Policy Brief
ISSUE 04 / MARCH 2019

# 1993 PSCs: The Steep Cost of Inaction

A quantitative study by NEITI and Open Oil shows that in ten years (2008 to 2017), Nigeria lost between \$16.03b and \$28.61b for failing to trigger a review of the terms of the 1993 PSCs after 15 years of operation, contrary to the law governing the PSCs

## Abstract

This report advocates for an urgent review of the terms of the 1993 PSCs. Such a review is particularly crucial in light of the Supreme Court judgement of 17 October 2018, where the Attorney General of the Federation was mandated to recover all lost revenue from failure to review the terms of these Production Sharing Contracts (PSCs). It is also very critical because production from PSCs has outstripped production from Joint Ventures (JVs), and thus production from PSCs constitutes now the largest component of oil production in Nigeria.

By virtue of the provisions in Section 16 of the law governing the PSCs, the PSC contracts ought to have been reviewed first, in 2004 (when real oil prices exceeded \$20 per barrel); and secondly on 1st January 2008 (15 years from 1st January 1993). The \$20-trigger was the subject of the recent ruling by the Supreme Court, and is thus not covered by this study. Thus, this study concentrates on the second trigger – 15 years after January 1, 1993. Making use of financial modelling analysis, the standard methodology in the industry, this report employs data on production, oil prices and the applicable fiscal regimes to arrive at comparative revenue figures for the period 2008 - 2017.

The results reveal that if the PSC contracts had been reviewed in 2008, and the fiscal regime from the 2005 PSC licensing round had been applied, additional revenue to the Federation between 2008 and 2017 would have been higher by between \$16.03 billion and \$28.61 billion.

**2004**
when real oil prices exceeded \$20 per barrel

**2008**
15 years from 1st January 1993

# Introduction

The Supreme Court of Nigeria on October 17, 2018 delivered what has been considered a landmark judgement in Nigeria's petroleum fiscal space. The governments of Rivers, Bayelsa and Akwa Ibom states had sought relief from the apex court against the failure of the Federal Government to adjust the share of (additional) revenue accruable to the Federation from the PSCs after the price of crude oil exceeded $20 per barrel in real terms. Such adjustments in revenue were provided for by the enabling law of the PSCs.

**$21 - $60bn**

"Dr. Ibe Kachikwu projected that Nigeria has lost between $21 billion and $60 billion due to failure to review the terms of these PSCs".

In the judgement on Suit No. SC964/2016 [Attorney General of Rivers State & Anor (Appellants) VS Attorney General of the Federation (Respondent)], the Supreme Court mandated the Attorney General of the Federation to work jointly with the three state governments to recover all lost revenue accruing to the Federation. Such calculation of lost revenue would apply with effect from the respective times the price of crude oil exceeded $20 per barrel in real terms. The state governments are to be paid all outstanding statutory allocations (including 13% derivation), after deductions of cost of recovery.

The central issue in this suit derived from Section 16, subsection 1 of the enabling law of the PSCs leased in the 1990s.

Section 16 (1) of the Deep Offshore and Inland Basin Production Sharing Contracts Act Cap. D3. LFN 2004 stipulates that:

> *"the provisions of the Act shall be subject to review to ensure that if the price of crude oil at any time exceeds $ 20 per barrel, real terms, the share of the Government of the Federation in the additional revenue shall be adjusted under the Production Sharing Contracts to such extent that the Production Sharing Contracts shall be economically beneficial to the Government of the Federation."*

The Supreme Court has ruled on this. However, the law contains a second trigger point, which was not brought before the apex court for determination, possibly because it is more straight-forward, though observed in the breach.

Section 16 (2) states that

> *"Notwithstanding the provisions of subsection (1) of this section, the provisions of this Decree shall be liable to review after a period of 15 years from the date of commencement and every five years thereafter".*

Agitations for action on the provisions of Section 16 of the PSC Act are not new. On the part of the government, the Minister of State for Petroleum Resources, Dr. Ibe Kachikwu projected that Nigeria has lost between $21 billion and $60 billion due to failure to review the terms of these PSCs. Concerned citizens, including legislators, have also raised this issue and highlighted that the Federation is losing much needed revenue.

The Nigeria Extractive Industries Transparency Initiative (NEITI) has also been interested in this issue based on our mandate . Sections 2 (a) and (b) of NEITI's enabling law state that the primary objectives of the NEITI are:

a. To ensure due process and transparency in the payments made by all extractive industry companies to the Federal Government and statutory recipients;

b. To monitor and ensure accountability in the revenue receipts of the Federal Government from extractive industry companies.

In addition, Section 3 (f) of the NEITI Act enumerates one of NEITI's functions as follows:

a. Monitor and ensure that all payments due to the Federal Government from all extractive industry companies, including taxes, royalties, dividends, bonuses, penalties, levies and such like, are duly made.

"If the PSC contracts had been reviewed in 2008, and the fiscal regime from the 2005 PSC licensing round had been applied, revenue to the Federation would have been higher by between $16.03 billion and $28.61 billion."

In line with these provisions, NEITI has produced this report to further advocate for the importance of the review of these PSCs. Unlike others, this report provides quantitative evidence on the differences between what the country has earned and what it would have earned if the PSC contracts had been reviewed as stipulated by the law. Making use of financial modelling analysis, the standard methodology in the industry, this report employs data on production, oil prices and the applicable fiscal regimes to arrive at revenue figures for different scenarios.

By virtue of the provisions in Section 16, the contracts for the PSCs ought to have been reviewed first, in 2004 (when real oil prices exceeded $20 per barrel); and secondly on 1 January, 2008 (15 years from 1 January, 1993) . This report conducts a counter-factual estimation of the type of revenues that could have accrued to the Federation if the second review had been done.

As stated previously, this study does not delve into the first trigger point, as this has already been catered for by the Supreme Court judgement. Thus, this study applied only the second trigger point. Therefore, the analysis considers a review of the PSCs from 2008.

In summary, the results reveal that if the PSC contracts had been reviewed in 2008, and the fiscal regime from the 2005 PSC licensing round had been applied, revenue to the Federation would have been higher by between $16.03 billion and $28.61 billion.

[1] http://thenationonlineng.net/nigeria-lost-21bn-oil-production-sharing-contract-kachikwu/

[2] https://www.thisdaylive.com/index.php/2017/08/07/kachikwu-nigeria-lost-60bn-to-non-enforcement-of-pscs-with-oil-majors/
http://leaders.ng/nigeria-lost-60bn-non-enforcement-pscs-oil-majors-kachikwu/

[3] http://www.legaloil.com/NewsItem.asp?DocumentIDX=1436211667&Category=news

[4] http://www.legalnigeria.com/2016/04/nnpc-oil-companies-looters-owe-nigeria.html

[5] NEITI 2006 – 2008 Financial Report, Appendix N: Non Financial Flows

# Changing Structure of Oil Production in Nigeria

From the discovery of oil in the country until the 1990s, production was focused onshore in the Niger Delta basin. While substantial reserves of oil and gas have been discovered in the Niger Delta, there have been a number of difficulties such as community instability and agitations, and attacks and sabotage of facilities and installations.

In a bid to follow new global developments of deep drilling technology and further increase oil production, Nigeria ventured into offshore and deep-water exploration with the commencement of the licensing rounds starting from 1990. The government deviated from the existing practice of JVs and shifted to PSCs as the preferred contract type for the award of these deep-water and offshore licenses. This was largely down to the difficulties of meeting up with cash-call obligations and the desire to be free from further financial burdens.

PSCs are a type of contractual agreement for petroleum exploration and development where the state, as owner of the mineral resources, engages a contractor to provide technical and financial services for exploration and development operations. Indonesia is credited as the first country to use PSCs in contracts for petroleum exploration and development. Following negative public agitation against the contractors (in Indonesia's case, multinational oil companies), PSCs were introduced because the production arrangement retains control of the mineral assets in the hands of the government. Although the MNOCs initially resisted this arrangement where they did not own the assets, they eventually relented and participated in the PSCs. Thus, production arrangements subsequently gained popularity and their use quickly spread across the world.

PSCs have two characteristics that distinguish them from other contract types . Firstly, all exploration risk is borne by the contractor. The contractor takes the position of a contractor and does not own any equity in the asset. The contractor operates at its sole risk, its own expense and under the control of the country.  Secondly, both the mineral resource and installations are owned by the government. The title to the equipment and installations purchased by the contractor passes to the country either immediately or over time, in accordance with the cost recovery schedules .

"PSCs are a type of contractual agreement for petroleum exploration and development where the state, as owner of the mineral resources, engages a contractor to provide technical and financial services for exploration and development operations".

**1990**

Nigeria ventured into offshore and deep-water exploration with the commencement of the licensing rounds starting from 1990.

[6] By a letter dated 26 July, 2007, the Directorate of Petroleum Resources (DPR) informed the Operators/ Contractors of the 1993 PSCs, that the Federal Government intended to review the 1993 PSC elements in line with the provisions of Sections 16 (1) and (2) of the PSC Act. Unfortunately, this review never happened.

[7] Bindemman, K. (1999) Production-Sharing Agreements: An Economic Analysis, WPM 25, Oxford Institute for Energy Studies

"The Deep Offshore and Inland Basin Production Sharing Contracts Act was enacted on March 23, 1999, with its commencement backdated to January 1, 1993, thereby making it applicable to all PSCs involved in the 1991 licensing round."

The first licensing round for the PSCs was conducted in Nigeria in 1991 and the 1993 PSCs were drawn up as the contractual agreements for assets involved . These agreements were drafted while the country was going through both political and economic upheavals. On the political front, the early 1990s was a period of severe uncertainty with the ongoing transition to democratic rule which was eventually aborted. The country was under enormous pressure both internally and externally to democratise and it was difficult to access international credit markets. The country also had the desire to retain ownership of its oil assets. On the economic front, this was a period of low oil prices which negatively impacted revenue inflows. Other economic factors included difficulty in funding JV cash calls and high risks associated with exploration of deep-water basins. These conditions explain the widely held view that the 1993 PSCs in Nigeria unfairly favoured the oil companies especially in terms of royalties and petroleum taxes, to the detriment of the country , .

The Deep Offshore and Inland Basin Production Sharing Contracts Act was enacted on March 23, 1999, with its commencement backdated to January 1, 1993, thereby making it applicable to all PSCs involved in the 1991 licensing round. The Act was enacted following pressure and concerns from foreign investors who questioned government's commitment to the PSCs.

JVs used to account for over 90% of total oil and gas production in Nigeria but this has since changed, and PSCs' contribution to total production has increased as more deep-water acreages have been explored and existing JVs are re-negotiated. Figure 1 shows annual production from JVs and PSCs. Between 1998 and 2005, total production through PSCs was below 100,000,000 barrels per year while JVs consistently produced over 650,000,000 barrels per year. Beginning from 2006, production from PSCs started rising while at the same time JV production started falling. By 2017, total production from PSCs was 305,800,000 barrels which was 44.32% of total production. Total production from JVs was 212,850,000 barrels, representing 30.84% of total production.

[8] Ibid.

