The Petroleum Industry Act: Fiscal Framework

FISCALS

Overview

The PIA, enacted on 16 August 2021, modified key fiscal provision applicable to the petroleum industry, especially the upstream sector. The key changes include:

- Segregation of upstream-midstream-downstream assets into separate companies for tax purposes
- Reduction of income tax and production-based royalty rates
- Introduction of price-based royalties for upstream production of oil
- Limitation of tax-deductibility of costs to 35% of gross revenues
- Zero tax-deductibility for interest, litigation & arbitration costs, and bad debt

Right after the assent of the PIA into law, the President immediately approved a steering committee to oversee the process of implementation of the PIA within 12 months. From a broad perspective, the fiscal provisions of the PIA become effective from the effective date[1] of the PIA. The effective date is especially relevant for pre-existing marginal field assets and upstream leases & licences issued post enactment of the PIA. For other holders of existing upstream licences and leases, the PIA fiscal provisions will only be applicable to them upon entering a voluntary licence/lease conversion contract under Section 92 of the PIA by the conversion date[2] .

It is expected that impacted companies will begin to evaluate their financial and fiscal projections to ascertain whether to voluntarily convert and become subject to the fiscal provisions of the PIA or continue to be under the pre-existing fiscal provisions and automatically transition to the fiscal provisions of the PIA upon the expiration of their current licence/lease. Transition to the PIA fiscal provisions may necessitate significant impairment of deferred tax assets arising from reduced tax rates.

Apart from critical tax incentives introduced for gas based midstream operations and amended modified administrative provisions, the fiscal provisions applicable on midstream and downstream petroleum industry activities are unchanged from the pre-existing fiscal provisions.

Key fiscal issues

1.

Royalties

Royalties are amounts payable by oil and gas producing companies to the Federal Government of Nigeria (FGN), being the resource owner, based on volumes of oil and gas produced from fields, as measured at the measurement points.

Until November 2019, only production-based royalties existed in Nigeria. Upon the amendment of the Deep Offshore Inland Basins and Production Sharing Contract Act (DOIBSPSCA) in November 2019, price-based royalty became applicable on crude oil and condensates produced from deep offshore acreages when price exceeds $20 per barrel. PIA has now introduced price-based royalty on crude oil and condensates produced from all forms of contract areas when price per barrel exceeds $50; price-based royalty shall be credited into the Nigerian Sovereign Wealth Fund.

[1]The effective date is yet to be made publicly available, as at the time of issuance of this piece.

[2]The earlier of 18 months from the PIA effective date and expiration date of on oil mining lease/conversion date of an oil prospecting licence to an oil mining lease

Other key royalty related provisions of the PIA are as follows:

1. Condensates are treated as crude oil and natural gas liquids (NGLs) are treated as natural gas.

2. For natural gas and NGLs, royalty rate is 5% for export and 2.5% for domestic utilisation. Under the Petroleum Act (PA), royalty rate was 7% for onshore areas and 5% for offshore areas; there was no differentiation between export and domestic utilisation.

3. Producing marginal fields may continue to apply the reduced royalty rates applicable under Pre-PIA legislation even after executing a conversion contract under Section 92 of the PIA.

4. Production and price-based royalty rates are summarised in the tables below:

Production based royalties - crude oil and condensates

Field area/Terrain	Production volumes in barrels of oil per day	PIA	PA/DOIBPSCA
Onshore areas	>10,000	15%	20%
Shallow water (Up to 100m water depth)		12.5%	18.5%
Shallow water (Up to 200m water depth)			16.5%
Onshore fields and shallow waters, including marginal fields	1 – 5,000	5%	2.5%
	5,001 – 10,000	7.5%	7.5%
Onshore fields and shallow waters (marginal fields only*)	10,001 – 15,000	N/A	12.5%
	15,001 - 25,000		18.5%
Deep offshore (greater than 200m water depth)	1 – 50,000	5%	10%
	>50,000	7.5%	
Frontier basins	>1	7.5%	7.5%

