THE NIGERIAN UPSTREAM PETROLEUM REGULATORY COMMISION (NUPRC)

2024 ANNUAL REPORT

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EXECUTIVE SUMMARY

In accordance with the provisions of sections 24(9) and (10) of the Petroleum Industry Act 2021, The Nigerian Upstream Petroleum Regulatory Commission (NUPRC) is charged with the responsibility of presenting annual report of its operations, performance, and an audited financial account to the Honourable Minister of Petroleum Resources for the year not later than 31st March of the following year.

The fourth edition of the Commission's 2021 Annual Report highlights significant achievements and initiatives by NUPRC over the past year, which have positively impacted the industry and the economy.

The Nigeria 2024 Licencing Round is another second in a series of bid rounds, aimed at further development of this prospective petroleum basin and will be held in accordance with the Petroleum Industry Act 2021 (PIA), with its enhanced legal and regulatory frameworks that seek to encourage new investors and investments into the next phase of exploration in Nigeria.

As at 1/1/2024, the hydrocarbon reserve stood at **37.50** billion bbls for Oil and Condensate. **209.26** trillion scf for associated and non-associated gas. 2024 crude oil reserves increased by 1.45% from January 1, 2023, when compared with 2023 which stood at 36.096 billion barrels for (Oil + Condensate). Gas Reserves status as of January 1, 2024, is **209.26 TCF** representing a minimal net increase of 0.21% over January 1, 2023, position of 208.83 TCF. The total volume of crude produced for 2024 is **578,521,740 barrels** (**482,819,991 barrels** of Oil and **95,701,748 barrels** of Condensate). The daily average production figure is **1,580,369 million** barrels per day (**1,318,939** barrels of Oil per day and **261,430** barrels of Condensate per day). Production performance against TAR in 2024 was about **67%**.

A total of 2.511TCF of Associated and Non-Associated Gas was produced at an estimated daily average production of 6.86BCF/D. This represents a slight increase of about 0.53% compared to year 2023. The daily average Associated, and Non-Associated Gas production stood at 3.924 BCF/D and 2.938 BCF/D representing 57.2% and 42.8%, respectively. A total of 2.317TCF (92.26%) was utilised, 0.193TCF (7.64%) was flared and 0.003TCF (0.10%) was reported as shrinkage. The net addition to 1.1.2024 reserves is

The total approved budget for 2024 was N N286,936,780,410.37 with total income of N281,343,861,025.79 and total expenditure was N191, 115,525,044.54.

The total revenue generated was N 12,250,607,908,453.30 which signified a 76.74% increase as compared to the annual budget of N6,931,236,009,076.00.

732 oil spill incidents were reported. 59.01% of the spills was a result of sabotage.

The Commission has successfully closed out 6 cases in the year 2024.

INTRODUCTION

The Commission's 2024 Annual Report is in fulfilment of the Petroleum Industry Act 2021, Sections 24(9) and (10). The Commission is statutorily required to submit to the Honourable Minister of Petroleum Resources an annual report of its operations and performance.

The report is structured in accordance with the PIA, starting with, Development & Production, Exploration & Acreage Management, Health Economic Regulation & Strategic Planning, Safety, Environment & Community, Corporate Services & Administration, and Finance & Accounts.

1.0 DEVELOPMENT AND PRODUCTION

1.1 RESERVES

Table 1.1: Hydrocarbon Reserves as at 1/1/2024.

Oil (Billion Barrels)	Condensate (Billion Barrels)	Associated Gas Reserves (Trillion SCF)	Non-Associated Gas Reserves (Trillion Scf)
31.56	**5.94**	**102.59**	**106.67**
37.50		**209.26**	

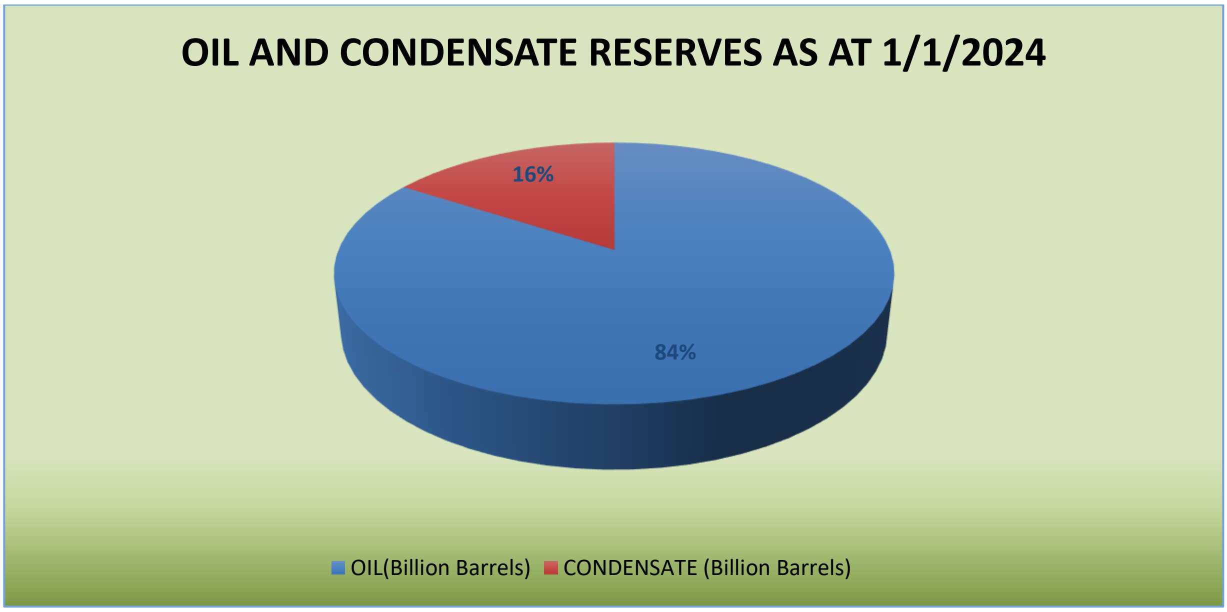


Figure 1.1: Oil and Condensate Reserves as at 1/1/2024.

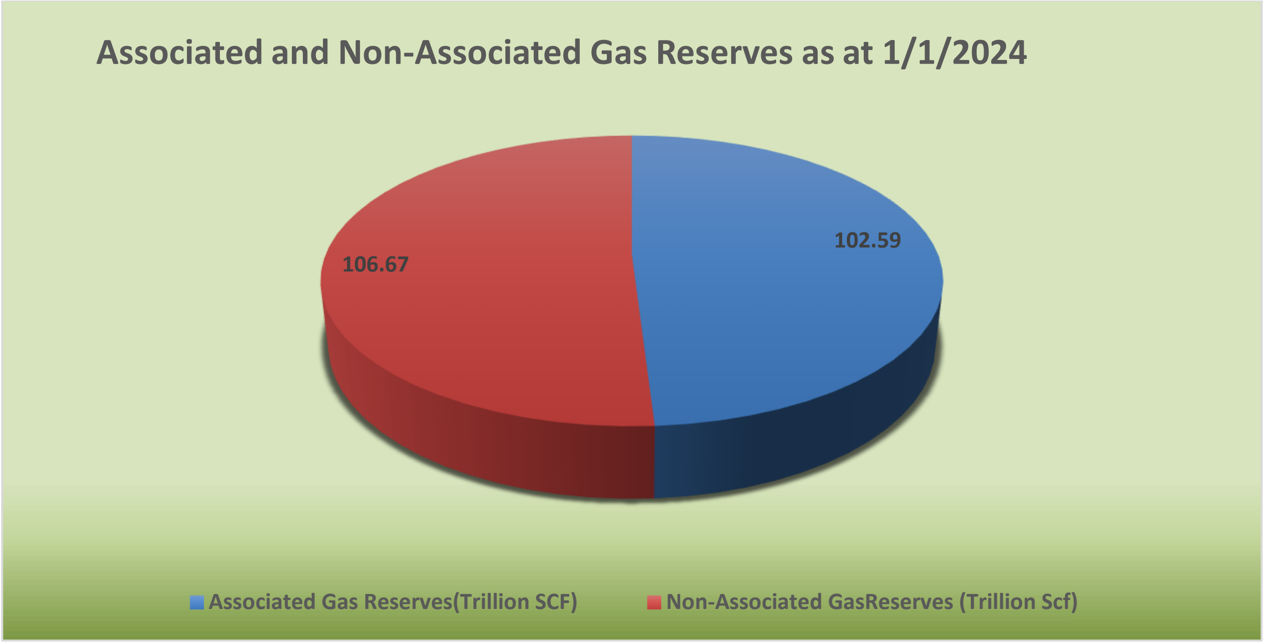


Figure 1.2: Associated And Non-Associated Gas Reserves as at 1/1/24

The National Gas Reserves status as of January 1, 2024, is **209.26 TCF** representing a minimal net increase of 0.21% over January 1, 2023, position of 208.83 **TCF.**

1.1.2 COMPARISON OF 2023 VS 2024 CRUDE OIL AND CONDENSATE RESERVES

2024 crude oil reserves increased by 1.58% and condensate increased by 0.67% respectively when compared with 2023. which stood at 37.50 billion barrels for (Oil + Condensate) and 209.26 TCF for (Associated + Non-Associated Gas) respectively.

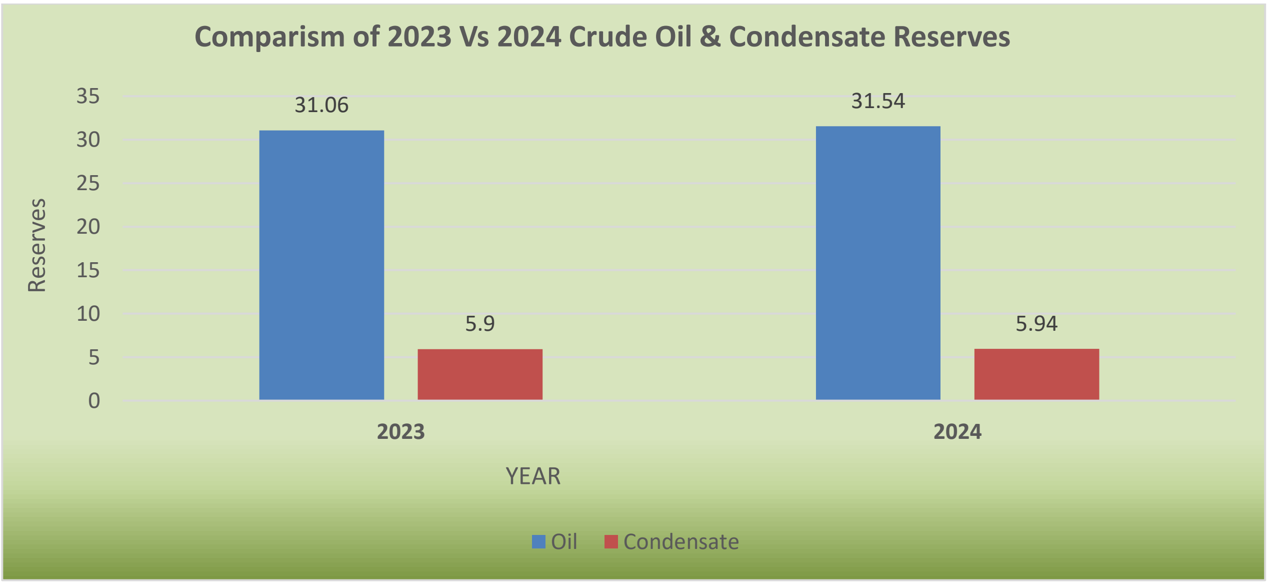


Figure 1.3: Comparison of 2023/2024 Oil and Condensate Reserve

1.2 OIL PRODUCTION

1.2.1 PRODUCTION ALLOCATION AND CURTAILMENT

1.2.2 TECHNICAL ALLOWABLE RATE (TAR)

The technical allowable rate (TAR) is the optimised production capacity of all wells in-country that is determined by the Commission after the execution of the statutory bi-annual maximum efficiency rate test (MER) by all operators. The MER test serves as the first technical basis for hydrocarbon measurement and accounting.

Table:1.2 2024 approved Technical Allowable Rat (TAR)

	OIL (BOPD)	CONDENSATE (BPD)	Supplementary TAR (BOPD)	OIL + COND. (BPD)
1H2024	1,961,426	374,066	112,110	2,335,492
2H2024	1,857,675	372,109	86,964	2,229,784
	3,819,101	746,175	119,074	4,565,276

1.2.3 PROVISIONAL PRODUCTION

The total volume of crude produced for 2024 is **578,521,740 barrels** (**482,819,991 barrels** of Oil and **95,701,748 barrels** of Condensate). The daily average production figure is **1,580,369 million** barrels per day (**1,318,939** barrels of Oil per day and **261,430** barrels of Condensate per day).

Production performance against TAR in 2024 was about **67%**.

*** Please note that these figures are unreconciled volumes and should not be reported as export volumes. Kindly note that unreconciled volumes play an important role in reservoir management, production measurement and accounting.**

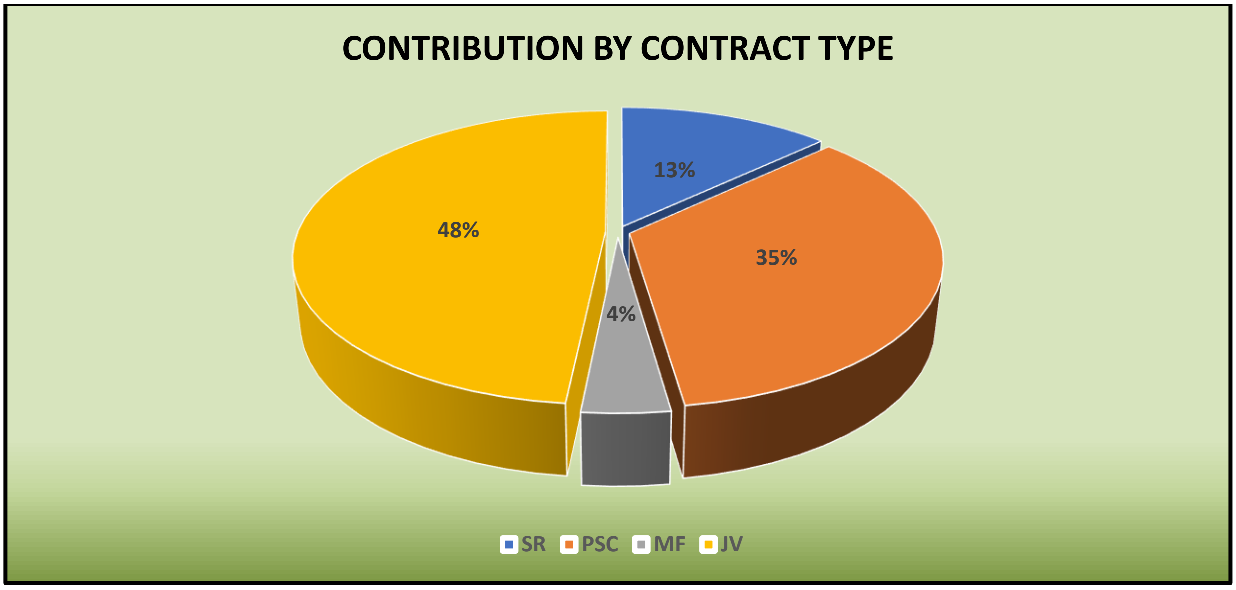


Figure1.4: Production percentage (%) contribution by contract type

Table 1.3: Production percentage (%) contribution by contract type

Sole Risk (SR)	13%
Production Sharing Contract	35%
Marginal Field	4%
Joint Venture	48%

1.2.4 PRODUCTION CONTRIBUTION BY TERRAIN

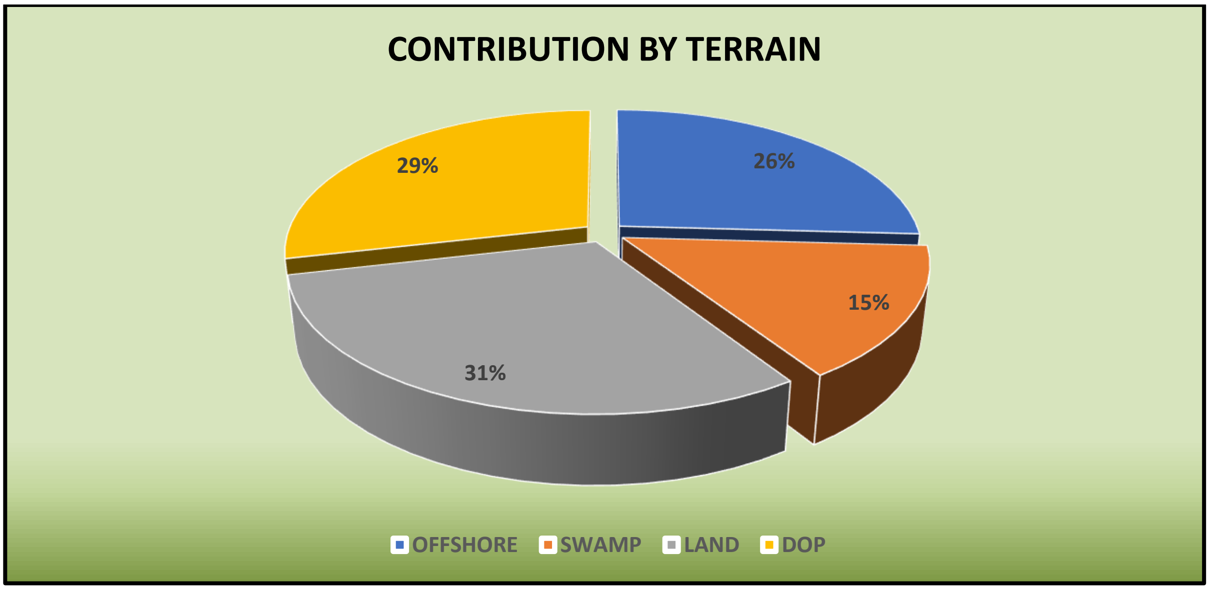


Figure 1.5: Production percentage (%) Contribution by Terrain

Table 1.4: Production percentage (%) Contribution by Terrain

Swamp	15%
Land	31%
Offshore	26%
Deep Offshore (DOP)	29%

1.2.5 CRUDE OIL & CONDENSATE PRODUCTION ON COMPANY BASIS

NEPL is the highest single producer for 2024, contributing 11.9% of the Nations production, followed by SPDC with 10.6% and MPNU with 9.4%.

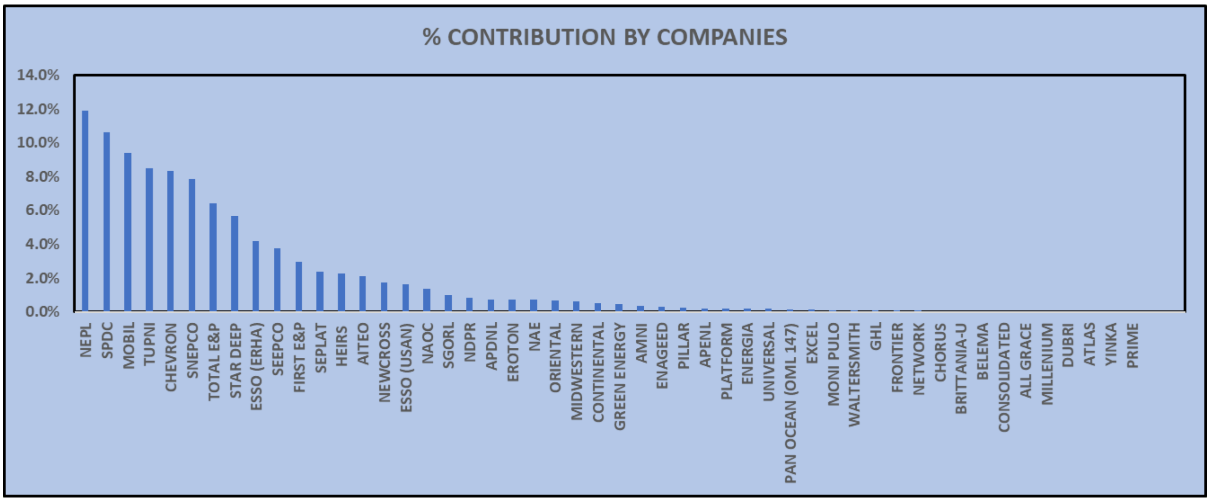


Figure 1.6 2023 Provisional Crude and Condensate Production (bbl) On company Basis

1.2.6 COMPARISON BETWEEN 2023 vs 2024 PROVISIONAL PRODUCTION

Table 1.5: Comparison of 2023 vs 2024 provisional production performance.

