Unaudited results for the nine months ended 30 September 2025

30 October 2025

Reliable energy,
limitless potential

Interim Management Report

Lagos and London, 30 October 2025: Seplat Energy Plc ("Seplat Energy" or "the Company"), a leading Nigerian independent energy company listed on both the Nigerian Exchange Group and the London Stock Exchange, announces its unaudited results for the nine months ended 30 September 2025.

Summary

In 9M 2025 we delivered further production growth, underpinning FY2025 guidance, which we narrow to the upper half of the range at 130-140 kboepd. Generated over $1 billion in after tax CFFO, up over 180% YoY, supporting our Capital Markets Day ('CMD') ambitions. Strong cash generation delivers a reduction in net debt to $386 million, with net leverage improving to 0.27x ND/EBITDA, and aligned with CMD capital allocation plans, declare 7.5 US cents per share dividend for 3Q 2025, +63% QoQ.

Operational highlights

- 9M 2025 production averaged 135,636 boepd up 185% from reported 9M 2024 (47,525 boepd), and up 18% vs. pro-forma 9M 2024 production, while 3Q 2025 production averaged 137,888 boepd, a 1% improvement on 2Q 2025.
  - 3Q 2025 production onshore of 56,219 boepd, was up 5% QoQ supported by production improvement in OML40.
  - 3Q 2025 production offshore of 81,669 boepd was down 2.5% QoQ, continued strong performance of the idle well programme offset by planned downtime on EAP, due to the IGE replacement project and lower output from A/K.
- Offshore, the idle well restoration programme added c.33.4 kbopd gross production capacity from the first 33 wells restored to production.
- First Liquefied Petroleum Gas ('LPG') cargo sold to the domestic market, improving domestic energy access and supporting clean cooking.
- Recorded one Lost Time Injury ('LTI') to the hand of one person at Oben. Fire incident at Yoho production platform on 27 September, no injuries sustained. Yoho expected to be offline to year end, 4Q 2025 net production impact of approximately 10-12 kboepd.
- ANOH gas plant on track to deliver first gas in 4Q 2025.
- Carbon emissions intensity for onshore assets: 25.2 kg CO_2/boe 21% lower than revised 9M 2024: 32.0 kg CO_2/boe. End of routine flaring for onshore assets on track for end 2025 completion. Carbon emissions intensity for our offshore assets was 51.2 kgCO_2/boe in 9M 2025.

Financial highlights

- Revenue $2,177 million up c.204% on prior year (9M 2024: $715 million).
- Unit production operating cost of $14.1/boe (9M 2024: $9.7/boe), within guidance of $14-$15/boe.
- Adjusted EBITDA of $1,112 million, up 190% on prior year (9M 2024: $383.0 million).
- Cash generated from operations of $1,395.4 million, up 239% on prior year (6M 2024: $423.3 million).
- Cash capital expenditure of $180.0 million (9M 2024: $102.4 million).
- Balance sheet remains strong, end-Sept cash at bank $579.8 million (9M 2024: $433.9 million), excluding $135.4 million restricted cash.
- Net Debt at end-Sept of $386 million down 43% on prior quarter (2Q 2025: $676 million). Pro-forma ND/EBITDA improves to 0.27x.
- Repaid and cancelled Westport junior facility and refinanced Westport senior reserve based loan ('RBL') facility at lower cost of debt.
- Repaid the outstanding $100 million on our RCF. At end September 2025, the $350 million RCF is undrawn and fully available.

Dividend

- Outlined new dividend policy at the CMD. Strong YTD cash generation supports additional distribution. 3Q 2025 declared dividend of 7.5 US cents per share, +63% QoQ and +108% YoY, consisting of 5.0 US cents per share base and 2.5 US cents per share special.

2025 Outlook

- 2025 guidance is updated as follows:
  - Production guidance narrowed to the upper half at 130-140 kboepd (previously 120-140 kboepd).
  - Capex guidance narrowed to $270-290 million (previously $260-320 million).
  - Unit production operating cost guidance is unchanged at $14.0-15.0/boe.

