY

Total is the leading E&P company in Angola, with an average production of 229,000BOPD as at 2017. Further, the company has made up its mind to develop Block 17's deep offshore area, known as Zinia 2, as planned. In order to keep Pazflor Field Production running smoothly, the Zinia 2 project will have a production capacity of 40,000BOPD. To fully utilize the block's potential, it will link satellite reservoirs to the Pazlor FPSO. The total cost of the nine wells that will be linked to the Pazflor FPSO as part of the Zinia 2 project is estimated to be $1.2 billion. These boreholes have water depths between 600 and 1,200 meters. Total, with a 40% stake, is responsible for managing Block 17, while Equinor, Exxon Mobil, and BP each have 20% stakes and BP a 10% stake. Almost one-seventh of a percent. Angola's state-owned oil company, Sonangol, is the concessionaire.

GABON FISCAL SYSTEM FOR DEEPWATER OIL AND GAS DEVELOPMENT

Gabon is the eighth oil producer in Africa. It has an estimated proven reserves of 2.0 billion BBL and total daily production of 194,000 BOPD as the end of 2018 (BP, 2019). The ownership of the hydrocarbon resources is vested on the state. The State concessionaire is the State Oil Company Societe Nationale Petroliere Gabonaise (SNGP). The Department of Hydrocarbons supervised by the Minister of Mines, Petroleum and Hydrocarbon is primarily responsible for the development and regulation of oil and gas industry in Gabon. Upstream licenses are distributed in accordance with the terms of production sharing contracts, which are governed by the Hydrocarbon Code, which replaced Law No. 14/82 on August 28, 2014. (PSCs). The New Hydrocarbon Code governs the PSC's taxation in Gabon. Contractors must make contributions on top of taxes and other revenue streams for the government. Income taxes, surface rent paid once a year, and production royalties make up the bulk of the economy. Bonuses for production volume ranging from $500,000 to $1,000,000, production royalties of 6% to 12% of gross, and signature bonuses of at least $215 per square kilometer of land. At least $215 per hectare must be paid in production royalties. Companies operating under exploitation and production sharing agreements pay taxes of 35% to 40% of their profits, while those operating under concession agreements pay taxes of 73% to 100% of their profits.

IMPACT ON ATTRACTING FOREIGN INVESTMENTS AND GABON ECONOMY

Over fifty percent of GDP and eighty percent of export earnings in Gabon are attributable to the oil industry. However, declining oil production and prices have had a negative impact on the country's economy. Many ongoing activities have been halted as a result. The government of Gabon is planning to upgrade the country's infrastructure and facilities to attract and retain more foreign investment. The better functioning of the roads is a target. By 2020, the government of Gabon hopes to have paved an additional 700 kilometers of roads. The government of Gabon is investing in a number of SEZs like the Mandji Island SEZ, which will give preference to the hydrocarbons industry. About half of Gabon's total land area, or about 128,000 square kilometers, is covered by licensed deepwater plays. Gabon is home to 19 distinct deepwater plays, all of which are operated by 10 separate businesses. The likes of Marathon Oil, Shell, and Vaalco are global giants among these corporations. To support its future production goals, Gabon has invested in exploration and is now selling off large blocks of deepwater property. The Gabonese Ministry of Petroleum and Hydrocarbons contracted with Oslo-listed business Spectrum and French geoscience firm CGG to conduct a multi-client seismic survey. The South Basin blocks will soon be ready to be marketed to international operators, thus a study is being conducted to prepare them. Twenty-five thousand square kilometers were examined.

NIGERIA FISCAL SYSTEM FOR DEEPWATER OIL AND GAS DEVELOPMENT

History of Nigeria Deep Offshore PSC

The Nigerian hydrocarbon reserves have grown significantly after the discovery of hydrocarbon in Oloibiri in 1956. Nigeria ranked 7th in the world in 1972, and became the 6th largest oil-producing country in the world by 2011 (OPEC, 1979). Nigeria has an estimated proven reserves of 37.5 billion BBL and total daily production of 2.05 million