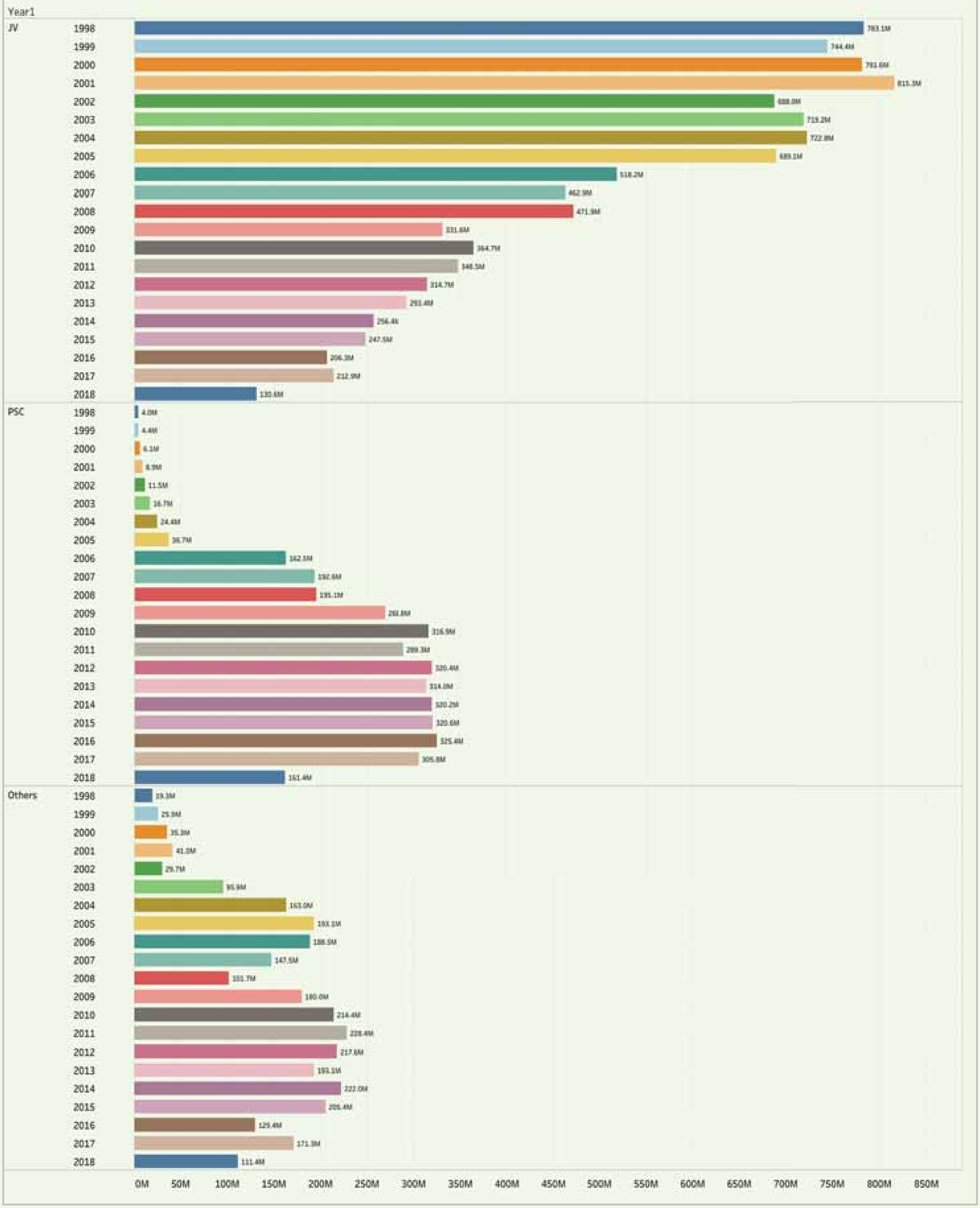
[9] Duval, C., H. Le Leuch, A. Pertuzio, and J. Weaver (2009) International Petroleum Exploration and Exploration Agreements: legal, Economic and Policy Aspects, 2nd edition. New York: Barrows Company Inc.

[10] Four additional licensing rounds were held between 2000 and 2007: 2000, 2005, 2006, and 2007. These gave rise to two additional PSCs: 2000 PSC and 2005 PSC

[11] The contractors producing under the 1993 PSC are in dispute with NNPC over several aspects of interpretation of the PSC, including: ring-fencing of the PSCs; the applicable royalty rates; deductibility of certain expenditures for PPT purposes; the entitlement to and timing of capital allowances; the entitlement to and correct application of Investment Tax Credit ("ITC"); cost consolidation.

[12] As a result of the disputed issues, there are disagreements between the NNPC and the Contractor/Working interest holders on issues such as: the allocation of crude oil recovered from contract area; the amount of Royalty and PPT payable in respect of contract area.

FIG 1: Oil Production by Production Arrangement (barrels per year)




*Source: NNPC Monthly Financial and Operations Reports*

*Note: Figures for 2018 are from January to July*

# 1993 PSCs: Overview of the Fields


"Abo (OML 125), Agbami-Ekoli (OML 127 & OML 128), Akpo & Egina (OML 130), Bonga (OML 118), Erha (OML 133), Okwori & Nda (OML 126), Usan (OML 138). "

The analysis conducted in this policy brief examines the seven producing fields of the 1993 round of PSCs. These are: Abo (OML 125), Agbami-Ekoli (OML 127 & OML 128), Akpo & Egina (OML 130), Bonga (OML 118), Erha (OML 133), Okwori & Nda (OML 126), Usan (OML 138). This section provides a brief overview of each of these fields as follows :

## a. Abo (OML 125)

OML 125 is a deepwater block located in the western Niger Delta, 40 kilometres from the coast. It contains three fields: Abo, Abo North and Okodo. Abo's reserves are small compared to other deepwater projects in Nigeria. Total recoverable reserves were 143 mmbbl of oil. Remaining reserves as at January 2018 were 22 mmbbl of oil. Abo has an area of 1,219 km2 and lies in water depth of 477 – 915 metres. At present, Abo is exclusively owned and operated 100% by Eni. However, it has gone through various stages of participation over the years.

## b. Agbami-Ekoli (OML 127 & OML 128)

Agbami is a deepwater field in the central part of the Niger Delta. It is located in water depths between 750 and 2,600 metres. It is one of the biggest stand-alone developments in Nigeria, and accounts for over 10% of Nigeria's total oil production. Agbami-Ekoli comprises two OMLs – 127 and 128 – and total recoverable reserves for the two OMLs are estimated to be over one billion barrels. At the last arbitration to determine composition Agbami-Ekoli, OML 127 was assigned 62.47%, while OML 128 was assigned 37.53%. The reserves and production are split based on this formula. The two OMLs have different fiscal regimes applying to them. OML 127 is operated by Chevron. Its equity interest comprises Famfa Oil (60%), Chevron (32%), and Petrobras Oil & Gas (8%). OML 128 is operated by Chevron. Equity participation is: Equinor (53.85%) and Chevron (46.15%).

[14] The discussion in this section draws heavily from Wood Mackenzie reports
[15] A summary overview of the producing fields from the 1993 PSCs is provided in the appendix

## Overview of the Fields

| | NAME | OML | Water Depth | PRODUCTION STARTED | LEASE EXPIRY | PARTICIPANTS | RECOVERABLE RESERVES | REMAINING RESERVES AT 01/01/18 |
|---|---|---|---|---|---|---|---|---|
| 1 | Abo | 125 | 477 - 915m | 2003 | 2023 | Eni (100%) | 143 mmbbl oii | 22 mmbbl oil |
| 2 | Agbami-Ekoli | 127 | 1450 - 1850m | 2008 | 2024 | Famfa Oil (60%), Chevron (32%), Petrobras Oil & Gas (8%) | 867 mmbbl oil | 377 mmbbl oil |
| | | 128 | 1450m | 2008 | 2024 | Equinor (53.85%), Chevron (46.15%) | 512 mmbbl oil | 226 mmbbl oil |
| 3 | Akpo & Egina | 130 | 1154 - 1568m | 2009 (Akpo) 2018 (Egina) | 2025 | OML 130 PSA: Petrobras Oil & Gas (32%), South Atlantic Petroleum (20%), Total (48%); OML 130 PSC: CNOOC Ltd (90%), South Atlantic Petroleum (10%); OML 130 Gas: NNPC (60%), Total (40%) | 668 mmbbl oil, 823 mmbbl (condensates), 1868 bcf sales gas | 666 mmbbl oil, 299 mmbbl condensates, 856 bcf sales gas |
| 4 | Bonga | 118 | 1020 - 1245m | 2005 | 2025 | Shell (55%), ExxonMobil (20%), Eni (12.5%), Total (12.5%) | 1,710 mmbbl oil, 1,040 mmbbl sales gas | 942 mmbbl oil, 607 bcf sales gas |
| 5 | Erha | 133 | 1000 - 1696m | 2006 | 2026 | ExxonMobil (56.25%), Shell (43.75%) | 805 mmbbl oil | 209 mmbbl oil |
| 6 | Okwori & Nda | 126 | 42 - 150m | 2005 | 2024 | Addax (100%) | 142 mmbbl oil | 14 mmbbl oil |
| 7 | Usan | 138 | 639 - 910m | 2012 | 2025 | Chevron (30%), ExxonMobil (30%), Nexen (20%), Total (20%) | 307 mmbbl oil | 104 mmbbl oil |

### c. Akpo & Egina (OML 130)

OML 130 is located in the deepwater Niger Delta, 130 kilometres offshore. It is located in water depths between 1154 and 1568 metres. Total recoverable reserves were estimated at 668 mmbbl of oil. There are two contracts applying to OML 130. An indigenous sole risk contract (PSA), and production sharing contract (PSC). Unlike Agbami-Ekoli, there is one OML applying to Akpo and Egina. However, the reserves, production and costs are split 50/50 between the PSA and PSC. Equity participation in OML 130 is as follows: OML 130 PSA: Petrobras Oil & Gas (32%), South Atlantic Petroleum (20%), Total [operator] (48%); OML 130 PSC: CNOOC Ltd (90%), South Atlantic Petroleum [operator] (10%).

### d. Bonga (OML 118)

OML 118 is a deepwater block comprising the fields: Bonga main, Bonga SW, Bonga NW, Bonga North. Bonga main was the first major deepwater development in Nigeria. Bonga lies in water depths ranging between 1,020 and 1,245 metres. Estimated recoverable reserves are 1,710 mmbbl of oil and 1,040 bcf of gas. Bonga is operated by Shell. Equity participation is as follows: Shell (55%), ExxonMobil (20%), Eni (12.5%), Total (12.5%).

### e. Erha (OML 133)

OML 133 is a deepwater block comprising three fields: Erha, Erha North and Bosi. OML 133 covers an area of 1,100 km2 and lies in water depths ranging between 1,000 and 1,696 metres. Gross recoverable reserves were 805 mmbbl of oil. Erha is operated by Exxon Mobil. Equity participation is: ExxonMobil (56.25%) and Shell (43.75%).

### f. Okwori & Nda (OML 126)

OML 126 is a shallow water block in the Niger Delta, comprising four fields: Okwori, Nkelu, Okwori South, Nda. Development of OML 126 has been technically difficult due to the physical properties of the field reservoirs. Gross recoverable reserves were 142 mmbbl of oil. Remaining reserves as at January 2018 were 14 mmbbl of oil. OML 126 is 100% owned and operated by Addax.

### g. Usan (OML 138)

OML 138 is a deepwater field located in the eastern Niger Delta, about 70 kilometres offshore. Recoverable reserves of OML 138 are 307 mmbbl of oil. Usan occupies an area of 656 km2 and lies in water depths between 639 and 910 metres. Usan is operated by ExxonMobil and the participants are: ExxonMobil (30%), Chevron (30%), Nexen (20%), Total (20%).

# Quantifying Lost Revenue: Financial Modelling of the 1993 PSCs


This policy brief conducts financial modelling analysis of Nigeria's 1993 PSCs. The scope to be addressed by financial analysis was: what would the impact have been on revenues to the Nigerian government if a review had been carried out, and terms altered, at some stage in the development of the Nigerian offshore sector?

## Trigger point: 15 years from the original bid round

As outlined above, Section 16 of the Deep Offshore and Inland Basin Production Sharing Contracts Act No. 9 of 1999 stipulated two different possible trigger points for a contract review: the first, when the price of crude oil exceeded $ 20 per barrel, real terms; and the second, when 15 years had elapsed after the commencement of the law. This study simulates what would have happened in the second case only: 15 years after the launch of the 1993 PSCs.