Roger Brown, Chief Executive Officer, said:

"At our CMD in September, we set out our medium term vision for the Company, targeting 200 kboepd working interest production and $1 billion in cumulative dividends in our roadmap to 2030.

"As we approach the first anniversary of the MPNU acquisition, we are clearly displaying our ability to operate a business at scale. We delivered a third consecutive quarter of production growth at the upper end of production guidance, and we are pleased to be able to narrow production to 130-140 kboepd. Our financial performance year to date has been extremely robust, generating after tax cash flows in excess of $1 billion, enabling significant deleveraging to 0.27x ND/EBITDA, well below our target levels. In addition, while we anticipate some cash outflow in 4Q 2025, our strong cash generation year to date supports declaring a special dividend of 2.5 US cents/share, delivering a total dividend to shareholders this quarter of 7.5 US cents/share. This is aligned with the new dividend policy of returning an increasing share of free cash flow to shareholders, laid out at the CMD.

"Unfortunately, at the end of September, we had a fire incident at Yoho. While there were no injuries and the safety systems worked efficiently, the event reinforces our decision to focus and prioritize additional investment in integrity and maintenance activities. We are now working to restore production safely and swiftly.

“We have continued the momentum into the final quarter of the year, making substantial progress in the past few days to ending routine flaring onshore, a commitment we have made for 4Q 2025, and we expect to complete the PIA conversion process for our onshore business imminently, which will further support the delivery of our ambitious 2030 roadmap laid out at the CMD.”

Summary of performance

	$ million			₦ billion	
	9M 2025*	9M 2024	% change	**9M 2025***	9M 2024
Revenue **	**2,176.6**	715.3	204 %	**3,356.2**	1,070.9
Gross profit	**879.5**	355.0	148 %	**1,356.0**	531.5
EBITDA ***	**1,111.9**	383.0	190 %	**1,714.5**	573.4
Operating profit	**711.0**	274.8	159 %	**1,096.2**	411.3
Profit before tax	**570.1**	245.0	133 %	**879.0**	366.7
Profit after tax	**95.1**	35.3	169 %	**146.6**	52.8
Cash generated from operations	**1,395.4**	423.3	230 %	**2,151.5**	633.8
Working interest production (boepd)	**135,636**	47,525	185 %		
Volumes lifted (MMbbls)	**27.9**	7.5	270 %		
Average realised oil price ($/bbl)	**71.93**	82.89	(13)%		
Average realised gas price ($/Mscf)	**2.95**	3.18	(7)%		
LTIF	**0.12**	—			
CO2 emissions intensity from operated onshore assets, kg/boe	**25.2**	32.0	(21)%		

*Throughout results 9M 2025 reported figures consolidate offshore assets contribution, while 9M 2024 information relates solely to Seplat's Onshore assets
** 9M 2025 reported revenue excludes an underlift of $3.8 million, 9M 2024 excludes an underlift of $8.2 million
*** Adjusted for non-cash items

Responsibility for publication

This announcement has been authorised for publication on behalf of Seplat Energy by Eleanor Adaralegbe, Chief Financial Officer, Seplat Energy Plc.

Signed:

Eleanor Adaralegbe
Chief Financial Officer

Important notice

The information contained within this announcement is unaudited and deemed by the Company to constitute inside information as stipulated under Market Abuse Regulations. Upon the publication of this announcement via Regulatory Information Services, this inside information is now considered to be in the public domain.