*PROVISIONAL PRODUCTION (2023 VS 2024)			
	2023	2024	% PERFORMANC
OIL (BBLS)	457,979,318	482,819,991	5%
CONDENSATE (BBLS)	94,974,702	95,701,748	1%
OIL + CONDENSATE (BBLS)	552,954,019	578,521,740	5%
AVG. OIL (BOPD)	1,255,466	1,318,939	5%
AVG. CONDENSATE (BPD)	260,194	261,430	0.5%
OIL+CONDENSATE (BPD)	1,515,660	1,580,369	4%

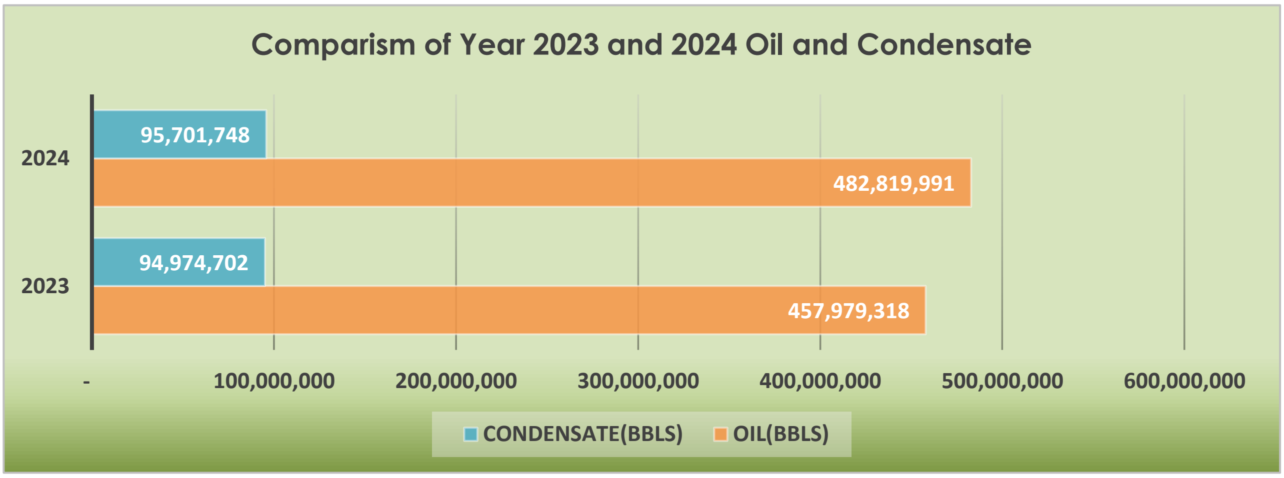


Figure 1.7: Comparison Of Year 2023 And 2024 Oil & Condensate

1.2.7 DOMESTIC CRUDE OIL SUPPLY OBLIGATION (DCSO)

The Commission carried out several initiatives towards implementation of the Domestic Crude Supply Obligations (DCSO) in accordance with the provisions of PIA (2021). They include:

a. The Production Curtailment and Domestic Crude Supply Obligation Regulations was drafted in July and fully gazetted in September 2023 respectively.
b. A letter was sent out to all Exploring and Producing Companies, requesting them to furnish the Commission with copies of all functional crude sales and purchase agreements tied to crude oil sales that might impact on domestic crude oil supply.
c. Series of industry-wide engagements to sensitize the stakeholders (all exploration & producing companies, operators, equity owners, refinery owners) on domestic crude supply obligations. (November 1st, 2023, with Producers) and (November 8th, 2023, with equity owners).
d. Facilitated domestic crude supply to Dangote refinery and other refiners using the monthly production curtailment platform (February 16th, 2024)
e. Established a working committee (comprising of NUPRC, Oil Producers Trade Section (OPTS), Independent Petroleum Producers Group (IPPG), Crude Oil Refinery-Owners Association of Nigeria (CORAN), NUIMS) whose objective was to develop a comprehensive framework that addresses major concerns that could affect the implementation of the DCSO policy (26th – 27th March 2024
f. Developed metrics that take into consideration of every producer's functional capability (past, present and forecast) before allocating them a daily obligation; to be issued to every producer on a bi-annual basis.
g. DCSO guidelines using the operational template jointly developed by industry stakeholders, was finally endorsed by the CCE (July 11th, 2024).

h. All Companies with the forecasted ability to produce more than 3kbpd were issued their domestic monthly obligations for the rest of the year 2024 (July 31st, 2024).
i. The Commission received several pushbacks from IPPG, OPTS, some producers and their equity partners via formal letters, either requesting for waivers on the allocated monthly obligations, or giving detailed explanations why they might not be able to meet up with the allocated volumes etc. (August 16th, 2024).
j. Meeting with the Permanent Secretary, Ministry of Petroleum Resources and other relevant stakeholders in the industry towards the implementation of domestic crude supply obligations (Sept 2nd, 2024, at the NNPC towers).
k. Following several complaints from operators about the presence of refiners at curtailment meeting, another letter was sent to refiners, notifying them of the Commission's decision to put all refiners' attendance at the monthly Production Curtailment Meeting (PCM) on hold temporarily till further notice (Sept 13th, 2024).
l. The Commission received a letter from NNPCL (via its subsidiary, NNPC Trading Ltd (NTL)), highlighting the status report on crude supply to Dangote Petroleum Refinery and Petrochemicals (DPRP) (Sept 20th, 2024)
m. The Commission facilitates crude supply to local refineries as needed
n. Provided data for publishing on the Commission's website and three newspapers on July 1st, 2024, and Jan 1st, 2025, in line with the provisions

1.2.8 DEFERRED OIL AND CONDENSATE VOLUMES IN 2023

The average production deferment for 2023 was 183,011bopd.

1.3 GAS

1.3.1 GAS PRODUCTION, UTILIZATION AND FLARE

A total of 2.511TCF of Associated and Non-Associated Gas was produced at an estimated daily average production of 6.86BCF/D during the year under review. This represents a slight increase of about 0.53% compared to year 2023. The daily average Associated, and Non-Associated Gas production stood at 3.924 BCF/D and 2.938 BCF/D representing 57.2% and 42.8%, respectively. A total of 2.317TCF (92.26%) was utilised, 0.193TCF (7.64%) was flared and 0.003TCF (0.10%) was reported by NAOC and TEPNG as shrinkage. These volumes were produced by forty-eight (48) oil and gas companies as shown in the figure and Table below. I*t is worthy to note however,* ***that Q4 volumes are yet to be reconciled*** *with the operators, thus there may be slight changes upon final reconciliation in absolute figures, and percentage changes for year 2024.*

Table 1.6: 2023 Annual Gas Production, Utilization and Flare Data (MMscf)

S/NO	COMPANIES	CONTRACT TYPE	TERRAIN	GAS PRODUCTION AG	NAG	AG+NAG	GAS UTILIZATION	GAS FLARED	GAS SHRINKAGE	% GAS FLARED
1	SHELL	JV	Onshore/Offshore	72,798.75	383,927.44	456,726.19	442,715.88	14,010.32	-	3
2	SNEPCO	PSC	Deep Offshore	32,431.74	-	32,431.74	32,121.63	310.11	-	1
3	CHEVRON	JV	Offshore	126,965.20	91,635.59	218,600.79	203,063.14	15,537.66	-	7
4	CHEVRON STAR DEEP	PSC	Deep Offshore	153,525.05	-	153,525.05	148,016.89	5,508.16	-	4
5	MOBIL	JV	Onshore/Offshore	277,460.53	-	277,460.53	253,862.00	23,598.52	-	9
6	ESSO	PSC	Deep Offshore	142,375.64	-	142,375.64	133,873.10	8,502.54	-	6
7	NAOC	JV	Onshore/Offshore	50,065.81	105,338.94	155,404.75	144,296.41	8,966.42	2,141.92	6
8	TEPNG	JV	Onshore/Offshore	132,373.50	117,755.96	250,129.46	247,230.12	2,476.66	422.68	1
9	TUPNI	PSC	Deep Offshore	172,819.32	-	172,819.32	171,001.25	1,919.09	-	1
10	NAE	PSC	Deep Offshore	16,861.70	-	16,861.70	13,910.42	2,951.28	-	18
11	Antan Producing	PSC	Onshore/Offshore	26,436.13	-	26,436.13	8,547.46	17,888.67	-	68
12	PAN OCEAN	PSC	Onshore	10,686.10	-	10,686.10	10,101.05	585.05	-	5
13	NEPL	SR	Onshore/Offshore	103,537.89	143,103.03	246,640.91	204,340.57	42,301.54	-	17
14	ENAGEED	PSC	Onshore	1,354.01	-	1,354.01	50.33	1,303.68	-	96
15	AMNI	SR	Offshore	2,677.36	-	2,677.36	2,018.34	659.02	-	25
16	MONIPULO	MF	Offshore	141.92	-	141.92	19.27	122.65	-	86
17	ARADEL	MF	Onshore	3,963.63	7,820.14	11,783.77	11,695.23	88.54	-	1
18	CONTINENTAL	SR	Offshore	3,139.35	-	3,139.35	229.91	2,909.44	-	93
19	CONSOLIDATED	SR	Offshore	261.67	-	261.67	85.97	175.70	-	67
20	DUBRI	SR	Onshore	377.42	-	377.42	48.87	328.55	-	87
21	PLATFORM	MF	Onshore	3,290.42	7,426.84	10,717.26	10,299.57	417.69	-	4
22	WALTER SMITH	MF	Onshore	374.69	197.60	572.28	488.97	83.31	-	15
23	MID WESTERN	MF	Onshore	1,473.09	-	1,473.09	69.36	1,403.73	-	95
24	PILLAR	MF	Onshore	704.84	-	704.84	504.17	200.67	-	28
25	GENERAL HYDROCARB	MF	Offshore	3,594.21	-	3,594.21	3.65	3,590.56	-	100
26	ENERGIA	MF	Onshore	1,944.88	4,862.06	6,806.93	5,831.78	975.15	-	14
27	Britania-U	MF	Offshore	215.21	-	215.21	192.46	22.75	-	11
28	SEPLAT	JV	Onshore	17,837.11	79,464.88	97,301.99	88,643.70	8,658.29	-	9
29	ORIENTAL ENERGY	MF	Deep Offshore	4,816.77	-	4,816.77	4,267.48	549.29	-	11
30	SEEPCO	PSC	Onshore	12,793.09	61,684.44	74,477.54	74,471.47	6.06	-	0
31	FRONTIER	MF	Onshore	794.97	44,225.68	45,020.65	44,589.05	431.60	-	1
32	New Cross	JV	Onshore	8,498.05	-	8,498.05	5,811.79	2,686.27	-	32
33	EROTON (NOEL)	PSC	Onshore	5,929.01	7,628.50	13,557.51	8,418.64	5,138.87	-	38
34	UNIVERSAL ENERGY	MF	Onshore	747.96	-	747.96	49.89	698.07	-	93
35	AITEO	JV	Onshore	7,403.64	-	7,403.64	5,122.23	2,281.41	-	31
36	NETWORK	MF	Onshore	886.41	-	886.41	119.77	766.64	-	86
37	BELEMA OIL	JV	Onshore	338.41	-	338.41	91.50	246.91	-	73
38	GREEN ENERGY	MF	Onshore	2,389.30	-	2,389.30	1,716.47	672.83	-	28
39	EXCEL	MF	Onshore	216.25	49.41	265.66	155.49	110.17	-	41
40	MILLENIUM	MF	Onshore	4.76	-	4.76	-	4.76	-	100
41	SGORL	PSC	Onshore	367.90	-	367.90	363.57	4.32	-	1
42	CHORUS ENERGY	MF	Onshore	-	6,033.61	6,033.61	5,857.22	176.40	-	3
43	FIRST E& P COMPANY	MF	Deep Offshore	10,193.21	-	10,193.21	4,433.66	5,759.55	-	57
44	ALL GRACE ENERGY	MF	Onshore	165.82	-	165.82	-	165.82	-	100
45	HEIRS HOLDING OIL & (	JV	Onshore	11,497.32	5,967.93	17,413.39	10,774.62	6,638.76	-	38
46	NEWCROSS PETROLEUM	PSC	Onshore	9,273.34	-	9,273.34	9,273.34	-	-	-
47	AMALGAMATED OIL &	SR	Onshore	-	2,189.25	2,189.25	2,188.19	1.06	-	
48	STERLING GLOBAL EXPL	PSC	Onshore	141.09	5,941.13	6,082.22	6,082.22	-	-	
				1,436,144.5	1,075,252.4	2,511,345.0	2,317,048.1	191,834.6	2,564.6	7.6

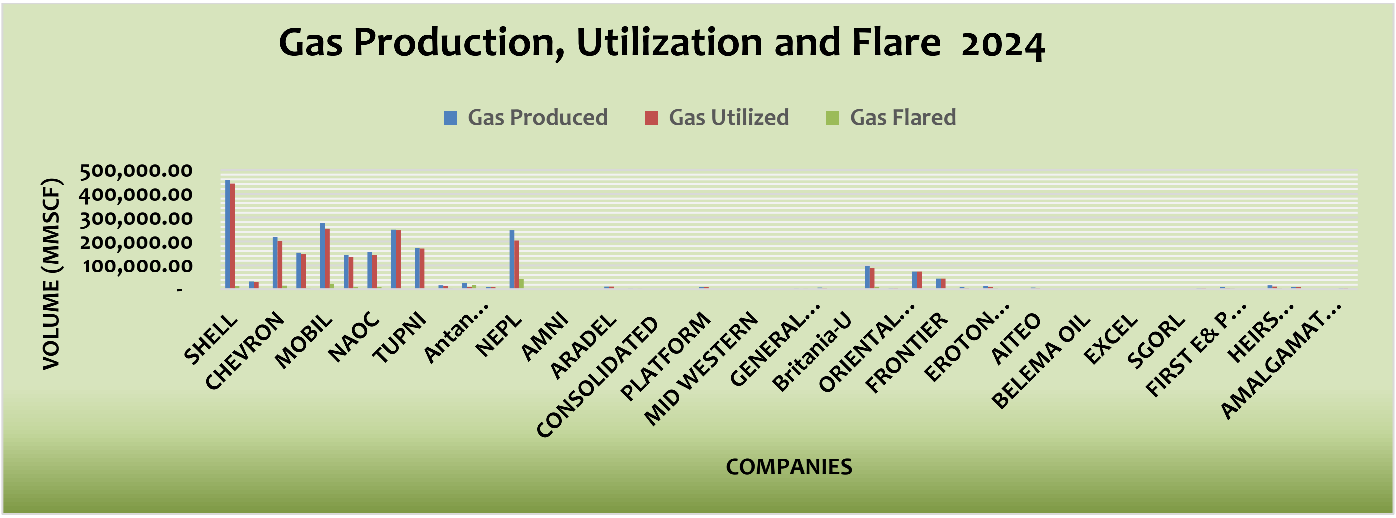


Figure 1.8: Gas production, Utilization & Flared.

1.3.2 Monthly DGDO Performance

In terms of the overall daily DGDO performance, the table and chart below show the average daily supply of gas to the domestic market and the performance in respect to the allocated daily DGDO.

Table 1.7: Monthly DGDO Performance for 2024

Months	Allocated (Mmscf/d)	Delivered (Mmscf/d)	% Performance
January	2,261	1,629	72%
February	2,261	1,559	69%
March	2,261	1,693	75%
April	2,261	1,681	74%
May	2,261	1,721	76%
June	2,261	1,592	70%
July	2,261	1,795	79%
August	2,261	1,656	73%
September	2,261	1,847	82%
October	2,261	1,801	80%
November	2,261	1,917	85%
December	2,261	1,971	87%

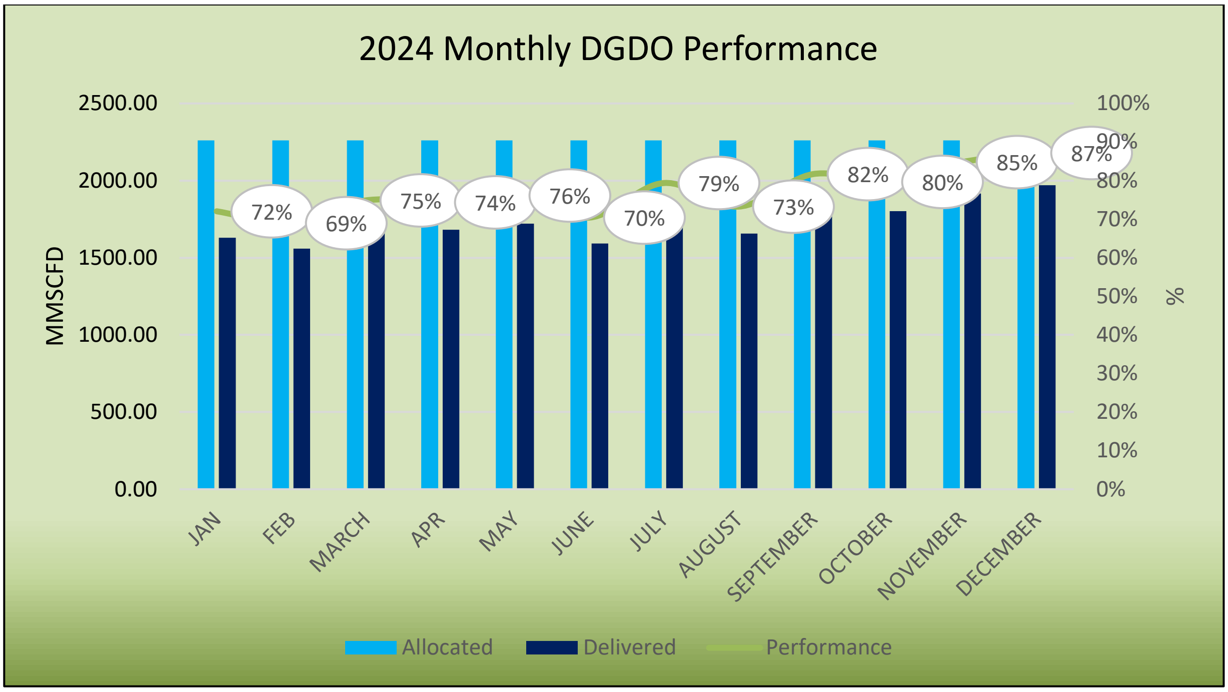


Figure 1.9: 2024 Monthly DGDO Performance

The chart shows that on average, about 77% of the total daily allocated DGDO has been delivered in the year under review.

Challenges Militating Against DGDO Performance.

A. **Gas Infrastructure Issues**

- Inadequate in-country gas infrastructure and interconnectivity
- Gas transmission pressure challenges ELPS (Back pressure & midline booster compression issues)
- Unreliability of the off takers in taking allocated nominations
    - Unavailability of the 24" ELPS since 2018 & frequent outage of the functional 20" Line
- Gas Inventory Challenges on the ELPS (Pressure & Volume Accounting)

B. **Grid Power Infrastructure Constraint**

- Challenges with transmission grid capacity and reliability
- Rejection of power-by-power distribution companies leading to reduced gas offtake.

C. **Security Issues**

- Vandalism and theft in the Niger Delta area affecting liquid evacuation and gas production e.g., Trans Niger Pipeline (TNP) and the Nembe Creek Trunk Line (NCTL) etc.