Consideration of revenues accruable from the other trigger point of oil price of $20 per barrel in real terms is already being conducted by the Attorney Generals of the Federation and Bayelsa, Rivers and Akwa Ibom states. Clearly, the gains to the Nigerian government will be higher if the reviews are done for the two trigger points. It would be possible to get some estimates of this sum by adding the amounts arrived at by the Attorney Generals with the amounts estimated from this study.

"Since Nigeria launched a round of offshore bids in 2005, the scenario chosen was to assume that in 2008 the contract review was triggered on the 15-year rule, and resulted in the conversion of all of the first-round offshore projects to the terms that prevailed in the 2005 round."

## 2005 Offshore licensing round terms applied from 2008

Because the study is of a counterfactual or what-if nature, a discrete alternative scenario is needed to quantify any question of different results. Since Nigeria launched a round of offshore bids in 2005, the scenario chosen was to assume that in 2008 the contract review was triggered on the 15-year rule, and resulted in the conversion of all of the first-round offshore projects to the terms that prevailed in the 2005 round.

Clearly the real world is messier than these assumptions. Companies would have been involved in a contract review, and any change of terms would have involved fresh negotiations. The implications of this are discussed in the section on results.

A summary of the fiscal terms of the 1993 and 2005 PSCs are presented in the table below.

### TABLE 1: FISCAL TERMS OF THE 1993 AND 2005 PSCS

| FISCAL INSTRUMENT | 1993 PSC | 2005 PSC |
|---|---|---|
| Royalty | Graduated royalty rate, water depth dependent, 0-16.67%:<br>Inland basin: 10%<br>100 to 200m: 16.67%<br>201 to 500m: 12%<br>501 to 800m: 8%<br>beyond 1,000m: 0% | Graduated royalty rate, water depth dependent, 8-18.5%:<br>0 to 100m: 18.5%<br>100 to 200m: 16.5%<br>201 to 500m: 12%<br>501 to 800m: 8%<br>801 to 1000m: 8%<br>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 non-producing 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 1998 |

"Since Nigeria launched a round of offshore bids in 2005, the scenario chosen was to assume that in 2008 the contract review was triggered on the 15-year rule"

# PSAs - Peculiar Characteristic of PSCs in Nigeria Featuring no Profit Oil for Government

The Nigerian oil sector has a peculiar feature of PSCs which is not found anywhere else in the world. There are some cases, where the PSCs are referred to as Production Sharing Agreements (PSAs). For these PSAs, there is no provision for profit sharing with the government; the oil company takes all profit after payment of taxes. This situation leads to a suboptimal situation for the Federation, as potential revenue is lost as a result of the companies not sharing profit oil with government. Such a situation exists for OPL 245 (Malabu), where the latest fiscal terms for the block emanating from the 2011 Resolution Agreement signed in 2012 provided for a production sharing arrangement for profit sharing between Shell and Eni, but the Nigerian government is completely left out of profit sharing. Recent quantitative evidence showed that the Federation stands to lose between $4.5 billion and $5.9 billion if the PSA for OPL 245 is implemented as against if the 2003 or 2005 PSC fiscal terms are used .

The 1993 PSCs being examined in this report have two PSAs. These are for OML 127 (Agbami-Ekoli) and OML 130 (Akpo & Egina). Agbami consists of OML 127 and OML 128 but different fiscal terms apply to the two OMLs. While there is splitting of profit oil between the government and oil companies for OML 128, government does not get any profit oil from OML 127. Famfa Oil acquired an indigenous sole contract for 100% of OPL 216 in 1993. Famfa Oil's application for conversion of OPL 216 to an Oil Mining Lease was granted in December 2004 and OPL 216 became OML 127. This OML 127 has been a source of contention between Famfa Oil and the Federal Government. The government has tried to acquire interests in OML 127 through 'Back-in-Right' regulations which would have given government a share of profit oil . This was contested by Famfa Oil and the Supreme Court's judgement in May 2012 adjudged that government is not entitled to any profit oil in OML 127. Considering the fact that the current determination of reserves for Agbami-Ekoli gave OML 127 (62.47%) a higher proportion of reserves than OML 128 (37.53%), the government is really losing out on potential profit oil.

Unlike Agbami which has two OMLs, Akpo & Egina has only one OML (OML 130) . However, OML 130 has two contracts – a PSA and a PSC – where production and reserves are split in half between both contracts. The PSC half is treated as a typical PSC where the government has a share of profit oil. However, the PSA does not feature profit sharing with government. Thus, only the oil companies share profit oil from the PSA half of OML 130.

"The PSC half is treated as a typical PSC where the government has a share of profit oil. However, the PSA does not feature profit sharing with government. Thus, only the oil companies share profit oil from the PSA half of OML 130."

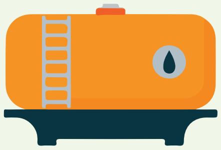
NEITI has accounted for this situation with PSAs by conducting the analysis using two scenarios. In the first scenario, the modelling is done using the 2005 fiscal regime but treating profit oil as currently subsisting for Agbami and Akpo where the government does not get some share of profit oil. The second scenario is modelled also using the 2005 fiscal regime but government now gets a share of profit oil. Although the situation regarding government share of profit oil for these fields may not be revised, this has been included in this analysis to show the huge revenue that government is missing. This knowledge is useful for the government to note especially in future contracts.

[15] https://www.globalwitness.org/documents/19524/Take_the_Future_.pdf
[16] https://www.globalwitness.org/documents/19525/R4D-Nigeria245-GovernmentRevenueAnalysis-Final.pdf
[17] OPL 245 is not yet producing. The analysis was conducted for expected future revenue inflows, taking into account projected data on oil prices and production, based on the fields' recoverable reserves of oil.
[18] The Deep Water Block Allocations to Companies (Back-in-Rights) Regulations 2003 is a subsidiary legislation of the Petroleum Act that grants the Federal Government rights to acquire five-sixths of an allottee's interest in a relevant oil prospecting licence and oil mining licence.
[19] The judgement rested on the fact that the Federal Government's actions in trying to acquire interest in OML 127 was not in line with the Petroleum Act which required negotiations between the Minister of Petroleum and the Allottee of the licence. However, the NNPC, relying on the Back-in-Rights Regulations, was of the opinion that such negotiation was not necessary, as the Back-in-Rights Regulations provided for such acquisitions without the need for negotiations. The Supreme Court ultimately ruled that the Petroleum Act is substantive or principal law while the Back-in-Right Regulation is a subsidiary of the principal law. "… so, subsidiary legislation must conform with the principal law"
[20] Egina started production in December 2018

# Modelling Assumptions

## i. Production, Price and Cost Data

NEITI was able to obtain precise production histories for each of the seven offshore fields modelled since their inception. This was obtained from subscription to Wood Mackenzie . For price, Wood Mackenzie also provided the ratio of prices of each field to the price of Brent. This ratio was then applied to the price of Brent in order to obtain prices for the crude streams.



"The model assumes that in 2008 a switch was made on the seven fields from the original offshore PSC structure to the replacement regime which came into effect in 2005."

A combination of production and price figures then yielded revenue figures for each field, year by year.

Cost data were also obtained from Wood Mackenzie. Such data relate to costs of development. Further costs relate to costs for capital expenditure and operating expenditure, and decommissioning.

These estimates were transformed into per barrel estimates for exploration, capital expenditure, operating expenditure and decommissioning.

Sensitivity parameters were also added to the dashboard of the model to explore susceptibility of the results to changes in either operating or capital expenditure.

## ii. Fiscal Regime Interpretation and impact

The model assumes that in 2008 a switch was made on the seven fields from the original offshore PSC structure to the replacement regime which came into effect in 2005. Major changes included an increase in royalties, treatment of investment tax credits and tax allowances, and rules regarding consolidation of cost structures.

As discussed previously, two scenarios are estimated. The first scenario (SC1) uses the subsisting regimes with respect to government share of profit oil. The second scenario (SC2) calculates

[21] Wood Mackenzie is a global energy, chemicals, renewables, metals and mining research and consultancy group with an international reputation for supplying comprehensive data, written analysis and consultancy advice.

government share of profit oil from the PSAs for Agbami and Akpo, which currently do not share profit oil with government.

## iii. Calculation of Government Revenue

The model calculates revenue accruable to the Federation based on Nigeria's PSC fiscal regime. For each field, the amount of crude oil produced is multiplied by the oil price to obtain total gross revenue from such field. Subsequently, the terms of the PSC fiscal regimes are applied to extract how much revenue should accrue to government. The sequencing of the fiscal tools are as follows:

a. **Royalty:** royalties, commonly referred to as an "off the top" payment, are the first line of payment by contractors. Royalties are a percentage of the gross value of production. For the PSCs, both the 1993 and 2005 fiscal terms allocate royalties based on water depth, that is, the depth of water in which the field is located. Under the 1993 PSC terms, fields in very deep water do not pay any royalty. With the 2005 PSC, royalty is paid for all water depths, but fields located in deeper water pay lower royalty. Royalty is the first component of government revenue.

b. **Cost Oil:** following deductions for royalties our calculation proceeds to deduct cost oil for the contractors. Since under PSCs, contractors bear the full cost of development and exploration, they are allowed to recover their costs. The law enables recovery of cost oil to cover at least operating costs. Cost oil accrues to the contractors, and thus, they do not feature in government revenue.

c. **Taxation:** following deduction of cost oil for the contractors, the balance is subjected to taxation. Unlike JVs, the rate of Petroleum Profits Tax (PPT) for PSCs is 50%. ITC or ITA, as the case may be, are deducted from assessable profits, before PPT is computed. The amounts from taxation form the second component of government revenue.

d. Profit Oil: after deduction for taxation, the remaining revenue is shared between the NNPC and contractor as profit oil. The formula for sharing is based on the contractual terms. The share of profit oil accruable to NNPC forms the third and last component of government revenue. Total government revenue is then computed as the addition of royalty and taxation and profit oil.

"The model calculates revenue accruable to the Federation based on Nigeria's PSC fiscal regime."

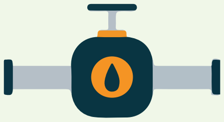
# Results

If all seven fields had been converted to the 2005 PSC fiscal structure in 2008, then the baseline scenario (SC1) shows Nigeria would have earned $16.03 billion more in revenue between 2008 and 2017. Table 2 presents the breakdown of the revenue figures. Under the fiscal terms of the 1993 PSCs, total revenue from the seven fields amounted to $73.78 billion. However, total government revenue from these fields would have amounted to $89.81billion if the terms of the 2005 PSCs had been used. This increase in projected revenues amounts to a 21.72% increase from the 1993 fiscal terms to the 2005 fiscal terms.

For the second scenario (SC2), the model reveals that if government was able to obtain profit share from all fields, then using the terms of the 2005 fiscal regime, total government revenue from the fields would have amounted to $102.39 billion. This represents an increase of $28.61 billion, showing a 38.78% increase.

Table 2 and Figures 2a and 2b reveal that revenues from the fields vary considerably. In absolute terms, the largest revenue increase would have come from Agbami, where revenues would have increased from $17.72 billion to $22.15 billion, giving a total increase of $4.44 billion. This increase would have been higher for the second scenario where revenue for Agbami would have increased to $31.51 billion, representing an increase of $13.79 billion. Conversely, the lowest increase in revenue of $0.39 billion would have come from Usan, where revenue would have increased from $4.27 billion to $4.66 billion.

In terms of percentages, the highest percentage increase in revenue is from Akpo where for scenario 1, there would be a 50.91% increase in the 2005 fiscal terms over the 1993 fiscal terms. For scenario 2, Akpo also would have the largest percentage increase of 102.07%. The lowest percentage increase of 9.08% would be for Usan.