Certain statements included in these results contain forward-looking information concerning Seplat Energy's strategy, operations, financial performance or condition, outlook, growth opportunities or circumstances in the countries, sectors, or markets in which Seplat Energy operates. By their nature, forward-looking statements involve uncertainty because they depend on future circumstances and relate to events of which not all are within Seplat Energy's control or can be predicted by Seplat Energy. Although Seplat Energy believes that the expectations and opinions reflected in such forward-looking statements are reasonable, no assurance can be given that such expectations and opinions will prove to have been correct. Actual results and market conditions could differ materially from those set out in the forward-looking statements. No part of these results constitutes, or shall be taken to constitute, an invitation or inducement to invest in Seplat Energy or any other entity and must not be relied upon in any way in connection with any investment decision. Seplat Energy undertakes no obligation to update any forward-looking statements, whether because of new information, future events or otherwise, except to the extent legally required.

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About Seplat Energy

Seplat Energy Plc (Seplat) is Nigeria's leading indigenous energy company. Listed on the Nigerian Exchange Limited (NGX: SEPLAT) and the Main Market of the London Stock Exchange (LSE: SEPL). Through our strategy to build a sustainable business and deliver energy transition, we are transforming lives by delivering affordable, reliable and sustainable energy that drives social and economic prosperity.

Following the acquisition of Mobil Producing Nigeria Unlimited, Seplat Energy's enlarged portfolio consists of eleven oil and gas blocks in onshore and shallow water locations in the prolific Niger Delta region of Nigeria, which we operate with partners including the Nigerian Government and other oil producers. Furthermore, we have an operated interest in three export terminals including the Qua Iboe export terminal and Yoho FSO, as well as an operated interest in the Bonny River Terminal (BRT), and two large NGL recovery plants at Oso and EAP. We operate two gas processing plants onshore, at Oben in OML 4 and Sapele in OML 41, and are soon to open the 300 MMscfd ANOH Gas Processing Plant in OML 53 as a joint venture with NGIC. Combined, these gas facilities augment Seplat Energy's position as a leading supplier of natural gas to the domestic power generation market.

For further information please refer to our website; https://seplatenergy.com/

Operating review

Group Production

Working interest production for the nine months ended 30 September 2025

Asset	Seplat WI %	9 months ended 30 Sept 2025 Liquids bopd	Gas MMscfd	NGLs* bpd	Total boepd	9 months ended 30 Sept 2024 Liquids bopd	Gas MMscfd	NGLs* bpd	Total boepd
OMLs 4, 38, 41	45 %	16,921	132.5		39,763	15,067	103.6	—	32,928
OML 40	45 %	11,142			11,142	11,468	—	—	11,468
OML 53	40 %	2,828			2,828	1,516	—	—	1,516
OPL 283	40 %	1,566			1,566	1,613	—	—	1,613
Seplat Onshore		**32,458**	**132.5**	**—**	**55,299**	**29,664**	**103.6**	**—**	**47,525**
OMLs 67, 68, 70, 104	40 %	68,623	30.3	3,719	77,562	—	—	—	—
OML 99 (A/K Field)	9.6 %	712	12.0		2,775	—	—	—	—
Seplat Offshore		**69,335**	**42.2**	**3,719**	**80,337**	**—**	**—**	**—**	**—**
Total		**101,793**	**174.7**	**3,719**	**135,636**	**29,664**	**103.6**	**—**	**47,525**

*Working interest on NGLs is 51%
Liquid production volumes as measured at the LACT (Lease Automatic Custody Transfer) unit for OMLs 4, 38 and 41; OML 40 and OPL 283 flow station.
Gas conversion factor of 5.8 boe per scf.
Volumes stated are subject to reconciliation and may differ from sales volumes within the period.
A/K Field refers to Amenam-Kpono field

In 9M 2025, average daily working interest production for the group was 135,636 boepd (9M 2024: 47,525 boepd), firmly within the upper half of our original production guidance (120,000 - 140,000 boepd). Total crude & condensate production increased by 242% to 27.8 MMbbls, compared to the 8.1 MMbbls produced in 9M 2024. Total gas produced during the period rose 68% to 47.7 Bscf (9M 2024: 28.4 Bscf), and we also produced 1.0 MMbbls of NGLs in 9M 2025. As such, aggregate production for the period rose 184% to 37.0 MMboe (9M 2024: 13.0 MMboe), reflecting the transformational impact of the offshore assets consolidation and strong performance on our onshore assets.