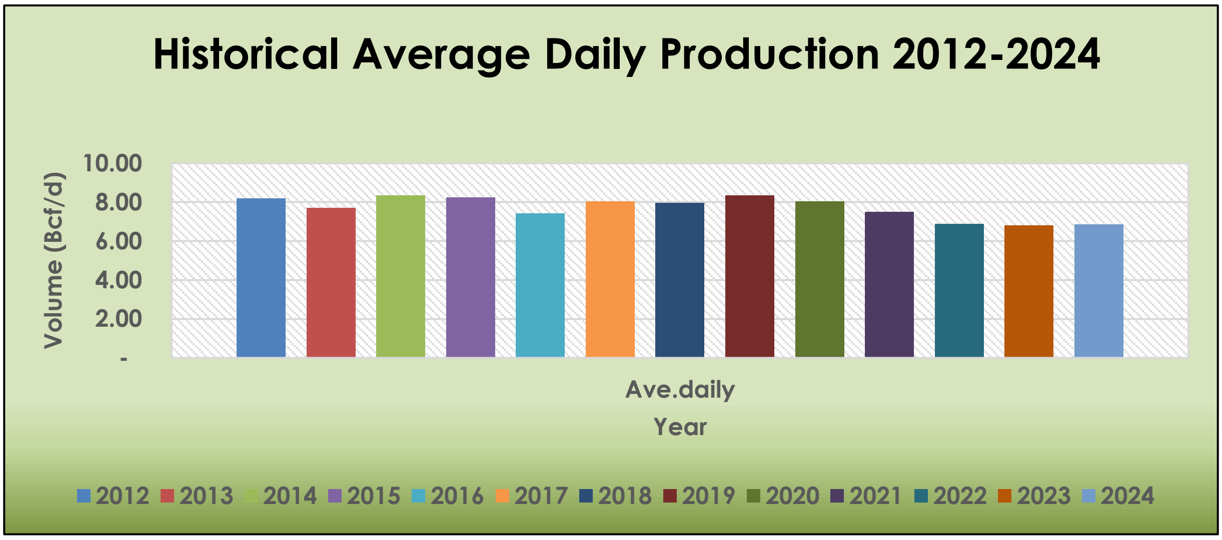


Figure 1.9.1: Historical Average daily production performance for 2012-2024

1.3.3 GAS PRODUCTION ON CONTRACT TYPE BASIS

It is important to note that out of the 2.511Tcf of Gas produced during year 2024, Joint Venture (JV) companies contributed 1.489 Bcf (59.30%), Production Sharing Contract companies produced a total of 0.660 Bcf (26.29%), Sole Risk (SR) companies produced 0.255 Bcf (10.17%), while Marginal Fields (MF) produced a total of 0.106 BSCF (4.24%) as depicted in the table and figure below:

Table 1.8: Gas Production on Contract Basis

Contract Type	Total Production (MMSCF)	Total Gas Utilised	Total Gas Flared	Average Production MMSCF/Day)	% Production	% Utilized	% Flared
Joint Venture (JV)	1,489,277.20	1,401,611.38	85,101.22	4,069.06	59.30	60.49	44.36
Production Sharing Contract (PSC)	660,248.20	616,231.38	44,117.84	1,803.96	26.29	26.60	23.00
Sole Risk (SR)	255,285.96	208,911.85	46,375.31	697.50	10.17	9.02	24.17
Marginal Field (MF)	106,533.66	90,293.48	16,240.18	291.08	4.24	3.90	8.47
TOTAL	**2,511,345.02**	**2,317,048.09**	**191,834.55**	**6,861.60**	**100.00**	**100.00**	**100.00**

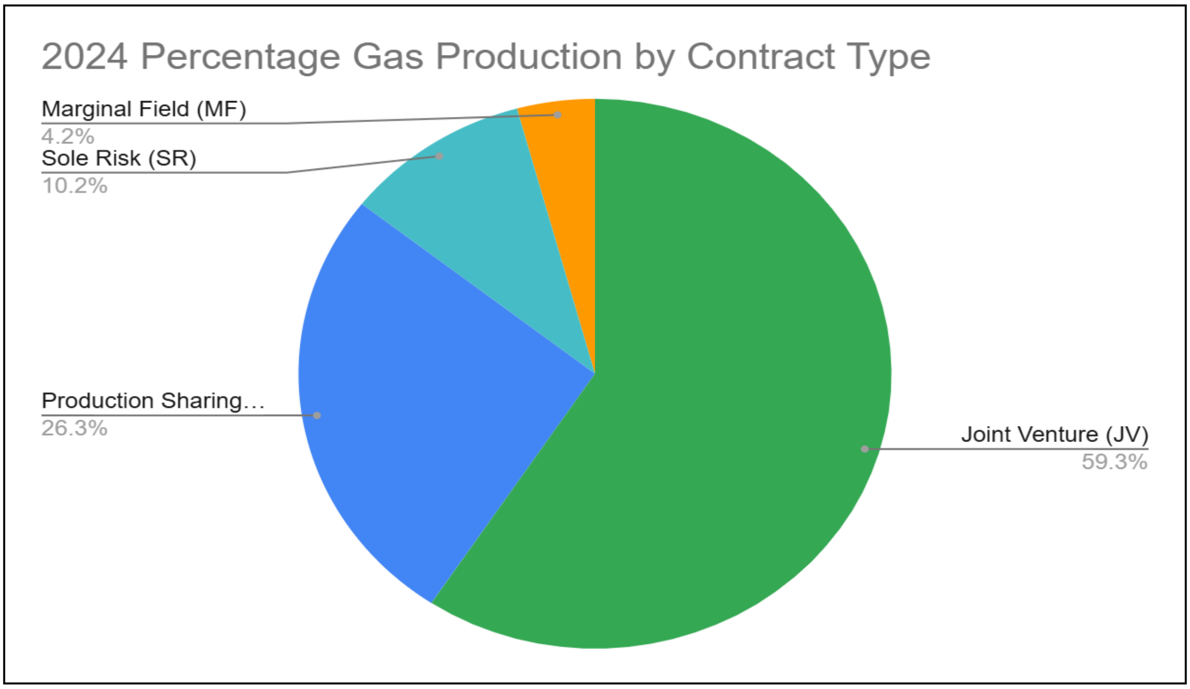


Figure 2.0: Gas production on contract basis

1.3.4 GAS UTILIZATION

2.511 TCF of gas was produced and a total of 2.317TCF (92.26%) was utilized which is a slight uptick of about 0.67% compared to the previous year 2023. Gas utilization by the Companies were for in-house gas consumption for fuel, gas lifting, injection for pressure maintenance or storage and sales to either the domestic or export markets. Export sales (39.5% gas produced) continue to trump domestic market (28.7% gas produced) which is indicative of the historical challenges confronting the domestic gas sector. The details of gas utilization breakdown for the period are as shown in the table below.

Table 1.8: Gas Utilization Profile for the year 2023 (MMSCF)

Gas utilization	Volume (MMscf)	% Utilization
Fuel Gas	140738.0532	6.1
Gas Lift	110884.9623	4.8
Gas re-Injection	483476.518	20.9
Domestic Sales	665781.266	28.7
Export Sales	916167.2937	39.5
Total	**2,317,048.093**	**92.263**

1.3.5 GAS FLARE

2.511 TCF of gas produced, a total of 0.1918 TCF (7.64%) was flared. This represents 0.28% difference compared with the 7.36% flaring recorded the previous year. The table below shows the volume of gas flared in the country on monthly basis.

Table 1.9: Monthly Gas Flare Profile for the January-December (MMSCF)

Month	Gas Production (MMscf)	Gas Flared Volume (MMscf)	% Flared
January	221,517	18,268	8.25
February	192,768	15,633	8.11
March	198,590	15,039	7.57
April	189,794	14,379	7.58
May	201,494	14,059	6.98
June	202,892	14,416	7.11
July	223,784	15,356	6.86
August	212,604	15,808	7.44
September	204,505	14,599	7.14
October	220,250	17,145	7.78
November	227,821	18,065	7.93
December	215,324	19,067	8.85
Total	**2,511,345.0**	**191,834.6**	**7.64**

Flaring contributions by operating companies with average daily flare above 2MMscf/d during the year. "Others" are companies whose flare is less than 2mmscf per day in 2024.

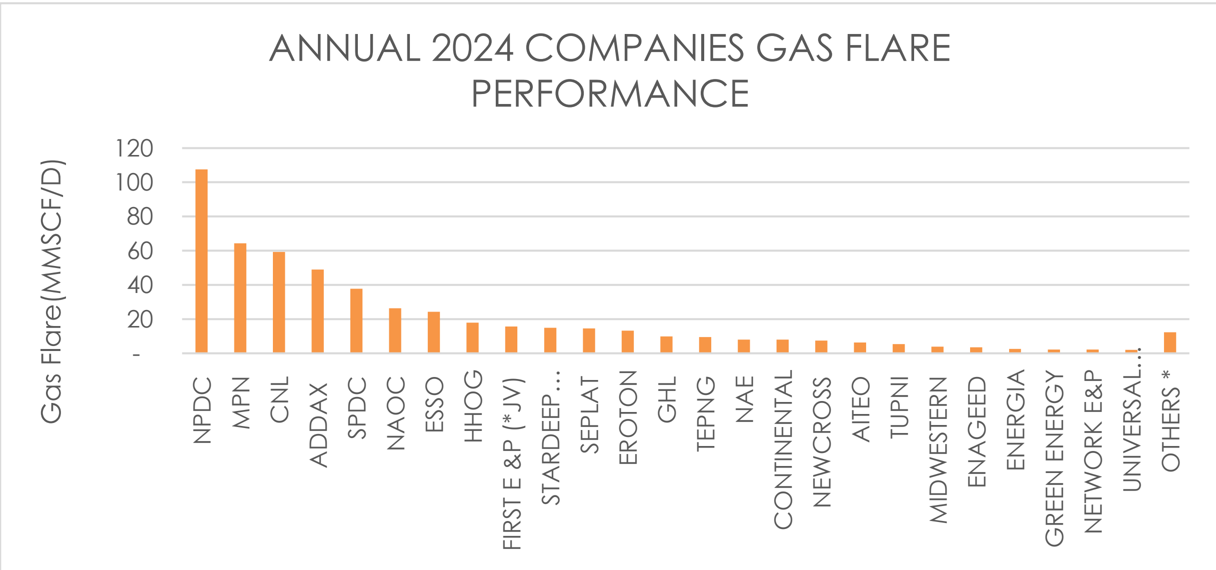


Figure 2.1: Companies Flare Performance in 2024

1.3.6 DOMESTIC GAS DELIVERY OBLIGATION AND PERFORMANCE.

In terms of the overall daily DGDO performance, the table and chart below show the average daily supply of gas to the domestic market and the performance in respect to the allocated daily DGDO.

Table 2.0: 2023 DGSO Allocation and Performance

Months	Allocated (Mmscf/d)	Delivered (Mmscf/d)	% Performance
January	2,261	1,629	72%
February	2,261	1,559	69%
March	2,261	1,693	75%
April	2,261	1,681	74%
May	2,261	1,721	76%
June	2,261	1,592	70%
July	2,261	1,795	79%
August	2,261	1,656	73%
September	2,261	1,847	82%
October	2,261	1,801	80%
November	2,261	1,917	85%
December	2,261	1,971	87%

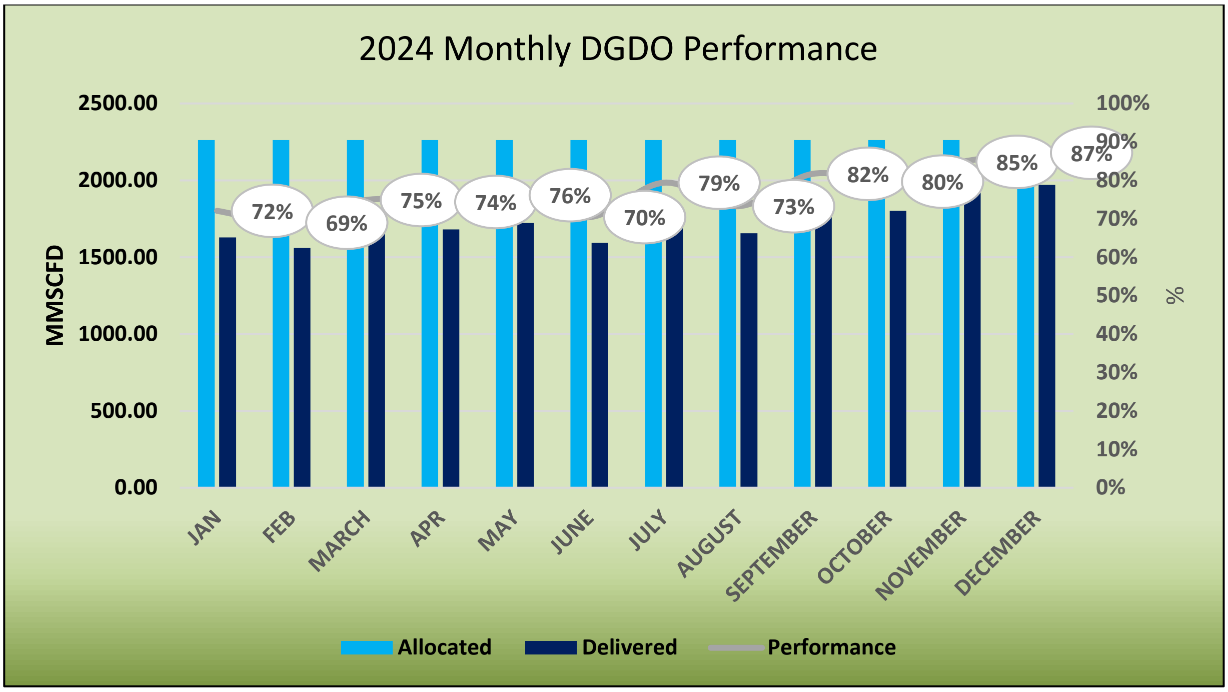


Figure 2.2: Domestic Gas Delivery Obligation (DGDO) Performance for 2024

1.3.7 FIELD DEVELOPMENT PLAN (FDP)

It is imperative to note that in 2024 a total of **forty-one (41) FDPs were approved**, and **one (1) FDP was disapproved**, this represents an **approval rate of about 80%.** Our benchmark of 100% close out rate would have been achieved but for the eleven (11) FDPs currently under review which were submitted within the last quarter of the year 2024. It is important to highlight that all FDP applications submitted within Q1 and Q3 2024 have been closed out. Additionally, thirty-four (34) and seven (7) of the approved forty-one (41) FDPs intend to develop oil and NAG fields respectively.

Also, figure 2 below highlights the distribution by terrain of the **forty-one (41) approved FDPs in year 2024**; it shows that 64% of the approved FDPs aim to develop fields in land terrain, while 6% propose to develop fields in swamp terrain, 19% aim to develop fields in offshore terrain and 11% intend to develop fields in deep offshore terrain. Evidently, this shows a significant preference by operators to develop fields on land terrain, which has a lower cost of development compared to the other terrains.

The **thirty-four approved oil field development** plans aim to develop about **1,366.91 MMstb and 10.7 TCF of oil and gas reserves respectively,** with an anticipated oil and gas production of about **572.74 kbopd and 4,113.78 MMscf/day respectively**. On the other hand, the **seven approved NAG field development plans** aim to develop **4.41 TCF of gas reserves** with an anticipated gas production of **1,562 MMscf/day.** In view of current energy realities, achieving the latter shall position Nigeria to meet growing energy demands that is expected from gas as our transition fuel.

Table 2.1: 2024 Approved FDPs with the value addition

S/N	Company	Block	Field	FDP Type	Terrain	Expected Oil Recovery (MMSTB)	Expected Gas Recovery (BSCF)	Expected Condensate Recovery (MMSTB)	Expected Oil Rate (bopd)	Expected Gas Rate (MMscf/D)	Expected Condensate Rate (bcpd)	First Oil Date	CAPEX (US$M)	OPEX (US$M)	UTC ($/boe)	Drilling Commencement Date	Approval Date
1	NEPL	OML 40	Sibiri	FDP	Swamp	14.81	2.23	-	27,300	4	-	Q1 2024	118.40	91.80	14.20		**22 Feb 2024**
2	SPDC	OML 118	Bonga	FDP Rev-10.1	Deep Offshore	12.00	7.00		4,000	2		Q3 2024	66.70	88.60	14.78	Q1 2024	**22 Feb 2024**
3	Seplat Energy	OML 4	Oben	FDP Rev-8	Onshore	26.47	337.68		11,700	199		Q2 2024	263.50	742.20	13.67	Q1 2024	**29 Feb 2024**
4	Seplat Energy	OML 41	Sapele	FDP Rev-1	Onshore	2.60	0.07		1,500	0		Q2 2024	15.46	64.61	33.30	Q1 2024	**29 Feb 2024**
5	Midwestern	OML 56	Umusadege	FDP Rev-1	Onshore							Q3 2024	26.30	12.97	7.51	Q3 2024	**29 Feb 2024**
6	Green Energy	OML 11	Otakikpo	FDP Rev-2	Onshore	92.85	108.81		30,200	37		Q2 2024	-	413.90	17.41	Q3 2024	**4 Mar 2024**
7	CNL	OML 49	Isan	FDP Rev-1	Offshore	2.89	6.65	-	1,970	5	-	Q3 2024	4.29	33.70	34.80	Q3 2024	**4 Apr 2024**
8	CNL	OML 90	Mefa	FDP Rev-2	Offshore	42.34	35.20		22,000	15	-	Q2 2027	296.50	202.29	0.14	Q2 2027	**4 Apr 2024**
9	Aradel Energy Limite	OML 54	Ogbele	FDP Rev-4	Onshore	8.10	157.80		4,800	116		Q2 2024	193.10	427.10	15.30	Q2 2024	**26 Apr 2024**
10	Seplat	OML 38	Orogho	FDP Rev-1	Onshore	10.66	19.87		5,222	18		Q4 2023	69.10	230.40	23.40	Q1 2023	**7 May 2024**
11	SPDC	OML 31	Kolobiri	FDP	Swamp		359.50	7.20		120		Q3 2029	216.58	102.65	6.52	Q3 2029	**7 May 2024**
12	SPDC	OML 28	Abasare	FDP Rev-1	Onshore		379.00	3.80		150		Q2 2029	301.94	59.63	6.40	Q4 2027	**7 May 2024**
13	Britania U	PML 6	Ajapa	FDP Rev-1	Offshore	61.00	95.43		24,500	23			225.00	57.50		Q2 2024	**20 May 2024**
14	TotalEnergies	OML 99	Ikike	FDP Rev-2	Offshore	13.91	4.40		9,800	42		Q1 2025	56.50	21.46	4.69	2029	**4 Jun 2024**
15	TotalEnergies	OML 58	Ibewa NAG	FDP Rev-1	Onshore		343.80			171		Q2 2027	63.93	6.37	7.41	Q2 2026	**19 Jun 2024**
16	NEPL	OML 11	Ohuru-Obuzo-Ngboko	FDP	Onshore	106.00	639.20		27,200	508		Apr-25	706.50	1,256.80	15.06	Q1 2025	**2 Jul 2024**
17	NEPL	OML 11	Okoloma-Obeakpu	FDP Rev-1	Onshore		439.20	41.96		142	7,945	Apr-24	156.10	473.46	5.48	45323	**5 Jul 2024**
18	Seplat	OML 38	Okporhuru	Revision-2	Onshore	4.00	128.79		3,000	60		Q3 2024	63.93	216.40	11.39	Q1 2025	**10 Jul 2024**
19	TEPNG	OML 58	Obagi/ Obagi Deep	FDP Rev-1	Onshore	1.57	512.80		600	403			14.60	2.08	2.54	Q1 2026	**22 Jul 2024**
20	SPDC	OML 28	Gbaran	FDP Rev-8	Onshore		13.34			65		Q4 2024	97.20	14.10	1.14		**22 Jul 2024**
21	TotalEnergies	PML 3	Egina	FDP Rev-3	Deep Offshore	18.00	21.50		4,500	18		Q3 2024	-	51.29	3.16	Q3 2024	**22 Jul 2024**
22	Sunlink	OML 144	HI	FDP Rev-1	Offshore		1,954.00			440		Q2 2029	1,995.00	582.37		Q4 2027	**22 Aug 2024**
23	Esso	OML 139/154	Owowo	FDP	Deep Offshore	443.00	613.00		240,000	315		Oct 2030	6,414.00	2,792.00	23.30	Q3 2028	**12 Aug 2024**
24	All Grace	OML 17	Ubima	FDP Rev-1	Onshore	52.91	89.63	-	14,000	9	-	Q4 2024	253.20	1,390.38	38.06	Q4 2024	**13 Aug 2024**
25	NEPL	OML 13	Ibotio	FDP	Onshore	19.19	39.60	-	7,000	20		Q2 2026	153.65	268.93		Q4 2024	**30 Aug 2024**
26	NEPL	OML 13	Ekim	FDP	Onshore		921.00	14.00		475	6,749	Q2 2026	341.00	461.00		Q4 2024	**4 Sep 2024**
27	SGEPL	OML 157	Ikwegbu	Revision	Onshore	17.84	56.39		5,600	18		Q4 2024	112.41	284.88	14.35	Q4 2024	**17 Sep 2024**
28	TotalEnergies	OML 102	Ofon	FDP Rev-3	Offshore	3.50			1,300			Q1 2025	6.22	7.93	3.79	Q4 2024	**17 Sep 2024**
29	Enageed	OML 148/111	Oki-Oziengbe South	FDP Rev-1	Onshore	39.30	112.60		15,175	25		Q3 2024	176.10	646.21	17.09	Q3 2024	**19 Sep 2024**
30	Apani Energy	PPL 225	Apani	FDP	Onshore	0.44	27.79	1.15	300	23	800	Q1 2025	44.08	11.60	13.02	Q4 2027	**26 Sep 2024**
31	TotalEnergies	OML 99	Amenam	Revision-5	Shallow Water	11.90	34.30		16,000	53		Q3 2026	172.35	66.16	11.55	Q4 2026	**2 Oct 2024**
32	SEEPCO	OML 143	Unere	Revision-1	Onshore	27.19	44.95		5,400	7		Q4 2024	117.70	216.97		Q3 2024	**2 Oct 2024**
33	SEEPCO	OML 143	Ameshi	Revision-1	Onshore	27.39	30.02		6,100	7		Q1 2025	121.75	208.09	22.95	Q4 2024	**2 Oct 2024**
34	Conoil	OML 136	Amatu-Akarino	FDP	Offshore	14.10	2,688.00	15.00	3,000	550	3,365	Q4 2025	1,530.00	2,088.00		Q4 2024	**25 Oct 2024**
35	Multisub Enerrgy	PPL218	Olure	FDP	Shallow Water	40.84	240.54		4,300	6		Q1 2026	131.00	1,403.00	21.80	Q1 2025	**30 Oct 2024**
36	IUCL	PPL 236	Ibom	FDP	Offshore	23.56	34.92		11,847	8		Q4 2024	269.00	567.89	7.51	Q1 2025	**8 Nov 2024**
37	Ingentia Energies	PPL 202	Egbolom	FDP	Onshore	83.28	47.08		22,500	13		Q4 2025	316.54	3,589.02	43.24	Q3 2025	**15 Nov 2024**
38	Pillar	PML 17	Umuseti-Igbuku	FDP Revision	Onshore	2.11	3.17		1,478	2		Q2 2025	16.90	0.30	8.15	Q1 2025	**28 Nov 2024**
39	SGORL	OML 146	Agu	FDP Revision	Onshore	35.96	55.82		8,450	11		Q1 2025	196.74	452.26	17.82	Q4 2024	**21 Nov 2024**
40	Star Deep Water	127 (PML 52)/OM	Agbami	FDP Rev-5	Deep Offshore	74.00	47.40		25,000	30		Q3 2026	2,024.30	700.66	36.82	Q2 2026	**4 Dec 2024**
41	SEEPCO	OML 143	Enyie	FDP Rev-3	Onshore	33.20	45.61		7,000	7		Q2 2025	143.40	256.44	23.18	Q1 2025	**16 Dec 2024**
						1,366.91	**10,698.09**	**83.11**	**572,741.80**	**4,113.78**	**18,859.00**		**17,490.97**	**20,563.40**	**15.46**		

The average unit development cost for the approved FDPs on terrain basis are as follows.