Price based royalties - crude oil and condensates

Price range ($ per barrel)	PIA	DOIBPSCA
Below $20	0%	0%
Above $20 - $40		2.5%
Above $40 - $50		
Above $50 - $60	Linear interpolation	
Above $60 – less than $100		4%
At $100	5%	
Above $100 - $150	Linear interpolation	8%
Above $150	10%	10%

Dual taxation regime[3]

PIA introduced a dual income tax regime for upstream petroleum companies, i.e., Hydrocarbon Tax (HT) and Companies Income Tax (CIT). HT is generally applicable to crude oil profits and profits derived from field condensates and liquid NGLs obtained from associated gas (AG), to the extent that the underlying fields are in onshore or shallow water acreages. Profits from frontier and deep offshore acreages are not subject to HT. CIT is applicable to all profits, whether those profits are subject to HT or not.

Profits from midstream and downstream activities are subject to only CIT and not HT.

[3] Dual taxation regime means the imposition of two income taxes (i.e. HT and CIT) on the same profits.

Under the Pre-PIA fiscal regime, a dual taxation regime was not existent. Only petroleum profits tax (PPT[4]) was chargeable on the profits derived from crude oil and field condensates, while other upstream profits (including gas profits) were subject to CIT and no more.

The table below, summarises how HT and CIT applies to upstream activities depending on the stage of development, as described under Sections 93(1) and 93(6):

	Stage of development		
Tax type	Before appraisal	Upon appraisal, commercial discovery or significant gas/crude discovery	Upon field development or commercial production
HT	0%	15%	30%
CIT	30%	30%	30%

HT computation

a. *Determination of crude oil revenue*

1. Crude oil revenue, to be subjected to HT, is the value of any chargeable oil adjusted to the measurement points, based on proceeds of all chargeable oil sold and value of all chargeable oil disposed.
2. Where crude revenue of a company is less than the product of the fiscal oil price, as advised by the Nigerian Upstream Petroleum Regulatory Commission ('NUPRC' or 'the Commission'), and crude oil volumes sold or disposed, the excess shall be added to crude oil revenue and subject to tax.

b. *Allowable deductions*

Adjusted profit is calculated as crude revenue less allowable deductions (per Section 263[1]). All expenses wholly, reasonably, exclusively, and necessarily[5] incurred in a company's upstream petroleum operations generally constitute allowable deductions in determining the company's adjusted profit. The reasonability test was hitherto not applicable under the PPTA in determining allowable deductions.

The key allowable deductions include the following:

1. Rents incurred pursuant to a Petroleum Mining Lease (PML) or Petroleum Prospecting Licence (PPL).
2. Royalties **incurred** and **paid**, within a period, in respect of crude oil and associated gas. It may be impractical to pay all royalties incurred within a calendar year in that year, considering that royalties are typically due for payment two months in arrears of sales. Royalties relating to December of a particular year can only be paid in the following year, which creates the risk of not being an allowable deduction in any of both years because it fails to meet the condition to be **incurred and paid within a period**. Under the PPTA, royalties only needed to be incurred to be deductible, the requirement to be paid did not exist. This appears to be an unintended consequence of the drafting of the underlying section.
3. While certain components of AG are taxable only under CIT, such as natural gas and gaseous NGLs, the underlying royalties are also only deductible under CIT. Under PPTA, all forms of royalties (whether relating to oil or gas) were deductible for PPT only, even though gas is taxable only under CIT.
4. Tangible and intangible drilling cost directly incurred in connection with the drilling of first exploration well and first two appraisal wells in the same field.
5. Contribution to the abandonment and decommissioning fund, provided that the surplus or residue of the fund is subject to tax under the PIA at the end of the life of the field, where such surplus is returned to the lessee.
6. Cost of gas reinjection wells (used for re-injecting natural gas that would have been flared).
7. Contribution to funds, scheme or arrangement approved by the Commission, including the host communities' development trust fund, environmental remediation fund, Niger Delta Development Commission (NDDC) and other similar contributions.