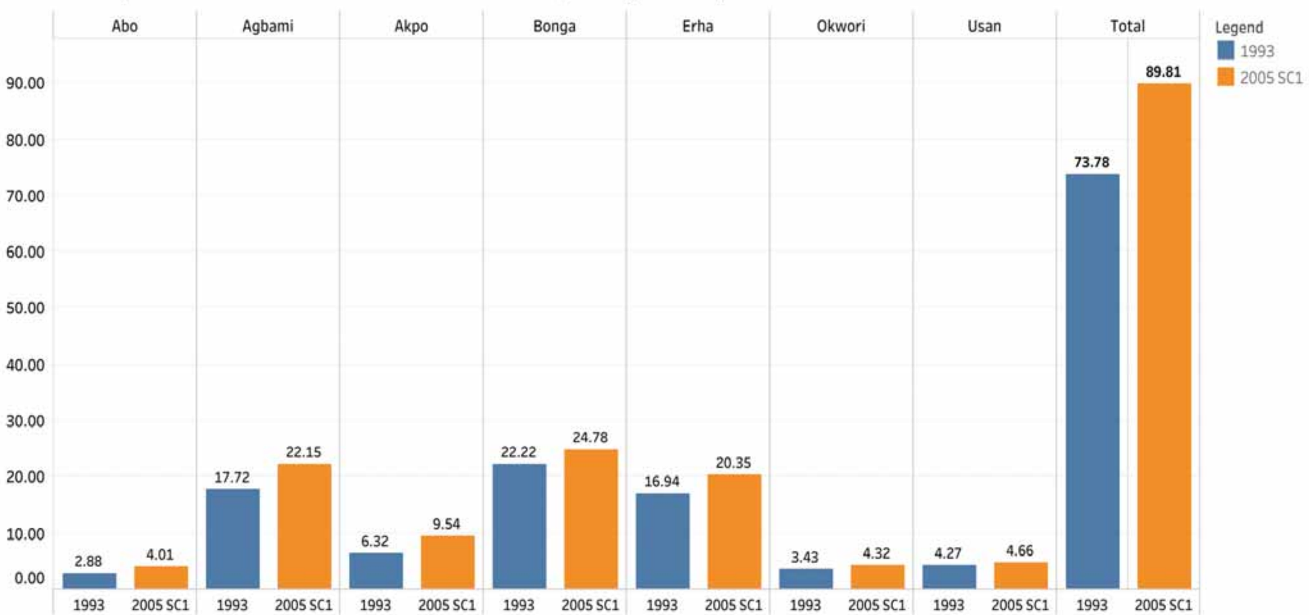
"Total government revenue from the fields would have amounted to $102.39 billion. This represents an increase of $28.61 billion, showing a 38.78% increase"

### Table 2: Total Government Revenues, 2008 to 2017 ($ billion)

| Table 2a: Total Government Revenues, Scenarios 1 (No Profit Share for Akpo and Agbami) | | | |
|---|---|---|---|
| | 1993 PSC Fiscal Terms | 2005 PSC Fiscal Terms SC1 | Difference |
| Abo | 2.88 | 4.01 | 1.13 |
| Agbami | 17.72 | 22.15 | 4.44 |
| Akpo | 6.32 | 9.54 | 3.22 |
| Bonga | 22.22 | 24.78 | 2.56 |
| Erha | 16.94 | 20.35 | 3.40 |
| Okwori | 3.43 | 4.32 | 0.90 |
| Usan | 4.27 | 4.66 | 0.39 |
| Total | 73.78 | 89.81 | 16.03 |

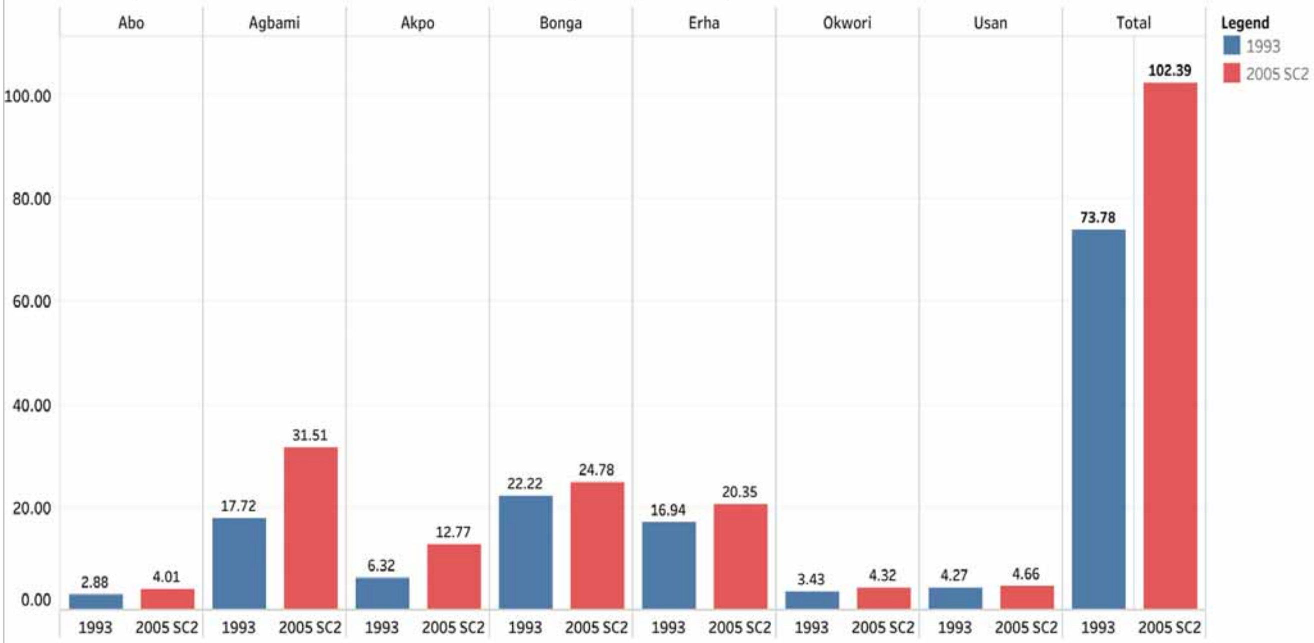
| Table 2b: Total Government Revenues, Scenarios 1 (Profit Share for Akpo and Agbami) | | | |
|---|---|---|---|
| | 1993 PSC Fiscal Terms | 2005 PSC Fiscal Terms SC2 | Difference |
| Abo | 2.88 | 4.01 | 1.13 |
| Agbami | 17.72 | 31.51 | 13.79 |
| Akpo | 6.32 | 12.77 | 6.45 |
| Bonga | 22.22 | 24.78 | 2.56 |
| Erha | 16.94 | 20.35 | 3.40 |
| Okwori | 3.43 | 4.32 | 0.90 |
| Usan | 4.27 | 4.66 | 0.39 |
| Total | 73.78 | 102.39 | 28.61 |

FIG 2a: Project-level Difference: 1993 to 2005 PSC, SC1 ($ billion)




1993: 1993 PSC Fiscal Terms
2005 SC1: 2005 PSC Fiscal Terms (No Profit Share from Agbami & Akpo)

FIG 2b: Project-level Difference: 1993 to 2005 PSC, SC2 ($ billion)




1993: 1993 PSC Fiscal Terms
2005 SC2: 2005 PSC Fiscal Terms (With Profit Share Agbami & Akpo)

Reasons for differences between one project and another mostly depend on production since 2008. The fields vary in size between high producing fields such as Agbami and Bonga and other, smaller fields such as Usan. Figures 3 to 5 present the composition of total revenues from the fields. Under the 1993 fiscal terms, Figure 3 shows that Bonga contributed the most to total revenues with 30%, while Agbami was the second highest contributor (24%). The third highest contributor to total revenue was Erha (23%), while Akpo contributed 8% to total revenue. Contributions from the other fields were Usan (6%), Okwori (5%), and Abo (4%). These contribution figures only change slightly under the first scenario of 2005 fiscal terms. Figure 4 shows that Bonga still contributed the largest share to revenues with 27%. Agbami is still second with 25%, Erha is third (23%), while Akpo is fourth (11%). Others are Okwori (5%), Usan (5%) and Abo (4%). However, the figures are very different under the second scenario using the 2005 fiscal regime. Agbami now contributed 31% to total revenue while Bonga was second with 24%. Others are Erha (20%), Akpo (12%), Usan (5%), Okwori (4%) and Abo (4%).

**36%** The contribution of petroleum tax dropped

But it is important to understand that the impact is not straightforward. In projects where royalty increased, revenues from petroleum tax were likely to fall, despite the fact that the project sustained a net loss from sticking to the 1993 PSC regime. Figures 6 to 8 present the different components of total revenue for the different fiscal terms. From Figure 6, it is seen that under the 1993 fiscal terms, petroleum tax was the largest source of revenue (51%). This was followed by profit oil (43%), royalty (5%) and withholding tax (1%). Figure 7 reveals that under the first scenario of the 2005 fiscal terms, profit oil increased and became the largest source of revenue with 43%. The contribution of petroleum tax dropped to 36%. The contribution of royalty increased to 20%, while withholding tax remained constant at 1%. Figure 8 reveals that under the second scenario of the 2005 fiscal terms, the contribution of profit oil increased to 50%. Petroleum tax contributed 31%, royalties contributed 18% and withholding tax was still 1%.

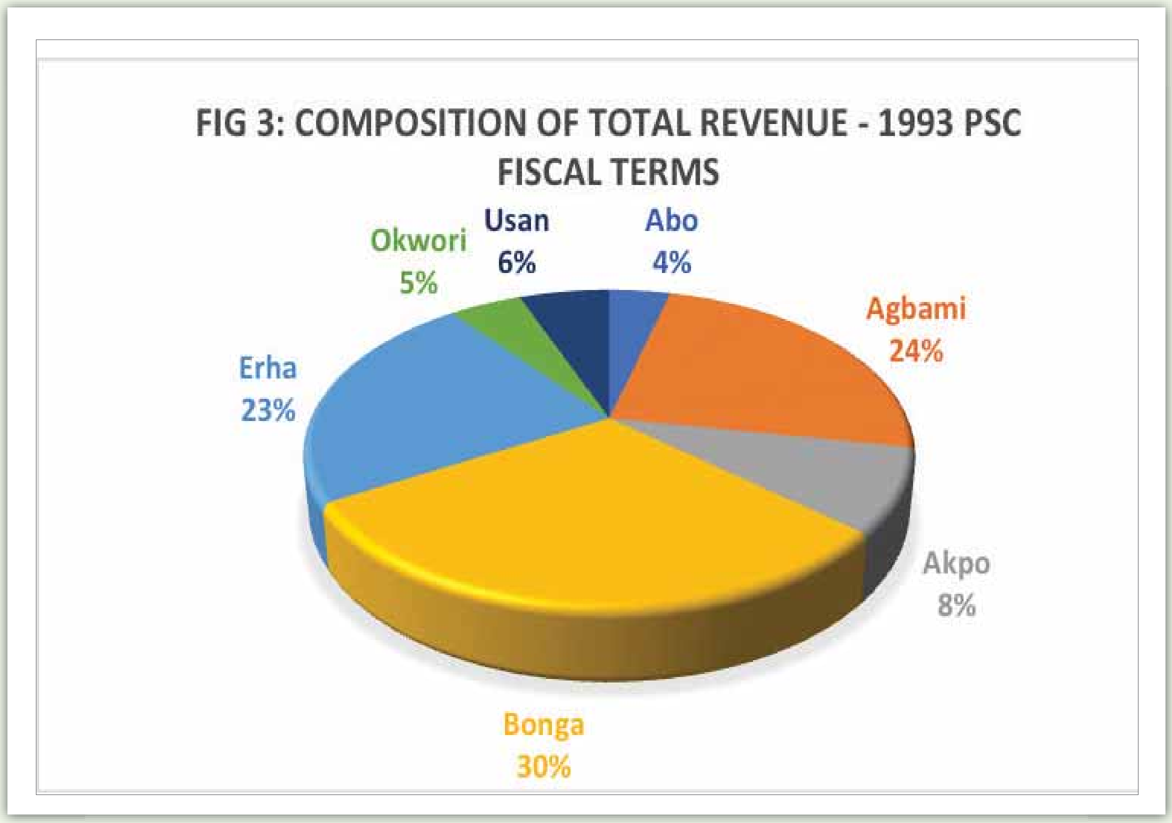


FIG 3: COMPOSITION OF TOTAL REVENUE - 1993 PSC FISCAL TERMS
Okwori 5%
Usan 6%
Abo 4%
Agbami 24%
Erha 23%
Akpo 8%
Bonga 30%

