Nigeria's Petroleum Industry Act at Five: Regulatory Reform and Its Impact on Energy Investment

Nigeria's Petroleum Industry Act 2021 replaced a fragmented legal order with a coherent one, and the institutional and fiscal scaffolding is now largely in place. The record of the past five years nonetheless shows that enactment, implementation and market response are three distinct things moving at three different speeds. While the Act has made Nigerian upstream investment considerably more legible, it has not yet made it decisively more competitive.

Introduction

Five years after Nigeria enacted the Petroleum Industry Act 2021 (the "Act"), the most defensible assessment is also the least satisfying to either the reform's champions or its critics. The Act, which took effect on 16 August 2021, replaced a legal order assembled from the Petroleum Act 1969 and decades of accreted subsidiary regulations with a single statute governing institution, licensing, fiscal terms, host community obligations and the national oil company.[1] Its drafting achievement is real and substantially complete. Its implementation is well advanced but uneven, strongest where the regulator acts unilaterally and thinner where progress depends on other institutions. Its market effect is the most modest of the three: capital is returning to Nigerian acreage, but selectively, and on terms that have required repeated executive intervention to make attractive. Distinguishing enactment, implementation and investment response allows for a more nuanced assessment of what the Act has delivered and what remains a work in progress.

Two Regulators: Separation Achieved, Coordination Developing

Before the Act, the Department of Petroleum Resources was the principal petroleum regulator with responsibilities spanning upstream, midstream and downstream activities. At the same time, the Nigerian National Petroleum Corporation held the state's commercial interests and performed functions that were regulatory in substance. Investors therefore dealt with a counterparty that also influenced the rules. The Act dismantled that arrangement. It created the Nigerian Upstream Petroleum Regulatory Commission (NUPRC), with technical and commercial responsibility for upstream operations, and the Nigerian Midstream and Downstream Petroleum Regulatory Authority (NMDPRA) for activities downstream of the wellhead.[2] This functional separation is one of the Act's clearest structural gains, and it is substantive rather than nominal.

Since its establishment, NUPRC has become an active rule-maker and an increasingly responsive approval body. It has issued nineteen gazetted regulations, together with licensing round regulations, acreage management rules and an assignment of interest regime that codifies the previously opaque path to ministerial consent for asset transfers.[3] Throughput has also improved measurably: NUPRC approved 41 field development plans in 2024, a 32% increase on the previous year that the Commission attributes to fiscal and legal clarity under the Act, alongside 508 of 529 well re-entry approvals.[4] Several instruments now provide for deemed approval if NUPRC does not decide within a specified period, which converts regulatory delay from an open-ended commercial risk into a bounded one. For lenders modelling a project timeline, that shift matters more than any rhetorical commitment to efficiency.

Coordination between the new institutions is still developing, but the framework is moving in the right direction. NUPRC and NMDPRA formalised cooperation at a meeting in January 2026, and NUPRC has entered comparable arrangements with the revenue service, the local content board and the nuclear regulator.[5] While institutional seams that require memoranda to close can reopen, it is expected that both regulatory bodies will continue to synergise towards achieving the objectives of the Act.

POLICY

Federal Ministry of Petroleum Resources

• Overarching policy and legislative framework • Acreage and licence management decisions

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UPSTREAM	NUPRC	NMDPRA	DOWNSTREAM
	NUPRC Nigerian Upstream Petroleum Regulatory Commission • Technical and commercial regulation of upstream operations • Nineteen gazetted regulations issued since 2021 • Licensing rounds, acreage management, field development approvals • Deemed approval mechanisms with defined timelines • Host Communities Development Trust oversight	**NMDPRA** Nigerian Midstream and Downstream Petroleum Regulatory Authority • Regulation of all activities downstream of the wellhead • Midstream gas infrastructure including gas flare penalties • Downstream petroleum product pricing and distribution • Pipeline licensing and tariff regulation • Consumer protection in the downstream sector	