Table 2.2: Average Unit development cost for approved FDPs on terrain basis

S/N	TERRAIN	UTC/ ($/boe)
1	Onshore	16.27
2	Swamp	14.17
3	Offshore	10.41
4	Deep offshore	19.52

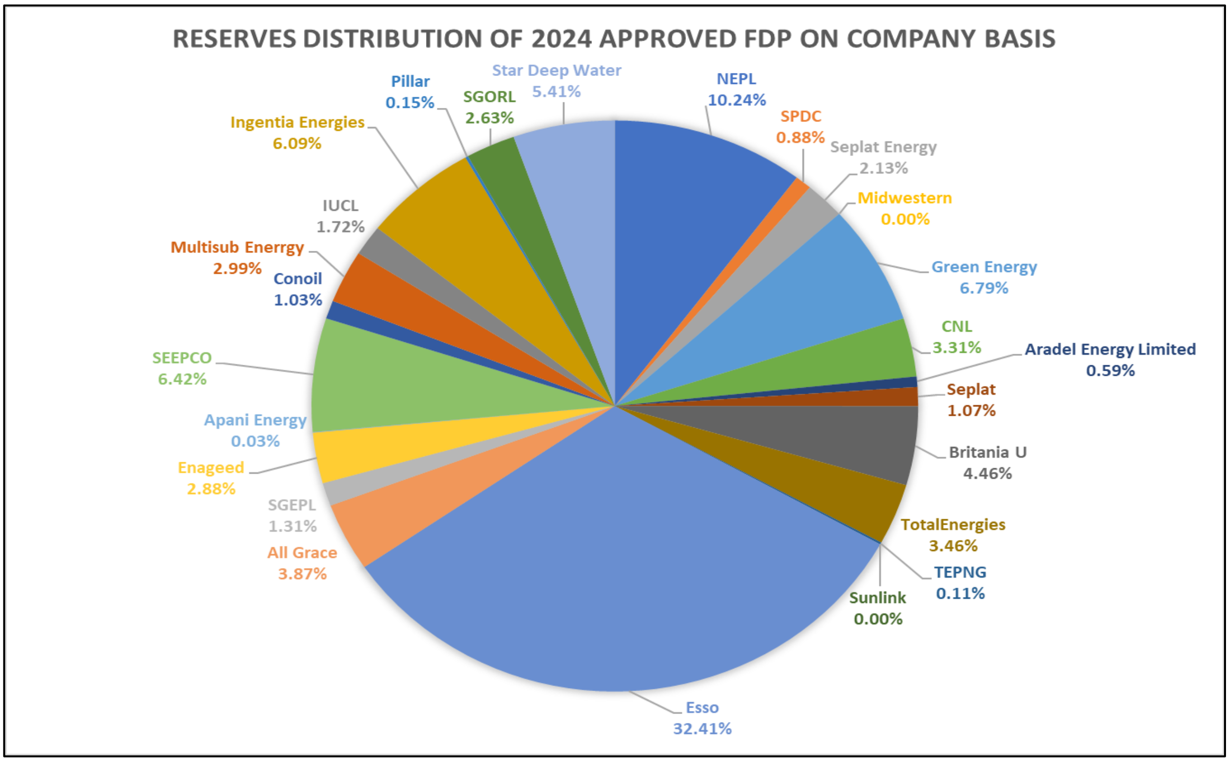


Figure 2.3: Reserve distribution of 2024 approved FDP on company basis

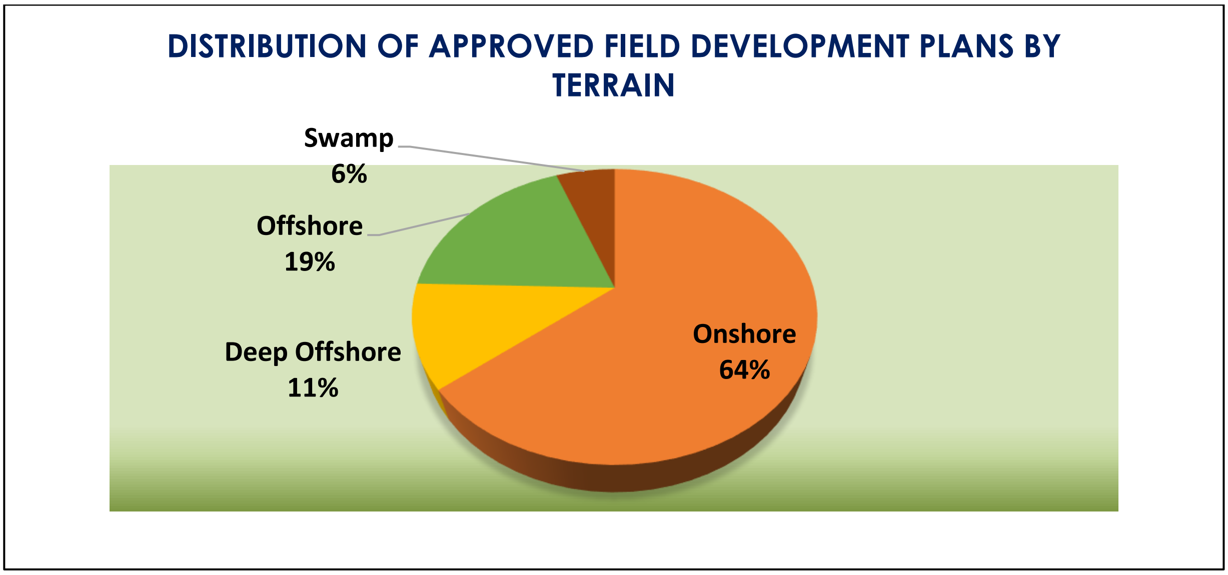


Figure 2.4: Year 2024 FDP distribution by terrain

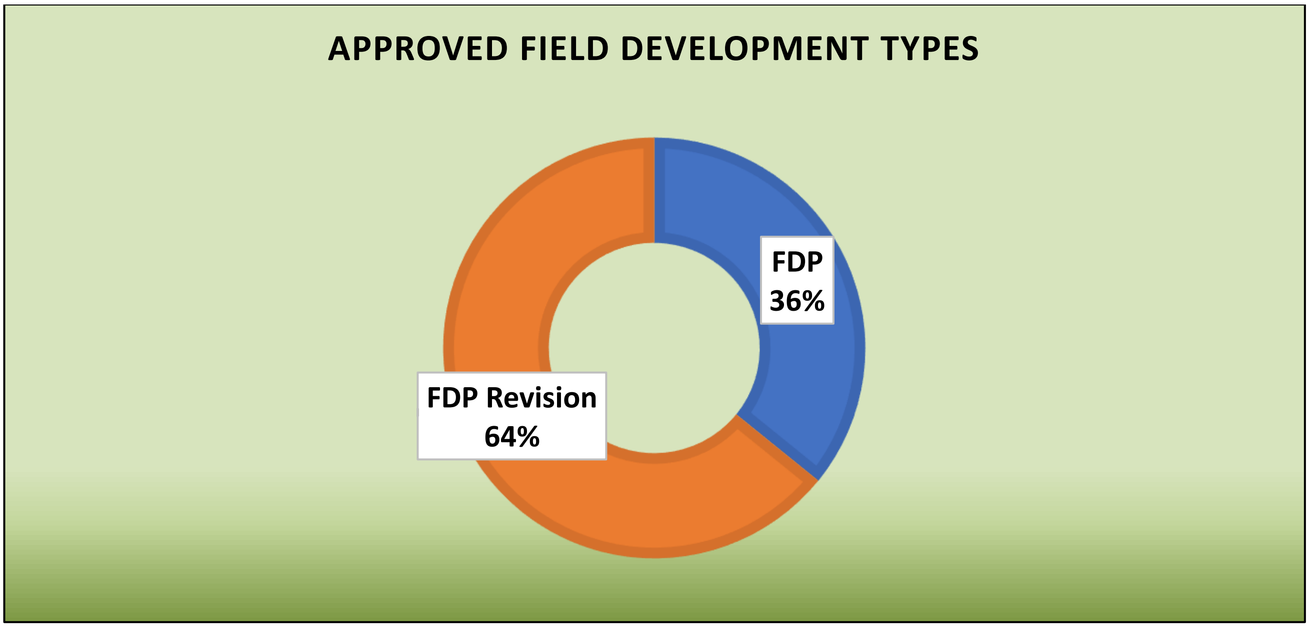


Figure 2.5: Year 2024 FDP Types distribution

There was 32% increase in FDP approvals relative to year 2023 which can be attributed to the impact of the Petroleum Industry Act 2021due to clarity on fiscal and legal framework for the oil and gas industry in Nigeria. This has increased investors' confidence to commit funds towards long-term investments in the industry.

1.3.8 WELL DRILLING PROPOSALS

A total of one hundred and twenty (120) well drilling proposals were received, and **five (5) development well applications were disapproved**, this represents an **approval performance of about 88%.** Our benchmark of 100% close out rate would have been achieved; but for the **seventeen (17) applications** currently under review which were submitted in December 2024. Additionally, **eighty-four (84) (i.e 70%) of the approved one hundred and twenty (120) development well applications aim to develop oil fields** while the remaining **thirty-six (36) (i.e 30%) development well applications intend to develop NAG assets.** Figure 5 highlights that out of the **one-hundred and twenty (120) approved wells, one-hundred and seven (107) wells have been drilled, ninety (90) successfully reached the intended targets, two (2) were plugged or suspended, while drilling is ongoing in fifteen (15) wells.**

Figure 2.6: Status of Well Drilling Activities in Year 2024

1.3.9 Distribution of Wells Drilled on Terrain Basis in Year 2024

Figure 2.7 below shows that out of the **one-hundred and seven (107) wells drilled in the year 2024**; **73% were drilled in land terrain** (100% of approved gas development wells aim to develop fields in land terrain)**, 12% drilled in swamp terrain, 9% in offshore terrain and 6% in deep offshore terrain**.

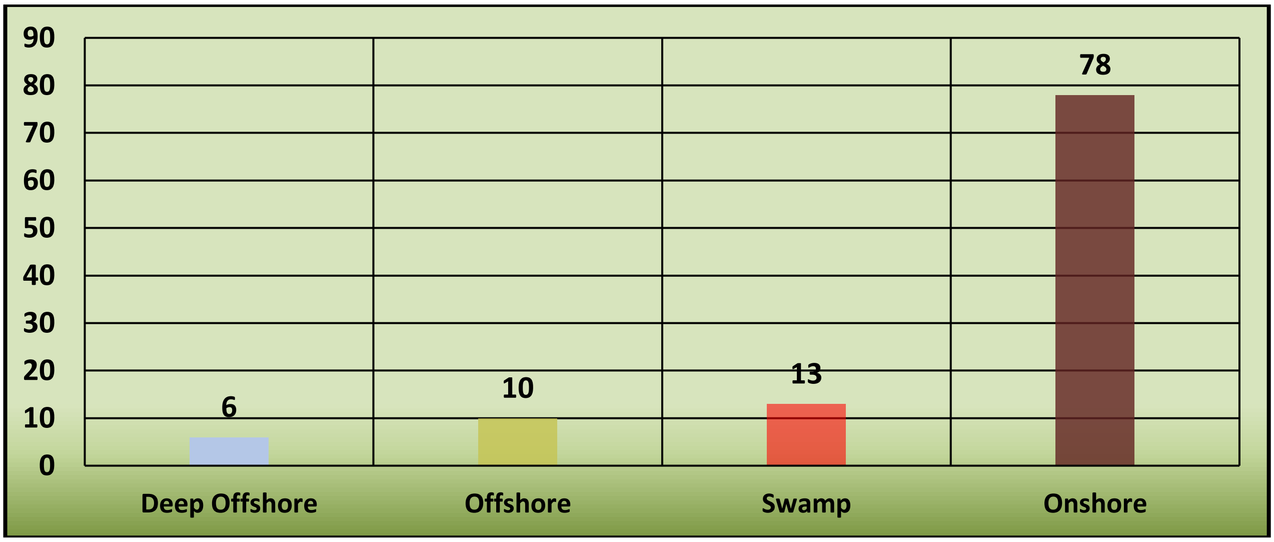


Figure 2.7: Distribution of Wells Drilled on Terrain Basis in Year 2024

1.3.9.1 Gas Development Wells

NAG development wells. The NAG wells aim to develop about **2.63 TCF of gas reserves** with an anticipated gas production of **764.50 MMscf/day.**

1.4 WELL RE-ENTRY

Five Hundred and Twenty-nine (529) applications were received for various re-entry activities aimed at restoring existing wells to production. Of these, 508 applications were approved, reflecting an approval rate of approximately 96%. Additionally, 13 applications are still under evaluation, 7 were disapproved, and one (1) was retrieved by the applicant company.

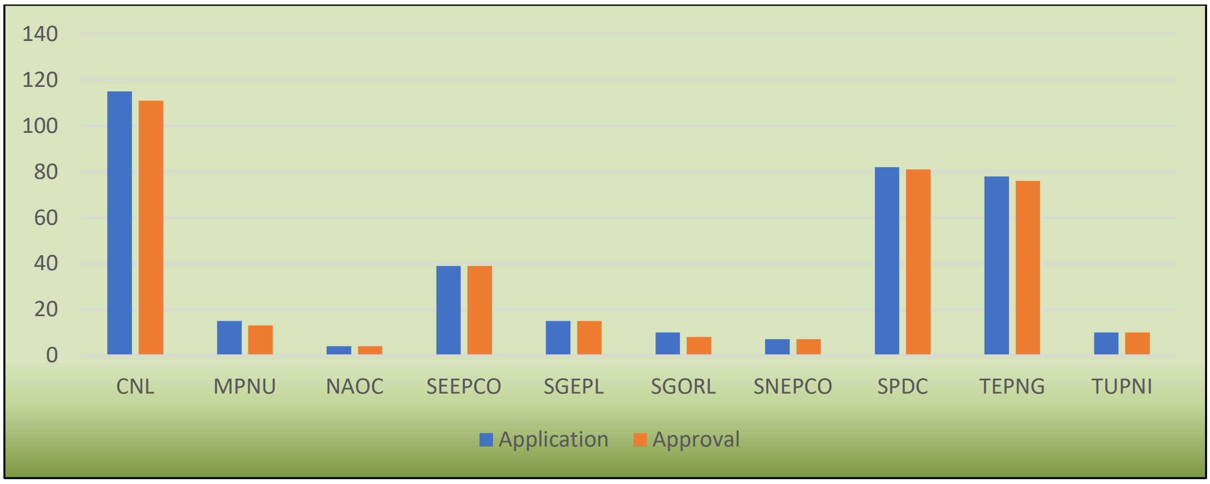


Figure 2.8: Well Re-entry Approvals Granted to International Oil Companies in Year 2024

One hundred and forty-three (143), re-entry approvals were granted to 37 Indigenous operators out of 152 applications received, representing an approval performance of over 94%. Key Indigenous operators contributing significantly to these re-entry operations include NEPL, Seplat, Heirs Energy, Midwestern Oil and Gas, and Oriental Energy. Additionally, some new Petroleum Prospecting License (PPL) awardees, notably Atamba E&P, Anatolia Energy, Ashgrove, Eyrie Energy, BAP Energy, and Korolei Energy Limited, also received approvals to re-enter wells within their portfolios. These efforts aim to gather critical data to guide the development of fields and restore production.

The approvals granted to Indigenous operators are expected to enable the restoration/development of **370MMstb** of oil and **2,087.04BCF** of gas to production, with an estimated daily output of approximately **143,869bopd** and **585.48MMscf/d**, respectively. **Figure 7** provides a detailed breakdown of these company approvals, illustrating the contributions of both established and new entrants in advancing field development/optimization and production restoration.

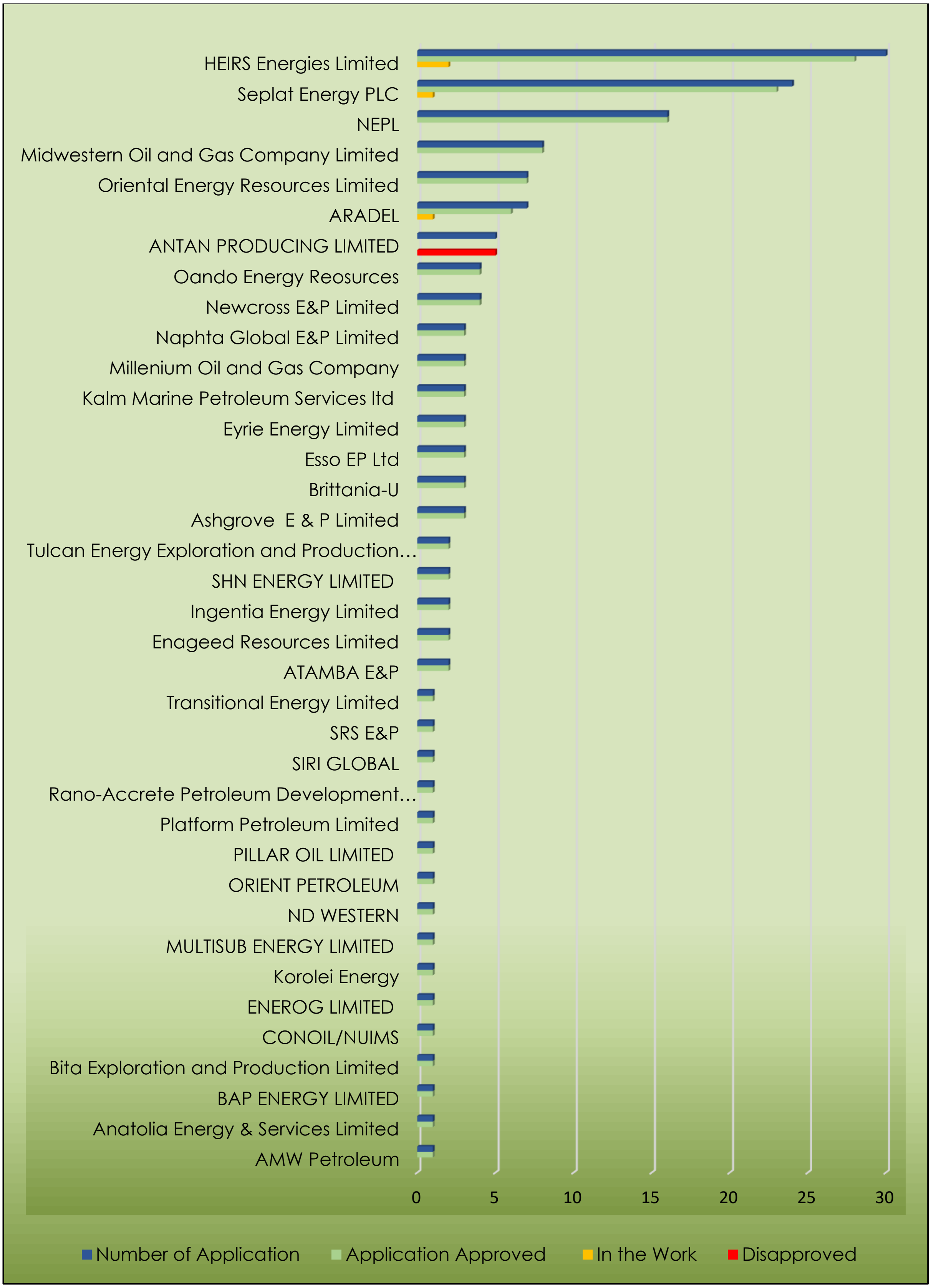


Figure 2.9: Well Re-entry Approvals granted to Indigenous Companies - 2024

1.4.1 COST BENCHMARKING OF DEVELOPMENT WELLS

In line with the commercial functions of the Commission as enshrined in the PIA. The drilling costs for all wells approved in year 2024 were benchmarked based on well type and operational terrain (land, swamp, offshore, deep offshore). Approved wells were analyzed to identify convergence or variance in costs. This approach forms the basis for querying operators about estimated drilling costs in compliance with the Commission's commercial regulation mandate. Outliers in drilling costs were identified for further engagement and alignment with the respective companies.

Furthermore, it was observed that the key cost drivers for drilling wells across the four terrains include geological formations, wellbore complexity, environmental conditions, total depth (TD), community free-to-operate (FTO) obligations, and rig availability.

Table 2.3 Established Cost Range and Average Cost of Approved Development Wells by Terrain

Terrain	AFE/Cost Range (Million USD)	Most Common (Average) Cost (Million USD)
Onshore	9 – 20	14.5
Swamp	11 – 22	19.13
Offshore	12 – 24	15.80
Deep Offshore	22 – 52	44.13

1.4.2 Rigs/Vessels Disposition

The rig disposition as of December 2024 indicates that 54 drilling rigs were tracked within the country. 42 rigs were fully licensed for operations and 31 were actively engaged across various operators and terrains. Meanwhile, 10 rigs were on the move and 13 rigs remained on standby or stacked positions at different times during the year. In contrast, 10 vessels, hoists, and barges were operational in-country in 2024.