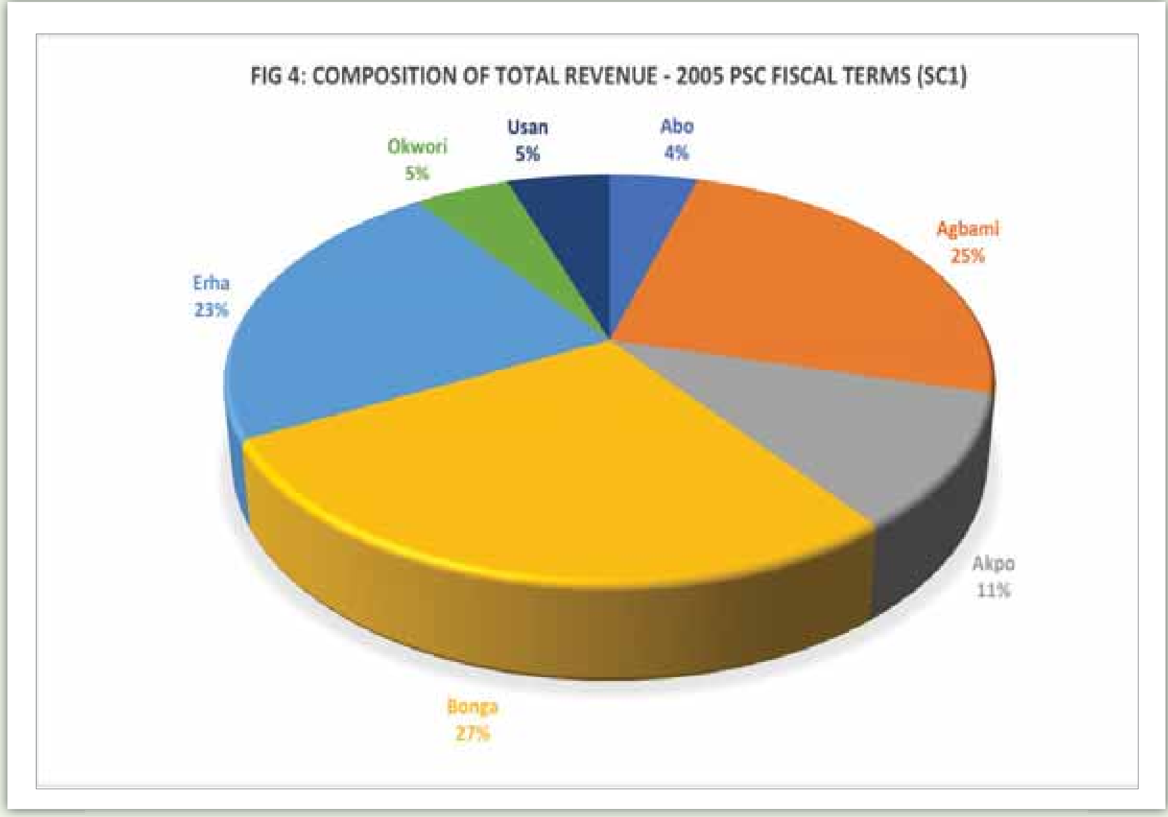


FIG 4: COMPOSITION OF TOTAL REVENUE - 2005 PSC FISCAL TERMS (SC1)
Okwori 5%
Usan 5%
Abo 4%
Agbami 25%
Erha 23%
Akpo 11%
Bonga 27%

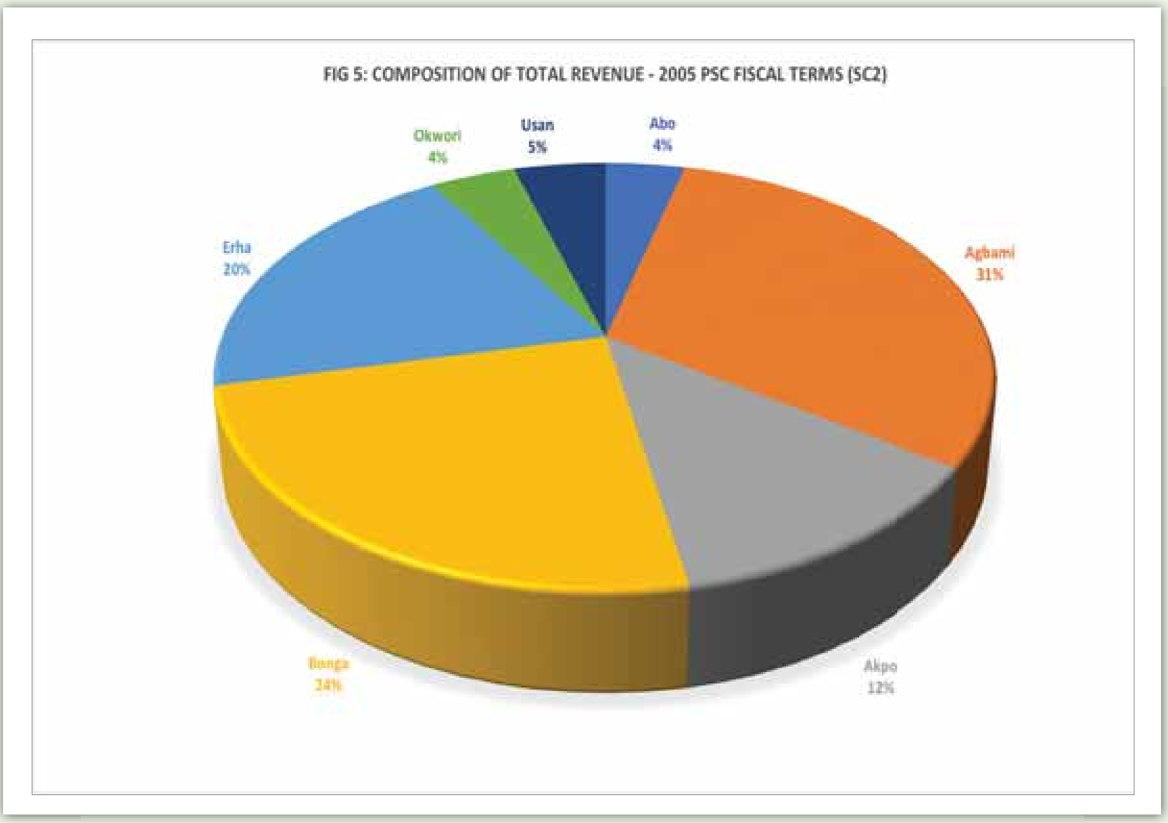


FIG 5: COMPOSITION OF TOTAL REVENUE - 2005 PSC FISCAL TERMS (SC2)
Okwori 4%
Usan 5%
Abo 4%
Agbami 31%
Erha 20%
Bonga 24%
Akpo 12%

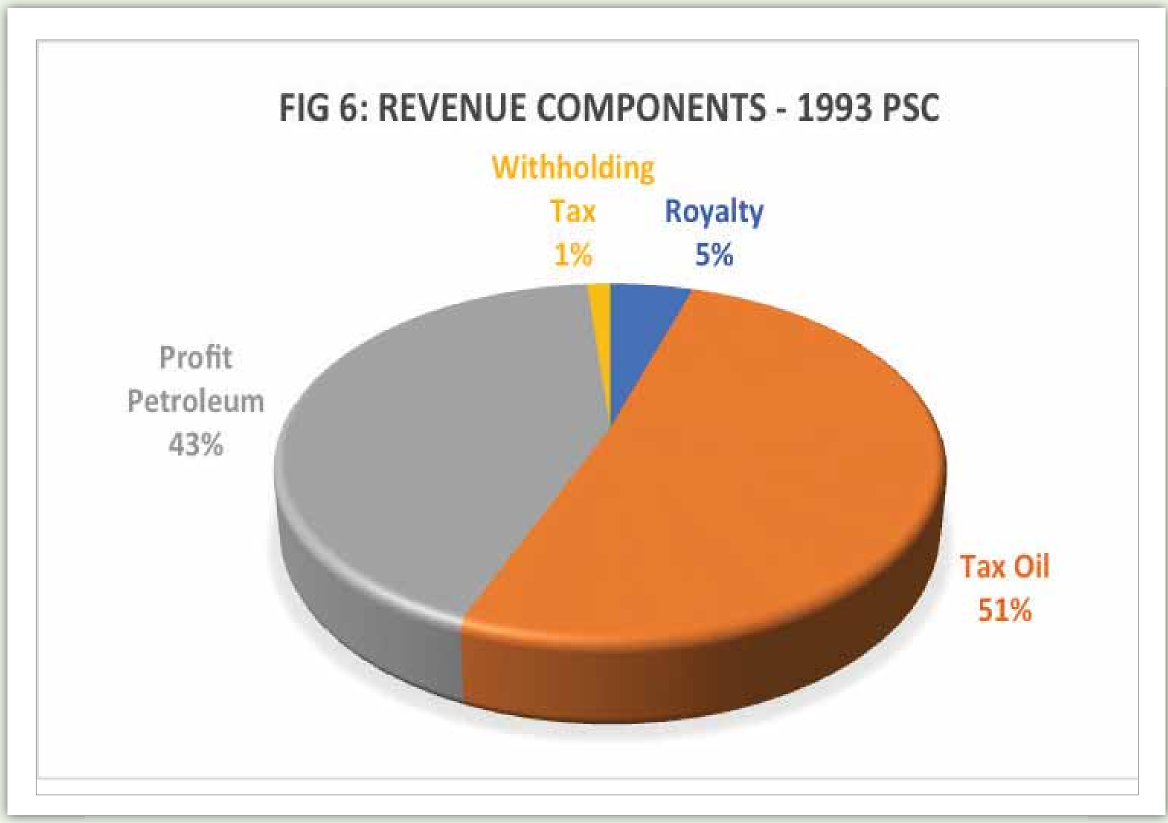


FIG 6: REVENUE COMPONENTS - 1993 PSC
Withholding Tax 1%
Royalty 5%
Profit Petroleum 43%
Tax Oil 51%

