



Petroleum Industry Act (PIA) 2021 - A Game Changer ?

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Preface



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The President has finally signed the Petroleum Industry Act (PIA), 2021. The key objective of the PIA is to overhaul and transform the Nigerian oil gas industry. However, the key question that is being asked is: will the PIA be the game changer for the industry at a time when major oil producers are seeking to transition to clean energy? Only time will tell.

The oil and gas industry has a significant impact on the Nigeria's economy. Though the industry contributes less than 10% to the country's gross domestic product, it contributes about 90% of the foreign exchange earnings and 60% of total income. Consequently, any adverse change in the industry will have a big and long-term impact on government finances. This is the reason why successive governments have remained focused on the sector despite various discussions on diversifying the economy.

For the past 20 years, there have been various attempts at reforming the industry. However, none of these efforts has yielded any tangible result until the introduction of the Petroleum Industry Bill (PIB) 2020. Prior to now, there were various iterations of the PIB. The PIB started as an omnibus bill and was later divided into 4 separate bills before emerging in 2020 as a consolidated bill.

It is a fact that previous attempts at passing the PIB in 2009, 2012 and 2018 failed because of factors such as lack of ownership, misalignment of interests between the National Assembly and the Executive, perceived erosion of ministerial powers, stiff opposition by the petroleum host communities and push back by investors on the perceived uncompetitive provisions in those versions of the bill. The PIA 2021 is set to address all the issues to the extent possible. It should be noted that the present administration and the 9th National Assembly have demonstrated unparalleled commitment to passing the bill. They understand the importance of passing a bill that is competitive, balanced, fair, reasonable and realistic.

The jury is out on whether the PIA will achieve these objectives. One thing is clear – government has tried to strike a balance between immediate revenues demands and the need to attract long-term investment for the

industry. This has become extremely crucial when one considers the fact that only 4% of the \$70billion investments made in Africa's oil and gas industry between 2015 and 2019 was in respect of Nigeria even though it is the biggest producer and has the largest reserves on the continent. According to the National Bureau of Statistics, only \$53.5m or 0.55% of total investment of \$9.680billion in Nigeria in 2020 was made in the industry.

If we must achieve our ambition of 40 billion barrels of oil in reserves and 4million barrels of oil per day, we need to attract new investments into the sector. This task has even become more daunting in the light of the various challenges facing the industry, especially with respect to the renewed focus on renewables and energy transition. The oil in the ground is of no use to the country if it cannot monetize it. Therefore, the PIA must lead to a massive transformation of the industry and succeed in attracting the desired investment required to reposition the industry. Otherwise, Nigeria's production will continue to decline significantly with the adverse effect on revenue. It is also important that we continue to explore new areas to increase our oil and gas reserves given that our reserves will get depleted within the next 50 years at the current rate of production. Our ability to increase reserves is only possible if the country carries out exploratory activities. This provides the justification for the introduction of the Frontier Exploration Fund.

Though the PIA 2021 is not a perfect law, It is a good way to start. Hopefully, the provisions of the PIA will be enough to stimulate the desired investment though it has not addressed the issue of energy transition from fossil fuel to clean energy.

Overall, the PIA 2021 should help to transform the Nigeria oil and gas Industry given the myriads of challenges it seeks to address: - encourage investments, improved focus on midstream operations, improved funding for JV operations, environmental remediation and abandonment, and transfer of effective control to host communities in terms of project selection, execution and ownership.



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Glossary

AG	Associated Gas
ACT	Additional Chargeable Tax
BoT	Board of Trustees
CA	Capital Allowance
CAC	Corporate Affairs Commission
CAMA	Companies and Allied Matters Act
CGT	Capital Gains Tax
CIT	Companies Income Tax
CITA	Companies Income Tax Act
COVID-19	Coronavirus
CPR	Cost Price Ratio
DOIBPSCA	Deep Offshore and Inland Basin Petroleum Sharing Contracts Act
DPR	Department of Petroleum Resources
ETR	Estimated Tax Return
FID	Final Investment Decision
FDI	Foreign Direct Investment
FG	Federal Government
FIRS	Federal Inland Revenue Service
HT	Hydrocarbon Tax
HCDT	Host Communities' Development Trust
MMBtu	Metric Million British Thermal unit
NAPIMS	National Petroleum Investment Management Services

NDDC	Niger Delta Development Commission
NGLs	Natural Gas Liquids
NNPC	Nigerian National Petroleum Corporation
NUPRC	Nigerian Upstream Regulatory Commission
OML	Oil Mining Lease
OPL	Oil Prospecting Licence
PA	Production Allowance
PIA	Petroleum Investment Allowance
PIB	Petroleum Industry Bill
PIFF	Petroleum Industry Fiscal Framework
PHCD	Petroleum Host Community Development
PML	Petroleum Mining Lease
PPL	Petroleum Prospecting License
PPMC	Pipelines and Product Marketing Company
PPPRA	Petroleum Products Pricing Regulatory Agency
PPTA	Petroleum Profits Tax Act
QCE	Qualifying Capital Expenditure
QDE	Qualifying Drilling Expenditure
TET	Tertiary Education Tax
TP	Transfer Pricing
WREN	Wholly, Reasonably, Exclusively, Necessarily





Key Provisions of the PIA

- Dual Regulators for the oil and gas industry - The Commission and the Authority.
- Voluntary conversion of existing oil prospecting or mining contracts in exchange for significant relinquishment of up to 60% of acreages.
- Effective acreage management through relinquishment, deep rights and drill or drop concepts.
- PIA Funds – Frontier Exploration Fund (30% of Profit oil and gas of NNPC Ltd), Midstream and Downstream Gas Infrastructure Fund (0.5% of wholesale price of petroleum products sold in Nigeria and natural gas produced and sold in Nigeria), Environmental Remediation Fund (will be based on size of operations), Decommissioning/ Abandonment Fund (as determined in the field development plan and periodic appraisal of the costs required) and Host Community Trust Fund (3% of annual operating expenditure in prior year).
- Incorporation of NNPC Limited with Ministry of Finance Incorporated and Ministry of Petroleum Incorporated as shareholders.
- Voluntary conversion to incorporated Joint ventures, subject to the guiding principles defined in the second schedule to the PIA.
- Ministerial approval of lease or consent on assignment subject to the recommendation of the Commission and must be given within the specified period; otherwise, it is deemed as given.
- Acquisition cost of interest in a lease to be broken into value of rights and value of assets.
- Establishment of New Licences and Leases under the Act, namely: Petroleum Exploration Licence (equivalent to the current Oil Exploration Licence), Petroleum Prospecting Licence (equivalent to the current Oil Prospecting Licence) and Petroleum Mining Lease (equivalent to the current Oil Mining Lease).
- Development of Model Licence and Model Lease, which shall be incorporated into contracts before approval of Licence or Lease by the Minister.
- Oil producing companies to pay HT and CIT. HT will be at 15% for PPLs and 30% for PMLs. However, deep offshore operations are NOT subject to HT while only costs directly related to production are allowable in calculating HT. The non-direct costs will, however, be deductible under CIT.
- Costs allowable for HT (i.e., capital allowances and operating costs but excluding rentals on PPLs and PMLs, royalties and contributions made in respect of Host Community Fund, Environmental remediation, NDDC and similar funds) limited to 65% of gross revenues.
- Operators are entitled to production allowances rather than investment allowances and investment tax credits.
- Additional Chargeable Tax may become payable by an Operator in an accounting year based on the fiscal price advised by the Commission.
- Requirement to submit revised HT returns whenever prices, costs and volumes change, and strict penalty for non-compliance.



- Royalty based on production and price. However, there is a preferential royalty rate for oil sold to Nigerian refineries and gas utilised in-country.
- Segregation of upstream operations from midstream/downstream operations, except for strategic projects. However, stamp duties and CGT will not apply upon segregation.
- Requirement for Producing Marginal Field to convert to Petroleum Mining Lease within 18 months from the Effective Date of the PIA.
- Introduction of Environmental and Gas Flare Management with annual contribution that is dependent on the size of the operations and risk involved.
- PIA provides for suppliers and buyers to willingly agree on price. However, the Authority will still regulate gas prices.
- Companies with active refining licences or proven track record of international crude oil and petroleum products trading will be allowed to import any product shortfall that domestic refineries are unable to meet.
- Gas flare penalties from upstream operations to be utilized for environmental remediation and relief of the impacted host communities while that arising from midstream operations will be credited to the Midstream and Downstream Infrastructure Fund to be utilized for midstream and downstream infrastructure investment in the affected host communities.
- Marginal Field redefined as a field or discovery declared a marginal field prior to 1st January 2021 or which has been dormant for 7 years after its discovery prior to the enactment of the PIA.

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Governance

Chapter 1 of the Petroleum Industry Act, 2021 ('PIA' or 'the Act') vests the property and ownership of petroleum within Nigeria and its territorial waters, continental shelf and Exclusive Economic Zone in the Federal Government of Nigeria, and outlines the following objectives for the governance and administration of the industry:

- To create efficient and effective governing institutions, with clear and separate roles for the petroleum industry;
- To establish a framework for the creation of a commercially-oriented and profit-driven national petroleum company;
- To promote transparency, good governance, and accountability in the administration of the petroleum resources of Nigeria; and
- To foster a business environment conducive for petroleum operations.