Table 2.4: Active rig disposition as at the end of the year 2024

S/N	RIG NAME	RIG TYPE	Location	License Status
1	HILONG 7	Land Rig	Eriemu	Valid
2	Depthwize, RIG IMPERIAL	Semi-submersible	OVHOR	Valid
3	DURGA 12	Land Rig	OGUALI	Valid
4	DURGA-11	Land Rig	AMESHI	Valid
5	Durga-14	Land Rig	Enyie	Valid
6	DURGA-15	Land Rig	ETE	Valid
7	Durga-16	Land	AKAI	Valid
8	Durga-17	Land	UTA	Valid
9	DURGA-4	Land Rig	UTA	Valid
10	DURGA-6	Land Rig	UTA	Valid

11	Durga-8	Land	AMESHI	Valid
12	Hilong-19	Land Rig	ZARAMA	Valid
13	HILONG-27	Land Rig	Gbaran	Valid
14	Hilong-29	Land Rig	KWALE	Valid
15	HPEB 120	Land Rig	Ogbele	Valid
16	HPEB-187	Land Rig	Utorogu	Valid
17	NIGER BLOSSOM 101	Land HWU	Ogbele	Valid
18	Niger Blossom Jack Hardy	Land HWU	KOCR	invalid
19	NOBLE GERRY DE SOUZA	Deep Offshore (DrillShip)	AKPO	Valid
20	OES Respect	Land Rig	Soku	Valid
21	Oritsetimeyin	Jack-up	UDIBE	Valid
22	Shelf Drilling Mentor (SDM)	Jack-up	Tom	Valid
23	T-57	Land Rig	OWEH	Processing
24	T-80A	Land Rig	ZARAMA	Valid
25	OES Teamwork	Swamp Barge	ATALA	Valid
26	Discovery-202	Land Rig	OBEN	Valid
27	OES Teamwork	Swamp Barge	ATALA	Valid
28	ADRIATIC-1(AD 1)	Offshore (Jackup)	MBUOTIDEM	Valid
29	HPEB-119	Land Rig	OBEN	Valid
30	St. Elaine(AVIAM RIG -01)	Swamp Barge	ODEAMA	Valid
31	Durga-1	Land	Enyie	Valid

1.4.3 Year-on-Year (YoY) Active Rig Comparison

Month	Active Rigs (2023)	Active Rigs (2024)	YoY Change (%)
January	18	29	+61%
February	18	30	+67%
March	15	30	+100%
April	18	28	+56%
May	20	30	+50%
June	25	37	+48%
July	25	38	+52%
August	30	38	+27%
September	28	37	+32%
October	26	37	+42%
November	26	31	+19%
December	28	31	+11%

To gain a deeper understanding of drilling operations and further support strategic planning, a Year-on-Year (YoY) active rig comparison examines changes in rig activity between 2023 and 2024, offering key insights into industry trends and operational efficiency.

The analysis reveals that in 2023, 28 rigs were active throughout the year, with a utilization rate of 40%. Whereas, in 2024, 31 rigs were active, achieving a utilization rate of 57%. The weighted effect of active rig counts translates to **43%** year-on-year increase in rig activity signals industry rebound, primarily attributed to improved regulatory efficiency in approving new projects, drilling, and Wells re-entry operations.

1.4.4 VESSEL DISPOSITION

Table 2.6: Vessel Disposition

Vessel/Berge Count	Active	Standby	Total
Licensed	2	0	**2**
Unlicensed	0	0	**0**
Total	**2**	**0**	**2**

List of Vessel

Table 2.7: List of Vessel

Vessel name	Vessel type/capacity	Operational Status (Location)
African Vision	Intervention Vessel	IRM (Bonga Field)
Siem Marlin	Intervention Vessel	Inspection/Maintenance (Akpo Field)

Active Workover Hoists Units/BARGES Disposition

Unit name	Operating Company	Unit Type	Location)	Operational Status
Future	CNL	Barge	OK	Active
Mother Mary	CNL	Barge	OB	Active
Delta Victory	CNL	Barge	OK	Active
Oil Fish	CNL	Barge	PB	Active
Neremi-01	CNL	Barge	GB	Active
Blue-fin Tuna	CNL	Barge	PARABE	Active
Creole Fish	CNL	Barge	TA	Active

1.5 FACILITY ENGINEERING

The Commission provided regulatory oversight to forty-one (41) active projects in 2024, with the corresponding incremental volume, current project phase etc. The projects have a crude oil handling capacity of 668kbopd and a gas handling capacity of 2062MMscf/d, along with an additional crude oil storage capacity of 2050Kbopd.

PROJECT ENGINEERING AND MONITORING

The Project Engineering and Monitoring (PEM) Unit was created in late April 2023, and charged with the following mandate:

1. Project Planning and Co-ordination (nominations for: monitoring, Equipment Inspections and Tests, milestone activities, Safety and Technical Studies, etc.)
2. Project Performance Monitoring and Reporting (review of project status reports, scheduling of Quarterly Management Reviews and Project Technical Reviews, maintenance of a comprehensive Project Database)
3. Project Implementation/Risk Assessment and Mitigation (review of project risks and mitigation strategies during execution phase).
4. Project Cost and Budget Management (monitor project expenditures and cost controls).

Key achievements of the Project Engineering and Monitoring Unit in the year 2024 are:

1. Successful processing of **297** project-related requests.
2. **47** new/modification projects recorded.
3. The demonstration of PEM Dashboard (for project activity nominations) in collaboration with ICT. The Dashboard is expected to be fully active in Q1 of 2025.
4. Quarterly presentation to all project monitors on their expected roles and responsibilities during the project execution phase.
5. E-forms designed for Project Status report submission by Project Monitors, which has significantly improved monthly report submission rates.
6. Collation, review, and analyses of the reports in (c) above, with issues requiring Management's attention escalated accordingly.
7. Scheduling of Projects Quarterly Management Review Workshops where Management is presented with high-level project update and challenges (if any) are resolved expeditiously.

Table 2.8. Approvals issued by Facilities Engineering 2024

	APPROVALS GRANTED													
S/N	**Approval Type**	**Jan**	**Feb**	**Mar**	**April**	**May**	**Ju**	**Jul**	**Aug**	**Se**	**Oct**	**Nov**	**Dec**	**Total**
	Conceptual Design Approval (CDA)/ FEED	0	0	0	0	0	3	0	0	0	0	0	0	**3**
	Permit to Survey (PTS)	5	4	3	5	0	6	24	1	0	5	2	5	**57**
	Right of Way Permit (ROWP)	0	0	4	0	0	0	0	1	0	0	4	0	**9**
	Oil Pipeline License (OPLL)	5	5	1	5	5	2	0	6	5	2	2	5	**35**
	Detailed Engineering Design/Approval to Construct	0	0	0	1	0	3	3	0	0	0	0	0	**7**
	Pre- commission/Approval to introduce hydrocarbon	0	0	0	1	0	4	0	2	0	2	0	0	**9**
	License to Operate	0	0	0	145	0	113	14	6	0	0	0	0	**278**
	Metering													
	Conceptual Design Approval (CDA)/ FEED			1				1	1		1	1		
	Detailed Engineering Design/Approval to Construct		1	1							1			
	Approval to Introduce Hydrocarbon				2						1	1		**4**
	LTO			5	2			1						**8**
	Facilities													
	Conceptual Design Approval (CDA)/ FEED		3	3	5					1		2		
	Detailed Engineering Design/Approval to Construct		1	2	3			1						
	Pre-commission/Approval to introduce hydrocarbon				1				1			2		**4**
	License to Operate				1									**1**
	Total Approval Granted for Year 2024	**10**	**14**	**20**	**171**	**5**	**131**	**44**	**18**	**6**	**12**	**14**	**10**	**455**

SUMMARY OF PRODUCTION FACILITIES LICENCED IN 2024

S/N	TYPE OF FACILITIES	LTO ISSUED
1.	Flowstations	**84**
2.	FPSO/EPF/MOPU	**16**
3.	Terminal / FSO	**18**
4.	Production Platforms	**76**
5.	Wellheads	**46**
6.	Accommodation Platforms	**5**
7.	Gas Handling Facilities	**29**

1.5.1 DEPLOYMENT OF NEW TECHNOLOGY AND INNOVATION

The Commission is empowered via Section 10 (d) of the Petroleum Industry Act 2021 (PIA) to set standards to promote the adoption of new technologies for upstream operations". To this end, the Technology Adaptation Unit has facilitated the deployment of novel technologies in the Nigerian Upstream Oil and Gas Industry.

The Technology Adaptation Unit is saddled with the regulatory mandate of qualification, approval and deployment of upstream novel technologies that aim to reduce the unit cost of production, improve production efficiency, provide assurance of hydrocarbon delivery through transport infrastructures and accurate measurement and accountability of produced hydrocarbon.

Through the effort of the Unit over the years, significant gains have been made in several areas of the Nigeria Oil and Gas Upstream Industry. These areas of high impact are as listed below:

a) Concluded draft of Technology Adaptation Process Guidelines and Technology Plan.
b) Increased Oil Discovery and Production via the deployment of qualified State of the Art Technology.
c) Reduced cost of Pipeline Maintenance and Integrity threshold
d) Improved Metering accounting Technology.
e) Automation Technology of Facilities and Production Platforms
f) Improved Safety and Health standards through deployment of qualified high-end security and safety solutions.

1.5.2 Status of New/Novel Technology applications

Applications	Jan-December 2023
Received	63
Pilot/Validation Approvals	22
Final/Full Approvals	11
Rejected	20
High Impact Technology	05
Ongoing Pilot activities/Deployments	4
Processed/Processing	10

Table 2.9.0: Status of Novel Technology Applications

1.5.3 High Impact Technologies Approved

- NOV Oil and Gas Services Nigeria Limited's **Single Anchor Loading Technology (SAL)**
- XSENS **Ultrasonic Clamp on meter (EXACT, XRATE)**
- Melios Limited's **Risk Evaluation and Barrier Monitoring Solution**
- McAlpha **CMR Technolgy for Produced Water Conversion to Ammonia**

KEY ACHIEVEMENTS

- Thirty-three (33) novel technology approvals were granted within the Period under review.
- Concluded final review of the technology Adaptation Process guideline. Presentation slides transmitted for final management approval

LOOK AHEAD

- Approval of the Technology Adaptation Process Guideline.

1.5.4 DECOMMISSINING AND ABANDONMENT (D&A)

The Decommissioning and Abandonment (D&A) unit of the NUPRC is guided by PIA 2021 sections 59(2)(i) (requiring that all field development plans must include a decommissioning and abandonment plan), and sections 232 and 233 mandating that all assets must be sufficiently provisioned for ahead of eventual cessation of production, with adequate planning for the decommissioning activities at the end of economic life of an asset, and that the decommissioning and abandonment obligations as estimated by the lessee are adequate and securely funded.

The following subsections detail the activities of the D&A Unit in 2024 to bring all operating companies into compliance with the D&A regime by ensuring adequate D&A planning in terms of methodology, risk assessments and mitigation strategies, cost estimation and establishment of individual D&A Funds. These sections demonstrate the trends and enumerate the challenges impacting complete rollout of the D&A administration (protocols) and concludes with an outlook seeking Management steer and intervention in proposed strategies to achieve PIA objectives.

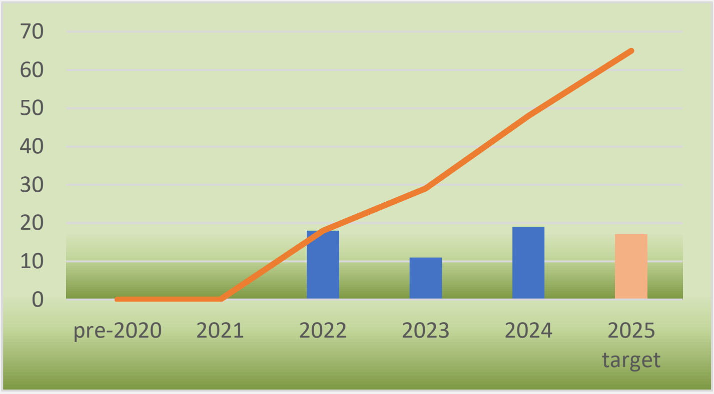
1.5.5 D&A Plans (Legacy)

The D&A Unit received and/or processed **40nos.** legacy D&A Plans for [1]*assets under development or in production* in compliance with Section 233(4)(a) of the PIA 2021. Activities included review of submissions, conducting D&A Plan review workshops and communication of reminders to operators.

Submissions from a total of **48nos.** operators/entities are under review.

Table 2.9.1: Legacy D&A Plan (2024)

Legacy D&A Plan (2024)	
Performance	**Qty**
Operators / entities engaged	**65**
Operators yet to forward a DAP	**17**
Total submitted DAPs to date (73.8%)	**48**
DAPs (drafts / revisions) received / processed (includes workshops)	40
Recommended for workshop	5
Workshops held in 2024	19
DAPs (draft/revision) under review	**46**
DAFO (∴ DAPs) approved-in-principle i.e. **NAOC**, **MPNU** (3.1%)	**2**

Figure 2.9.1: Industry Compliance	D&A Unit has identified 65nos. Operators to date based on the June 2024 Concession Situation Report. With reminders and follow up, compliance performances has improved from 62% (2023) to 74% (2024); DAU targets 100% compliance by end 2025. These targeted engagements exclude PPL, OPL and Flare-site awardees. However, DAU has received and processed D&A Plans under the PPL/OPL group as part of FDP conversions and/or their annual work program commitments.
	

1.5.6 PRODUCTION ALLOCATION AND CURTAILMENT

a. Participated actively in monthly curtailment meetings and helped resolve majority of the oil companies' concerns relating to crude oil lifting and issuance of export permit and/or clearance.
b. Helped expedite applications that could slow down operations at the terminal.
c. Worked closely with NNPCL Upstream Investment Management Services (NUIMS) to ensure that the monthly engagement is held accordingly.

1.5.7 CRUDE OIL AND GAS TERMINAL OPERATION (COGTO)

1.5.8 Crude Oil/Condensate/Gas Export Permit Applications

A total of **five hundred and eighty-seven (587)** export permit applications for hydrocarbon (crude oil/condensate/gas) export were received and processed for the year 2024 as follows:

Table 2.9.2: Showing Export Permit applications received in 2024

S/N	DESCRIPTION	NO. OF APPLICATIONS
1	Crude - Renewal Applications	496
2	Crude - Supplementary Application	51
3	Gas - Renewal Application	40
TOTAL		**587**

1.5.9 Crude Oil/Condensate /Gas Vessel Clearances

One thousand, nine hundred and thirty-seven (1,937) vessel clearances were received and processed in the year 2024 with **One thousand, nine hundred and twenty-eight) (1,928)** issued and **Nine (9)** halted while three hundred and forty-six (346) applications were also revised. The total quantity of hydrocarbon lifted during the period under review is as follows:

Table 2.9.3: Showing Vessel clearance applications received and nominated quantity.

S/N	DESCRIPTION	QUANTITY CLEARED (NOMINATED)
1.	CRUDE OIL/CONDENSATE (bbls)	586,167,094
2.	NGLS (MT)	799,900
3.	Refinery Supply (bbls)	52,497,128

1.6.0 Outturn Verification Exercise Participation

The COL Unit successfully processed twenty (20) outturn verification applications of the sixty (60) applications received during the year 2024.

1.6.1 Oil Loss Claim and Retest/Sample

Twelve (12) applications for Oil Loss Claim and Retest were received and successfully processed during the period under review.

1.6.2 Terminal Establishment Order

A total of four (4) New Terminal Establishment Order application was initiated in the year 2024 as stated below:

- Utapate FSO Terminal by NEPL
- OML 18 Terminal by NEOL.
- Otakikpo Onshore Terminal by Green Energy International Limited (GEIL).
- Okwok Terminal by Oriental Energy Limited.

Additionally, the following companies commenced the process of establishing offshore crude oil export terminals within the reporting period:

- Commercial Consult Nigeria Limited (CCNL): FSO Kafilat Terminal Offshore Escravos Waters.
- Ajivin Group of Companies: Eastern Region Ibom Crude Oil Export Terminal and Western Region Meren Crude Oil Export Terminal.

Four (4) Terminal Establishment Order were initiated in the year 2023.

1.6.3 Functional Export Terminals

A total of thirty-two (32) crude oil and gas terminals were operational during the year 2024 for adequate export of crude oil

1.6.4 Barging and Trucking Permit

A total of one hundred and seven (107) permits for barging and trucking operations in the year 2024 were processed as follows:

Table 2.9.4: Showing 2024 Barging and Trucking Permits Issued.

S/N	PERMIT	NO. OF APPLICATIONS
1	New Barging Permit	10
2	Renewal Barging Permit	45
3	Supplementary Barging Permit	17
4	New Trucking Permit	7
5	Renewal Trucking Permit	23
6	Supplementary Trucking Permit	1
	TOTAL	**107**

1.7.2 LACT Units/Small Volume Provers, Crude Storage Tanks

Ninety-nine (99) measurement facilities and sixty-three (63) storage tanks were calibrated and recertified to ensure the accuracy of measurement systems.

1.7.3 Maintenance Jobs

Sixty-nine (69) maintenance approvals were given to operators via the Regional and Field offices.

Table 2.9.8: 2024 Inventory of Flare Metres Installation

Summary of Flare Meter Inventory	
Total Flare Sites	**162**
Total Flare Points	**213**
Total Meters Installed	**188**
Total % Compliance	**88%**
Total No. of Companies	**49**
Companies that Submitted Current Flare Meter Details	**33**
Companies yet to Submit Current Flare Meter Details	**16**
Number of NGFCP Sites Listed	**49**
Flare Points with Meters	**188**
Flare Points without Meters	**25**

1.7.4 Gas Meter Inventory Administration

Currently there are 162 flare sites, with 213 flare points, from 49 companies. Out of these flare points, 188 flare meters are installed, representing 88% compliance to Section 106 (1) and (2) of the Petroleum Industry Act, 2021.

Nevertheless, flare meters are yet to be installed in 25 flare points, as shown below.

The **Sales Gas Meters** Calibration and Validation inventory is currently being collated and reviewed, following submission from operators.

1.7.5 Decade of Gas & Presidential Fiscal Incentives Directives

Expert study by industry stakeholders revealed a gas supply gap of more than 3BSCFD by 2030. The Decade of Gas initiative identifies the need for intentional efforts to utilize the enormous gas resources in the country, to uplift the economy through a gas-based industrialization. The aim of the initiative is to transform Nigeria into a gas- powered economy by 2030, by deepening domestic utilization, developing industrial gas markets and enhancing monetization of gas through export to global markets.

These initiatives are underpinned by the Government's commitment to critical interventions that would facilitate market driven pricing mechanism for the domestic gas market; address issues of legacy debt to power sector gas suppliers, infrastructural deficits and upstream gas supply unlocks.

In the year 2024, the Commission facilitated the identification of 20 critical projects that can meet the volume requirement and achieve final investment decision (FID) early in the decade, if the necessary unlocks are in place.

Arising from joint engagement sessions with gas producers and strategic stakeholders, legacy debts, domestic base price of gas, local content contracting requirements and early lease renewal strategy were identified as major impediments that must be unlocked to bring certainty to the industry as well as desired investments. The Commission's unlock responsibility included the facilitation of the "Early Lease Renewal" for certain projects. In the year under review Gas Utilisation accomplished the following:

a. Provided strategic support and facilitation for the issuance of the **Presidential Fiscal Incentives Directives** on Gas (Onshore and Shallow Offshore)

b. Developed the Implementation Guidelines for the Presidential Fiscal Incentives Directives.

c. Currently developing additional guidelines detailing mechanisms for entry into the fiscal incentives scheme.

d. Facilitation of the **settlement of gas to power legacy debt** through robust gas production data collation and validation necessary for gas royalty determination and calculation

e. Facilitation of the development of bespoke framework for critical upstream gas supply assets' early lease renewal

1.7.6 Uncommitted Gas Reserves Monetisation Programmes

a. In line with Section 6(c) and (h), which mandate the Commission to "promote an enabling environment for investment in upstream petroleum operations" and "ensure optimal government revenue generation"; an in-house multifunctional study was conducted which revealed that circa 57TCF of gas reserves have remained unmonetized decades after their discovery.

b. In period under review, the team facilitated the engagement of the identified gas assets holders and the conduct of portfolio assessments, proceeded by the identification and development of viable monetization pathways for *uncommitted/undeveloped gas reserves,* in collaboration with other departments.

1.7.7 ASSET INTEGRITY MANAGEMENT

Below is a summary of achievements in the Asset Integrity Management Section of the Production Division for the Year 2024.

- Implemented the 2024 Framework for the conduct of the Annual Conformity Assessment Verification Exercise to ensure the Facility Integrity of all Upstream Oil and Gas Production Facilities.
- Supervised the conduct of the Conformity Assessment Verification Exercise on Oil and Gas Production Facilities Nationwide with the participation of the

Regional Offices and issued the underlisted Conformity Assessment Certificates as applicable.

- Reviewed, approved, and monitored inspection and maintenance requests from operators of oil and gas facilities.
- Conducted the re-assessment and revalidation of Risk Based Inspection Methodologies and its applications on designated facilities.
- Processed applications for the Annual License to Operate Oil and Gas Facilities.
- Processed applications for the Annual Coastal Vessel License for vessels engaged in Upstream Oil and Gas operations.

Conformity assessment test was carried out on some facilities and the following were the observations made on the assessment of the facilities.

Table 2.9.9: Observations on the assessment of the facilities

Facilities Inspected	248
Conformity Assessment Certificates issued.	183
Conformity Assessment Certificates Non-issuance	61
Conformity Assessment Certificates under process	4

1.7.8 PRODUCTION SURVEILANCE & AUDIT

1.7.9 STATUS OF WELL STRINGS AS AT END DECEMBER 2024

The number of shut – in strings stood at **2700** while the number of Producing strings is **2344**. NEPL, SPDC, Mobil, Chevron, HEIRS and Aiteo have the highest number of Shut – in wells.

However, there is a deliberate effort by the unit to collate and update the status of the shut-in wells/strings with a restoration timeline and potential from all the exploration and production companies.

Furthermore, the unit is a major stakeholder in project 1MMBOPD.