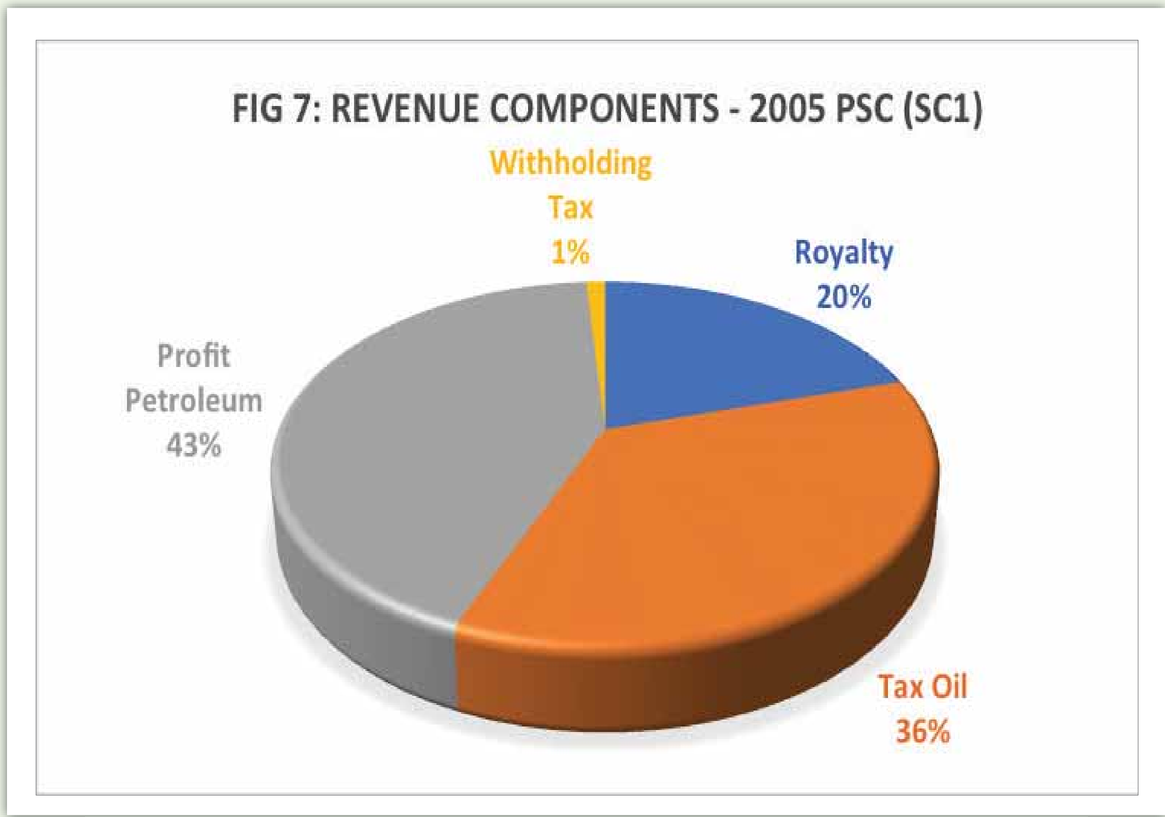


FIG 7: REVENUE COMPONENTS - 2005 PSC (SC1)
Withholding Tax 1%
Royalty 20%
Profit Petroleum 43%
Tax Oil 36%

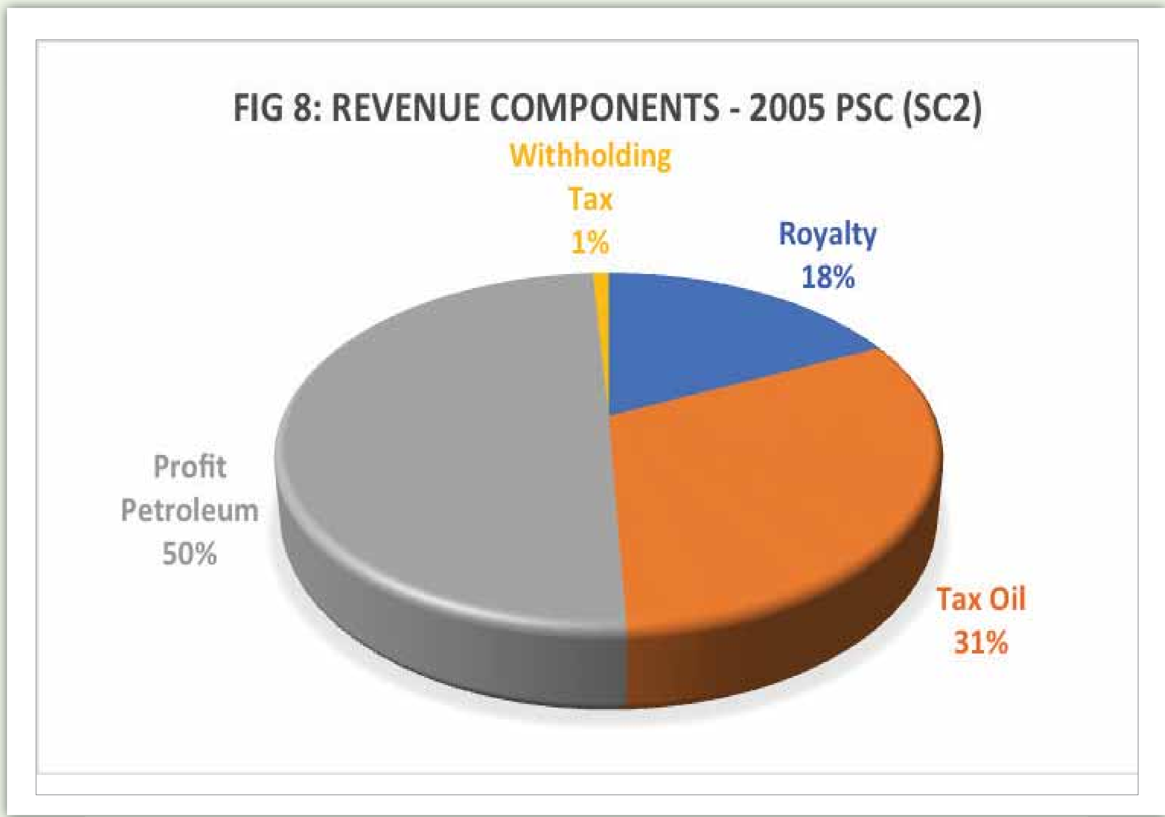


FIG 8: REVENUE COMPONENTS - 2005 PSC (SC2)
Withholding Tax 1%
Royalty 18%
Profit Petroleum 50%
Tax Oil 31%

# Profitability for Companies

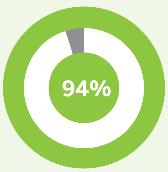
One other factor to consider is whether companies would have agreed to assumed regime changes, which is based partly on rates of return. Here, timing of trends in the global market might have facilitated a chance, since 2008 was the year in which the highest oil prices, in both real and nominal terms, were recorded, and it would have been hard for companies to argue that project economics could not sustain the change in regime. Of course, the impact would have been on economics for the duration of the project. Nevertheless, a high price environment would have made resistance more difficult. The model computes post-fiscal rates of return above 13% for the projects even after a shift to the 2005 PSC structure. A rule of the thumb in the industry deems a project viable with anything above 10% rate of return.

# Conclusion

This study conducted a financial modelling analysis of how much would have accrued to the Federation between 2008 and 2017 if the PSC contracts had been reviewed. The results of the model showed that the Federation would have earned between $16.03 billion and $28.61 billion more in revenue if the terms of the PSCs had been revised.

Thus, failure to revise the terms of these contracts has invariably resulted in the Federation losing much needed revenue. To put these results in perspective, NEITI notes the following:

**i.** The lower threshold of the estimated losses ($16.03 billion) could have funded the entire Federal Government budget in 2015. This figure can also fund 55% of the federal government's proposed budget for 2019. The higher threshold estimate ($28.61 billion) can fund 99% of the proposed budget for 2019;

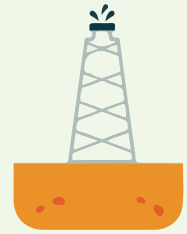



**ii.** The lower threshold of the estimated losses ($16.03 billion) makes up 94% of the total revenue that accrued to the Federation from oil and gas in 2016;

**iii.** The estimated cost of the Port Harcourt – Maiduguri Rail Line is between $14 billion and $15 billion, which the lower threshold of estimated losses would conveniently fund;

**iv.** The estimated cost of the Mambila Power Plant of 3,050 MW is $5.72 billion, while the estimated cost of the Ibadan-Ilorin-Minna-Kano Standard Gauge Line is $6.1 billion. The combined cost of these projects is $11.82 billion, which is less than the lower threshold of estimated losses;

v. The lower threshold of estimated losses is also sufficient to fund the combined costs of the Calabar-Lagos Rail line ($11 billion), Fourth Mainland Bridge ($1.4 billion), Badagry Deep Water Port Complex ($1.6 billion), and Lekki Deep Seaport ($1.2 billion).



"The lower threshold of the estimated losses ($16.03 billion) makes up 94% of the total revenue that accrued to the Federation from oil and gas in 2016"

NEITI notes that such revenues are not exclusively for the Federal Government, but are to be shared amongst all three tiers of government. However, such comparisons help us to highlight the relevance of such lost revenues to the proper functioning of government and benefits to the country.

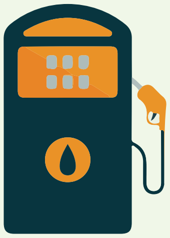
In conclusion, NEITI advocates for urgency on the part of government to review the terms of these PSCs to make them more economically beneficial to the Federation. NEITI concludes by acknowledging/highlighting some practical issues that need to be taken into account in this process:

i. The contractors need to be carried along in this process. The contracts have stability clauses in them which the contractors may use to drive a hard bargain. However, NEITI's understanding is that the contractors are willing to negotiate these terms once government is ready;

ii. Further to (i) above, the NNPC needs to follow international best practices and make the contracts with oil companies public. This not only ensures transparency but will also ensure maximum government take, as Nigerians can properly scrutinize such contracts and draw attention to areas of improvement. This report would have been improved and probably come sooner had such contracts been made available;

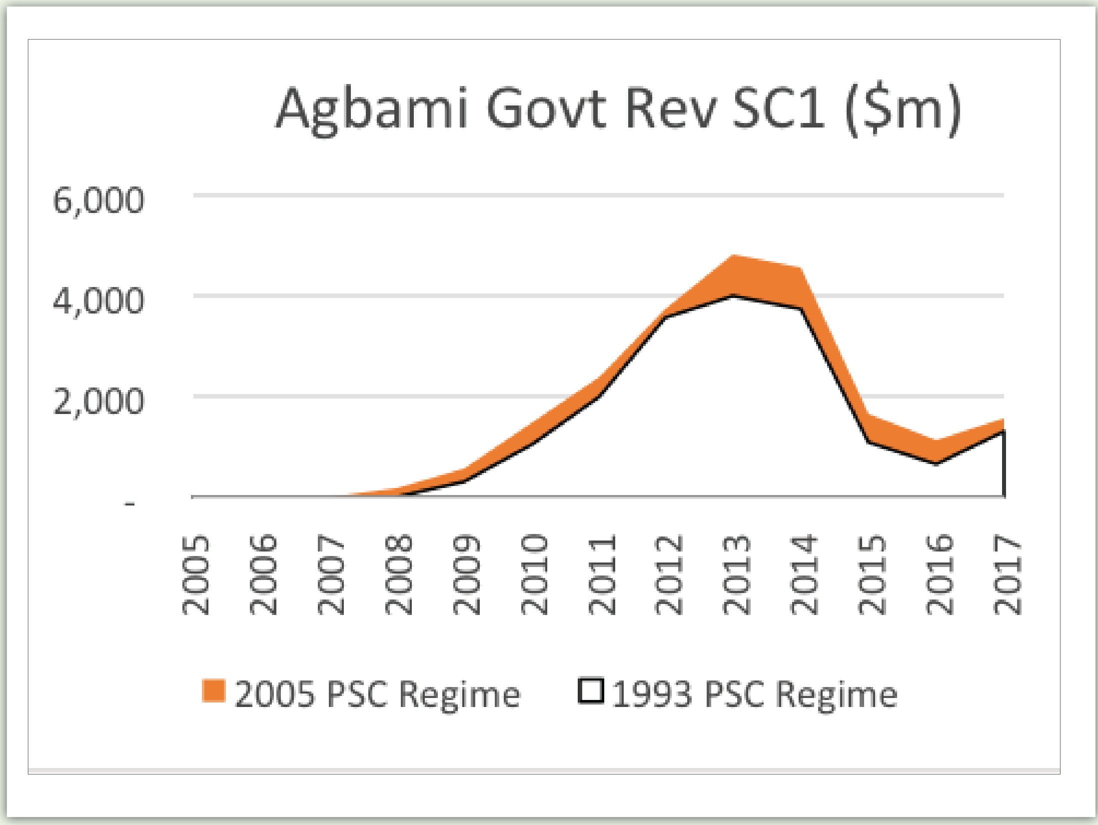
iii. State governments also need to be carried along in this process. The recent judgement by the Supreme Court in favour of three oil-producing states buttresses this fact. Such an action might not have been necessary if the FG had reviewed these contracts and informed the state governments of such action;