1.1 Governance Arrangements

The PIA proposes to formally segment the Nigerian petroleum industry into upstream sector on one hand, and the midstream and downstream sectors, on the other. The upstream sector is to be overseen by the Nigerian Upstream Regulatory Commission ('the Commission'), while the midstream and downstream sectors would be under the oversight of the Nigerian Midstream and Downstream Petroleum Regulatory Authority (the 'Authority'). General oversight powers over the petroleum industry is vested in the Minister of Petroleum ('the Minister'), whom the Commission and Authority are required to report to.

The three governance organs are discussed below:

1.1.1 *The Minister of Petroleum ('the Minister')*

Section 3 of the PIA retains the Minister's general oversight and supervisory powers over all facets of the petroleum industry. This remains unchanged from the previous governance regime under the Petroleum Act.

Specifically, the Minister is empowered to formulate, monitor, and administer the Federal Government's policy over the petroleum industry. The Commission and Authority are required to report to the Minister, ensuring his oversight powers over the industry, are total.

However, there have been important deviations from the general powers of the Minister of Petroleum as hitherto granted under the previous regime. A glaring change is that the Minister's former unfettered, sole discretion and power to grant or revoke oil licenses have been curtailed. The Act specifically requires that the Commission provide recommendations to the Minister before the Minister can exercise such powers. Overall, the Act limits itself to grant of general powers to the Minister unlike under the Petroleum Act which vested the power to grant specific approvals in the Minister. Such specific approvals have been generally vested in the Authority or Commission. The key question, therefore, is whether the Minister, who may also be the President, may be bound by the recommendations of the Commission on the award of licences given that the President can remove any member of the Commission. Notwithstanding the bold changes in the PIA, it seems that the Minister will continue to exercise a significant influence in the industry.



1.1.2 *The Nigerian Upstream Regulatory Commission ('the Commission')*

Section 4 of the PIA establishes the Commission to have primary regulatory powers and oversight over the technical and commercial activities of the upstream petroleum industry.

The Commission will regulate all technical activities in the upstream sector by enforcing, administering, and implementing all laws, regulations, national and international policies, standards, and practices relating to the sector. The Commission is also to enforce compliance with the conditions of all leases, licences, permits and authorisations issued to companies in the sector. Such technical activities include seismic operations, drilling operations and design, construction, and operation of upstream facilities, among others. Given that these powers were exercised by the Department of Petroleum Resources ('DPR'), it is clear that the Commission would replace the DPR in that regard as Section 10 vests the Commission with the power as the successor to the DPR and the Petroleum Inspectorate Division.

The PIA empowers the Commission to oversee commercial activities in the upstream, such as reviewing and approving commercial aspects of field development plans, supervising costs and cost control in upstream petroleum operations, implementing cutback orders by the Minister. It seems safe to surmise that the Commission is to take over some of the commercial regulatory previously undertaken by NNPC's National Petroleum Investment Management Services ('NAPIMS').

Further, with a firm view on encouraging activities in frontier basins, Section 9 specifically outlines the responsibilities of the Commission in that regard. To ensure that the desired promotion activities over frontier basins are undertaken, the PIA proposes a Frontier Exploration Fund, to consist of 30% of the share of profit oil and gas of NNPC Limited from its production sharing contracts, profit sharing contracts and risk service contracts. Any basin where there has been no previous exploratory activity, discovery, undeveloped or as determined by the Commission as Frontier basin will qualify as such. This will include basins which are currently not producing such as Dahomey, Bida, Anambra, Benue, Sokoto and Chad.

The vision to promote exploration activities in frontier basins is commendable, as it will ensure long term sustainability of the industry by boosting the available reserves. However, discretion must be exercised to ensure that current reserves are maximized, and the promotion activities over frontier basins are undertaken in areas that are potentially commercially viable, and not a dissipation of energy.

The PIA requires any government body whose action would impact the upstream industry to consult with the Commission, prior to taking such action and to comply with any recommendation that the Commission may propose. This specific inclusion is commendable as it should help to minimize disruption by government agencies seeming to work at cross purposes when the overall objection should be viability of the petroleum industry.

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1.1.2.1 Management of the Commission

The Commission is to be run by a Governing Board, which is responsible for its policy and general administration. The members of the Governing Board, which is to be headed by a non-executive Commissioner, are to be appointed by the President subject to the Senate's confirmation. The Commissioners are to hold office for a term of 5 years, which is renewable for a future 5-year term.

The confirmation of the members of the Governing Board is commendable as it enables the Senate to discharge its constitutional oversight function. However, the President solely has the power to remove the members without deferring to the Senate.

The Commission will have six Executive Commissioners for its operational management although only two of the Executive Commissioners (those for Exploration and Acreage Management, and Finance) are to be members of the Governing Board, along with the Chief Executive Officer.

The PIA requires that the salaries of the Commission's employees be benchmarked against the general standard in the petroleum industry, after consultation with the National Salaries, Incomes and Wages Commission.

One of the sources of funds to the Commission will be from fees earned from services rendered to licensees. This is concerning, given the reputation of Nigeria which is rife with incidences of rent seeking by government officials, and issues of conflict of interest, as well.



1.1.3 The Nigerian Midstream and Downstream Petroleum Regulatory Authority ('the Authority')

Section 29 of the PIA establishes the Authority to have technical and commercial regulation of midstream and downstream petroleum operations in the midstream and downstream segments of the petroleum industry.

The Authority's functions include the regulation of petroleum liquid operations, domestic natural gas operations and export natural gas operation. It is also to determine the appropriate tariff methodology for processing of natural gas, transportation and transmission of natural gas, transportation of crude oil, bulk storage of crude oil and monitoring the quality of service provided. The Authority is empowered to issue regulations in pursuance of its regulatory oversight powers.

The Authority is empowered to impose a gas flare penalty for midstream operations. The penalty will be to the credit of the Midstream and Downstream Gas Infrastructure Fund, and would be utilized for midstream gas infrastructure investment within the host community where the flare occurs. The objective is to compensate the host community for the environmental damage cause by the flaring or venting.

Interestingly, the PIA seems to suggest that the sole power to grant, issue, modify, cancel, or terminate all licences, permits and authorisations for midstream and downstream petroleum operations, is vested in the Authority. This is a significant departure from the previous regime whereby such powers were typically vested in the Minister. The powers vested in the Authority seem to indicate that it is taking over the functions of the NNPC (PPMC) and the PPPRA.

1.1.3.1 Management of the Authority

The Authority is also to be run by a Governing Board, which is responsible for its policy and general administration. The members of the Governing Board, which is to be headed by a non-executive Commissioner, are to be appointed by the President subject to the Senate's confirmation. The Commissioners are to hold office for a term of 5 years, which is renewable for a future 5-year term.

As noted with the Commission, one of the sources of funds to the Authority, is to be from fees earned from services rendered to licenses. As previously noted, this should be revisited as quickly as possible, and eliminated to ensure that the Regulators are put on the proper pedestal.

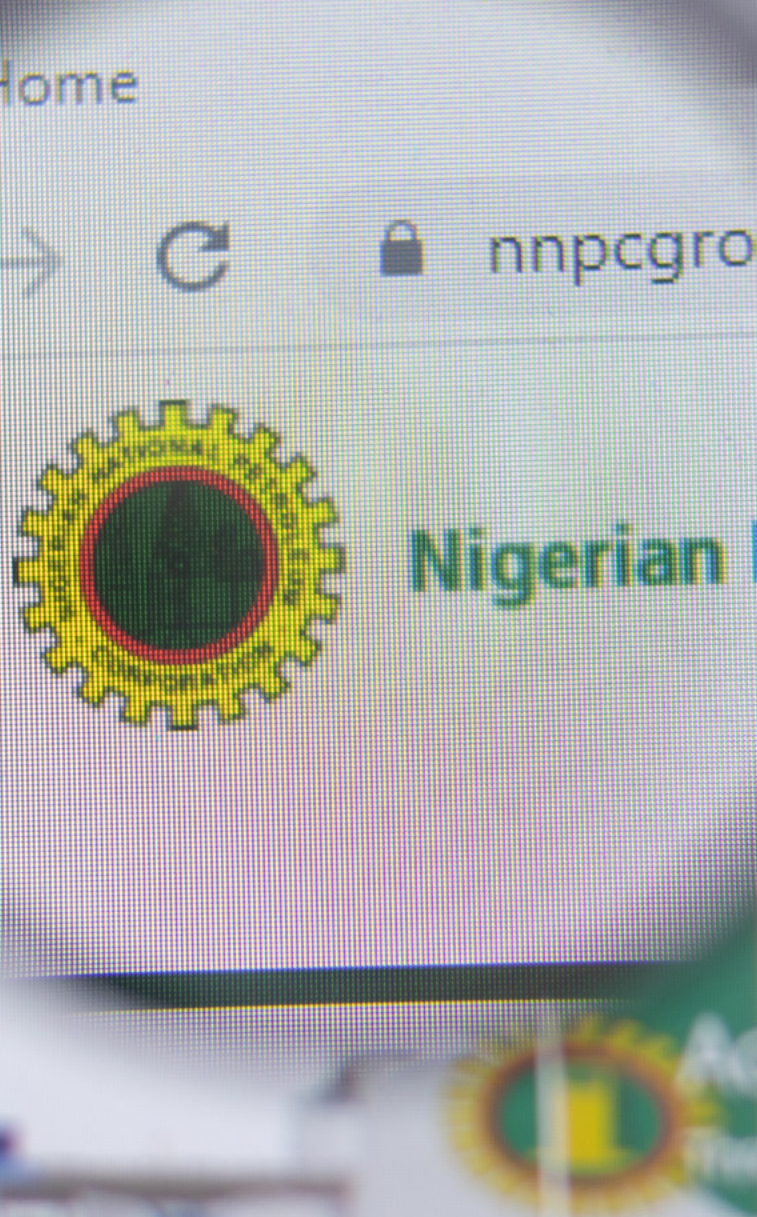
Also worthy of note is the 0.5% levy to be imposed on the wholesale price of petroleum products in Nigeria. The stated intention of the PIA is to move away from regulated prices to those determined by market forces. However, a multiplicity of levies and charges may act to distort that reality.