COMMERCIAL	**NNPC Limited** National Oil Company — commercial entity under general company law · Concessionaire of production sharing and risk service contracts · JV partner and project developer across upstream and midstream · Domestic crude supply obligation concessionaire · Frontier Exploration Fund management (3% deduction from proceeds)	**Licensees and Lessees** International and indigenous operators — production, development and exploration · Petroleum prospecting licences and petroleum mining leases · Field development plan approval obligations · Host Communities Development Trust contributions (3% opex) · Decommissioning fund contributions per 2026 Regulations	**OPERATORS**

▪ **Policy** ▪ **Regulation** ▪ **Commercial**

Figure 1. Upstream governance architecture under the Petroleum Industry Act 2021, showing the separation of policy, regulation and commercial functions.

From Legislative Reform to Regulatory Certainty: Early Impact on Upstream Investment

Prior to the Act, Nigeria experienced years of declining upstream investment driven by regulatory uncertainty and protracted sector reform. The Act responded with a revised fiscal regime intended to improve project economics while preserving public revenue, introducing new royalty structures, hydrocarbon taxation mechanisms and more transparent licensing processes. Together, these measures were designed to bring Nigerian upstream terms closer to international practice while giving investors a clearer basis for evaluating projects.

NUPRC has expressly linked its post-Act regulatory approach to investment certainty, describing the framework as a move from discretion to rules, ambiguity to clarity, and delay to defined timelines. The licensing regime illustrates this shift. The Act provides a statutory framework for licensing rounds and acreage administration, and NUPRC has increasingly adopted digital and competitive processes. In the 2025 licensing round, NUPRC made bid materials, guidelines, timelines, asset maps and other requirements available through a digital portal, reflecting an effort to make acreage allocation more transparent and predictable.

NUPRC has cited the Act as a major factor behind the resurgence of investment activity, reporting that post-PIA reforms have supported major field developments and attracted more than US$[10] billion in investment commitments linked to several projects. The Act also introduced the "drill or drop" principle under section 94, requiring licence holders to develop assets actively or relinquish them. This provision has reduced speculative licence holding and increased the availability of acreage for new entrants, contributing to stronger participation in recent licensing rounds.

Fiscal Reforms and the Path to Capital Deployment

The Act's fiscal chapter was the reform's commercial centrepiece, replacing petroleum profits tax with hydrocarbon tax, resetting royalties and offering better terms for gas and deep water. Since enactment of the Act, the Federal Government has supplemented the statutory baseline with three additional fiscal instruments: an order granting tax credits and allowances for non-associated gas, midstream and deep-water projects; the Upstream Petroleum Operations (Cost Efficiency Incentives) Order 2025, which allows operators that outperform NUPRC cost benchmarks to claim credits capped at 20% of annual tax liability; and a deep offshore tax remission order issued in 2026.[7] The sequence shows an effort to refine the statutory framework as project conditions become clearer. It also means investors must model both the Act and the implementing incentives when assessing returns.

Year	Instrument / Core Mechanism	Commercial Effect
2021	**PIA 2021, Chapter 4** *Hydrocarbon tax replacing petroleum profits tax; revised royalties; gas and deep-water differentiation*	Statutory fiscal baseline; removes negotiated variability
2022	**Petroleum Royalty Regulations** *Procedures for calculating and verifying royalties; credits for gas re-injection*	Precise royalty modelling; rewards reinjection
2024	**Oil and Gas Companies Order** *Tax credits over ten years for greenfield non-associated gas, midstream and deep-water projects*	Improves post-tax returns on gas-led development
2025	**Cost Efficiency Incentives Order** *Tax credit where unit operating costs fall below NUPRC benchmarks; credit capped at 20% of tax liability; expires 31 May 2035*	Converts cost discipline into a fiscal asset; introduces benchmark risk
2026	**Deep Offshore Tax Remission Order** *Remission targeted at deep offshore development where unit development cost is highest*	Addresses the highest-cost terrain

Figure 2. Principal fiscal and incentive instruments layered over the Petroleum Industry Act 2021.