Production performance in our onshore operations remained strong, up 16% from the equivalent period in 2024 (9M 2025: 55,299 boepd; 9M 2024: 47,525 boepd). The growth was underpinned by a confluence of positive catalysts including good performance of new onstream wells, sustained gas production from the Western assets and production growth in OML 53. Production deferment in the period was 21% onshore (9M 2024: 24%) and 20% offshore. Onshore deferments improved compared to 9M 2024, underpinned by export route availability for our Eastern assets and resumption of Trans Escravos Pipeline (TEP) operations following 2Q 2025 scheduled downtime. Offshore deferments were due to planned EAP shutdown and three-day production downtime in Yoho production platform caused by the fire incident (details in the HSE section).

Quarter on Quarter working interest production for 2025

Asset	Seplat WI %	Q3 2025 Liquids bopd	Gas MMscfd	NGLs* bpd	Total boepd	Q2 2025 Liquids bopd	Gas MMscfd	NGLs* bpd	Total boepd	Q1 2025 Liquids bopd	Gas MMscfd	NGLs* bpd	Total boepd
OMLs 4, 38, 41	45 %	16,842	128.6	—	39,010	17,626	136.9	—	41,228	16,291	132.0	—	39,050
OML 40	45 %	12,779	—	—	12,779	7,969	—	—	7,969	12,676	—	—	12,676
OML 53	40 %	2,759	—	—	2,759	2,793	—	—	2,793	2,935	—	—	2,935
OPL 283	40 %	1,671	—	—	1,671	1,420	—	—	1,420	1,535	—	—	1,535
Seplat Onshore		**34,051**	**128.6**	**—**	**56,219**	**29,808**	**136.9**	**—**	**53,410**	**33,437**	**132.0**	**—**	**56,196**
OMLs 67, 68, 70, 104	40 %	70,024	33.3	3,615	79,379	70,409	37.2	4,164	80,990	65,385	20.2	3,376	72,239
OML 99 (A/K Field)	9.6 %	603	9.8	—	2,290	720	12.1	—	2,807	816	14.1	—	3,239
Seplat Offshore		**70,627**	**43.1**	**3,615**	**81,669**	**71,129**	**49.3**	**4,164**	**83,797**	**66,201**	**34.3**	**3,376**	**75,478**
Total		**104,678**	**171.7**	**3,615**	**137,888**	**100,937**	**186.2**	**4,164**	**137,207**	**99,638**	**166.3**	**3,376**	**131,674**

*Working interest on offshore NGLs is 51%

On a quarter-on-quarter ('QoQ') basis, group production rose 1% to 137,888 kboepd. This is reflective of the progressive impact of our production growth efforts and resumption of production on our Elcrest operations which experienced some downtime in 2Q 2025. Onshore production grew 5% QoQ, while. Offshore production fell 2% QoQ as production additions from the idle well restoration programme, did not fully offset scheduled downtime on the East Area Project (EAP) platform where we commenced installation of the Inlet Gas Exchanger (IGE) in September.

Seplat Offshore

Crude, Condensates & NGLs Production

In OMLs 67, 68, 70, and 104, working interest liquids production for 9M 2025 was 68,623 bopd. On a QoQ basis, liquids production declined marginally by 1% to 70,024 bopd in 3Q 2025, from 70,409 bopd in 2Q 2025. The QoQ decline was due to scheduled downtime on our East Area Project (EAP) platform where we commenced installation of the Inlet Gas Exchanger (IGE) in early September. The scheduled downtime partially offset the positive impact of our idle well restoration programme (more details in the next section).

Natural Gas Liquids (NGLs) production declined 13% QoQ to 3,615 bpd in 3Q 2025, from 4,164 bpd in 2Q 2025. The decline reflects the impact of the scheduled operations shutdown at EAP in early September as highlighted earlier. For 9M 2025, NGLs average daily working interest production was 3,719 bpd. In the quarter we sold our first cargo of Liquefied Petroleum Gas ('LPG') to the domestic market from the Bonny River terminal. The cargo of 12,600 MT LPG (Butane) was lifted in August and will contribute towards greater domestic energy supply.