1.1.3.2 The Midstream and Downstream Gas Infrastructure Fund

Section 52 of the PIA establishes the Midstream and Downstream Gas Infrastructure Fund, which is to be a body corporate with its own Governing Council chaired by the Minister of Petroleum.

The stated purpose of the fund is to *"make equity investments of Government owned participating or shareholder interests in infrastructure related to midstream gas operations aimed at – (a) increasing the domestic consumption of Natural Gas in Nigeria in projects which are financed in part by private investment; and (b) encouraging private investment."*

“Interestingly, the PIA seems to suggest that the sole power to grant, issue, modify, cancel, or terminate all licences, permits and authorisations for midstream and downstream petroleum operations, is vested in the Authority.”



The major source of funding for the Midstream and Downstream Gas Infrastructure Fund is a 0.5% levy on the wholesale price of petroleum products sold in Nigeria, and natural gas produced and sold. This levy is in addition to the one to be collected by the Authority. The only distinction that the base is expanded to include “natural gas produced and sold in Nigeria”.

Given the oversight of the Authority over this area, it may have been more optimal to make this fund a part of the Authority, rather than seek to have it stand alone as it has been currently set up as this seems as a duplication of governance structures.

1.1.3.3 The Nigerian National Petroleum Company Limited ('NNPC Ltd')

Section 53 directs that the Minister, within six months of the PIA's commencement, incorporate a Nigerian National Petroleum Company Limited at the Corporate Affairs Commission ('CAC'). The shares are to be held by the Ministry of Finance Incorporated and the Ministry of Petroleum Incorporated in equal proportions on behalf of the Government.

The PIA provides that the Minister of Petroleum and the Minister of Finance are to determine which assets, interests, and liabilities of the current statutory NNPC, are to be transferred to NNPC Ltd. Six (6) months after that determination, The Minister of Petroleum, the Minister of Finance and the Attorney General are to outline a framework for payment of the liabilities that were not transferred to NNPC Ltd. It should be noted that the PIA empowers the Minister to consult with the Minister of Finance to appoint NNPC Ltd as the liquidation agent of the NNPC.

Overall, the direction of the PIA seems to be that NNPC Ltd be run as a commercial entity, like any other incorporated entity. It specifies that the company pay its fair share of royalties, fees, rents, taxes and other payments due to the Government, and that it should pay out the bulk of its profits as dividends after retaining 25% for reinvestment.

Section 58 indicates that the Board of NNPC Ltd is to be constituted in accordance with the provisions of the Companies and Allied Matters Act ('CAMA') and the company's Articles of Association. However, some of its provisions seem contrary, and not apposite, to NNPC Ltd being run commercially. For example, Section 59 indicates that the members of the Board would be appointed by the President, and Section 60 comments on the constitution of Committees for the Board. Indeed, Sections 61-64 highlight matters which are ordinarily determined by the CAMA, Memorandum & Articles of Association and Shareholders' Agreements. The Government has taken a bold step by incorporating NNPC Ltd as a CAMA entity. It should bite the bullet by freeing it up to run the same way that other private companies are run, albeit with interventions as its shareholder.

Interestingly, Section 65 encourages NNPC Ltd and its joint venture partners to explore the use of incorporated joint venture companies, under the principles enumerated under the Second Schedule to the PIA.





Administration

The administration and management of petroleum resources and their derivatives, as provided for in the Petroleum Industry Act (PIA), apply to activities within or associated with petroleum operations, the petroleum industry and persons involved in such activities. It is aimed at promoting exploration and exploitation of petroleum products for the benefit of the Nigerian people. The PAB is built on the tenets of effectiveness, efficiency, accountability, competitiveness, safety, conducive business environment, among others.

In order to drive the achievement of its main objectives, the PIA has the following major administrative structures and provisions:

2.1 Administration of Upstream Petroleum Operations

The PIA provides that the upstream subsector of the Nigerian Oil and Gas industry shall be regulated by the Nigerian Upstream Regulatory Commission (the "Commission"). The Commission is expected to perform similar technical and commercial regulatory functions previously performed by the Department of Petroleum Resources. The areas of influence of the Commission in the upstream oil and gas sector include:

2.1.1 Recommendation on issuance of licences/lease:

The Commission is empowered to make recommendations to the Minister on granting licences or lease to operating companies incorporated and validly existing in Nigeria under the Companies and Allied Matters Act. The Commission has the responsibility of receiving application for licences and leases and make necessary technical and commercial appraisal that would form the basis of its recommendation to the Minister on the granting of licence/lease to respective applicants. The form of the major licences/lease to be issued for upstream operations are:

- *Petroleum Exploration Licence (equivalent to the current Oil Exploration Licence):* A Petroleum Exploration Licence (PEL) is granted for exploration of petroleum on a speculative and non-exclusive basis and shall be for 3 years and may be renewable for additional period of 3 years.
- *Petroleum Prospecting Licence (equivalent to the current Oil Prospecting Licence):* A Petroleum Prospecting Licence (PPL) is granted for exploration of Petroleum on an exclusive basis. A PPL for onshore and shallow water acreages shall be for a duration of not more than 6 years, comprising an initial exploration period of 3 years and an optional extension period of 3 years. For deep offshore and frontier acreages, it shall be for a duration of not more than 10 years, comprising an initial exploration period of 5 years and an optional extension period of 5 years.
- *Petroleum Mining Lease (equivalent to the current Oil Mining Lease):* A Petroleum Mining Lease (PML) is granted to qualified applicant to search for, win, work, carry away and dispose of crude oil, condensates and natural gas and shall be for a maximum period of 20 years and may be renewable for one or more additional period of not more than 20 years each, subject to meeting specified conditions.

The PIA prescribes that where the Minister does not act upon the recommendation of the Commission for the award of licence within 90 days, the approval shall be deemed as given. However for Ministerial consent, it is 60 days. These provisions will greatly help in enhancing transparency.



2.1.2 Environmental management:

The Commission has a regulatory role of monitoring and ensuring compliance with the PIA with respect to environmental sustainability and environmental degradation that may result from petroleum operations of licensees and lessees. A licensee or lessee, who engages in upstream petroleum operations, is required by the Commission to submit for approval an environmental management plan in respect of projects which require environmental impact assessment within one year of the effective date of the PIA or six months after the grant of the applicable Licence or Lease. The Commission gives its approval of such plan, provided it is in compliance with regulations issued under the Act and the applicant has the capacity or has provided for the capacity to rehabilitate and manage negative impacts on the environment.

Furthermore, in order to be sure of the safety of people and the environment, the PIA requires that the applicable permit and approval is granted by the Commission to upstream operators before chemicals can be used for their operations. As a condition for the grant of a licence or lease and prior to the approval of the environmental management plan by the Commission, a licensee or lessee is required to pay a prescribed financial contribution to an Environmental Remediation Fund established by the Commission, for the rehabilitation or management of negative environmental impacts with respect to the licence or lease issued to such licensee or lessee.

This is a notable feature of the PIA that is aimed at engendering a culture of good environmental consideration practice that has been called to question in the sector. It may also help to deal with the perennial issue of oil spillage in the Niger Delta as a result of petroleum operations.

2.1.3 Gas flaring management:

Gas flaring is one of the age-long ills that plague the Nigerian Oil and Gas sector. It has been attributed to unfavourable cost-benefit outcome to the operators in the sector that may choose to harness and monetise associated gas. The cost of processing gas for sale is generally adjudged higher than the benefits that would be derived from commercializing the processed gas. As such, associated gas is preferred to be flared or vented by operators. Considering the environmental impact of gas flaring, the PIA has upheld the prohibition of gas flaring, except for a few circumstance in which there is no other reasonable option than to flare gas.

According to the PIA, a licensee or lessee shall pay a penalty prescribed pursuant to regulation issued by the Commission. The only recognized few instances where gas flaring may be allowed by the PIA are as follows:

- i. in the case of an emergency
- ii. pursuant to an exemption granted by the Commission.
- iii. as an acceptable safety practice under established regulations.

“As part of the efforts to manage the flaring of gas, the Commission requires upstream operators that produce natural gas to submit, within 12 months of the effective date of the PIA, a natural gas flare elimination and monetisation plan to the Commission.”