The commercial logic behind that sequencing is visible in the cost data. NUPRC's benchmarking puts average unit development cost at approximately US$19.52 per barrel of oil equivalent in deep offshore, compared with US$10.41 offshore and US$16.27 onshore. Average development well costs in deep offshore range from US$22 million to US$52 million.[8] Deep water is where most of Nigeria's remaining large volume potential sits and also where project economics have been most demanding. NUPRC anticipates 22 offshore projects between 2026 and 2030 with potential investment of US$30 billion to US$50 billion and has welcomed a US$1 billion commitment by ExxonMobil and its partners to the Usan infill project.[9] These statistics indicate positive effect of the supplementary rules and massive potentials, which requires active commitment from all stakeholders to materialise.

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Production offers a similarly qualified measure of progress. Output averaged 1,580,369 barrels per day of oil and condensate in 2024, 4% above 2023. Even so, that level represented 67% of the technically allowable rate, with 2,700 shut-in well strings compared with 2,344 producing wells.[10] Nigeria met its OPEC quota for a third consecutive month in July 2026 at 1.67 million barrels per day.[11] The recovery is meaningful, but much of it is restored rather than new production, and a substantial share of the constraint is not fiscal at all. Some 702 spill incidents were recorded in 2024, 59% attributable to sabotage.[12] These are inherited structural problems that the Act cannot remove by itself.

Host Community Development Trusts: A Statutory Social Licence Still Being Built

One of the most significant innovations introduced by the Act is the Host Communities Development Trust (HCDT) framework established under Chapter 3. The Act requires every settlor — being the holder of a petroleum prospecting licence, petroleum mining lease or other qualifying interest — to incorporate an HCDT for the benefit of its host communities and to make an annual contribution equivalent to three per cent of actual operating expenditure incurred on operations affecting those communities in the preceding financial year.[13] In doing so, Nigeria transformed what had historically been a largely discretionary corporate social responsibility practice into a statutory and ring-fenced funding mechanism for community development.

Five years in, implementation has advanced considerably. Based on information published by NUPRC, 172 HCDTs have been established, supported by 39 fund managers and 16 designated banks, with approximately 1,176 development projects under execution across host communities. The NUPRC reports that approximately US$9.4 million has been remitted into the Trust system to fund community development initiatives. NUPRC has also deployed a dedicated digital compliance platform, "HostComply", aimed at simplifying reporting and compliance obligations for settlors.[14]

Beyond its governance objectives, the regime is increasingly viewed as supporting operational stability in petroleum-producing areas. By creating a direct economic stake for host communities in the sustainability of petroleum operations, the HCDT framework has reportedly contributed to reductions in pipeline vandalism, crude theft and community unrest, thereby strengthening asset security in certain producing areas. Investors must nonetheless recognise that HCDT contributions are linked to operating expenditure and therefore increase as operational activity expands, making them a recurring and potentially material cost consideration, particularly in onshore and swamp assets.

Certain structural challenges remain. A recurring concern is the potential overlap between the HCDT regime and pre-existing development intervention mechanisms in the Niger Delta. The Nigeria Extractive Industries Transparency Initiative (NEITI) has recommended a clearer alignment between the functions of the Niger Delta Development Commission and the HCDT framework in order to minimise duplication of expenditure and promote accountability in the delivery of community development initiatives.[15] Until that coordination is achieved, operators face a residual risk of being required to fund similar development outcomes through multiple mechanisms.

NNPC Limited: Repositioning Nigeria's National Oil Company for Commercial Operations

The Act converted the national oil company into NNPC Limited, a company incorporated under general company law, required to conduct its affairs on a commercial and profitable basis without recourse to government funds, to declare dividends to its shareholders and to retain twenty per cent of profits as retained earnings.[16] It is also vested as concessionaire of all production sharing, profit sharing and risk service contracts, remitting sale proceeds to the Federation less a thirty per cent deduction covering its management fee and the Frontier Exploration Fund.[17] In addition, the Act permits existing joint venture arrangements to be restructured into incorporated joint venture companies, replacing the traditional cash call model with a corporate vehicle capable of raising and deploying capital on its own balance sheet.[18]

For international partners, the commercial significance of these reforms is substantial. Every production sharing contract counterparty and every joint venture participant now engages with a corporate entity designed to operate within a commercially driven framework. The transition to NNPC Limited reflects a significant shift in the governance and operational structure of Nigeria's petroleum sector, with the objective of enhancing efficiency, transparency, competitiveness and long-term value creation.