The Amenam-Kpono (A/K) field contributed 712 bopd to average daily liquids working interest production in 9M 2025.

Idle Well Restoration Programme

The programme to restore production from idle wells continued during 3Q 2025. A further four idle wells were worked on during the quarter taking the total well count to 33 in 2025, well ahead of plan. Of the 33 wells, 26 have been successfully restored to production. The 3Q 2025 idle well programme restored an additional 7.5 kbopd gross production capacity, with wells accessed by the jack-up barge particularly coming back at above-plan rates. The idle well programme continues to be a strong value-adding activity, with year to date additions to gross production capacity up to 33.4 kbopd from 26 productive wells, delivered at a net working interest cost of less than $40 million.

We remain on track to meet our previously upgraded target of 50 well work-overs from the idle well inventory during 2025.

EAP Inlet Gas Exchange (IGE) Update

The East Area Project ('EAP') Inlet Gas Exchanger (IGE) replacement project is the main project offshore in 2025 and is designed to increase gross JV NGL production at EAP by 8 to 10 kboepd to c.12 kboepd when operational. In the quarter, the old unit was removed and the replacement IGE was installed in its location on the platform. Works to connect the IGE continued beyond quarter end, and are on track to complete during 4Q 2025. Production via EAP is currently curtailed pending completion of the project, and is expected to ramp up post completion during 4Q 2025.

Seplat Onshore

Western Assets

In OMLs 4, 38, & 41, working interest liquids production rose by 12% to 16,921 bopd (9M 2024: 15,067 bopd). The growth was aided by good performance of new wells coming onstream which helped to arrest decline on the assets and support growth. In addition, export route availability remained strong during the period with the two export routes, Amukpe-Escravos pipeline ('AEP') and Trans Forcados pipeline ('TFP') both achieving 91% and 89% uptime respectively during the period. Total deferments on the asset in 9M 2025 stayed stable at 16% (9M 2024: 16%).

OML 40

Production at OML 40 (inclusive of Abiala Marginal Field) declined in 9M 2025, falling by 3% to 11,142 bopd (9M 2024: 11,468 bopd). The decline in production was predominantly due to the outages recorded in 2Q 2025, as a result of a planned 21-day shut down for maintenance by the line operator on the Trans Escravos Pipeline ('TEP') which transports our crude to the Forcados Oil Terminal ('FOT'). OML 40 production recovered strongly in 3Q 2025, up 60% QoQ to 12,779 bopd, compared to 7,969 bopd in 2Q 2025. Total deferments on OML 40 rose during the period to 29% (6M 2024: 13%).

Eastern Assets

In OML 53, overall performance was strong, with average daily working interest production increasing by 87% to 2,828 bopd in 9M 2025, from 1,516 bopd in 9M 2024, due to continuous availability of the evacuation routes for the asset, principally the Trans Niger Pipeline ('TNP'). Total pipeline availability for the TNP-BOT evacuation route for our Ohaji operations in 9M 2025 was 83% (9M 2024: 6%)

We also continued to supply the Waltersmith refinery during the quarter. Production from our Jisike field continued to improve as the reliability of the Antan-Ebocha-Brass terminal route was sustained in 9M 2025. Uptime on the route improved to 83% (9M 2024: 45%).

In OPL 283, liquids production declined by 3% to 1,566 bopd in 6M 2025 (9M 2024: 1,613 bopd).

Onshore drilling activities

Our drilling programme maintains a target of delivering 13 new onshore wells in 2025. Due to timing of rig availability, the schedule has been modified to; Western Assets - 9 wells (previously 8); Eastern Assets - 2 wells; Elcrest - 2 wells (previously 3).