As part of the efforts to manage the flaring of gas, the Commission requires upstream operators that produce natural gas to submit, within 12 months of the effective date of the PIA, a natural gas flare elimination and monetisation plan to the Commission. This is expected to be prepared in accordance with regulations made by the Commission under the PIA.

Monies received in respect of gas flaring penalties for upstream petroleum operations are to be utilized for environmental remediation and relief of the host communities impacted. However, gas flare penalties in respect of midstream operations are to be transferred to the Midstream and Downstream Gas Infrastructure Fund to be used for midstream and downstream gas infrastructure investment in the affected host communities.

2.1.4 Domestic crude oil supply obligations:

In line with the principles of free market and healthy competition, the PIA provides that the supply of crude oil and condensates for the domestic market shall generally be on a willing supplier and willing buyer basis. However, to manage national exigencies and in the interest of the Nigerian people, the Commission is empowered to issue regulations or guidelines on the mechanism for setting domestic crude oil supply obligation for lessees in the upstream petroleum operations. This power is exercised where, in the opinion of the Commission, the domestic market results in shortages or inadequate supplies of crude oil and condensates for holders of crude oil refining licences. The Commission liaises with the Nigerian Midstream and Downstream Petroleum Regulatory Authority (the "Authority") to ascertain the crude oil requirements of refineries in operation. This is a mediation role of the Commission to ensure that the local market is adequately supplied to the extent possible for the benefit of the Nigerian people, in line with the objectives of the PIA.

2.1.5 Domestic gas delivery obligation:

In order to establish an orderly, fair and competitive commercial environment

within the petroleum industry, the Commission, working hand in hand with the Nigerian Midstream and Downstream Petroleum Regulatory Authority, is responsible for determining, monitoring and ensuring that the volume of natural gas that is expected to be supplied by lessees to strategic sectors and aggregators is achieved. The Commission would manage this through an allocation system among lessees as determined by the Commission upon consultation with the Authority with consideration of supporting infrastructure availability.



Lessees who fail to comply with the domestic gas delivery obligation placed on them by the PIA, shall incur a penalty of US\$ 3.50 per MMBtu not delivered, subject to the penalty for failure to deliver as may be stated in any gas purchase and sale agreement between a lessee and a wholesale supplier of the strategic sectors. The penalty amount may be adjusted as the Commission may prescribe in a Regulation made under the PIA. The penalty does not apply in the following circumstances:

- i. force majeure
- ii. the inability of a purchaser to accept allocated natural gas volumes
- iii. the inability to transport the allocated natural gas for reasons beyond the control of the lessee; or
- iv. the failure of a purchaser to pay for allocated natural gas volumes

Apart from the penalty for non compliance, the PIA has made compliance with the domestic gas delivery obligation a condition for approval of the supply of natural gas for new export projects by lessees. However, it is important that the challenges and bottlenecks that affect the ability of gas producers to meet their domestic gas delivery obligations be addressed.

2.2 General Administration of Midstream and Downstream Petroleum Operations

The Nigerian Midstream and Downstream Petroleum Regulatory Authority (the “Authority”) shall be responsible for the management and administration of the midstream and the downstream sector of the Nigerian Oil and Gas Industry. The notable administrative areas of influence by the Authority are as follows:

2.2.1 Licence application:

The Authority is responsible for granting, renewing, modifying and extending licences and permits to operators in the midstream and downstream sector. Where the licence relates to the operation of a refinery, this is issued by the Minister on recommendation by the Authority. In performing this role and making relevant decisions, the Authority is saddled with the responsibility of considering commercial, technical and environmental factors, among others. The Authority is empowered to make and enforce regulations and guidelines that will help it discharge its duties in relation to licensing matters.

2.2.2 Tariff:

The Authority has the power to use Regulations to determine the pricing framework for transportation, distribution and processing of petroleum. The PIA requires that tariffs be determined in US dollars, but may be paid in naira, where the applicable exchange rate shall be based on the Securities and Exchange Commission over-the-counter market rate or any successor rate. The prices should be cost reflective and should allow for reasonable return for the operators.

“The Authority, prior to establishing a tariff methodology, is required to initiate and conduct a stakeholders’ consultation with applicants, operators, consumers, prospective customers, consumers associations, associations of prospective customers and any other persons with interest in the subject matter of the proposed tariff methodology.”



The Authority, prior to establishing a tariff methodology, is required to initiate and conduct a stakeholders' consultation with applicants, operators, consumers, prospective customers, consumers associations, associations of prospective customers and any other persons with interest in the subject matter of the proposed tariff methodology. Notwithstanding the requirements for stake holders' consultation, the Authority may establish a tariff methodology without conducting a stakeholders' consultation, where it considers it necessary to do so. According to the PIA, such tariff methodology so determined shall be valid for only six months subject to confirmation via due process of stake holders' consultation.

2.3 Administration of Midstream and Downstream Gas Operations:

The PIA requires a holder of a subsisting lease, licence or permit, who is engaged in activities in midstream or downstream gas operations prior to the effective date of the PIA, to apply to the Authority within 18 months from the effective date of the PIA for the appropriate licence or permit, as applicable. In order to properly administer gas operations in the sector, the PIA provides that the Authority can issue special guidelines and regulations as may be deemed necessary.

The Authority performs the customer-protection function by issuing regulations that require oil and gas product distributors and suppliers to:

- i. publish their terms of supply or distribution including tariffs; and
- ii. facilitate the establishment of a forum at which customers are able to express their views and raise concerns, among others.

The PIA provides that the Authority shall, prior to the 1st day of March of each calendar year, determine the domestic gas demand requirement and inform the Commission of this requirement.

2.4 Other Matters Related to Downstream, Midstream and Upstream Operations

The Authority exercises regulatory powers in the following areas for the overall objectives of the PIA:

2.4.1 Competition and Market Regulations:

One of the overarching objectives of the PIA is to engender a competitive market devoid of customer exploitation. Subject to the provisions of the Federal Competition and Consumer Protection Act, the Authority is to, among other responsibilities, curb monopoly and restrictive market practices of "powerful" operators, diagnose and forestall all tendencies of barrier to market entry. This would create and encourage an environment conducive for foreign direct investments. Where an operator is engaged in acts that contravene the requirements of the relevant chapters of the PIA, the Authority is empowered to state its intention to issue a "cease and desist" order to curb the unwanted actions of the operator. There is a penalty of a maximum of 5% of the annual turnover of the operator that fails to comply with the provisions of the "cease and desist" order.



2.4.2 Consultation for regulations:

The Commission and Authority are required to consult with stakeholders, such as licencees, permit holders and lessees, prior to finalizing any regulations or amendments to regulations. This may not be the case in instances of exigencies. A regulation made shall be valid for not more than 1 year with effect from its commencement date, except it is confirmed following a stakeholders' consultation.

2.4.3 Abandonment, decommissioning and disposal:

The PIA requires that necessary and adequate provisions be made for the decommissioning and abandonment of onshore and offshore petroleum wells, installations, structures, utilities, plants and pipelines for petroleum operations and shall be conducted in accordance with international best practice and guidelines by the Commission or the Authority. This exercise shall take place with the approval of the Commission or the Authority as applicable.

The PIA requires that each lessee and licensee shall set up and maintain a decommissioning and abandonment fund, which shall be held by a financial institution that is not an affiliate of the lessee or licensee in an escrow account which is accessible to the Authority or Commission. The fund so set up will be used for abandonment and decommissioning purposes. Where the licencee or the lessee fails to comply with the abandonment plan, the Commission or the Authority will access the fund for this purpose. Operators are required to make periodic payments, as may be determined from time to time, into the fund.

A licensee or lessee is required to inform the Commission or Authority, as the case may be, of the establishment of its decommissioning and abandonment fund not more than three months from the date of commencement of production for upstream petroleum operations or the commissioning of the facilities for midstream petroleum operations; and furnish the Commission or Authority, as the case may be, on an annual basis with statements of accounts with respect to its decommissioning and abandonment fund.

The PIA provides that, from the effective date, contributions to the decommissioning and abandonment fund are eligible for cost recovery and shall be tax deductible, provided that decommissioning and abandonment costs disbursed from the decommissioning and abandonment fund shall not be eligible for cost recovery or deductible for tax purposes. Where there is excess in the decommissioning and abandonment fund after the decommissioning and abandonment has been carried out and approved by the Commission or the Authority, as the case may be, the excess will be available for consideration as income for production sharing or tax purposes and the residual amount left over after the withholding of profit oil and any tax has been deducted shall be returned to the licensee or lessee.

“The PIA provides that, from the effective date, contributions to the decommissioning and abandonment fund is eligible for cost recovery and shall be tax deductible, provided that decommissioning and abandonment costs disbursed from the decommissioning and abandonment fund shall not be eligible for cost recovery or deductible for tax purposes.”



2.4.4 Conversion and Relinquishment of PPLs & PMLs

All existing OPLs and OMLs would be automatically converted to PPLs and PMLs upon their expiration.

However, the PIA allows holders of OPLs and OMLs under the current regime to voluntarily convert them to PPLs or PMLs, respectively.