BOPD as the end of 2018 (BP, 2019).The Minister of Petroleum Resources is charged for providing mining and operating permits in accordance with the Petroleum Act of 1969 and its revisions. The Department of Petroleum Resources (DPR), which is part of the Ministry of Petroleum Resources, is responsible for exercising regulatory authority and supervising all oil and gas industry operations carried out under licenses and leases. Through a number of different contract arrangements, the Federal Government of Nigeria engages in the oil business through the Nigerian National Petroleum Corporation (NNPC). In Joint Venture (JV) contract agreements, government has 60% share working interest, except with Shell in which it has a 55% working interest. The NNPC represents the government in PSCs by holding the relevant concession or license and contracting with independent operators to carry out petroleum operations. This organization falls under the category of public-private partnership. Most oil was produced on land in the Niger Delta basin prior to the 1990s. Large oil and gas reserves were discovered in the Niger Delta, which sparked protests, attacks, and sabotage on oil and gas facilities as well as instability in the host community. To increase oil production and keep up with global trends and technological advances in deep drilling, Nigeria began offshore and deep-water exploration in 1990, when the licensing rounds began. This decision was made because we care about staying informed about global events. The government has begun prioritizing PSCs over joint ventures as the optimal contract for granting these deep-water and offshore licenses. This shift took place over a period of years. The government was unable to meet its cash-call obligations and was unwilling to take on any additional debt. The establishment of Deepwater PSC has been extremely beneficial to Nigeria's petroleum industry, economy, and tax revenue. Currently, Deepwater PSCs account for 40% of Nigeria's total oil output. The Joint Development Zone (JDZ) PSC 2003, 1993, 2000, and 2005 all feature prominently, with the Nigerian National Petroleum Corporation (NNPC) playing a significant part in each. The Petroleum Profits Tax Legislation of 1959 served as the basis for the 1993, 2000, and 2019 model contracts published by the Petroleum Services Commission. In contrast, the Petroleum Profits Tax Act, Cap 354, Laws of the Federation of Nigeria 1990, was in effect for the Petroleum Services Commission in 2005.

1993 and 2005 PSC Terms and Instruments

The PSC has been meeting since 1993 to discuss signature agreements, production bonuses, and surface leasing prices. Depending on the depth of the water, the royalty rate will change. Royalty rates range from a maximum of twenty percent for onshore fields to a minimum of zero percent for those located in water deeper than one thousand meters. Expenditures made on "tangible development" (such as a building, structure, piece of equipment, or other facility) are amortized over five years at a straight-line rate in order to facilitate cost recovery. After deducting royalties, one hundred percent of revenue is allocated to covering expenses, and the entire perimeter is ring-fenced. This is the first of several bills currently in the works to ensure that the oil and gas industry follows all regulations. To help bring Nigeria's oil and gas industry up to date, a new bill proposes doing away with all of the current regulations. There have been numerous attempts at passing this bill in Congress over the previous sixteen years, but it has never been approved. Signature and surface rental costs are now negotiable thanks to the PSC Amendment of 2005. The total output is what counts toward the production bonus. The royalty rate varies according on the depth of the water. Royalty rates range from 0% for fields located below 500 meters of water to 20% for areas located beyond that depth. Depreciation on expenditures for tangible development, such as buildings, structures, equipment, machinery, and other facilities, is straight-lined over a period of five years for the purpose of cost recovery. A ring-fencing specification defines the area around the block, and once the royalty is deducted, cost recovery makes up 80% of the remaining 20% (Echendu et al., 2015). This is the first of numerous initiatives presently underway to ensure that the oil and gas business follows all applicable laws and regulations. All prior legislation in Nigeria pertaining to the oil and gas industry must be repealed in order to comply with the new law. There have been numerous failed attempts to introduce it in Congress during the past sixteen years. Comparison of the financial terms of the PSCs signed in 1993 and 2005 is in table 1.

Table 1: Summary of the Fiscal Terms of the 1993 and 2005 PSCs (NEITI Report, 2019)

FISCAL INSTRUMENT	1993 PSC	2005 PSC
Royalty	Graduated royalty rate, water depth dependent, 0-16.67%: Inland basin:10% 100 to 200m: 16.67% 201 to 500m: 12% 501 to 800m: 8% beyond 1,000m: 0%	Graduated royalty rate, water depth dependent, 8-18.5%: 0 to 100m: 18.5% 100 to 200m: 16.5% 201 to 500m: 12% 501 to 800m: 8% 801 to 1000m: 8% beyond 1000m: 8%
Petroleum Profit Tax (PPT)	PPT rate at 50%	PPT rate at 50%
Cost Oil – Cost recovery limit	No cost recovery limit	Cost recovery ceiling of between 60-80% of available crude oil

Profit Oil Split Mechanism	Cumulative production profit split	Profit Oil Split based on sliding R-Factor
Consolidation of Cost recovery	Not clear on cost consolidation – leading to disputes between IOCs and NNPC	Explicitly limits cost recovery to the producing OML or OPL and costs from a nonproducing OPL cannot be recovered from producing OPL/OML
Investment allowance	Investment tax credit (ITC) at 50% of qualifying capital expenditure (QCE) for PSC executed prior to July 1998	Investment tax allowance (ITA) of 50% for PSC executed with effect from July 199