[4] 85% is the principal PPT rate; a reduced 65.75% rate applies to new entrants within their first 5 years. 50% is the applicable PPT rate on deep offshore profits.

[5] In practice, deductibility of expenses that wholly, reasonably, exclusively, and necessarily incurred is described as the application of the WREN principle.

c. Non-deductibles

1. Interest on borrowing, financial & bank charges, arbitration & litigation costs, and bad debts
2. Head office, affiliate & shared costs
3. Production and signature bonuses
4. Tax inputted in a contract on a net tax basis and paid by a company on behalf of the vendor/contractor
5. Capital employed in making improvements as distinct from repairs
6. Retirement benefits
7. Custom duties
8. All income taxes, including Tertiary education tax (TET) and CIT.
9. Depreciation
10. Penalty, including gas flare penalty.

d. Assessable profit and losses

1. Assessable profit is calculated as adjusted profit less tax loss incurred in a previous accounting period. Due to the introduction of CPR concept in the PIA, which will be discussed later under paragraph 3(g), tax losses are unlikely to crystallise under the PIA, except for tax losses generated under the PPTA regime.
2. Where a company holds a PML and a PPL in either an onshore or shallow water acreage, it is exposed to HT at 30% or 15% depending on whether the underlying asset is in exploration, appraisal, development phase or commercial production. Separate calculations are required for the two classes of HT.
3. Tax losses can be carried forward indefinitely and every company has the right to elect to defer the deduction of tax losses to a later period. The right to elect may only be effected by notifying FIRS, in writing, within five months from the end of the relevant accounting period.

e. Chargeable profits

1. Chargeable profits are calculated as assessable profit less capital allowances (per fifth schedule), less production allowances (per sixth schedule) and less annual allowances in respect of petroleum rights' acquisition cost (per Section 266[1c]).
2. It is required to calculate separate chargeable profits and allowances for each HT rate.

f. Capital allowances (Fifth schedule costs)

1. Qualifying capital expenditure and acquisition costs of petroleum rights are eligible for annual allowance at the rate of 20% with a retention value of 1% in the last year until the asset is disposed
2. The following are the broad categories of qualifying capital expenditure: plant, pipeline & storage, building, and drilling [6].

[6] Qualifying drilling expenditure excludes tangible and intangible drilling expenditure treated as deducted under Section 263. It also excludes amounts that have benefitted from capital allowances in another entity.

3. Annual allowance at the rate of 20% may also be claimed on exploration and appraisal expenditures (subject to deductibility rules under Section 263 and 264) incurred pre-production with a retention value of 1% in the books in the fifth year.

4. Unutilised capital allowances are available for offset against chargeable profits even after the execution of a conversion contract under Section 92.

g. CPR limits

1. CPR limits the amount of deductible costs (i.e. Section 263 and fifth schedule costs) to 35% of gross revenue.

2. In applying the CPR restriction, it is reasonable to prioritise deductibility of Section 263 costs (i.e. allowable deductions) above fifth schedule costs (i.e. capital allowances) as the former is required to be deducted before the latter.

3. The following Section 263 costs are not subject to the CPR restriction:
   1. Rent incurred pursuant to a PML or PPL
   2. Royalties; and
   3. Contributions to any fund, scheme or arrangement approved by the Commission

4. Production allowances are not subject to CPR limits.

5. While the provisions of the sixth schedule does not expressly reference/state that cost incurred in respect of acquisitions cost of petroleum rights are subject to the CPR limits, we believe that the intention of the CPR limit is to consider all cost. Hence, the acquisition cost should also be subjected to CPR restrictions.

6. Excess costs incurred not allowed for deduction can be carried forward to the subsequent year and so on, however, the excess cost shall also be subject to the CPR restriction. Upon termination of upstream petroleum operations, any cost that is yet to be deducted because of the CPR restriction will no longer be tax-deductible.

h. Production allowances

1. For converted oil mining leases based on a conversion contract and their renewals, production allowance for crude oil production shall be the lower of $2.50 per barrel and 20% of the fiscal oil price.