The PIA provides some condition precedents which are to be contained in the Conversion Contracts. One such condition is a stipulation that all on-going arbitration and court cases would be terminated. Other conditions are that the fiscal stabilization clauses would not be grandfathered. OML holders will need to designate their acreages into 5 broad classes:

- parcels that merit an appraisal (for exploration);
- parcels to make a declaration of commercial discovery for which a field development plan is to be submitted;
- parcels that have a significant gas discovery;
- parcels which already have development programs underway; and
- parcels in which regular commercial production is occurring.

The PIA prescribes that these 5 parcels should cover 40% of the area of the license granted, and other areas are to be relinquished. However, where the parcels cover more than 40%, the licensees will be entitled to keep them. Consequently, the areas to be relinquished can be less than 60% in that situation. The proposed relinquishment of 60% appears to be onerous and may serve as a disincentive to conversion.



2.5 Comments:

While the provisions and the underlying tenets of the PIA are welcome developments, its effectiveness in transforming the Nigerian oil and gas sector is hinged on the ability of the administrative organs (the Commission and the Authority) to use data to drive operations and decision making. The starting point would be the seamless transfer of industry historical and current data on participants and operations from the current regulator- the Department of Petroleum Resources (DPR)- to the Commission and the Authority. This would aid a quick integration of existing operators into the system under the PIA and the compliance with necessary licence conversion requirements can be monitored.

The PIA proposes that the existing staff of DPR and PPRA be moved to the respective regulators. While this is a laudable move, it is important that proper skills gap assessment be conducted to ensure fit for purpose. Employees should only be transferred when it can be demonstrated that they have the experience, knowledge and skills to thrive in their new roles. It is also important that a manning requirements assessment be done to determine the number of employees required by each of the regulators.

The administrative organs should leverage technology in interfacing with operators for proper record and decision making. Application for licences, periodic returns and all other information flow should be digitalised. This is a required bedrock for qualitative information that will drive decision making and effective administration of the sector under the PIA.

As part of the kick-off exercise of the administrative organs, there should be awareness/knowledge sharing forum in form of roadshows, webinars, and stakeholders' forum discussions, to sensitize stake holders and also get feedback on opportunities and threats to their set objectives.

There are also concerns as to the cost-benefit analysis of having two regulators for the oil and gas industry. This is with reference to the cost of governance and practices in other comparable jurisdictions. Hopefully, the clarity in the role of the regulators will help to promote an efficient, effective and sustainable development of the Nigeria's petroleum industry. It may also help to focus attention on the midstream and downstream rather than the current situation where so much focus is on extraction of petroleum.

“The PIA proposes that the existing staff of DPR and PPRA be moved to the respective regulators. While this is a laudable move, it is important that proper skills gap assessment be conducted to ensure fit for purpose.”





Petroleum Host Communities Development

One of the issues that contributed to the delay in passing the previous versions of the PIA is host community. The host communities, Government and operators could not agree on the best way to address the concerns of the host communities. While the host communities are demanding more to deal with the issue of the environmental effect of oil operations, the government believes that enough is already being done in this area given all the agencies that are involved in the development of the Niger Delta region. It is, therefore, not surprising that the PIA 2021 adopts a novel approach to this issue.

Chapter 3 of the the Act introduces the Petroleum Host Community Development (PHCD) which has the following objectives:

- To foster sustainable prosperity within host communities;
- To provide direct social and economic benefits from petroleum operations to host communities;
- To enhance peaceful and harmonious co-existence between licensees or lessees and host communities; and
- To create a framework to support the development of host communities.

The PHCD is expected to improve the quality of life of the host communities' population and improve accountability in the management of host communities' development trust (HCDT or "the Trust") fund.

Some of the significant provisions of the framework are as follows:

3.1. Introduction of HCDT

Section 235 of the Act requires a settlor¹ or a group of settlors under a joint operating agreement to incorporate a HCDT. The Trust is to aid the development of the economic and social infrastructure of the communities within the petroleum-producing area. Where the HCDT is incorporated by a group of settlors under a joint operation, the operator under the agreement will be responsible for the Trust on behalf of the other parties.

The Act requires the settlor to appoint and authorise a Board of Trustees (BoT), which will be registered with the Corporate Affairs Commission, for the purpose of managing the Trust. The following administrative activities of the BoT are determined by the settlor –

- the selection process, the procedure for meetings, financial regulations and administrative procedures
- the remuneration, discipline, qualification, disqualification, suspension, and removal of members of the BoT; and
- other matters other than the above relating to the operation and activities of the BoT.

Further, Section 251 requires the settlor to conduct a host community needs assessment to determine the needs of each host community and develop a Community Development Plan to address the identified needs.

¹ A settlor is defined in the Act as "a holder of an interest in a petroleum prospecting licence or petroleum mining lease or a holder of an interest in a licence for midstream petroleum operations, whose area of operations is located in or appurtenant to any community or communities"



3.2. Regulation for Governance of Host Community Development

Section 234 of the Act requires the Commission to make regulations that will govern the implementation of the HCD. The regulations should include the following:

- i) Grievance mechanism to resolve disputes between the settlor and host communities
- ii) The ability of the settlor to make the adjustments to reduce expenditures where the available funds for the administration of HCDDT are insufficient by doing the following:
 - a) reduce the number of members of the BoT and frequency of their meetings
 - b) not fund the reserve fund nor hire fund manager
 - c) reduce the number of members of the management committee and the frequency of their meetings
 - d) reduce the frequency of meetings of the host community advisory committee.

3.3. Timeline for Setting up the Trust

The Act provides the following timelines for incorporating the Trust:

S/N	Timeline for Incorporation
a.	for existing OMLs, within 12 months from the effective date of the Act
b.	for existing designated facilities, within 12 months from the effective date of the Act
c.	for existing new designated facilities under construction on the effective date, within 12 months from the effective date
d.	for existing oil prospecting licences, prior to the application for the field development plan
e.	for petroleum prospecting licences and petroleum mining leases granted under this Act, prior to the application for the field development plan
f.	for licensees of designated facilities granted under this Act, prior to commencement of commercial operations

Failure to adhere to the stipulated timeline may result in grounds for revocation of any licence or lease governed by the Act.

“The Act requires the BoT to set up a management committee that comprises one representative of each host community as a non-executive member, and other executive members of high integrity and professional qualification.”



3.4. Other Key Definitions for the Administration of the HCDT

3.4.1. The Management Committee

The Act requires the BoT to set up a management committee that comprises one representative of each host community as a non-executive member, and other executive members of high integrity and professional qualification. Further, it empowers the management committee to prepare the budget of the fund, manage project awards on behalf of the Trust, supervise project execution, and other functions that may be assigned to it by the BoT.

3.4.2. The Host Community Advisory Committee

The Host Community Advisory Committee (“Advisory Committee”) is to be set up by the management committee in accordance with the constitution of the Trust. The Advisory Committee will be responsible for nominating members to represent the host communities on the management committee, communicating community development projects to the management committee, monitoring the progress of community projects, securing project facilities, and advising the management committee on measures to improve security and peace within the community.

3.5. Objectives of the Trust

The objectives of the Trust include the following:

- a) To finance and execute projects for the benefit and sustainable development of the host communities;
- b) To undertake infrastructural development of the host communities within the scope of funds available to the BoT for such purposes;
- c) To facilitate economic empowerment opportunities in the host communities;
- d) To advance and propagate educational development for the benefit of members of the host communities;
- e) To support healthcare development for the host communities;
- f) To support local initiatives within the host communities, which seek to enhance the protection of the environment;
- g) To support local initiatives within the host communities which seek to enhance security;
- h) To invest part of the available fund for and on behalf of the host communities; and
- i) To assist in any other developmental purpose deemed beneficial to the host communities as may be determined by the Board of Trustees.



3.6. Funding for the Trust

3.6.1. Source of Funding

Section 240 of the PIA requires each settlor to contribute 3% of its actual operating expenditure in the upstream petroleum operations in the preceding calendar year to a fund established by the Trust. The HCDT may also be funded by donations, gifts, grants or honoraria (received to achieve its objectives) and interests accruing to the Trust's reserve fund.

Under a joint venture agreement, the responsibility of the settlors with respect to host communities' development falls to the operator appointed under the agreement. Therefore, each settlor under a joint venture contract is required to make an annual contribution to the Trust through the appointed operator.

In line with Sections 256 and 257 of the Act, the funds of the HCDT are exempted from tax while contributions made by a settlor to the Trust are deductible for hydrocarbon tax and companies income tax purposes, respectively.

3.6.2. Forfeiture of Funds and Basis for Computation

The host community will forfeit its entitlement to any contribution to the extent of the cost to repair damages to the petroleum and designated facilities or disruption to production activities within the host community caused by an act of vandalism, sabotage or civil unrest. Therefore, the amount to be contributed by the settlor to the Trust shall exclude the computed cost of such repairs or disruption in petroleum productions.

Though the Act has not addressed a scenario where the cost of such repairs exceeds the settlor's contribution, it is more likely than not that the excess will be tax deductible in that year.

It is expected that this provision will foster responsibility and accountability amongst the host communities regarding petroleum assets operated in their respective communities.