On our Western Assets, we delivered five wells in 9M 2025 which were Sapele-39, Orogho-10, Orogho-11, Okporhuru-10 and Oben-58. Three of the completed wells are now onstream and producing at a combined gross rate of 3,440 bopd and 25 MMscfd. The remaining wells will come onstream in 4Q 2025.

On our Eastern Assets, we commenced the drilling programme in September, spudding the first well. Drilling of the well is ongoing and will be completed shortly. The second well in the sequence will commence in November with a plan to complete the well in December.

For Elcrest, drilling of the first well (Opuama-18) has commenced and drilling of the second well will commence in November. Both wells are expected to be completed by December and contribute to 2026 production.

We remain confident that our drilling programme will be delivered on time and within budget, enabling onshore production to remain robust heading into 2026.

Midstream Gas business performance

Group Gas Production

During the period, the Company produced 47.7 Bcf of gas, representing a 68% increase on 28.4 Bcf reported in 9M 2024. The average daily working interest gas production volumes increased by 69% to 174.7 MMscfd, from 103.6 MMscfd in 9M 2024. The growth in group gas production is reflective of the consolidation business plus new gas wells coming onstream and sustained production from the Sapele gas plant.

Seplat Onshore Gas Production

On our onshore assets, average daily working interest gas production increased by 28% to 132.5 MMscfd (9M 2024: 103.6 MMscfd). The increase was supported by commencement of production at the Sapele gas plant, new gas wells coming onstream, and continued strong production efficiency at the Oben gas plant.

Seplat Offshore Gas Production

Average daily working interest gas production from our offshore assets was 42.4 MMscfd in 9M 2025, benefiting from improved export pipeline availability and improvements in production efficiency. 3Q 2025 average daily working interest gas production declined 13% QoQ to 43.1 MMscfd (2Q 2025: 49.3 MMscfd), due to the scheduled downtime on EAP production platform and production ramp-up delays post planned Oso production platform downtime.

Oso-BRT Gas Plant Upgrade - Phase 1

Oso-BRT Gas Pipeline Capacity Upgrade project is designed to double the existing pipeline capacity from 120 MMscfd up to 240 MMscfd of sales gas to Bonny River Terminal ('BRT'). In 3Q 2025, detailed engineering design was progressed to approximately 75% completion and procurement of long lead items and bulk materials was initiated. Onshore fabrication will commence in 1Q 2026.

Sapele Gas Plant

We continued to progress towards full operationalisation of the Sapele Integrated Gas Plant in 3Q 2025. We are pleased to announce completion of the 90-day reliability test of train 2 (60 MMscfd MRU) of the Sapele gas plant, which qualifies us to receive the License to Operate ('LTO') from the regulators. The liquified petroleum gas ('LPG') module is expected to be commissioned in late 4Q 2025, and we plan to get a combined LTO for the gas plant and LPG module. The commencement of operations will have a three-fold impact for the Company by bringing us closer to eliminating routine flaring, reducing gas flare penalties, and growing gas revenue through additional gas sales from previously flared gas.

In October, we commissioned the Sapele gas plant LPG module achieving first gas from the LPG plant. The next phase of the project which is to commission the storage and offloading infrastructure is expected to be completed in 4Q 2025 with guidance to commence commercial operations by year end. The pumps, loading arms and other systems will be calibrated as commercial operations commence. This would provide Seplat Energy with a new revenue line through LPG.

ANOH Gas

AGPC continued its strong safety performance achieving a cumulative total of 17.0 million man-hours LTI free by the end of 3Q 2025.

Operations during 3Q 2025 continued to focus progress with the final commissioning of the ANOH gas plant with live hydrocarbons and execution of modification works in support of alternative gas export route. Progress with the gas export route modification to enable gas supply to Nigeria LNG is close to completion with first gas expected during 4Q 2025. Commercial negotiations for offtake via the alternative route have been concluded, with sufficient demand contracted on both a firm and interruptible basis to enable the plant to operate at name plate capacity.