2. Production allowances for leases granted after commencement of the PIA is detailed in the table below:

Field area / Terrain	Applicable rate
Onshore acreages	The lower of $ 8.00 per barrel and 20% of the fiscal oil price per barrel up to a cumulative maximum production of 50 million barrels from commencement of production and the lower of $ 4.00 per barrel and 20% of the fiscal oil price thereafter.
Shallow water acreages	The lower of $8.00 per barrel and 20% of the fiscal oil price, up to a cumulative maximum production of 100 million barrels from commencement of production and the lower of $4.00 per barrel and 20% of the fiscal oil price thereafter.
Deep offshore and frontier acreages	The lower of $8.00 per barrel and 20% of the fiscal oil price, up to a cumulative maximum production of 500 million barrels from the commencement of production and the lower of $4.00 per barrel and 20% of the fiscal oil price thereafter.

3 Production allowances are only applicable to crude oil, field condensates and NGLs derived from AG, as it is of no benefit for companies not subject the upstream HT.

4 Petroleum investment allowance, investment tax credits (ITCs) and investment tax allowances (ITAs) that were applicable under the PPTA and/or DOIBPSCA do not exist in the PIA. Any unutilised portion of these tax benefits would be lost upon the execution of a conversion contract under Section 92.

5 By switching from investment allowances to production allowances, the government effectively refocused its incentives from capital investments to production. Thus, the more you produce the higher your fiscal rewards.

CIT computation

The provisions of the Companies Income Tax Act (CITA) guides the subjection of profits from petroleum operations (upstream, midstream, and downstream) to CIT, with the modifications identified below:

1 Crude oil and gas revenues, to be subject to CIT, are based on proceeds and value of crude oil and gas volumes sold or disposed, as determined at the measurement points. Fiscal oil price adjustment applicable to crude oil for HT purpose is not applicable under CIT.

2 In determining CIT applicable to upstream companies, HT will not qualify as tax deductible.

3 Capital allowances in respect of upstream petroleum operations shall be based on the fifth schedule of PIA, as discussed under 3f. Capital allowances in respect of midstream and downstream petroleum operations shall be based on the second schedule of CITA. Capital allowances in respect of acquisition costs of petroleum rights is the same across upstream, midstream, and downstream petroleum operations and it is granted at an annual rate 20% with a 1% retention value until disposal of the underlying asset.

4 In addition to the deductions allowed under Section 24 of CITA, the following are allowable in determining CIT taxable profit

1. Rent and royalties incurred in a period in respect of crude oil/condensates/natural gas sold/delivered/disposed in a commercial manner.
2. Any amount contributed to a fund, scheme, or arrangement, approved by the Commission or Authority, in respect of abandonment, decommissioning, host communities' development and environmental remediation. Though not specifically listed, NDDC levy may qualify as deductible based on the WREN principle.
3. Other deductions as may be prescribed by Minister of Finance in an order published in the Gazette of FGN.

5 In addition to the non-allowable deductions under Section 27 of CITA, the following are also non-deductible in determining CIT taxable profit:

1. Expenditure incurred to purchase information relating to petroleum deposits. We expect that these costs will be capitalised.
2. Gas flare fees and penalties
3. Production and signature bonuses
4. Inputted tax

6 Petroleum profits of upstream companies will be assessed to CIT on actual year basis period (as applicable under HT) while midstream and downstream companies will be assessed to CIT on a preceding year basis period.

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Penalties and offences

1. The PIA stipulates the following penalties for non-compliance with its provisions:
   1. With respect to default in filing HT returns before the appropriate deadline, an initial administrative penalty of ₦10,000,000 and a further administrative penalty of ₦2,000,000 where the default continues beyond the period stipulated.
   2. A fine of ₦20,000,000 and a further fine of ₦2,000,000 when found guilty of an offense.
   3. An administrative penalty of the sum of ₦15,000,000 or 1% of the amount of tax which has been undercharged, in the case of making an incorrect account or false statement.
2. Taxes due in Naira and foreign currencies from a company involved in upstream petroleum operations will be subject to interest at the prevailing Nigerian Interbank Offered Rate (NIBOR) and London Interbank Offered Rate (LIBOR) respectively plus a rate of 10% on outstanding remittances from the date when the tax becomes payable until it is paid.