3.6.3. Allocation of Funds

Section 244 of the PIA prescribes the following allocation ratio for annual contributions to the fund:

- a) 75% of the annual contribution shall be used to fund capital projects;
- b) a maximum of 5% of the annual contribution shall be utilized solely for administrative costs of running the Trust and special projects; and
- c) 20% of the annual contributions shall be retained as a reserve fund. Also, the reserved fund shall be invested for the utilisation of the Trust when contributions from the settlor ceases.

“The host community will forfeit its entitlement to any contribution to the extent of the cost to repair damages to the petroleum and designated facilities or disruption to production activities within the host community caused by an act of vandalism, sabotage or civil unrest.”



3.7 Content of the Host Community Development Fund

The PIA provides that the HCDP shall include the following:

- a) the community development initiatives required to address identified issues in the host community needs assessment
- b) specific projects for implementing the development initiatives
- c) a detailed timeline for the specified projects
- d) a budget for the HCDP
- e) the reasons and the objectives of each project as supported by the host community needs assessment
- f) conformity with the Nigerian Content requirements as provided in the Nigerian Oil and Gas Industry Content Development Act
- g) continuous review and reporting to the Commission

3.8 Financial Responsibilities of the Trust

The Trust is required to maintain a 31 December financial year-end or as may be determined by the BoT. The Trust must prepare audited accounts on its activities annually and these must be submitted to the BoT not later than 28 February of the succeeding year. The BoT must also submit the approved audited accounts to the settlors, who will submit same to the Commission not later than 31 May of that year.

3.9. Comments

Given the introduction of the Petroleum Host Community Fund, the question that has arisen is what is the continued relevance of the contribution to the Niger Delta Development Commission (NDDC) The PIA is not clear on whether the host community fund contribution will be together with the 3% NDDC levy. If this is the case, then the objective of promoting a competitive oil industry will be suspect, given that the industry is already subject to multiple taxes. Of course, there is also the question as to whether the 3% of annual operating expenditure will be sufficient to secure the buy-in of the host communities. Most importantly, accountability for the judicious use of the funds is key. The hope, therefore, is that the trust fund shall be used for the benefit of all the host communities as envisaged by the PIA. If this happens, it will go a long way in reducing the constant agitation and restlessness in the Niger Delta.





Fiscal Provisions

Chapter 4 of the Act introduces the Petroleum Industry Fiscal Framework (PIFF), which has the following objectives: Fiscal Provisions:

- To establish a progressive fiscal framework that encourages investment in the Nigerian petroleum industry, balancing rewards with risk and enhancing revenues to the Federal Government (FG);
- To provide a forward-looking fiscal framework that is based on core principles of clarity, dynamism and fiscal rules of general application;
- To establish a fiscal framework that expands the revenue base of the FG, while ensuring a fair return for investors;
- To simplify the administration of petroleum tax; and
- To promote equity and transparency in the petroleum industry fiscal regime.

The Act amends and repeals various laws that have implications for the oil and gas industry. *Appendix 1* lists the relevant laws affected in this regard. It provides for the current Petroleum Profits Tax (PPT) to be split into two namely: Hydrocarbon Tax (HT) and Companies Income Tax (CIT). The HT, together with CIT, will apply to companies engaged in upstream petroleum operations.

The fiscal and tax amendments in the PIA will apply upon:

- a. conversion of existing Oil Prospecting Licences (OPLs) and Oil Mining Leases (OMLs) to Petroleum Prospecting Licences (PPLs) and Petroleum Mining Licences (PMLs)
- b. termination or expiration of unconverted licenses, and
- c. renewal of OMLs.

Consequently, holders of OPLs and OMLs that do not convert to PMLs will continue to be taxed under the current PPT Act pending the expiration of their licences.

One of the biggest concerns with the PIA, as introduced by the Executive, is whether the fiscal provisions are competitive enough in terms of government take in relation to comparable jurisdictions. However, the general sense is that the current fiscal provisions will help to attract the required investments and unlock value. Interestingly, the PIA has not addressed the issue of multiple taxes, fess and levies.

Some of the significant fiscal policies introduced by the Act are discussed on subsequent pages.



4.1 Introduction of HT Regime

The Act introduces the HT, which will be chargeable on the profits of upstream petroleum companies in the onshore and shallow water. The HT, which applies to crude oil, field condensates and natural gas liquids from associated gas, is charged at varying rates depending on the licence as follows:

Licence Type	Rates	
	Onshore & Shallow Waters	Deep Offshore
Converted PML	30%	0%
Converted PPL	15%	0%

The HT will not apply to deep offshore projects in order to encourage exploratory activities in that area. Given that HT is a resource tax, costs that cannot be directly attributable to production will not be allowable for deduction. However, such costs will qualify for deduction against companies income tax. The HT rates in the PIA appear competitive when compared to comparable jurisdictions. Hopefully, this will go a long way in attracting the desired investment.

4.1.1 Application of HT to Petroleum Operations

The HT will only apply to crude oil, condensates and natural gas liquids (NGLs) from associated gas (AG). Associated Gas, Condensates and NGLs from non-associated petroleum gas will not be subject to the tax even when subsequently commingled with oil, provided that the related volumes can be determined at the measurement points or at the exit of the gas processing plant. The PIA has effectively resolved the controversy relating to the applicable fiscal legislation for condensates and NGLs that are subsequently commingled with oil. The determination of the applicability of HT will depend on whether the volumes of the condensate or NGLs can be determined at the measurement point or exit of the gas processing plant. The measurement point is defined as the downstream of the flow station.

Further, only the costs that cannot be deemed to be exclusively incurred to produce associated gas will be claimed as tax deductions under the HT. Consequently, costs that are incurred solely on associated gas production will be claimed against the earnings from associated gas production under CIT.

Condensates, whether field or plant, will be treated as oil while NGLs will be treated as gas, for royalty computations. Therefore, price-based royalty will only apply to condensates and not to NGLs.

4.1.2 Ascertainment of crude oil revenue

Section 262 of the PIA provides that the crude oil revenue of a company, in any accounting period, shall be the value of any chargeable oil adjusted to measurement points based on proceeds of all chargeable oil sold and value of chargeable oil disposed. The value of chargeable oil disposed shall be based on the aggregate value of crude oil determined for royalties for all fields. Therefore, extraction, storage and transportation costs will no longer be added back in determining taxable revenue under the HT as is the case under the PPT regime. Further, income incidental to petroleum operations would not be taxable under HT.

“The HT will not apply to deep offshore projects in order to encourage exploratory activities in that area.”



4.1.3 Submission of returns and penalties for non-compliance

The requirements for submission of tax returns to the FIRS are similar to that in the PPTA.. Based on Section 277 (3) of the PIA, companies yet to commence bulk sales or disposal of chargeable oil are required to submit their tax returns within 18 months from the date of incorporation in the case of a new company, and within 5 months after any period ending on 31st December of the following year, in the case of any other company.

Further, Section 281 of the Act has significantly increased the general penalty for non-compliance from ₦10,000 and an additional ₦2,000 for each day of continued default to ₦10,000,000 and an additional ₦2,000,000 for each day of continued default. The stiff penalties are to encourage voluntary compliance. However, Section 218 provides for taxpayers that have genuine reasons that may impact their ability to file their tax returns as and when due to proactively engage the FIRS and agree an extension to avoid payment of the penalties.

4.1.4 Interest on revised estimated tax returns

Section 280 (2) requires companies to recompute and file a revised estimated tax return (ETR) whenever there are changes in the price or cost or volumes of condensates. Failure to submit a revised ETR will result in the imposition of interest at LIBOR + 10% on the additional tax that would have been payable if a revised return had been submitted.

Although submission of a revised ETR is not new to the companies operating in the upstream industry especially where the parameters that informed the initial estimate change; however, the imposition of interest for not revising the estimate may be considered harsh given the frequency of volatility in the industry. Interestingly, the Act is silent on what would happen if a company fails to file a revised ETR which results in a lower tax payable. Therefore, one may assume that the penalty is only effective when the revised ETR results in an additional tax payable rather than a measure to enforce voluntary compliance.

4.1.5 Allowable Deductions

Section 263 of the PIA introduced the following modifications to the list of allowable deductions under the extant PPTA:

a. inclusion of the term "reasonable" as a criterion for the deductibility of expenses for HT purposes

The Act introduces the concept of reasonableness to the tax deductibility test for HT purposes. However, it fails to define what will qualify a cost as "reasonable"; thus leaving it to the interpretation of the court in the event of a dispute. This amendment is particularly worrisome given the peculiar complexity of the oil industry and associated significant financial investments required for operations. Therefore, it will be difficult to determine what will not constitute a "reasonable" cost in the absence of an adequate provision in the enabling law. The court will definitely have a huge say on this.



b. bad debts are not allowable

With the twin impact of the global oil price and COVID-19 pandemic on the global economy, especially the oil and gas industry, it is inevitable that companies will incur bad/ doubtful debts. Therefore, the exclusion of bad/doubtful debt from allowable deduction may result in companies paying taxes on profits that are not recoverable.

Further, there is a potential risk that this provision will affect the cashflow of these companies as they may have to settle their tax liabilities out of capital or monies earmarked for additional investments without any recourse to recover the amounts owed them by the government.