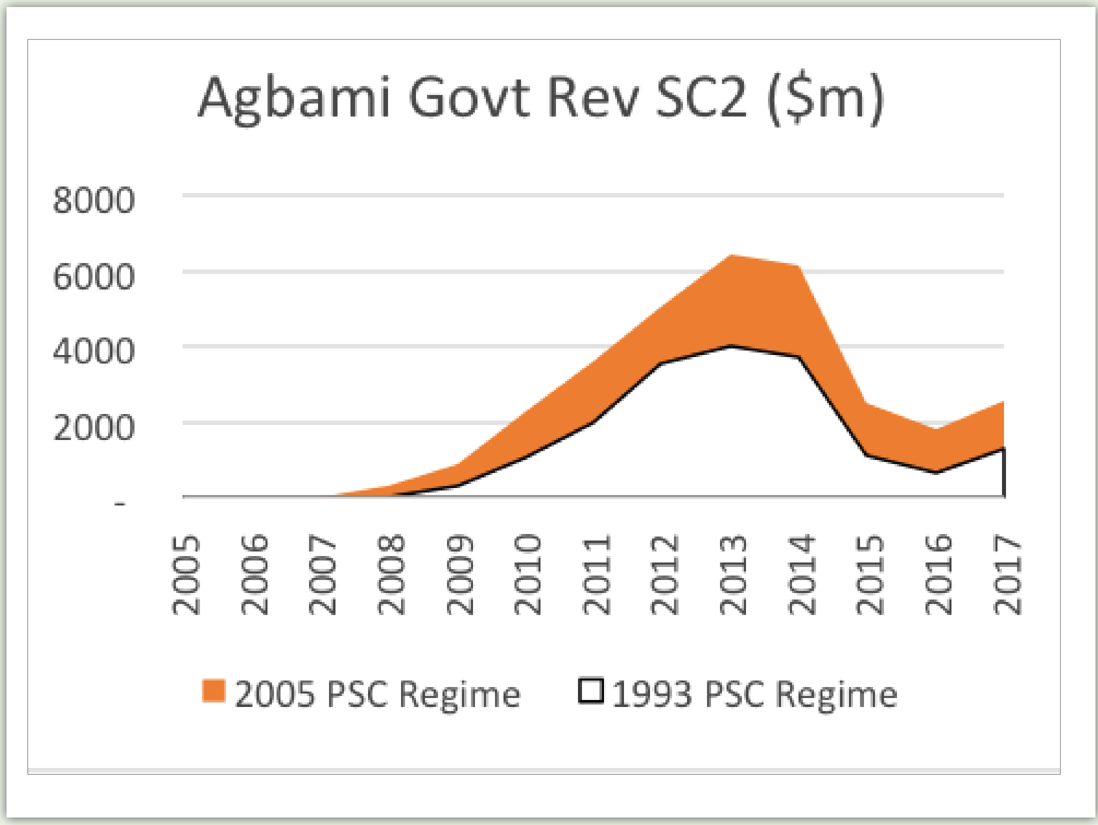
iv. The leases of these PSCs are due to expire between 2023 and 2026. Government should use the renewal process to get the best value for the country.

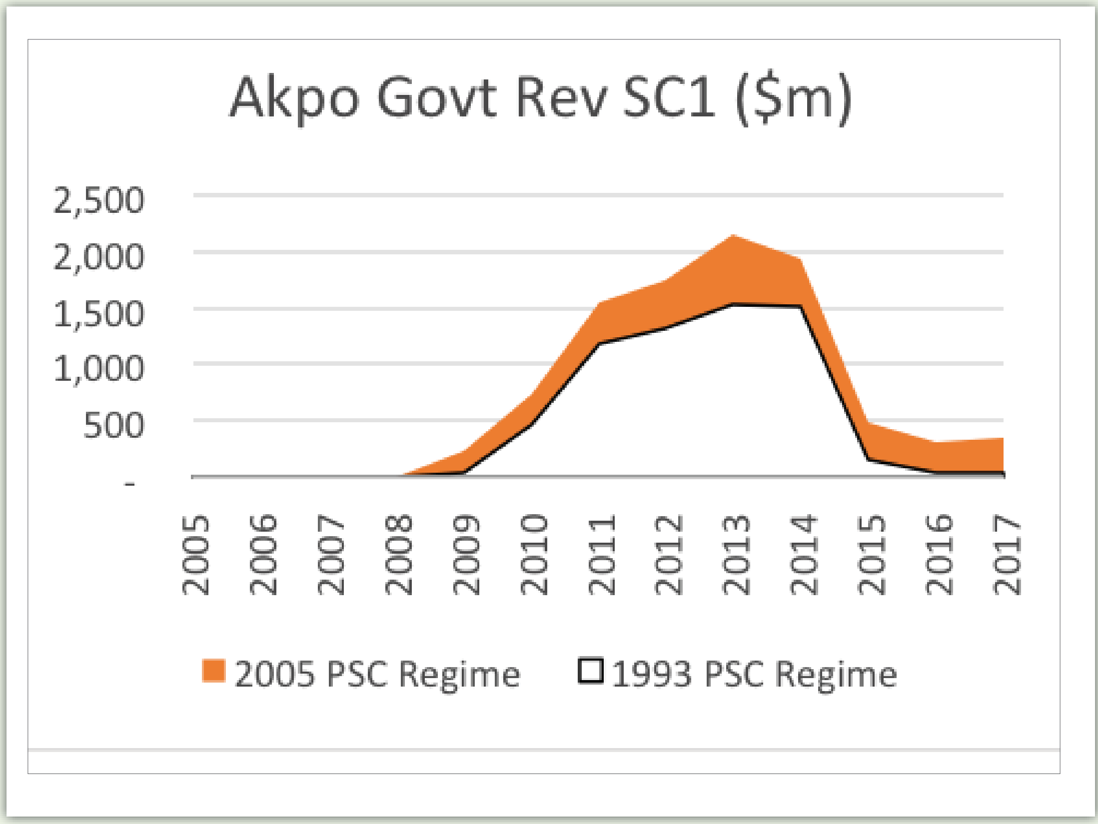


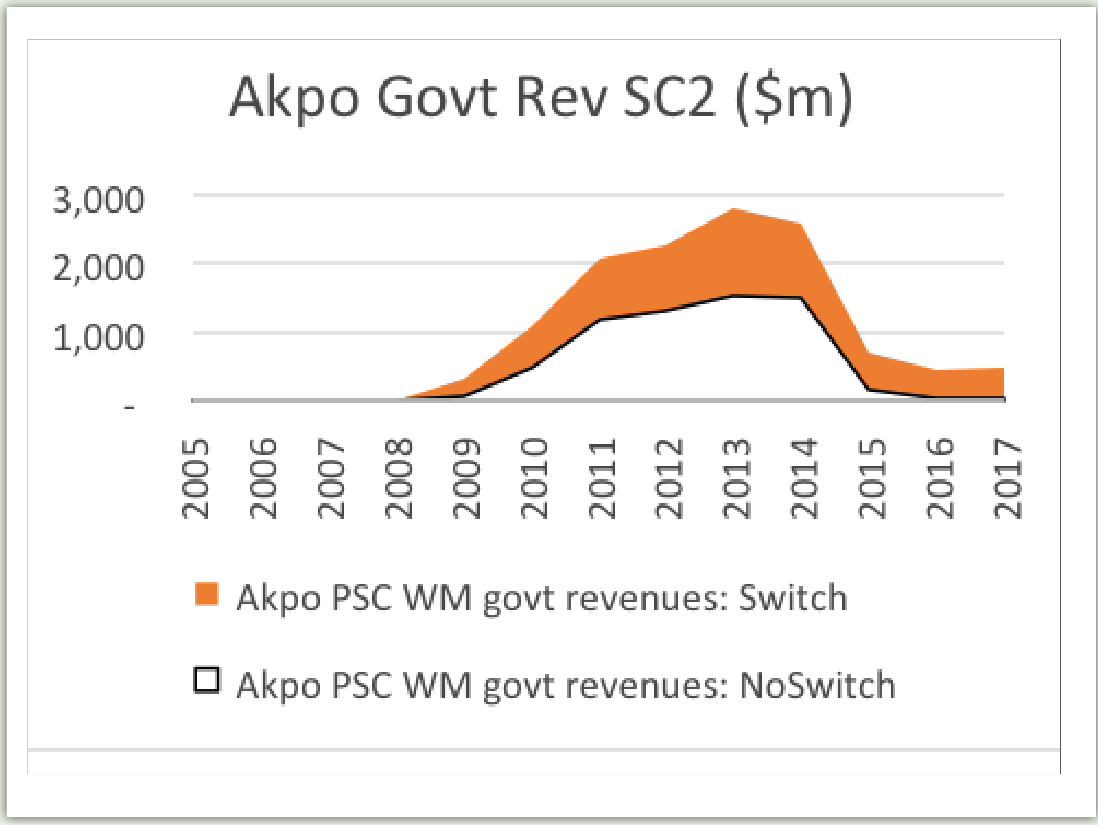
"State governments also need to be carried along in this process. The recent judgement by the Supreme Court in favour of three oil-producing states buttresses this fact."

# Appendix

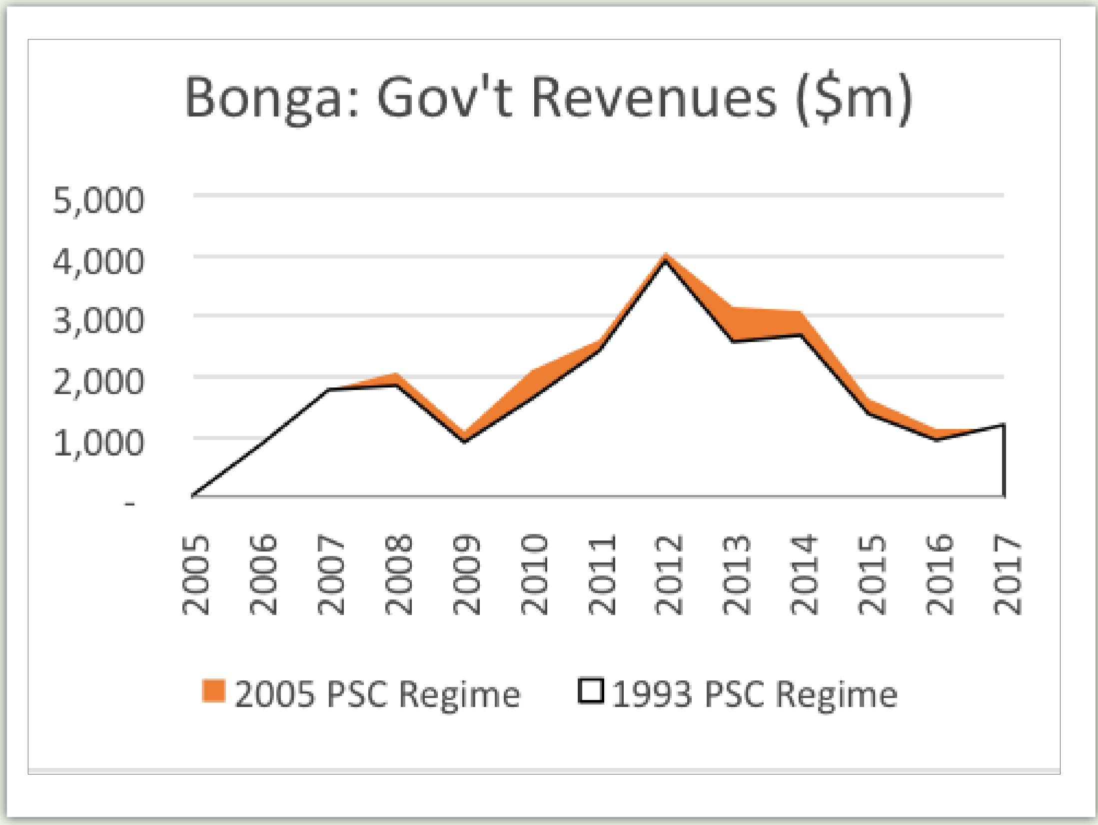

Agbami Govt Rev SC1 ($m)
6,000
4,000
2,000
-
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2005 PSC Regime
1993 PSC Regime