1.8.0 ENERGY SUSTAINABILITY/ CARBON MANAGEMENT DEPARTMENT

1. **Development of the Upstream Petroleum Decarbonisation, Energy Transition and Carbon Management Regulatory Framework:**
    a) The ES&CM Division has successfully developed a comprehensive regulatory framework for energy transition, decarbonization, and carbon management in the Nigerian upstream Oil and Gas sector.
    b) This framework serves as a crucial foundation for regulating and decarbonizing the industry while promoting environmentally responsible practices.

c) Industry Circular and Policy Statements were issued resulting from the Regulatory Framework in a bid of conscientizing various stakeholders on the instruments.
d) Implementation of Upstream Petroleum Decarbonisation Template with the Field Development Plan started from the half-year and the results were adjudged impressive from the operators.
e) Approval to implement the Template in wells, drilling & rig operations, and project/facility engineering was secured.

2. **Carbon Capture and Storage Studies:**
a) Engaged Schlumberger and Halliburton/Indorama on studies for potential CO2 sequestration in the Niger Delta basin.
b) The Division secured the Management's approval on the request of Indorama for data leasing fee waiver.
c) Internal alignment on the subsurface geological data that would support the studies is being worked at in collaboration with NDR and E&AM.
d) Drafted the required MoU for collaboration with Schlumberger. Action presently on SLB on the drafted MoU. Currently reviewing the draft MoU and NDA submitted by Indorama as measures for the immediate implementation.

3. **Carbon Markets Development and Revenue Maximisation:**
a) Developed global carbon market trends and opportunities for Nigeria.
b) Developed a roadmap for implementation of Upstream emissions reduction (UER) in Nigeria's carbon market.
c) Developed a Framework for implementation of carbon credit earnings as recognised in RAP for 2024 and near term.
d) At different stages of engagement with CarbonAi, Pangea, Amplus VG Energy and Vitol to explore carbon revenue through carbon credits and financing of net-zero carbon initiatives.

4. **Collaboration with Norwegian Entities (NOD & NEA)**
a) Institutional Cooperation: Re-established collaboration with the Norwegian Offshore Directorate (NOD)/ Norwegian Environment Agency (NEA) under the Energy for Development (EfD) Programme.
b) Regulatory Benchmarks: Leveraging their technical capacity and knowledge sharing to enhance energy sustainability strategies and Decarbonisation implementation.
c) Regional Leadership: Showcased and shared regulatory best practices on Gas flaring, emissions management and decarbonization with other

African Petroleum regulators during the Annual Energy Economics Forum.

d) Investments Outreach: Showcased opportunities for investment and participation on Nigeria’s upstream decarbonization with investors during the Nigerian Norwegian Gas Forum.

5. Collaboration with US DOE and Net Zero World Initiative and US Bureau of Energy Resource

a) ES&CM has established collaborative ties with the United States Department of Energy (US DOE), the Net Zero World Initiative and the US Bureau of Energy Resource which enhanced our access to global expertise and resources, facilitating the exchange of ideas and best practices.

b) ESCM is developing Measurement, Monitoring, Reporting and Verification (MMRV) Framework for GHG emissions management for improved tracking and transparency with these bodies to:

   i. Establish conformity assessment requirements and business model for independent third-party certification and accreditation of GHG supply chain emissions and data quality.

   ii. Establish requirements for tracking and retiring measurement and supply chain statements of attestation of conformance.

   iii. Establish transparent and consistent Tools for Estimating GHG Supply Chain Emissions and Data Quality

   iv. Establishment of data quality metrics and coordination of WSI subgroups

   v. Technical support on methane Leak Detection and Repair (LDAR) project and low-emission technologies deployment in the industry.

6. African Petroleum Regulators Forum (AFRIPERF):

a) ES&CM championed the establishment of the African Petroleum Regulators Forum (AFRIPERF).

b) An initiative that brings together oil and gas regulators from across Africa to collaborate, share best practices, and strengthen the regulatory landscape for the African energy sector.

7. Engagement with National Council on Climate Change (NCCC):

a) ES&CM has actively engaged with the National Council on Climate Change (NCCC) by participating and sharing insightful stance of the

Commission in the formulation of Nigeria Carbon Market Policy and validation workshop on the assessment of carbon pricing initiatives in Nigeria and several other workshops.

8. **Key Impacts**

The impact of ES&CM on the industry based on its mandate is as shown in Figure 1. Apart from sustainable oil and gas operations resulting from the reduced GHG emissions and accuracy in its tracking and reporting, enhanced technical capabilities and increased revenue generation from the carbon market activation are parts of the critical impacts that would come from ES&CM activities in 2025.

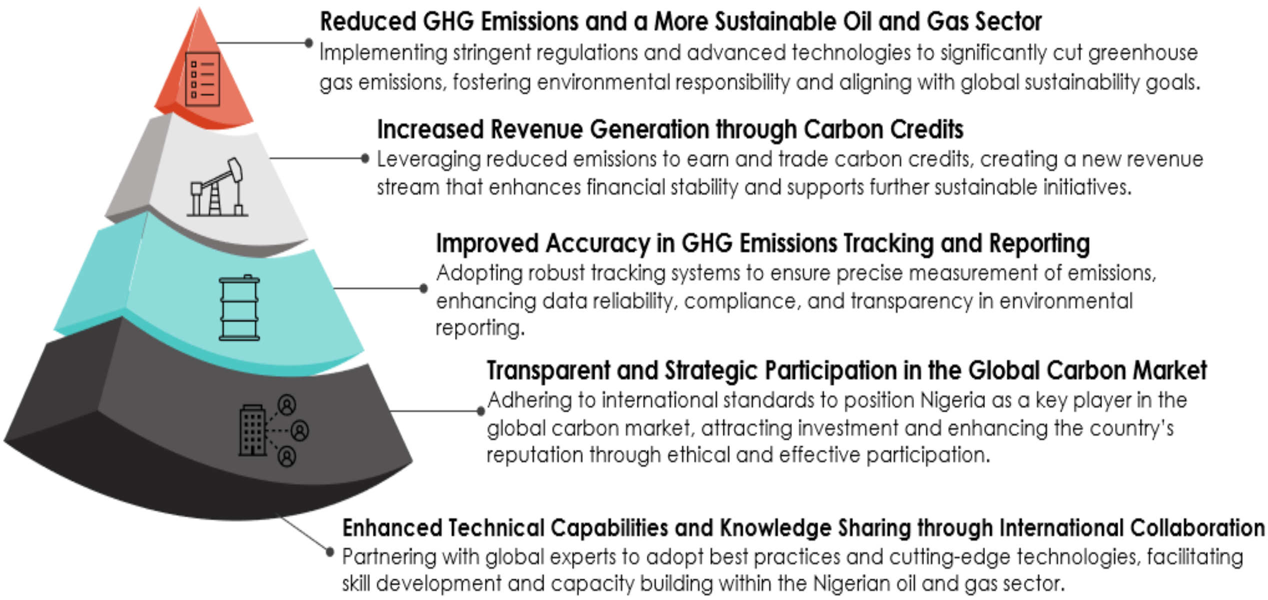


Figure 1: Regulatory impacts of ES&CM Mandate

9. **Capacity Building:**

a) The division has identified various energy transition and carbon management training programs, seminars, and conferences.
b) The capacity building initiatives are instrumental in building the skills and knowledge required to implement carbon reduction strategies effectively.
c) Request for relevant capacity building and trainings for the upskilling of the team's capacity have been sought from the EC and is awaiting favourable consideration.

1.8.1 LOOKAHEAD FOR THE ES&CM TEAM IN 2025

In the next phase of our efforts, the Energy Sustainability & Carbon Management Division (ES&CM) will continue to drive progress in the following key areas:

1. **Progressing Implementation of the Commission Upstream Petroleum Decarbonization Regulatory Framework:** The ES&CM Team's top priority is the effective implementation of the regulatory framework for energy transition, decarbonization, and carbon management. We will work closely with industry stakeholders to ensure compliance and monitor the impact of these regulations and a key success factor to these is liaising with all relevant stakeholders to draft the regulations and ensure the engagement of critical stakeholders.
2. **Development of a carbon pricing system for the Nigerian Upstream petroleum sector in line with the Regulatory Action Plan:** The ES&CM Team's foremost goal and mandate has been the establishment of a robust carbon-pricing system. We would work more closely with the NCCC on the Nigeria Carbon Market Policy and draft a preliminary guideline for the implementation of a carbon-pricing system, which will hold businesses accountable for their emissions and incentivize emission reductions through carbon credits in the upstream petroleum sector.
3. **CCS Project Development:** The potential CCUS project with relevant technological partners such as SLB, Baker Hughes, Haliburton etc. will be a focus of our efforts in 2025. We will work towards formalizing the project plan to advance carbon capture and storage in Nigeria.
4. **Capacity Building:** ES&CM will continue to identify and support training opportunities for staff and other industry professionals, ensuring that core staff and the Technical Advisory Committee are well-equipped to drive the energy transition and carbon monetization agenda in the Upstream petroleum industry.
5. **Partnership Expansion:** We seek to expand our partnerships with international organizations, research institutions, and industry players to stay at the forefront of emerging technologies and best practices in carbon reduction.
6. **Engagement with Government Agencies:** Collaborative efforts with government agencies such as the FMOE, NCCC, NETO, ECN, NMDPRA, etc will remain a priority, particularly in aligning our strategies with national climate goals and policies.
7. **Deepening Regional Leadership:** The ES&CM team will through the AFRIPERF deepen Nigeria's leadership position on the energy transition narrative and share and learn from the best practices across the border.
8. **Public Awareness and Communication:** ES&CM will engage in public awareness campaigns to educate stakeholders about the benefits of energy transition and carbon monetization, fostering support for sustainable practices in the upstream petroleum sector.

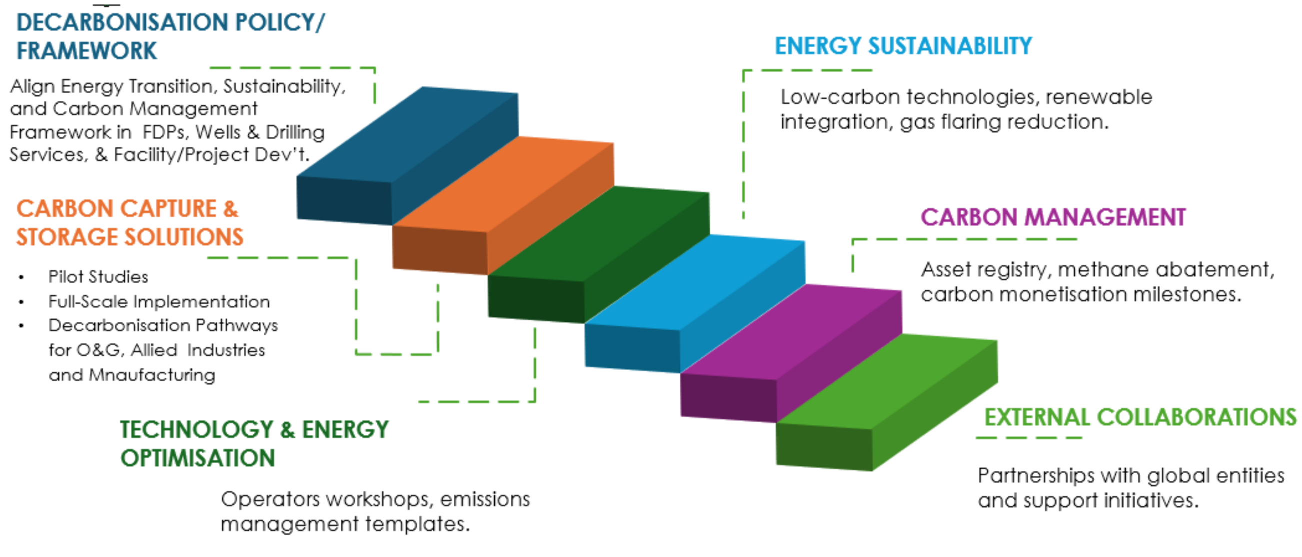


Figure 2: ES&CM Strategic Focus Areas for 2025

Figure 3: ES&CM Next Steps in 2025

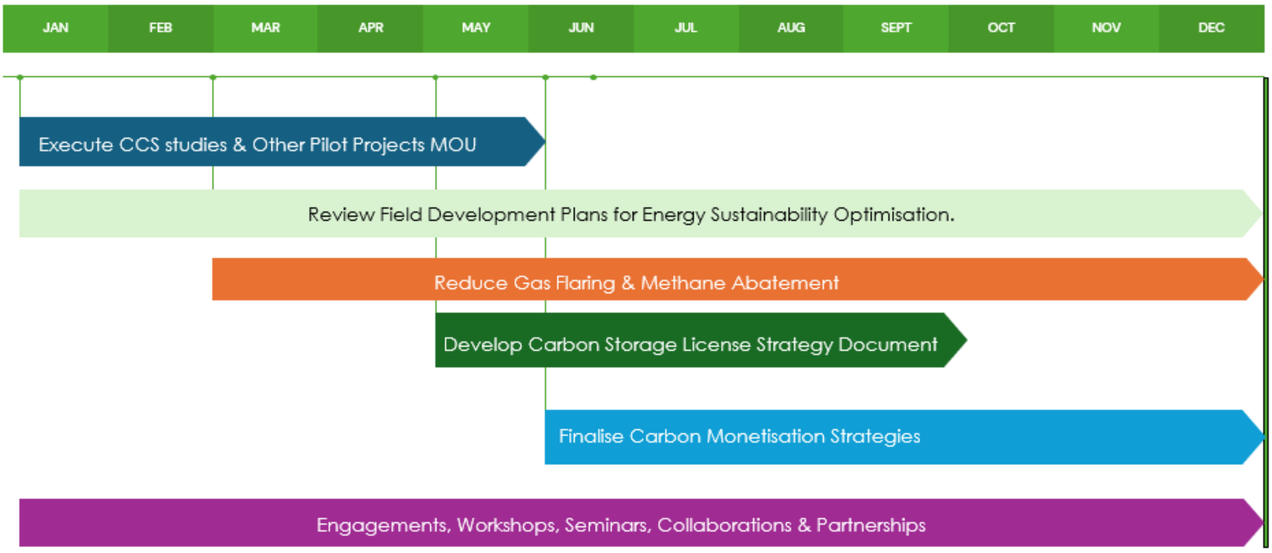


Figure 4: ES&CM Implementation Plan

In Figures 2, 3, and 4, the ES&CM strategic focus areas, next steps and implementation plan were respectively presented.

Based on the foregoing, the ES&CM team aims to continue making substantial contributions to decarbonizing the upstream petroleum sector and fulfilling our commitment to global emission targets and Net-Zero 2060 objectives. Our continuous dedication to these goals reflects our commitment to a sustainable and environmentally responsible future for the Nation and our Industry

2.0 EXPLORATION AND ACREAGE MANAGEMENT

2.1 EXPLORATION

1. Six (6) applications for seiemic data acquisition were approved. A total of 2,334.542sq.km and 736.7sq.km of 3D and 4D seismic was acquired by eight (8) companies.
2. Six (6) geotechnical surveys approvals were issued.
3. Five (5) licenses to operate geophysical/geotechnical vessels within Nigerian territorial waters were granted.
4. Six (6) data processing/reprocessing requests were approved.
5. Three (3) geophysical/geotechnical data for export under specialized category were approved.
6. Three (3) wells were drilled; one (1) drilled to total depth (TD) while two (2) are ongoing.
7. Five (5) change of field names were approved in OML 17.
8. Three (3) core samples acquisition were approved.
9. Two (2) core sample export was approved.
10. Four (4) core sample analysis were approved.
11. One (1) fluid data analysis was approved.
12. 1,940sq.km of 3D seismic data (PSDM) was reprocessed by TGS Geophysical Nigeria Limited.
13. Up to date transmission of monthly crude oil and gas production statistics to RMAFC (November 2023 – September 2024) for 13% derivative to the producing states.
14. Concluded twenty (20) Due Diligence exercises in respect of Assignment of interests on several PPLs.
15. Performance review of minimum work programme for 52 PPL's was carried out.
16. Three (3) plugback and abandonment were approved.
17. One (1) fluid data acquisition was approved.

2.1.1 Geophysical Data Acquisition

Four (4) companies employed the services of seismic contractors to acquire 3D and 4D seismic data. A total of **2,334.542sq.km** and **736.7sq.km** of 3D and 4D seismic data was acquired respectively in 2024.

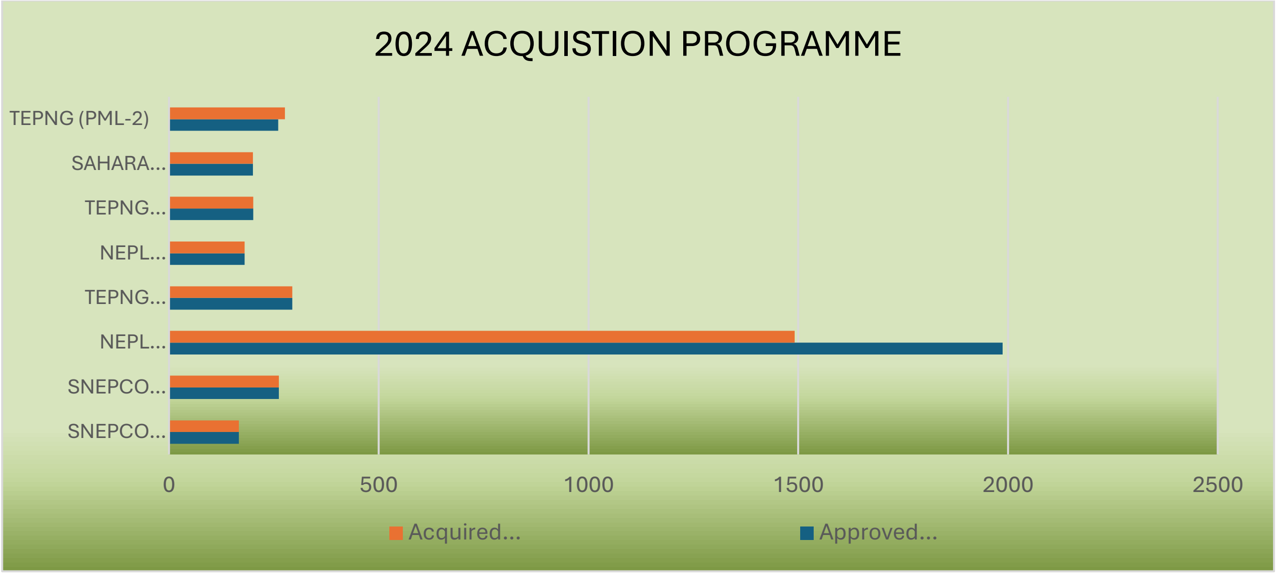


Figure3.0: 2024 Acquisition programme

2.1.2 Academic Data

A total of fifty-five (55) academic data requests were received from thirty-seven (37) universities. Thirty-seven (37) of the requests were forwarded to twelve (12) exploration and production companies, and seven (7) were treated within the Commission, while three (3) requests are pending due to incomplete information, and eight (8) requests are still under review. Nineteen (19) out of the fifty-five (55) requests were from foreign universities while thirty-six (36) were from Nigerian universities.

2.1.3 Core Analysis

Nine (9) core analyses were inconclusive due to Companies management's decisions, while three (3) other analyses await submission of results/report.

2.2 ACREAGE MANAGEMENT

2.2.1 Hydrocarbon Attribution

Monthly Crude Oil/Condensate and Gas Production Attribution on field by field and state by state basis for November 2023 to September 2024 was collated and forwarded to Revenue Mobilization Allocation and Fiscal Commission (RMAFC) as directed by the Presidency on monthly basis.