- c. contributions for decommissioning and abandonment will be tax-deductible, with any surplus/ residue liable to tax at the end life of the field. However, all funds, schemes or arrangements for this purpose must be approved by The Commission.
- d. royalty incurred in kind and payments made to the Federation Account related to production sharing, profit sharing, risk service contracts, etc. are allowable.
- e. amounts contributed to Funds such as the NDDC, NDCF, HCDTF, etc. are tax-deductible.
- f. cost of gas re-injection wells for natural gas which would otherwise have been flared, subject to the ratification of the Commission.

4.1.6 Non-allowable Deductions

In addition to the usual disallowable expenses, section 264 of the Act introduces the following as non-deductible expenses:

- Penalties and gas flare fees.
- Expenditure for the purchase of information on existence and extent of petroleum deposits, except in respect of geophysical, geological and geochemical data and information
- Financial/ bank charges, bad debts, interest on loans, arbitration and litigation costs.
- Costs incurred outside Nigeria including head office, shared costs, research and development cost and affiliate costs.
- Additional costs from tax gross-up clauses.
- Production/ signature bonuses, bonuses/ fees paid for renewing leases and licenses or for assigning rights to other parties.
- All custom duties.
- Costs that exceed the cost price ratio limit of 65% of gross revenue. Contributions in respect of host community, environmental remediation, NDDC levy and similar funds shall not be included in calculating the CRF limit.

“With the twin impact of the global oil price and COVID-19 pandemic on the global economy, especially the oil and gas industry, it is inevitable that companies will incur bad/ doubtful debts. Therefore, the exclusion of bad/doubtful debt from allowable deduction may result in companies paying taxes on profits that are not recoverable.”



4.1.7 Chargeable Profits and Allowances

The PIA introduces the following significant modifications to the calculation of chargeable profits and allowance:

- i) removal of the restriction on capital allowance (CA).
- ii) introduction of Production Allowances to replace the investment tax allowance and investment tax credits.
- iii) deletion of petroleum investment allowance.
- iv) separation of acquisition costs of petroleum rights into value of rights and value of assets, such that CA claimable on value of rights will now be 20% per annum for the purposes of CIT. However, for HT purpose, the annual allowance on the value of rights portion will be 20% while the value of assets shall be tax depreciated at 20% per annum, subject to a retention of 1% in the books.

The chargeable profits and allowances shall be determined separately for the two classes of assessable profits i.e assessable profits subject to HT at 30% and 15%, respectively.

4.1.8 Additional Chargeable Tax

Where the chargeable tax calculated by a company for any period is less than the chargeable tax for crude oil for the same period, the company will pay the difference between the two amounts as additional chargeable tax (ACT). The chargeable tax for crude oil is determined as the number of barrels of crude oil at the measurement point multiplied by the fiscal oil price per barrel established by the Commission at each measurement point on an export parity basis.

There may be concerns about whether the The Commission will be transparent in determining the fiscal oil price given the Government's desire to increase revenue. It is expected that the desire to increase government take will not be the driver for determining the fiscal oil price.

4.1.9 Cost Price Ratio (CPR) Limit

All deductible costs under the HT will be subject to a cost price ratio limit of 65% of gross revenues, subject to the relevant exclusions, determined at the measurement points. Any excess costs not deducted due to the restriction may be deducted in subsequent years of assessment provided that:

- i) the total costs to be deducted shall not exceed the actual costs incurred, and
- ii) in carrying costs forward, CA shall be carried forward with priority over operating costs, and
- iii) the total costs to be allowed as deduction in those subsequent years shall be such an amount that, if added to the sum of the total deductible costs, shall not exceed the specified cost price ratio limit of 65%; and

Any unrecovered costs (i.e., costs that exceed the cost price ratio limit) upon the termination of petroleum operations will not be deductible for HT purposes.



4.2 Application of CIT to Petroleum Operations

4.2.1 Consolidation of Taxes

Companies engaged in upstream petroleum operations will also be taxed under CIT and are required to settle their CIT liability on an actual year basis, using a similar estimate mechanism to that provided for HT. However, HT will not be deductible for CT purposes. CIT will be applied as an entity-based tax, thereby allowing for consolidation of results across terrains. This means that there are no field-by-field restrictions.

However, companies that acquire loss making companies in other to take advantage of the above incentive, would not be allowed to claim the losses of the acquired company.

4.2.2 General Requirements for Companies to pay CIT

- a) Companies, concessionaires, licensees, lessees, contractors or subcontractors involved in upstream, midstream and downstream petroleum operations will be liable to CIT.
- b) Allowable deductions are modified to include:
 - rents and royalties incurred with respect to commercial sale, delivery or disposal of crude oil, condensates and natural gas and payments to the Federation Account related to production sharing, profit sharing, risk service contracts or other contractual features
 - any amount contributed to any fund, scheme or arrangement for abandonment and decommission, petroleum host communities' development trust, provided that the fund/ scheme/ arrangement is approved by the Commission or Authority and any surplus or residue of such funds shall be subject to tax under CIT
 - other deductions as may be prescribed by the Minister of Finance by Order published in the Gazette.
- c) Non-allowable deductions are revised to include:
 - expenditure for the purchase of information on the existence and extent of petroleum deposits except in respect of geophysical, geological and geochemical data and information
 - any penalty incurred, including natural gas flare fee or charges
 - production bonuses, signature bonuses paid for acquisition of rights on petroleum deposits, signature bonuses or fees paid for renewing PML or PPL or fees paid for the assignment of rights to other parties including for marginal field
 - additional costs from tax gross-up clauses.
- d) Late payment of tax due from companies involved in upstream operations shall carry interest at NIBOR plus 10% from the due date until paid for naira remittance, and LIBOR or succession rate plus 10% from the due date until paid for foreign currency remittance.

“...companies that acquire loss making companies in other to take advantage of the above incentive, would not be allowed to claim the losses of the acquired company.”



4.3 Capital and Production Allowances

4.3.1 Capital Allowance

The PIA prescribes the following in the Fifth Schedule:

- i. Qualifying expenditure must relate to expenditure incurred directly for upstream petroleum operations applicable to crude oil for PML or PPL.
- ii. For a qualifying drilling expenditure (QDE) to qualify for CA, the cost of that QDE must not have benefited from CA prior to the acquisition of the asset by another entity.
- iii. Any loss suffered on assets disposed of before the beginning of a company's first accounting period would be disallowed upon commencement of the accounting period. Also, any profit realized upon disposal would be liable to capital gains tax.
- iv. The treatment of pre-production expenditure would depend on its nature. Where the expenditure would have been treated as a qualifying capital expenditure (QCE) if it was incurred in the first accounting year, then it would be classified as such, and CA claimed thereon. However, where the expenditure would have been treated as a tax-deductible expense, it should be amortized over a period of five (5) years with a 1% retention value.
- v. Where the owner of the relevant interest does not have statutory title to the asset, (i.e., it is not the licensee or lessee to the asset), the QCE and the accruing CA shall be to the benefit of the holder of the license or lease.
- vi. Capital expenditure will not be eligible for the claim of CA under HT, where the building, structure or works was previously used before the interest was acquired.

While the section is silent on whether the CA can be claimed under CIT, it may be pragmatic to assume that since CIT was not expressly stated, the building would qualify as QCE under the CIT.

- vii. Expenditure incurred on exploration and the first two (2) appraisal wells in the same field is to be treated as 100% deductible costs in the year incurred. However, additional exploration and appraisal expenditures in the same field relating to the pre-production period are to be amortized and deducted upon commencement of the company's accounting period at an annual allowance of 20% for the first four (4) years and 19% in the fifth year with a 1% retention value.
- viii. Other changes include the deletion of PIA, definition of "in use" and exclusion of certain expenditure.



4.3.2 Production Allowance (PA)

In the sixth schedule, the PIA has introduced the following provisions:

Contract Type	Rates	
	Onshore	Shallow Waters
Converted OMLs	Lower of US\$2.5% per barrel and 20% of fiscal prices	
New Leases	the lower of US\$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 US\$4.00 per barrel and 20% of the fiscal oil price thereafter	the lower of US\$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 US\$4.00 per barrel and 20% of the fiscal oil price thereafter

“Any loss suffered on assets disposed of before the beginning of a company’s first accounting period would be disallowed upon commencement of the accounting period. Also, any profit realized upon disposal would be liable to capital gains tax.”

4.4 Other Key Fiscal Provisions

4.4.1 Minister to request Petroleum Products or take-over works, plants or premises

The PIA empowers the Minister to request license/ lease holders to provide petroleum products to the FG or crude oil to third parties who own licenses to operate refineries. The price of the petroleum shall be at a “reasonable value at the point of delivery less discount to be agreed by both parties” or where no agreement was entered into before the Minister exercised the right of pre-exemption, a mutually agreed fair price at the port of delivery. Any arbitration may only take place after the petroleum or petroleum products have been delivered. Further, the Minister may take control of the licensee’s or lessee’s works, plants or premises in exchange for a “reasonable compensation”.

It is hoped that this provision will only be invoked in an emergency and not exercised arbitrarily.