The incorporated joint venture model in particular presents opportunities for greater operational flexibility and access to financing, supporting project development and investment across the sector. This evolving framework is of considerable relevance to investors, lenders and industry participants, who should closely monitor developments and disclosures published by NNPC Limited as the company continues to implement its commercial mandate and advance the objectives of the Act.

Decommissioning, Domestic Crude and the Price of Legacy Assets

The 2026 decommissioning regulations represent a significant step in operationalising the Act. Issued under sections 232 and 233 and gazetted on 9 March 2026, they revoke the 2023 regulations and provide a more detailed funding and enforcement framework.[20] The regulations clarify how funds are to be held, how liability follows a transferred interest and how the regulator may respond to non-compliance.

Feature	Requirement	Consequence for transactions
Fund structure	Dedicated interest-bearing escrow per licence/lease, denominated in US dollars; NUPRC named as party to every escrow agreement	Creates a ring-fenced, verifiable provision that can be confirmed in diligence
Custody of funds	Institutions rated A+ or equivalent; NNPC Limited pays onshore; international JV partner holds minimum 15% onshore and may hold balance offshore	Reduces counterparty and convertibility exposure relative to full onshore custody
Creditor protection	Escrow account kept free of charge, pledge, lien, guarantee or garnishee order	Insulates provision from operator insolvency; improves lender comfort
Transfer of liability	Decommissioning obligations attach to the interest transferred on assignment or novation	Liability follows the asset; pricing and indemnity architecture must reflect this
Timing	60 months notice for offshore; 12 months onshore; 6 months to submit updated plan for existing approved field development plans	Long lead planning obligations must be captured in transaction timetables
Enforcement	Administrative penalties of USD 500,000 per year for failure to submit plan or establish fund; USD 1,000,000 for	Converts non-compliance from a deferred risk to an immediate, irrecoverable cost

Feature	Requirement	Consequence for transactions
	unapproved decommissioning; penalties not cost-recoverable	
Self-help remedy	On default, NUPRC may within 60 days authorise the lifting of the defaulting party's crude, with the escrow account named as beneficiary on the bill of lading	Collection mechanism that does not depend on litigation

Note. *Decommissioning obligations are several and pro rata among joint venture parties and production sharing contractors; one partner's default does not attach to the others. Shortfalls in the Fund remain cost-recoverable and tax-deductible; surpluses are returned after tax.*

Figure 3: Selected features of the Nigerian Upstream Decommissioning and Abandonment Regulations 2025

The design is sophisticated, and the crude lifting remedy in particular gives the regulator leverage beyond a pure penal regime. Implementation is nonetheless the key question. NUPRC identified 65 operators and had received 48 decommissioning plans by the end of 2024, an improvement from a 62% to 74% compliance rate year on year, although only two funding orders had been approved in principle at that point.[21] A framework that is largely unfunded in practice does not yet transfer risk away from the state or from incoming buyers, which is exactly why the assignee liability rule now deserves close attention in transaction pricing. This matters commercially because Nigeria's onshore and shallow water asset base has changed hands substantially: NUPRC has confirmed ministerial consent for the divestments by Nigerian Agip Oil Company, Equinor, Shell Petroleum Development Company, Mobil Producing Nigeria and TotalEnergies, and has developed a divestment and exit guidance framework to govern such exits.[22] Those transactions moved mature, high-liability assets to indigenous operators, and the 2026 regulations determine who now pays to retire them.