Table 3.0: Crude Oil/Condensate and Gas Production Attribution on state basis

S/N	State	Crude Oil/Condensate (bbls)	Gas (Mscf)
1	Delta	99,903,790	318,166,310
2	Ondo	8,710,019	27,166,832
3	Edo	7,768,043	95,461,183
4	Rivers	50,837,013	391,313,140
5	Bayelsa	53,276,855	341,221,331
6	Akwa ibom	60,320,514	211,986,342
7	Imo	6,329,737	6,406,601
8	Abia	3,415,191	4,463,213
9	Lagos	0	0
10	Anambra	4,779,496	7,442,282
Total		**295,340,659**	**1,403,627,235**

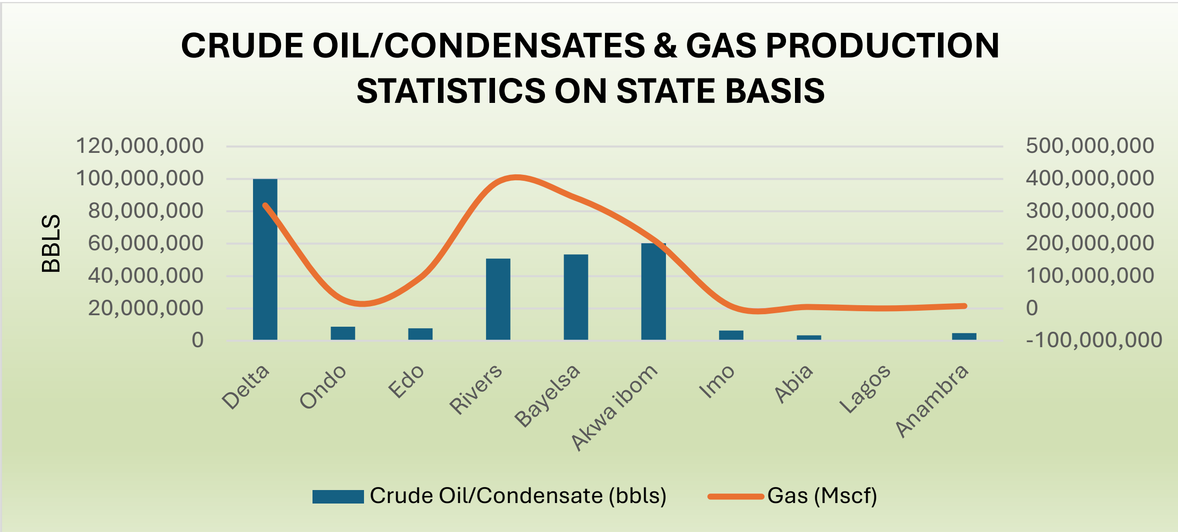


Figure 3.1: Crude oil/Condensate & Gas production statistics on state basis

NOVEMBER 2023 – SEPTEMBER 2024 CRUDE OIL/CONDENSATES & GAS PRODUCTION DATA FOR DEEPWATER FIELDS

S/N	Fields	Crude Oil/Condensate (Total) Bbls	Gas (Total) Mscf
1	Agbami	25,321,587	117,642,734
2	Erha	18,475,883	77,045,707
3	Abo	2,988,312	12,615,910
4	Akpo	14,221,484	92,467,104
5	Usan	7,052,738	26,682,450
6	Egina	22,793,678	32,466,214
7	Bonga	32,520,127	24,335,402
8	Oyo	304,753	2,276,540
Total		**123,678,562**	**385,532,061**

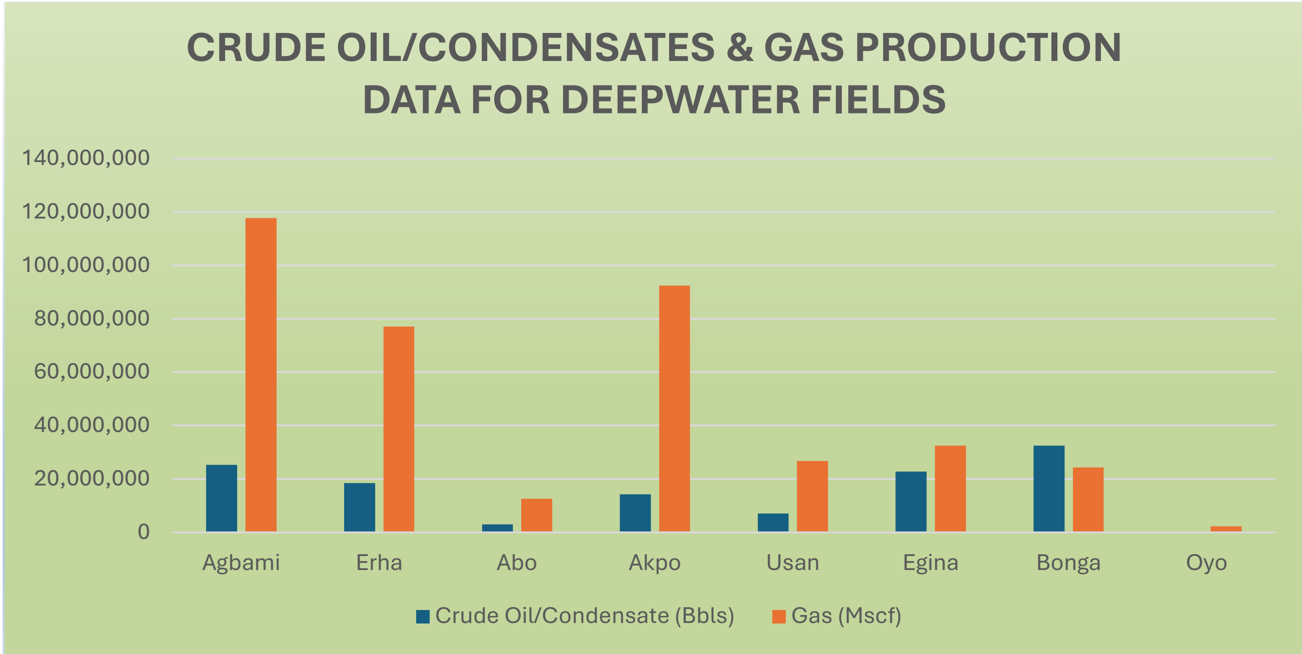


Figure 3.2: Crude oil/Condensate & Gas production statistics on state basis

2.2.2 Concession Mapping & GIS

- Charts and boundary description documents were produced, in conjunction with Daimler Geographics, for the twenty-four (24) blocks offered in the 2024 Nigeria Licensing Round.
- Charts and boundary description documents were also produced for newly converted and delineated PPLs and PMLs.
- The Commission, in conjunction with the National Boundary Commission (NBC), participated in the plotting of coordinates of wells drilled from January 2017 – December 2023 and Coordinates of wells in OMLs 143, 123, and 114, for determination of their location and attribution of the proceeds of those wells to the states.
- Charts and boundary description documents were produced, in conjunction with Daimler Geographics, for the twenty-four (24) blocks offered in the 2024 Nigeria Licensing Round.

2.2.3 Outstanding Boundary

As at end of 2024, some issues due are yet to be resolved as enumerated below:

1. **Korolei (PPL 215):** Meeting has been conducted awaiting submission of report.
2. **Okpolo field (PPL 206)** – Awaiting company's resolution with NEPL/Shoreline

2.3 ACREAGE ADMINISTRATION

2.3.2 Acreage Situation

Nigeria has a total of 282 licensed Blocks across the seven basins, covering onshore, shallow water, deep water terrains. Number of Oil Prospecting Licences (OPLs), Oil Mining Leases (OMLs), Petroleum Prospecting Licenses (PPLs) and Petroleum Mining Leases (PMLs) are 55, 107, 70 and 50 respectively.

Table 3.3 Summary of Acreage Situation

Summary Of Acreage Situation					
Geological Terrain/Location	**Blocks**				
	OPLs	**OMLs**	**PPLs**	**PMLs**	**Total**
Deep Offshore	18	16	2	4	**40**
Continental Shelf	12	31	32	17	**92**
Onshore Niger Delta	10	57	36	29	**132**
Anambra Basin	4	2	0	0	**6**
Benin Basin	3	1	0	0	**4**
Benue Trough	2	0	0	0	**2**
Chad Basin	6	0	0	0	**6**
Total	**55**	**107**	**70**	**50**	**282**

2024 Summary of Activities in Lease, Licence Administration and Acreage Performance		
S/N	**Activity**	**Quantity**
1.	Concession Grant	3
2.	Lease Renewals	7
3.	Voluntary Conversions	11
4.	Conversion of Licence to Lease	4
5.	Assignment of Interests: Leases	16
6.	Assignment of Interests: Licence	26
7.	Conversion from OPL to PML	0
8.	Extension	15
9.	Revocation	2

2.4 Achievements

- The Agreement for Charting and Harmonization between NUPRC and Daimler Geographics has been renewed.
- Concluded action on the collation of Crude oil and gas production figure/statistics on state basis for the month of January - September 2024.
- Concluded on the monitoring of the reprocessed 1,940sq.km of 3D seismic data (PSDM) by TGS Geophysical Nigeria Limited.
- Concluded on monitoring of the 2nd phase of acquisition operations (5,838sq.km) of Awele 3D project of TGS-Petrodata Offshore Services Ltd on February 2024.

- Concluded action on renewal of Brokerage Agreement between NUPRC and TGS Geophysical Limited.
- Provisional Award for a Petroleum Exploration Licence (PEL 2) to TGS-PetroData.
- Provisional Award of a Petroleum Exploration Licence (PEL) to Center Point Data Services Limited for Multiclient Speculative Seismic Survey Over the Anambra Basin, Nigeria.
- Provisional Award of a Petroleum Exploration Licence (PEL) to ATO Geophysical Limited.
- Up to date transmission of monthly crude oil and gas production statistics to RMAFC for the calculation of the 13% derivative to the producing states.
- Promotion of Nigeria Multi-client data at Africa Oil Week and Africa Energy Week conferences in South Africa.
- Promotion of Nigeria Assets (On-going Bid Round) and Multi-client data at Africa Energy Summit in London, UK.
- Concluded twenty (20) Due Diligence exercises in respect of Assignment of interests on several PPLs.
- Published Monthly Concession Situation report on the Commission's Website as at when due (January to December 2024)
- Concluded the evaluation of performance review of minimum work programme for 52 PPLs out of 57.

2.6.2 Concession situation as of January 2025 (Provisional)

The concession situation is in Appendix.

3.0 2024 FINANCIAL PERFORMANCE

3.1 COMPARISON OF INCOME FOR 2023 & 2024

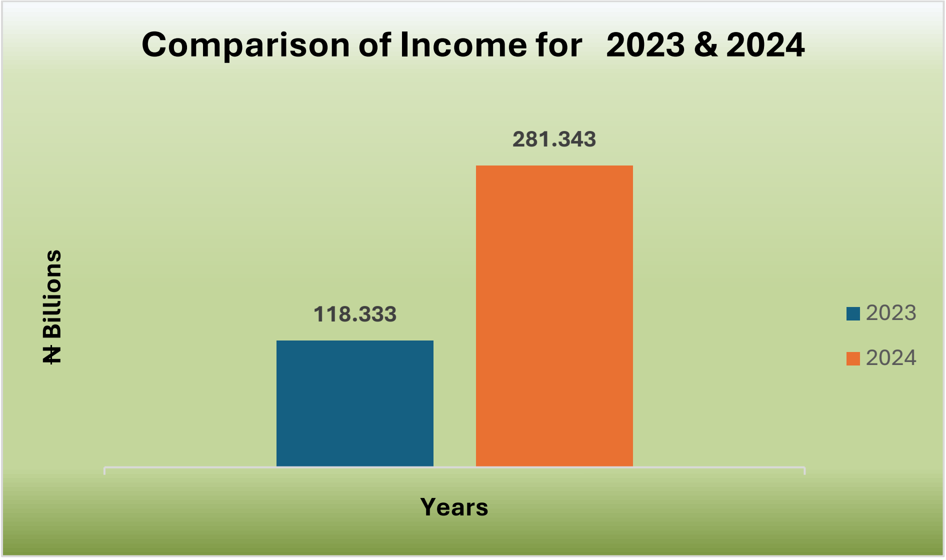


Figure 3.3: Comparison of income for 2023 & 2024

The Income received by Commission has increased by 237.76% in 2024 when compared with 2023.

Table 3.4: Comparison of Income for 2023 and 2024

REVENUE HEAD	2023 ₦	2024 ₦
Cost of Revenue Collection (CORC)	114,837,562,110.20	279,691,672,098.56
Internally Generated Revenue (IGR)	3,495,446,383.21	l,652,188,927.23
TOTAL	**118,333,008,493.41**	**281,343,861,025.79**

3.2 EXPENDITURE FROM JANUARY TO DECEMBER 2024

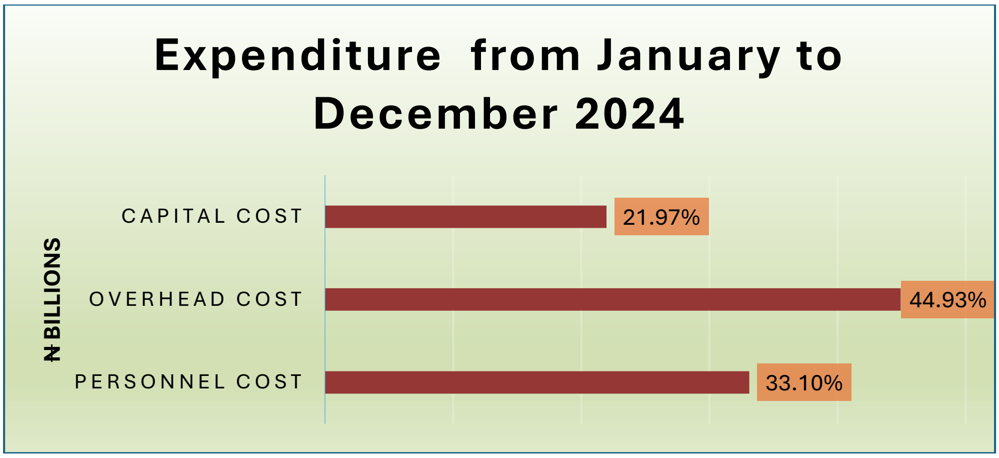


Figure 3.4: Expenditure from January to December 2024

Personnel cost: N 63, 257,812,159.52 billion Naira (33.10%)
Overhead cost: N 85,877,038,945.33 billion Naira (44.93%)
Capital cost: N 41,980,673,939.69 billion Naira (21.97%)

TOTAL EXPENDITURE: N 191, 115,525,044.54
OPERATING SURPLUS REMITTED TO CRF: N 6,521,990,361.29

Approved 2024 budget for the Commission was N286,936,780,410.37. The sum of NGN277,902,973,085.87 was paid to the Commission as Cost of Revenue Collection. This is inclusive of CORC arrears arising from Government Priority Projects (GPP), NNPC Limited Royalty Receivables Good and Valuable Consideration (GVC) and Signature Bonus.

4.0 ECONOMIC REGULATION AND STRATEGIC PLANNING

4.1 REVENUE GENERATION

4.2 2024 REVENUE PERFORMANCE

NUPRC revenue performance for January to December 2024 was 176.74%. The breakdown by revenue heads is as shown below:

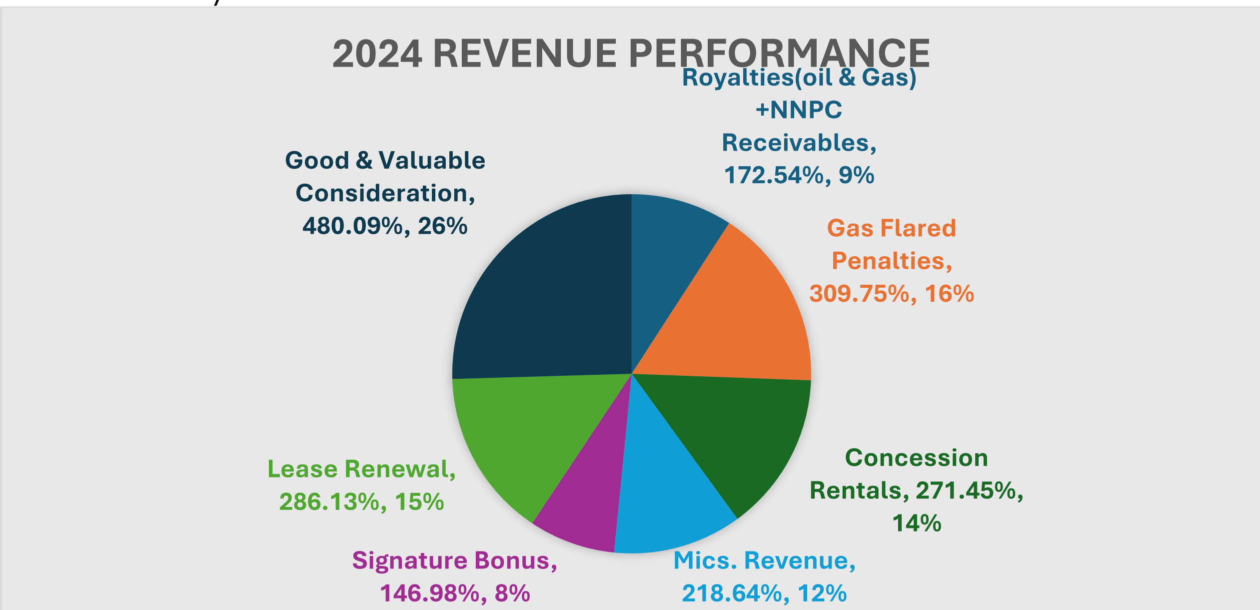


Figure. 3.5: 2024 Revenue Performance

The total revenue generated was N **12,250,607,908,453.30** which signified a 76.74% increase as compared to the annual budget N**6,931,236,009,076.00**.

Table 3.5: 2024 Budgeted Revenue, Actual Collection & Performance

REVENUE TYPE	2024 ANNUAL BUDGET (NGN)	ACTUAL COLLECTION	% PERFORMANCE
Royalties (Oil and Gas +NNPCL Receivables)	6,423,618,087,888.00	11,083,104,100,325.50	172.54
Gas flared penalty	126,315,710,771.00	391,264,227,593.46	309.75
Concession Rentals	8,734,914,342.00	23,711,047,815.34	271.45
Miscellaneous Oil Revenue	16,097,830,558.00	35,197,022,243.81	218.64
Lease Renewal	80,639,448,352.00	230,733,906,435.83	286.13
Signature Bonus	251,455,481,172.00	369,576,741,667.79	146.98
Good and Valuable Consideration	24,374,535,993.00	117,020,862,371.60	480.09
Grand Total	**6,931,236,009,076.00**	**12,250,607,908,453.30**	**176.74%**

Actual revenue performance in year 2024 is 76.74% over the budgeted revenue.

Table 3.6: ACTUAL REVENUE PERFORMANCE: 2022, 2023 & 2024.

REVENUE TYPE	2022 ₦	2023 ₦	2024 ₦
OIL & GAS ROYALTIES	**3,343,848,138,976.56**	**3, 756,455,736,932.09**	**11,083,104,100,325.50**
GAS FLARED PENALTIES	**70,422,698,758.57**	**140,542,799,981.78**	**391,264,227,593.46**
CONCESSION RENTALS	**6,223,801,170.38**	**10,216,458,225.76**	**23,711,047,815.34**
MISC. REVENUE	**13,416,309,755.36**	**16,378,599,446.27**	**35,197,022,243.81**
SIGNATURE BONUS	**132,013,296,530.16**	**256,992,218,005.85**	**369,576,741,667.79**
Lease Renewal	**166,218,190,238.70**	**00.00**	**230,733,906,435.83**
GOOD & VALUABLE CONSIDERATION	**49, 501,007,410.00**	**163,634,556,149.05**	**117,020,862,371.60**
TOTAL	**3,781,643,442,839.73**	**4,344,220,368,740.80**	**12,250,607,908,453.30**

There was an increase of 114.88% in 2023 over 2022 and 282% in 2024 over 2023 revenues.

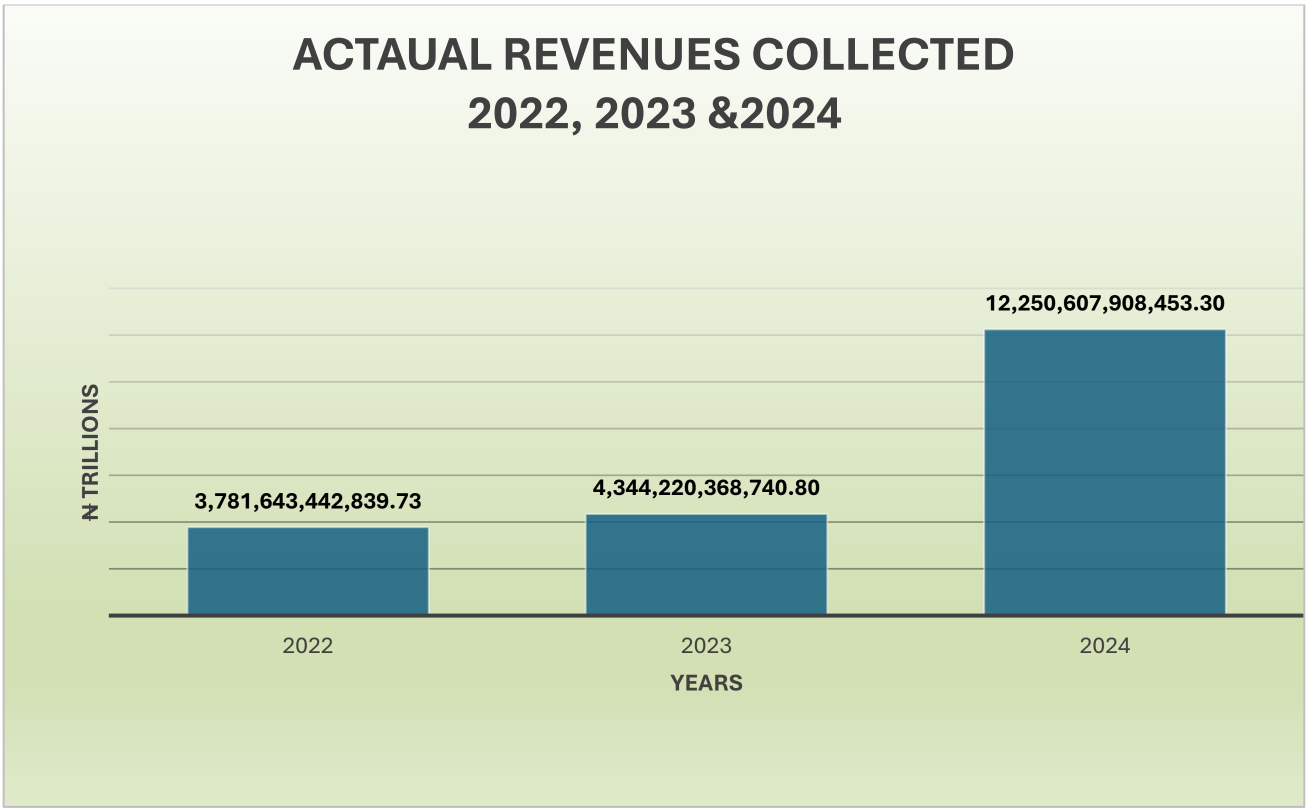


Figure 3.6: 2022, 2023 & 2024 Revenue Performance.

Revenue performance increased by 114.8% in 2023 when compared with 2022 and 282% in 2024 when compared with 2023.