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TET computation

As prescribed in the Tertiary Education Trust Fund Act (TETFA), TET is calculated as 2% of a company's assessable profits determined under the PPTA and/or CITA, as the case may be. On the basis that TETFA does not reference PIA, assessable profit computed under the PIA for HT purpose is not expected to be subject to TET, only assessable profit computed based on CITA rules is subject to TET. This also avoids the potential for double taxation.

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Consolidation of costs and taxes

1. Upstream companies can consolidate costs across terrains for the purpose of CIT.
2. Upstream companies can consolidate cost and taxes for only HT purpose along the lines of the two separate HT rates, as may be applicable.
3. A contractor in a PML or PPL may consolidate its losses and revenues for HT and CIT purposes.
4. For PSCs, adjusted profits can be consolidated separately across licenses/leases (i.e., PML or PPL) after the deduction of royalties and value of profit oil paid to FGN. Upon consolidation, the applicable tax rates should then be applied on the taxable profit after deducting capital allowances.

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Rendering of tax returns

a. Estimated returns

1. Upstream petroleum companies are required to submit an estimated return of its profits or losses, in respect of crude oil only, for that accounting period for the purpose of HT not later than two months after the commencement of each accounting period.

2. The first installment is equal to the monthly proportion of the estimated HT over the relevant accounting period and it is due by the third month of the relevant accounting. Subsequent installments are calculated in similar manner, subject to adjustments caused my revised estimated returns, and are payable in monthly succession.

3. Defaulting companies are required to pay ₦10,000,000 on the first day of default and ₦2,000,000 for every other subsequent day default continues.

4. Revised monthly estimated returns are required in the event of a change in price, cost or volume of crude oil. Upstream companies may have to submit revised estimated returns every month considering that it is expected that cost, price, or volume of crude oil will vary from estimates irrespective of the accuracy and reasonability of estimates. This creates additional burden for taxpayers and does not necessary add significant value especially where the revised estimates have only moved marginally.

5. Defaulting companies are liable to interest equal to LIBOR or any successor rate plus 10% points for the differential of the revised tax over the estimated tax paid.

6. Where a company fails to submit estimated HT returns and revised estimated returns, FIRS may determine the estimates and revisions based on its best of judgment and assess the defaulting company to tax accordingly.

b. Actual returns

1. Upstream petroleum companies are required to submit actual HT returns, in respect of crude oil only, in the prescribed format within five months after the end of the relevant accounting period. The payment of the final HT installment forms part of the actual HT returns.

2. Penalties are same as described under 'estimated returns'.

Business reorganisation and corporate restructuring

a. Transfer/sale of business – related parties and third parties

1. In respect of related upstream companies, in the event of a transfer or sale of upstream petroleum business or trade, including a transfer of management or assets from one company to another, the assets transferred shall be deemed to be sold for an amount equivalent to the residue of the qualifying expenditure. Also, all allowances enjoyed by the selling company would effectively be deemed to have been received by the company acquiring such assets.

2. The company selling or transferring such trade or business is expected to have made payment for its taxes in full, default which could lead to revocation and additional assessment.

3. All concessions that may have been enjoyed by the acquiring company would be rescinded in an event where substantial disposal of the assets occur within the succeeding three (3) years after acquisition date.