2019 PSC Amendments Terms and Instruments

The 1993 law aimed to incentivize businesses operating in the deep offshore and inland basin region by providing tax breaks and other benefits in exchange for capital investments in those regions. If the price of crude oil rises above $20 per barrel 15 years after the agreement was made, and then every five years after that, the agreement must be reviewed in accordance with the Public Service Commission Act of 1993 (Kenneth et al., 2019). These regulations had never been implemented prior to the 2019 amendment. If the Federation had reviewed the PSC contracts in 2008 and used the fiscal system from the 2005 PSC licensing round, it would have made between $16.03 billion and $28.61 billion more between 2008 and 2017, according to the NEITI 2021 report on 1993 PSCs. The goal of the 2019 amendments to the Petroleum Supply Chain Act is to increase revenue for Nigeria's oil and gas sector. The total chargeable volume of crude and condensates from each field will now be used to determine royalties, as per the new regulations. Each field in deep offshore waters (those deeper than 200 meters) will be charged 10%, while each field in frontier or inland waters will be charged 7.5%. If the price of crude oil increases by more than $20 per barrel, the royalty rate will also increase as per the amendment. If the price of crude oil is below $20, then the rate is 0%; if it is between $20 and $60, then it is 2.5%; if it is between $61 and $100, then it is 4%; if it is between $100 and $150, then it is 8%; and if it is above $150, then it is 10%. All PSCs must now be reviewed every eight years as per new Section 17 of the Act. According to Article 18, anyone found guilty of violating any provision of the Act is subject to a fine of at least NGN500 million or at least 5 years in prison. The penalty for failing to review the PSC agreement is also outlined in this section (Atinuke and Teniola 2019). This is a brand-new regulation, as no punishments were included in the prior revisions.

Impact on Foreign Investments and Economy

There are already a number of taxes, fees, levies, and tariffs in place in Nigeria, and adding a price-based royalty and increasing water depth-based royalties would have a negative impact on the country's competitiveness (Chike, 2019). According to him, by the year 2023, the $48 billion worth of oil and gas investments (including Owowo Fields) will no longer be profitable. This could cause a precipitous decline in output and tax revenue for the government. Future Deepwater investments, estimated at $43 billion, are also not included because they are highly unlikely to occur due to Nigeria's uncompetitive fiscal policies. As a result, the value chain in the oil and gas industry will suffer and fewer people will be able to find work. The Bill's proponents argue that it will increase government revenue by increasing royalties when oil prices are high, but that it fails to account for the accompanying increases in capital costs, operating costs, and service costs. This is so because the Bill seeks to increase government revenue by increasing royalties during times of high oil prices. Nigeria is rapidly losing potential investments to Mozambique, Angola, and Ghana due to the country's deep-water fiscal terms being among the least competitive in the Gulf of Guinea and in Africa as a whole. However, in the last decade, only Usan, Aje, and Egina have been approved as new deep-water projects for the Nigerian oil industry. Large sums of money have been invested in Egypt, Angola, and Ghana despite their countries having only about half of Nigeria's total reserves. They provide more favorable financial terms to entice Deepwater's investment. Only $27 billion has been invested in Nigeria, despite the country's 37.5 billion barrels of oil reserves. To ensure that the law is clear and certain, to maintain fiscal terms that are competitive worldwide so that investment commitments can be kept, and to create a business environment that will help businesses succeed, the Nigerian government must move quickly to pass the petroleum industry bill (Bariture and Omowumi 2018). If a transparent and competitive fiscal framework is already in place, the federal government can increase national revenue by holding a new round of bids for oil licensing.

CONCLUSION

The reviewed fiscal policies from seven different countries dispersed across the globe from Brazil in South America, Angola at the Gulf of Guinea, United Kingdom at the North Sea and China at the South China sea gave a global perspective of the complexities and the uniqueness of the various fiscal terms and instruments in attracting foreign investment. The Minister of Petroleum Resources is responsible for issuing mining and operations licenses in compliance with the Petroleum Act of 1969 and any subsequent revisions to the law. All activities in the oil and gas business that are conducted under licenses and leases are supervised by the Department of Petroleum Resources (DPR), which is part of the Ministry of Petroleum Resources. The Ministry of Petroleum Resources is responsible for

this matter. The Federal Government of Nigeria has established a number of contract arrangements in the oil business through the Nigerian National Petroleum Corporation (NNPC). The fiscal policies require constant monitoring for enforcement. Host government should be proactive in making amendment on fiscal terms to prevent undue exploitation by IOCs, which can result in significant loss of revenue to the host nation like in the case of Nigeria 1993 PSC Act. To further de-risk exploration in deep offshore, host government can carry out geological and geophysical surveys like seismic data acquisition, these data can be share with the interested investor for more detailed interpretation and analysis to facilitate decision making and improve their chances of a commercial find. International Investors and Oil companies are yearning for fiscal certainty, which will serve as an incentive to unlock billions of potential investments in the deep offshore environment. African Oil and gas rich Nations must invest in their people and make stable reforms and policies to give them a competitive edge.

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