The domestic crude supply obligation under section 109 illustrates the same pattern of maturing enforcement. NUPRC reported 97.4% performance in the second quarter of 2026 and now publishes quarterly statistics.[23] That is a marked improvement on the position in 2024, when producer groups and equity partners formally sought waivers from allocated volumes.[24] The obligation is nonetheless a real constraint on marketing flexibility and should be modelled as such, not dismissed as nominal.

Conclusion

Five years on, Nigeria has a single, published and largely gazetted framework in which licence terms, fiscal outcomes, host-community obligations and decommissioning liabilities can each be identified in advance and incorporated into investment models. That is a substantive change from a regime in which material terms were more often negotiated and outcomes could turn on institutional relationships. This greater legibility is a necessary precondition for institutional capital, and the Act has delivered it.

Judged as an investment proposition, the result is encouraging but not yet definitive. The Act has made Nigeria's petroleum regime more governable, improved the visibility of fiscal and regulatory obligations and created clearer channels for community participation and asset stewardship. The remaining challenges are familiar: project costs and infrastructure constraints continue to affect economics; security and production reliability require sustained attention; regulators must continue to build execution capacity; and NNPC Limited's commercial transition will be tested through financial performance and accountability. The successive fiscal measures, the more detailed decommissioning regime and a firmer enforcement posture since late 2025 indicate that the government is continuing to refine implementation rather than treating enactment as the end of reform. Credibility has improved, competitiveness is developing and durability will be measured through practice — when funds are drawn, Trust disputes are resolved and obligations are enforced. Sophisticated capital should therefore view the Act as a usable framework whose remaining risks can be diligenced, negotiated and priced. That is a considerable advance on where Nigeria stood in 2021, while leaving meaningful work ahead.

Endnotes

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2 PIA 2021 (Nigeria), ss 4, 6–10, 18(2)(b) and 31–32.

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8 NUPRC, 2024 Annual Report (n 4) 19 and 25, tables 2.2 and 2.3.

9 NUPRC, 'NUPRC Expects over 30bn Dollars Investments from 22 Offshore Projects' (news release, 5 August 2026); NUPRC, 'NUPRC Welcomes ExxonMobil's 1bn Dollar Investment' (news release, 8 July 2026). The investment range is a Commission projection.

10 NUPRC, 2024 Annual Report (n 4) 6–8 and 37.

11 NUPRC, 'Nigeria Meets OPEC Quota for Third Consecutive Month as Production Hits 1.67mbpd in July 2026' (news release, August 2026).

12 NUPRC, 2024 Annual Report (n 4) 3.

13 PIA 2021 (Nigeria), ch 3, ss 234–240; Nigeria Upstream Petroleum Host Communities Development Regulations 2022 (Nigeria).

14 Nigeria Upstream Petroleum Host Communities Development Regulations 2022 (Nigeria), reg 23(2); NUPRC HostComply portal publications; NUPRC, 'NUPRC Oversees Transfer of OLO Oilfield Host Community Obligation from TotalEnergies to Aradel' (news release, 27 February 2026).

15 NEITI, 2021 Oil and Gas Industry Report (NEITI 2023), recommendations on alignment of the Niger Delta Development Commission with host community development funds.

16 PIA 2021 (Nigeria), s 53(6) and (7).

17 ibid, ss 9(4) and 64.

18 ibid, s 65 and Second Schedule.

19 Nigeria Upstream Decommissioning and Abandonment Regulations 2026 (Nigeria), SI 15/2026, Official Gazette No 45, vol 113, 9 March 2026.

20 NUPRC, 2024 Annual Report (n 4) 31–32, table 2.9.1 and figure 2.9.1.

21 NUPRC, 2024 Annual Report (n 4) 64, on ministerial consents and the Upstream Asset Divestment and Exit Guidance Framework.

22 NUPRC, 'NUPRC Releases Q2 Report on DCSO Showing 97.4% Performance' (news release, 10 August 2026).

23 NUPRC, 2024 Annual Report (n 4) 9–10.

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