4.4.2 Companies to separate upstream and midstream operations

Companies engaged in the end-to-end value chain will have to segregate their upstream from their midstream operations. This may have a negative impact on the profitability of those midstream projects as the final investment decision (FID) was predicated on the consolidation of both operations. This may also trigger significant issues for existing operators especially with respect to current pipelines, transfer of assets/ liabilities, transfer of staff and related obligations, compliance costs, transfer pricing issues. This provision, therefore, needs to be revisited. To address these issues, there may be a need to grandfather existing projects or those that have already taken FID from this rule. As an alternative, the government may consider a Ring Fence Corporation Tax similar to that of the UK.



However, the PIA provides for a tax neutral segregation of upstream and midstream/downstream operations. It specifically states that CGT and stamp duties will not apply on segregation. However, strategic projects can be allowed as integrated projects provided that the oil and gas will be processed or refined to finished petroleum products and supplied in wholesale solely to the domestic market. In this situation, arm's length transfer prices will have to be established to fiscalise the hydrocarbons transferred to the midstream operations. In addition, capital investment in the midstream operations will be consolidated with that of upstream petroleum operations.

4.4.3 PSC Fiscal Stability Clause

Fiscal stability clauses, which serve as a guarantee or a sort of protection to investors against change in government policies or legislation, provided by the NNPC in any PSC or any contract of similar nature, in respect of OPLs and OMLs to be converted will now be null and void.

The discharge of these clauses will create a level playing field between old and new investors and address potential distortions that may have been created as a result of perceived discrimination. However, it is important that tax rates be not changed indiscriminately in a way that will affect the viability of projects started prior to the change.

4.4.4 Artificial Transactions

The PIA has made provisions of the Income Tax (Transfer Pricing) Regulations, 2018 the basis for determining artificial transactions. However, it is uncertain why deductibility of interest on loan is subject to the FIRS and Commission's approval and costs incurred outside Nigeria, head office costs, affiliate costs are included as non-deductible expenses, rather than both costs being subject to TP Regulations as obtained under the extant PPTA.

4.4.5 Trade or Business Sold or Transferred

The provisions for businesses sold or transferred are similar to that of the PPTA, except for the following modification

- the first accounting period will be from the date of acquisition/ transfer of the business till 31st December of that year.
- any concession enjoyed in terms of CA will be rescinded where the acquirer disposes of the assets within 3 years of acquisition.
- acquisition cost relating to business transfer/ sale between non-related parties will enjoy a 10% annual CA under the CITA but none under HT.

These modifications would ensure consistency in the accounting periods and discourage tax avoidance and profit shifting schemes.



4.4.6 Conversion of OPLs and OMLs.

The PIA would not apply to holders of OPLs or OML who have not converted their licences to PPLs or PMLs until such OPLs or OMLs are terminated. However, any renewal of an OML will be based on the PIA.

Consequently, the provisions of PPTA will continue to apply to unconverted OMLs and OPLs.

4.4.7 Set off of payments made in error

Where a company makes tax payment in error, the PIA provides for setting off "*the credit against the liabilities of a similar tax payable to the Service*." Though the Act does not clarify the applicable taxes under this provision, it is assumed that it will extend to CIT and TET as they are all taxes on income

4.4.8 Calculation of Royalties

i. Production Royalty

Production royalty will be calculated on a field basis and is chargeable on the volume of crude oil and condensates produced from the field area in the relevant month on a terrain basis as follows:

- a. onshore areas -15%
- b. shallow water (up to 200m water depth) - 12.5%
- c. deep offshore (greater than 200m water depth) with monthly production less than 50,000 bpd - 5%
- d. deep offshore (greater than 200m water depth) with monthly production above 50,000 bpd - 7.5%
- e. frontier basins - 7.5%

Where a single field covers two or more PMLs, the royalty shall be determined based on the total production from the field.

Though the royalty rates have been reduced from those contained in the Executive Biil, there is still some concern that the rates are not competitive enough. This may, therefore, not lead to new investments. There is also the issue of non-adherence to the principle of sanctity of contracts. In the Production Sharing Contracts executed by those operating above 10,000m, royalty rate is set as zero percent.

ii. Gas Royalty

For natural gas and natural gas liquids, royalty will be on the chargeable volume in the relevant area at the rate of 5% of the chargeable value. However, the royalty rate for gas produced and utilized in-country shall be 2.5%.

“ Though the royalty rates have been reduced from those contained in the Executive Biil, there is still some concern that the rates are not competitive enough. This may, therefore, not lead to new investments.”



iii. Price Royalty

In addition to production royalty, companies would be liable to additional royalty when crude oil, and condensate, prices exceed specified benchmark prices and are payable to the Nigerian Sovereign Investment Authority.

For fields in onshore, shallow water and deep offshore areas, the royalty rates will apply as follows:

- a. Below US\$50 per barrel – 0%
- b. At US\$100 per barrel – 5%
- c. Above US\$150 per barrel – 10%

Prices between ranges will be determined by “*linear interpolation*” (For example, if the price is US\$75/bbl, the price royalty rate shall be 2.5%). Further, the above rates are only valid for 2020, therefore they will be increased annually by 2% over prior year rates.

Price royalty do not apply to gas or production from Frontier acreages.

4.4.9 Stiffer Penalties

The Act introduced stiffer penalties to encourage voluntary compliance, curb default and entrench integrity. Taxpayers should therefore ensure strict compliance with the provisions of the Act to avoid unnecessary fines or penalties as they will be disallowed for tax purposes.

4.5 Other Key Fiscal Provisions – Gas

4.5.1 Domestic Gas Supply Obligation

PIA prescribes that supply of gas to midstream gas export operations will not be allowed until the domestic supply obligations have been met. This provision may undermine contractual obligations already entered by the gas supplier before the commencement of the Act.

This provision needs to be reviewed accordingly.



4.5.2 Domestic Base Price and Pricing Framework

The Third Schedule to the PIA provides that the Authority must consider the following principles in determining the domestic base price-

1. the price must be of a level sufficient to encourage voluntary gas production to meet domestic needs
2. unless required to satisfy the first condition, the price shall not be higher than the average of similar natural gas prices in major emerging countries that are significant producers of natural gas as determined by the Authority
3. the price shall be adjusted upward on a yearly basis to account for inflation
4. the Authority shall determine the domestic base price based on regulations within 3 months from the effective date of the Act and modify the price where required by the circumstances in the domestic market pursuant to regulations.

Given the consistent calls for the deregulation of the gas sector and the prescription of a ceiling price, the PIA does not appear to have been geared towards the effective deregulation of the gas industry.

4.5.3 Gas Pricing Framework

The gas price for gas-based industries shall be determined as follows:

$$CP = NRP * (1 + EPF) \leq EPP$$

Where:

CP is the applicable gas price in \$/MMbtu

NRP is the National Reference Price of \$1.00/MMbtu

EPF is the *End Product Factor which is (CMPP – PRP)/PRP*

EPP is the *Domestic Base Price*

CMPP is the *Average Current Month End Product Price in \$/MT*

PRP = *Product Reference Price in \$/MT which varies depending on the industry*

For ammonia, urea, methanol, polypropylene (LDPPE/HDPPE), the PRP (US\$/MT) is 250; while for low sulphur diesel (GTL), the PRP is 325.

The PIA provides that the price for the power sector shall be referenced to the Domestic Base Price (DBP) as determined by the Authority while the price for the commercial sector shall be DBP plus \$0.50 per MMBtu. However, the price for gas-based industries shall range from \$0.90 per MMBtu and the DBP.

“Given the consistent calls for the deregulation of the gas sector and the prescription of a ceiling price, the PIA does not appear to have been geared towards the effective deregulation of the gas industry.”





Appendix

The Act will amend the provisions of the Pre-Shipment Inspection of Oil Export Act, 1996 and Petroleum Equalisation Fund, and effectively repeal the following Acts:

- i. Associated Gas Reinjection Act, 1979 CAP A25 Laws of the Federation (LFN) 2004, and its amendments;
- ii. Hydrocarbon Oil Refineries Act No. 17 of 1965, CAP H5 LFN 2004;
- iii. Motor Spirits (Returns) Act, CAP M20 LFN 2004;
- iv. Nigerian National Petroleum Corporation (Projects) Act No. 94 of 1993, CAP N124 LFN 2004;
- v. Nigerian National Petroleum Corporation Act (NNPC) 1977 No, 33 CAP N123 LFN as amended, when NNPC ceases to exist pursuant to section 54(3) of this Act;
- vi. Petroleum Products Pricing Regulatory Agency (Establishment) Act 2003;
- vii. Petroleum Equalisation Fund (Management Board etc.) Act No. 9 of 1975, CAP P11 LFN 2004;
- viii. Petroleum Equalisation Fund (Management Board, etc.) Act, 1975;
- ix. Petroleum Profit Tax Act Cap P13 LFN 2004, (PPTA); and
- x. Deep Offshore and Inland Basin Production Sharing Contract Act (DOIBPSCA), 1993 CAP D3, LFN 2004 and its 2019 amendment.

Note:

There are transitional and savings provisions in the PIA to deal with cases of licensees that may not want to convert. Consequently, the extant laws, such as the PPTA and the DOIBPSA, will continue to apply until all the leases have expired and renewed under the PIA terms.





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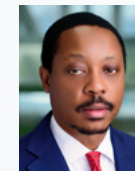
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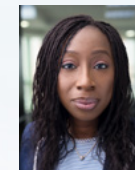
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