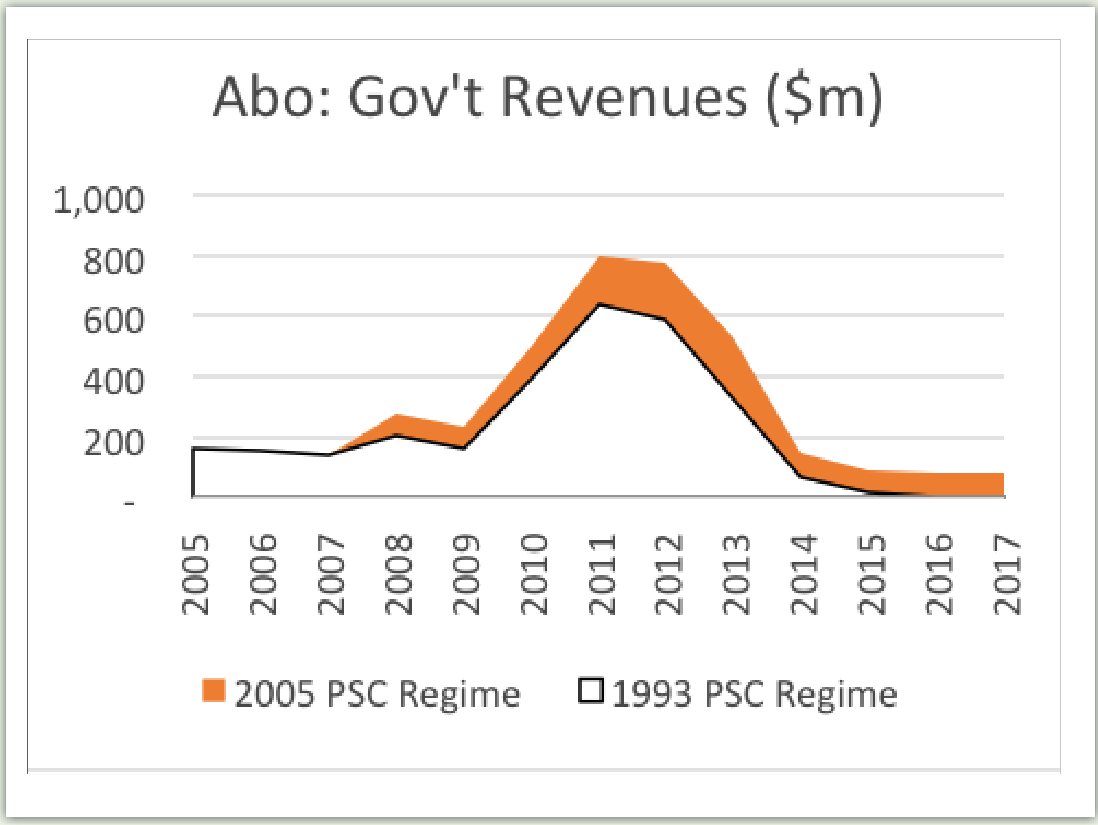

Agbami Govt Rev SC2 ($m)
8000
6000
4000
2000
-
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2005 PSC Regime
1993 PSC Regime

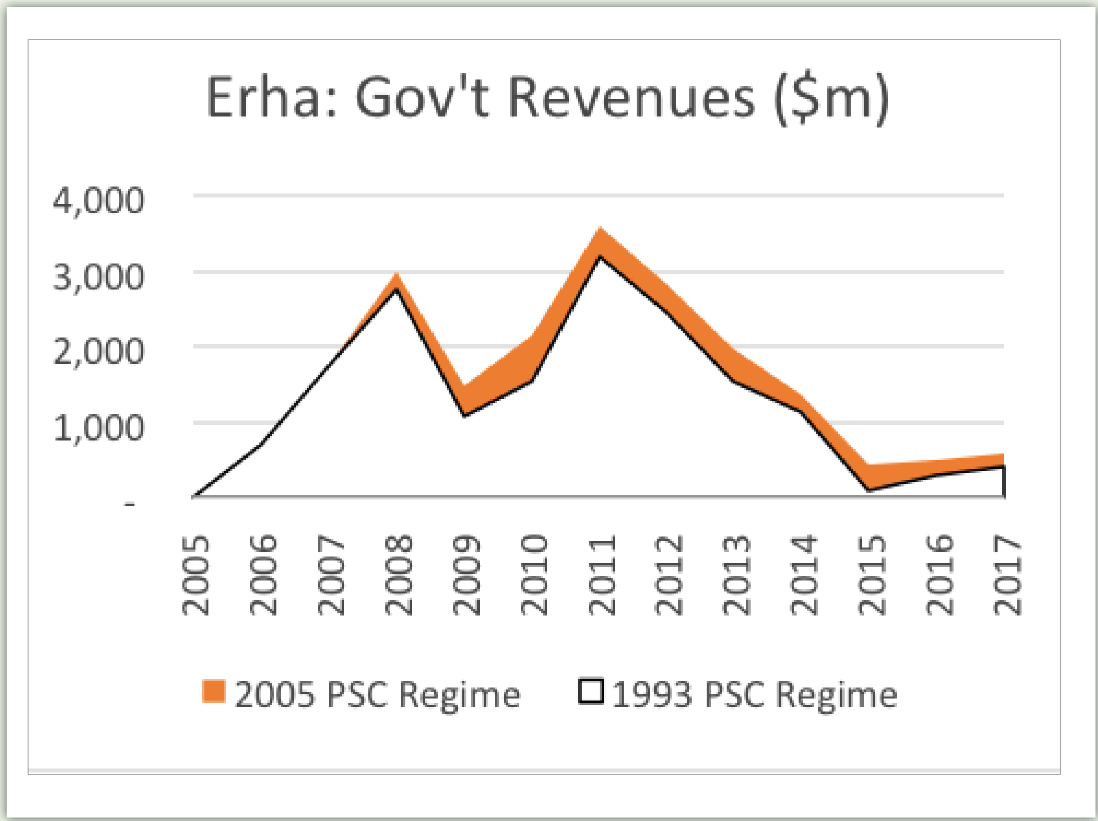

Akpo Govt Rev SC1 ($m)
2,500
2,000
1,500
1,000
500
-
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2005 PSC Regime
1993 PSC Regime

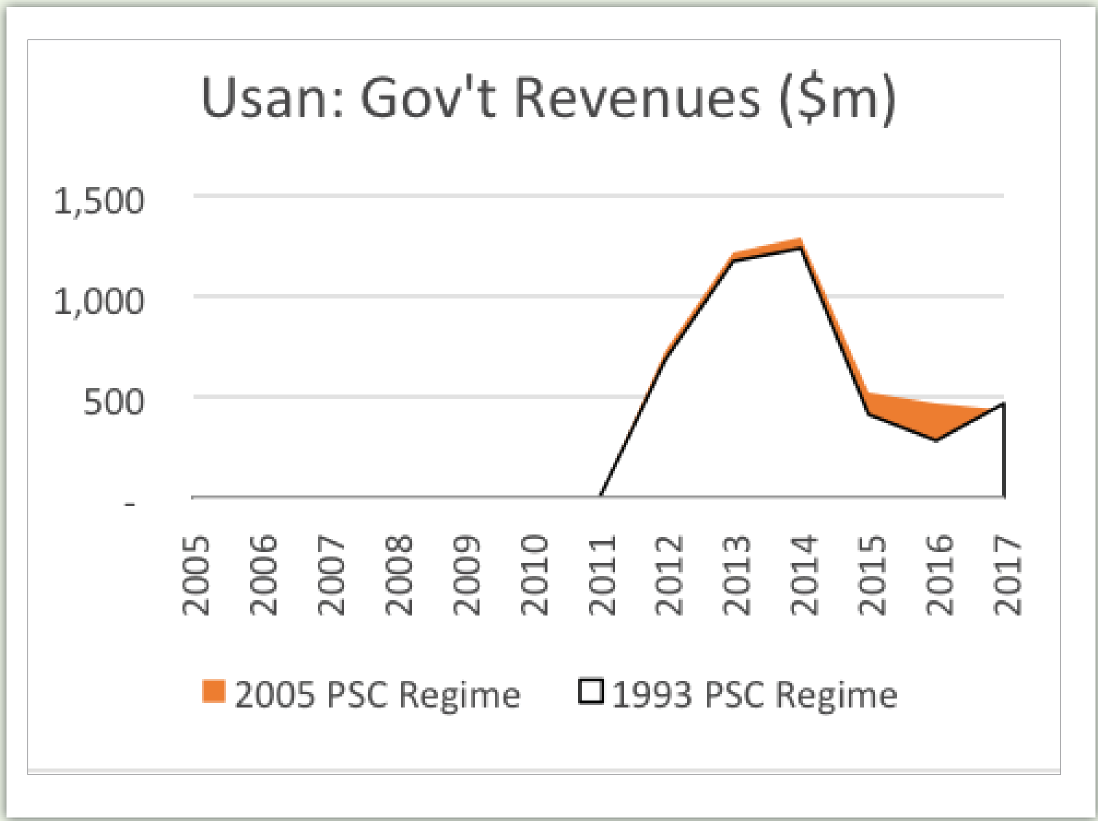

Akpo Govt Rev SC2 ($m)
3,000
2,000
1,000
-
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Akpo PSC WM govt revenues: Switch
Akpo PSC WM govt revenues: NoSwitch

# Appendix


Bonga: Gov't Revenues ($m)
5,000
4,000
3,000
2,000
1,000
-
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2005 PSC Regime
1993 PSC Regime


Abo: Gov't Revenues ($m)
1,000
800
600
400
200
-
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2005 PSC Regime
1993 PSC Regime


Erha: Gov't Revenues ($m)
4,000
3,000
2,000
1,000
-
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2005 PSC Regime
1993 PSC Regime


Usan: Gov't Revenues ($m)
1,500
1,000
500
-
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2005 PSC Regime
1993 PSC Regime

# Policy Brief

The full model can be accessed here:

**http://www.neiti.gov.ng/index.php/2017-07-27-13-55-55/policy-brief**

**NEITI wishes to acknowledge and thank Extractives Hub and FOSTER for support to training in financial modeling and to the building of the model.**

NEITI Nigeria Extractive Industries Transparency Initiative THE PRESIDENCY

NEITI, the Nigerian chapter of the global EITI, is mandated by the NEITI Act (2007) to promote transparency and accountability in the management of revenues from oil, gas, and solid minerals sectors in Nigeria.

The NEITI Policy Brief is one of NEITI's policy and advocacy instruments, designed to focus the attention of policy makers and the populace on important issues in the extractive sector in Nigeria.

Address: **No. 60, Nelson Mandela Street,**
**Off Kwame Nkrumah Street, Asokoro, Abuja.**
**Website: www.neiti.gov.ng**
**Email: info@neiti.gov.ng**