4. On the contrary, in respect of unrelated party upstream petroleum trade/business sale or transfer, the allowances as set out in the fifth schedule of the PIA will be applicable on such rights and assets, subject to the attendant conditions.

b. Avoidance by transfer

1. A company engaged in petroleum operations may be sued for the recovery of tax charged by the tax authority when it has been established that a transfer or sale of a substantial part of its assets is in a bid to avoid payment of taxes (CIT or HT) assessed or chargeable upon the company in an accounting period preceding such sale/transfer.

c. *Unbundling*

1. A company which intends to operate in more than one stream or sector of the oil and gas industry is required to incorporate a separate entity for each stream of petroleum operation.
2. This implies that companies previously operating consolidated assets will be required to separate these assets and incorporate separate and distinct companies to operate in each sector.

d. *Integrated Strategic Project (ISP)*

1. Companies that seek to engage in oil and natural gas production, processing and refining into finished products may elect to be established as ISP, where such products are solely targeted at wholesale domestic market supply.
2. This will effect the consolidation of midstream and upstream capital investments for tax purposes.
3. Nevertheless, the arms-length principle must be adopted in determining the hydrocarbon transfer prices from upstream to midstream petroleum operations.
4. In addition, capital investments for midstream petroleum operations, already consolidated with upstream petroleum operations cannot be considered for capital allowances when fiscalising the income from the midstream operations.

10 Partnerships

1. An individual is not permitted to carry out upstream petroleum operations on his own, jointly, or in partnership as such is tantamount to committing an offence. Where such operation has already been carried out and profits made, such profits will be liable to HT and CIT and the individual will be subjected to a penalty.
2. For partnership, joint ventures (JV) or concerts, apportionment of profits, outgoings, expenses, liabilities, deductions, qualifying expenditure and tax chargeable shall be in line with the equity interest of each party to the contract.

11 Incentives

1. Companies engaged in domestic midstream petroleum operations, downstream gas operations and large-scale gas utilisation industries are entitled to benefit from the gas utilisation incentives under CITA provisions.
2. Companies that participate in voluntary conversion of its leases or licences shall not be entitled to benefit from the existing incentive for utilisation of associated and non-associated gas.

12 Taxation of dividends

1. Dividend payment or other distribution paid out of profit by companies (upstream, midstream, and incorporate JVs) shall be subject to any withholding tax (WHT) applicable under the CITA.

Cost recovery for PSCs

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1. As opposed to the full cost recovery available presently (albeit limited under some PSCs), cost recovery (through lifting of Cost Oil) for existing PSCs that are converted under PIA is capped at 60% of the total oil production, a minimum of 55% haircut on disputed amount and for the purpose of determining profit oil share based on cumulative production. It is important to note that this would only be applicable to renegotiated PSCs.

2. Cost recovery (through lifting of Cost Oil) for PSCs under new acreages granted under the PIA, is capped at 70%.

3. In both cases above, gas flaring penalty or fines do not qualify for cost recovery.

Fiscal stabilisation

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1. Fiscal stabilisation clauses contained in any PSC or other contract entered after the commencement of the PIA will not apply to the following fiscal provisions:
   - a. generally applicable taxes, such as WHT, CIT, TET and value added tax.
   - b. levies, taxes or payments to comply with modern principles in respect of environment, labor laws, health and safety.
   - c. new taxes, levies or duties to implement Nigeria's commitments with respect to climate change under the United Nations Framework Convention on Climate Change and other related international agreements. There are concerns that this clause may open the door to carbon taxation in Nigeria.

Closure

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With the enactment of the PIA and modifications to certain fiscal provisions, the Nigerian petroleum industry is expected to attract more direct investments. It is however important for companies to evaluate the impact of the Act on their specific operations in order to ascertain if the fiscal provisions of the PIA are more beneficial to the company's operations in comparison to the Petroleum Act (PA)/PPTA and/or DOIBPSCA. Companies would typically have to run their economics and conduct scenario analysis to compare the impact of the transitioning to the PIA (or otherwise) on their operations for the foreseeable future. Companies looking to transition to the fiscal provisions of the PIA may also consider modifying its current tax computation model and reporting systems or developing new model to accommodate the changes in the PIA.

Furthermore, regardless of the attractiveness or otherwise of conversion, it is imperative for companies in the industry to review their project and portfolio economics for robustness under the PIA, given that all leases and contracts will automatically be converted upon expiration. Adoption can be delayed but it is inevitable. While updating the models, considerations should be given to ensuring compliance with the requirement of the PIA for royalties and filing of returns amongst others.