5.0 HEALTH, SAFETY, ENVIRONMENT AND COMMUNITY

5.1 ENVIRONMENT

5.1.1 ENVIRONMENTAL INCIDENT MANAGEMENT

In 2024, a total of 732 environmental incidents were recorded, as detailed in the table below, which outlines the breakdown of incidents by their respective causes.

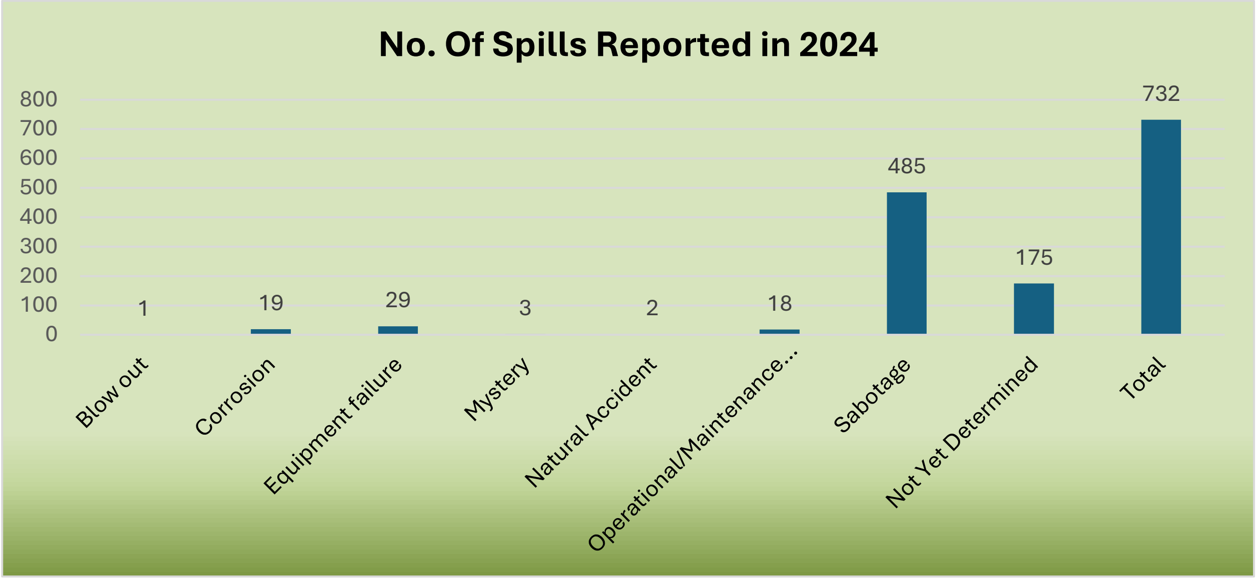


Figure 3.8: No. of Spill reported

Table 3.7: causes and number of spills reported

Cause Of Spill	No. Of Spills Reported
Blow out	1
Corrosion	19
Equipment failure	29
Mystery	3
Natural Accident	2
Operational/Maintenance Error	18
Sabotage	485
Not Yet Determined	175
Total	**732**

- Total Number of Oil Spill related petitions received- 48
- Total Number of RAP Application Received and Approved - 6

5.1.2 Waste Management

- 150 Waste Management companies were accredited.
- 183 Effluent/ Waste Discharge Permits (EWDP)were Issued.
- 35 Point sources (solid, liquid, and gaseous) were registered.

5.1.3 Environmental Assessment

- 35 Environmental Screening Report (ESR) and Preliminary Impact assessment Report (PIAR) approvals were issued.
- 91 Terms of Reference (TOR) and Scope of Work (SOW) approvals issued.
- 67 Environmental Impact Assessment (EIA)/Environmental Management Plans (EMP) approvals were issued and approved.
- 41 Environmental Evaluation Studies (EES) were approved.
- 30 Environment Baseline Study (EBS) and Environmental Seabed Survey were approved.
- 14 EIA waivers issued.
- 6 Extension of EIA/EES validity were issued.

5.1.4 Laboratory Services

- Eighty-three (83) laboratories were accredited.
- One hundred and thirty-four (134) oilfield chemicals were approved.
- Thirty (30) chemicals inventory reports were submitted.

5.1.5 Compliance and Enforcement

- One (1) Biological Monitoring Study (BMS) was approved.
- Seventy-eight (78) Environmental Compliance Monitoring Report (ECM) were submitted.

5.1.6 Climate Change Activities (Sustainability ESG and CCUS)

- Twenty-five (25) Greenhouse Gas Emission Management Plan (GHGEMP) reports were submitted.

5.2 SAFETY CONTROL

5.2.1 Accident/ Incident Management

Total number of thirty-one (31) incidents including twenty-two (22) fatalities were recorded in 2024.

5.2.2 Offshore Safety Permit (OSP)

- Total Registered – 26,185
- New permit issued -6,517 (out of which 360 are one-time flyers and 96 VIP flyers)
- Total renewal – 19,668

5.2.3 Radiation Safety Permit (RSP)

• 237 Radiation Safety Permits were issued.

5.2.4 Safety and Emergency Training Centres (SETC)

- Six (8) Safety and Emergency Training Centres were inspected and re – accredited.

5.3 Host Community

5.3.1 Host Community Development Administration (HCDA)

- Total Number of applications to incorporate HCDT: **207**
- Number of Approval by NUPRC to incorporate HCDT: **154**
- Number of HCDTs Incorporated by CAC: **136**

5.3.1 Host Community Project Management

- Total Number of Fund Managers Approved: 32
- Number of Ongoing Community Development Projects: 187

Table: 3.8: Total Remittance of 3% OPEX:

Remittances	NGN	USD ($)
Up to 2023	8,445,808,817	21,752,653
2024	57,068,651,974.94	80,445,409.76
Total to date	**65,514,460,791.94**	**102,198,062.76**

5.3.2 HostComply Digital Portal

- Large progress has been made with the development of HostComply. Information and data on the previous portal has been migrated and observed gaps are being filled progressively.

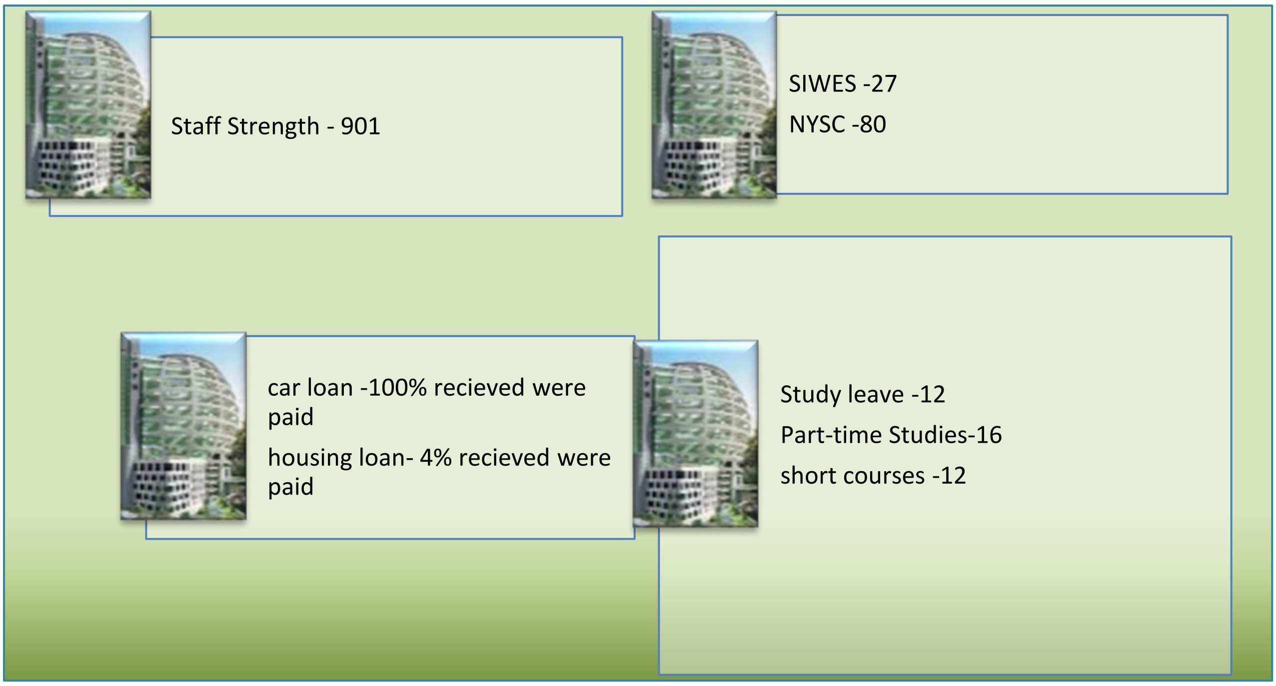
- Some modules are operational but have yet to be integrated (remittance splitting) while some such as Dispute resolution and conflict management are under development
- The following modules deployment and full integration are still outstanding; fund managers, vendors, conflicts and resolution management, fines and penalties, records and archives, notifications, reporting, incident management, ESG HCDP, OPEX module (calculation, posting and distribution), fund distribution matrix module, HCDT billing/demand notice/sabotage value modules, workflow approval.

5.3.4 Challenges

- Petitions and litigations stall incorporation of HCDT and set up of governance structures.
- Delayed deployment of HostComply portal for NUPRC HCDA team use, and for other stakeholders.

6.0 CORPORATE SERVICES AND ADMINISTRATION

6.1 Human Resources



Transformation of Appraisal System: The Employee Performance Management and Discipline Unit successfully ensured the 100% digitalization of the Commission's performance appraisal system, transitioning from a cumbersome paper-based process to a seamless digital platform.

6.2 TRANSFORMATION AND INNOVATION

Goal Setting and Job Alignment Document:
The Goal Setting and Job Alignment Document was updated to version 3 in 2024. This update incorporated input from over 100 business units and offices, improving clarity, accountability, and ensuring better alignment of employees' objectives with the Commission's broader strategic goals.

Development of Culture Transformation Program:
Designed to align with NUPRC's core values, this initiative promotes a positive shift in organizational culture. It includes various initiatives such as a Dress Code Policy, Team Bonding Exercise, Coaching and Mentorship Program, Leadership Development Program, and Mind-Well Program. The initiatives are being rolled out in phases, ensuring a sustainable cultural transformation.

Launch of the Commission's Innovation Hub:

The Innovation Hub was launched to encourage creativity and problem-solving within the organization. It includes an Idea Bank, a platform where employees can submit innovative solutions to drive organizational growth. This initiative promotes continuous learning and process improvements.

Institute Initiative for Technology Adoption:

The Commission achieved an 80% technology adoption rate, demonstrating the effectiveness of the initiative. Key activities include the launch of a Technology Adoption Campaign to promote digital tools, staff training, a Digital Productivity Leaderboard to track achievements, and a Digital Tools Resource Center to provide guides and tutorials.

6.3 Human Capital Development

Below are the activities of Human capital development unit for the year 2024:

S/N	ACTIVITIES	COMMENT
1	Recognition of Certificates	114 professional certificates were recognised.
3	**No. of Training & Workshop**	• A total of 429 employees (67 foreign and 362 local) attended trainings in 2024

		• 30 employees successfully completed the Basic Offshore Safety Induction & Emergency Training program in 2024. • 92 employees attended various Conferences during the period under review.
4	**NUPRC In-house Virtual Training Series** Exercise	This training series successfully engaged at least 250 employees per session, covering topics such as Microsoft Teams utilization, workplace wellness, artificial intelligence for productivity, NUPRC regulatory instruments, and corporate strategy.
	The NUPRC Knowledge Center	• Site Visits: 16,050 • No. of courses uploaded: Over 300+ • % of staff visits: 83%
	Junior Staff Conversion Exercise	A structured hybrid (physical/online) conversion test and interview process were conducted for Three (3) junior staff members.
	Salary Administration	• 2024 payroll and allowances were successfully processed.

6.4 MEDICAL SERVICES

- **Successful Onboarding of Staff, Dependents, and Retirees to Leadway HMO:**

The onboarding of all staff, dependents, and retirees onto the Leadway HMO platform has revolutionized healthcare accessibility within the Commission. By centralizing medical coverage under a robust system, employees now enjoy seamless access to healthcare services without administrative bottlenecks. This initiative has already saved the Commission ₦24 million, with an anticipated 40% reduction in future medical expenses

- **Conversion of Contract Medical Professionals to Permanent Staff**

The Commission has made significant strides in enhancing healthcare service delivery by transitioning contract medical professionals—including a doctor and a nurse—into permanent staff roles.

- **In-house Pharmacy**

The Pharmacy was well stocked with essential medications, ensuring staff members had seamless access to their routine prescriptions.

- **Look Ahead**:

The Medical Section aims to introduce more innovative healthcare solutions, including wellness programs that focus on mental health, nutrition, and lifestyle management. By integrating digital health tools and telemedicine services, the unit seeks to further enhance accessibility to medical consultation and promote a proactive approach to employee well-being. These strategies align with the Commission's vision of a highly productive workforce sustained by a strong health support system.

6.5 SERVICES

6.5.1 LOGISTICS AND TRAVEL SERVICES

- The Commission recently procured 17 additional vehicles to its fleet in the month under review. Three Official Vehicles were adequately allocated and sent to various locations
- Bills for both Local and Foreign Air Travels were paid
- NUPRC Outsourced driver personnel have been trained by FRSC and Certificates issued. Drivers were also trained on the usage of fire extinguishers in case of emergencies.

6.6 CONTRACT AND PROCUREMENT

361 contracts and procurements were carried out in the year 2024. The total 170 projects were executed, 1terminated and 190 are still ongoing.

7.0 LEGAL UNIT

7.1 Issuance of licence and lease instruments to awardees.

In the year 2024, the Legal Unit issued 50 Licence and Lease instruments in relation to award of petroleum prospecting licences, mandatory conversion of producing marginal fields and voluntary conversion of assets.

7.2 Promotion of transparency in the oil and gas sector:

In line with the Commission's mandate to promote transparency in the sector and its responsibility of keeping public registers of beneficial ownership, the Legal Unit, has continued to upload beneficial ownership information on the

Nogabor Portal. Compliance letters were issued to 131 companies who have submitted their beneficial ownership information.

7.3 Drafting of contracts between the Commission and Third Parties:

The Legal Unit drafted over 100 contract agreements between the Commission and third parties which includes projects and services agreements, bond agreements, data confidentiality agreements, tenancy agreements, memorandum of understanding, concession agreements, seismic/ geological survey agreements, multi-client agreements and indemnity agreements.

7.4 Provision of Legal Services in the 2022/23 and 2024 licensing round

During the period, the Legal Unit spearheaded the on-going development of a Production Sharing Contract (PSC) template for the 2022/2023 licensing round.

The unit also partook in the technical evaluation of bid submissions which ensured that the statutory provisions and provisions of the Licensing Round guidelines that guide the process were followed

7.5 Provision of legal services in the facilitation of assignment of interests in oil and gas leases and licenses:

The CSLA served as the Chairman of the Divestment Committee that amongst others developed the Upstream Asset Divestment and Exit Guidance Framework (the "Framework") upon which oil and gas divestments would be evaluated to ensure seamless, non-disruptive and value-driven divestments in the upstream petroleum sector.

The Legal Unit has continued to provide legal support in respect of the ongoing sale of oil and gas assets by some international oil companies (IOCs) (Divestments).

The Divestment by Nigerian Agip Oil Company Limited (NAOC), Equinor Nigeria Energy Company Limited, Shell Petroleum Development Company of Nigeria Limited (SPDC), Mobil Producing Nigeria Unlimited and TotalEnergies

EP Nigeria Limited (TotalEnergies) have all been concluded and consent granted accordingly.

The Legal Unit worked on the application by The Shell Petroleum Development Company of Nigeria Limited (SPDC) of 40% participating interest in Oil Mining Lease (OML) 144 (Asset) to Shell Nigeria Exploration and Production Company Limited (SNEPCo) The Ministerial consent was conveyed to SPDC subject to the payment by SPDC, of the sum of Four Hundred and Forty Thousand United States Dollars (US$440,000.00) as processing fee for the Ministerial consent to the Assignment.

7.6 Mediation between co-awardees towards the resolution of disputes:

- The Legal Unit facilitated the resolution of the lingering issues between Metropole Petroleum & Gas Limited and YY Connect Consulting Limited ('Awardees') which prevented the Awardees from finalizing their SPV agreements in compliance with the terms of the 2020 marginal field bid round. Following the meetings with the Awardees, the Awardees have notified the Commission that they have finalized the negotiation of the SPV Agreements and have duly executed same.

- The Legal unit also mediated between the Co-Awardees of Iheoma Marginal Field (now "PPL" 226), to resolve the outstanding issues regarding the inability to align and close out on the Special Purpose Vehicle (SPV) Formation Agreement for PPL 226.

7.7 Facilitating Early Lease renewal for gas producers in line with Nigeria's Decade of Gas Initiative:

The Legal department is actively engaged in facilitating early lease renewals under the Decade of Gas initiative in response to concerns from gas producers and a directive to explore viable solutions for this challenge. Significant progress has been made in developing an agreement for early renewal which addresses the urgent need for investment certainty for achieving the required FID.

7.8 Regulatory Compliance and interface with Regulatory Agencies:

The Legal also spearheaded the Liaison with other government Agencies such as EFCC, ICPC, NIETI and the NPF to aid their investigative activities.

7.8.1 Perfection of Title Documents:

The Legal Unit has obtained title documents for two real property which belongs to the Commission, located in Gombe and Bayelsa states respectively. The Unit obtained the Right of Occupancy (R of O) certificate for the land allocated to Commission by the Gombe State Government and accordingly, the original copy was forwarded to the EC, CS&A for safekeeping. In addition, the Legal Unit also obtained the Certificate of Occupancy for the Yenagoa land granted by the Bayelsa State Government to the Commission.

7.9 Dispute Resolution and Litigation:

During the review period, the Legal Unit handled the following matters:

- The Commission instituted 3 lawsuits to prevent the disposal of certain properties shared by the Commission and NNPCL in Kaduna, Port-Harcourt and Warri by the NNPC Pension Fund Limited.

- The Unit also received and reviewed 29 new lawsuits filed against the Commission.

- The Commission entered its defence in 14 out of the 29 lawsuits, and the Unit is currently monitoring the progress of the 15-lawsuit which are not defended by the Commission.

- **ICSID Case No: ARB/20/41 between ENI International B.V., Nigerian Agip Exploration Limited v. Federal Republic of Nigeria regarding the conversion of OPL 245 (OPL 245 Dispute).**

Following the presidential directive, several meetings have been held between representatives of the Federal Republic of Nigeria, comprising the Commission, the Nigerian National Petroleum Company Limited (**NNPC**), the Federal Inland Revenue Service (together "(**FGN Parties"**) and ENI, to attempt to agree on the documentation required to settle the dispute. These meetings have culminated in the parties agreeing to sign the following documents:

(a) The Petroleum Prospecting License and Petroleum Mining Lease Concession Contracts (the "**Concession Contracts**");
(b) The Petroleum Prospecting License and Petroleum Mining Lease General Conditions (the "General Conditions");
(c) Petroleum Prospecting License and Petroleum Mining Lease instruments; and
(d) The Production Sharing Contract (PSC).
(e) (together "Conversion Documents").

7.9.1 The Commission and ENI met from November 26 to 28, 2024, to finalise the Concession Contracts and General Conditions. The parties agreed on most matters; however, some outstanding issues have been referred to the Honourable Attorney General of the Federation for guidance. The Commission is currently awaiting a response from the HAGF.

9.9.2 The Commission, NNPC and ENI also met from December 9 to 13, 2024, to finalise the PSC. The parties agreed on most matters; however, some outstanding issues have been referred to the senior management of the NNPC for further guidance.

- The Commission has successfully closed 6 cases, which are:
  a. Suit No. FHC/L/CS/78/2024: - Sunlink Energies and Resources v. Shell Petroleum Development Company Nigeria Limited, Nigerian Upstream Petroleum Regulatory Commission and 3 others.
  b. Suit No. FHC/HC/BW/CV/173/22: Nigeria National Petroleum Corporation Limited v. Mobil Producing Nigeria Unlimited, Nigerian Upstream Petroleum Regulatory Commission and 3 others.
  c. Suit No. FHC/PH/CS/32/2024: Suffolk Nigeria Limited v. Nigerian Upstream Petroleum Regulatory Commission and 3 others
  d. Suit No: NICN/YL/04/2024- Incorporated Trustees of Johnbosco Human Rights Foundation V. Nigerian Upstream Petroleum Regulatory Commission & National Salaries, Income and Wages Commission.
  e. Suit No: FHC/ABJ/CS/68/2023: THE Incorporated Trustees of Onelga Oil & Gas Landlords Families Organization & Institute of

the Environment Limited V. Nigerian Agip Oil Company Limited, Nigerian Upstream Petroleum Regulatory Commission & 11 Others.

f. Suit No: DSMDC/WRI/WK/122024 Between Tsaye Mene and 7 Ors v. Nigerian Upstream Petroleum Regulatory Commission, NNPC E&P Limited and 2 Others

8.0 Board Secretariat

In the period under review, the Legal Unit successfully coordinated and facilitated the following key meetings:

Top Management Committee (TMC) Meetings:

- 18th TMC Meeting: Held on 1st March 2024
- 19th TMC Meeting: Held on 23rd May 2024
- 20th TMC Meeting: Held on 10th July 2024
- 21st TMC Meeting: Held on 4th November 2024

National Data Repository Advisory Council (NDRAC) Meeting:

- NDRAC Meeting: Held on 8th September 2024