Work on the OB3 gas pipeline remains halted while its owner NGIC works with its contractors to review the final stages of the river crossing element of the project.

On 26 September 2025, Vitol provided a 12-month $30m prepayment facility to AGPC at a cost of SOFR plus 10%. The facility was drawn and utilised for ongoing work to deliver first gas and also to meet interest payment obligations to the bank lenders.

Ending routine flaring

Reducing the carbon intensity of our operations is a key strategic focus. Seplat has implemented its End Of Routine Flaring ('EORF') roadmap, which includes investments across our facilities to minimise Scope 1 & 2 greenhouse gas emissions and improve overall energy efficiency.

The carbon emissions intensity recorded on Seplat's onshore operations for 9M 2025 was 25.2 kg CO_2/boe, 21% lower than the 32.0 kg CO_2/boe recorded in 9M 2024. For 3Q 2025, we report a carbon emissions intensity of 22.0 kg CO_2/boe 34% lower than the equivalent period last year. The decline in our carbon emission intensity is reflective of the progress made in our EORF projects with installation of compressors and Vapour Recovery Units (VRUs) at Oben, Amukpe, and Sapele completed during the year. As such, a significant portion of previously flared gas is now captured and processed at SIGP following commissioning of the plant.

Emissions Intensity	Unit	Q2 2024	Q3 2024	Q4 2024	Q1 2025	Q2 2025	Q3 2025
Onshore Operated Assets	kgCO_2/boe	31.79	33.17	32.29	30.65	23.17	22.00

As highlighted at the CMD in September, we had two EORF projects left to complete onshore. On the Western Assets, we commissioned the Oben LPG Project in October with the facility ready to flow gas to the Sapele gas plant LPG module. The Sapele gas plant LPG module has reached completion while the first phase of the LPG storage and loading facility was commissioned in October. The final phase of the facility is expected to be commissioned in 4Q 2025, in time to commence beneficial operations. Upon commissioning, the plant will commence production of LPG from previously flared gas in Oben and Sapele.

On our Eastern Assets, the Ohaji Flares Out Project (compressors and VRUs installations) reached mechanical completion in October. We also tested introduction of hydrocarbons into the AG compressor station and now on track to end routine flaring by Q4 2025. The project awaits receipt of AGPC's licence to introduce hydrocarbons into the ANOH gas plant. The installed VRUs and compressors will capture gas flares and inject them into ANOH for processing into dry gas and LPG. As such, we remain confident in the timeline to end routine flaring onshore in 2025.

Carbon emissions intensity for our offshore assets was 51.2 kgCO2/boe in 9M 2025. We continue to review the offshore flaring regime and will communicate our framework to end routine flaring at a future date.

HSE Performance

Safe and responsible operations continue to be the core of delivering our strategy and growing our business. After achieving 29.1 million hours over nearly three years on our operated onshore assets, an operating incident was recorded on 13th September at the Oben Gas Plant, resulting in an injury to the hand of one site personnel. The circumstances that led to the incident has been investigated and necessary measures put in place to prevent future occurrence.

Post the LTI recorded in September, we recorded a total of 0.412 million hours without LTI on our operated onshore assets and 1.056 million hours on operated assets offshore. Across the group's operated assets, post the event at Oben, we achieved a total of 1.47 million hours without a Lost Time Injury ('LTI').

Year-to-date, across our operations, we recorded five Tier-1 Loss of Primary Containment ('LOPC') incidents of which, one was a fire incident (discussed below), two gas releases and two oil spills. Additionally, we recorded two Tier 2 LOPC incidents related to oil spills.

LTI-Free hours worked	Q1 2025	Q2 2025	Q3 2025*	9M 2025*
Onshore Operated Assets	2,482,479	2,787,286	412,404	412,404
Offshore Operated Assets	4,759,567	5,302,475	1,055,562	1,055,562
Total Operated Assets	**7,242,046**	**8,089,761**	**1,467,966**	**1,467,966**
Elcrest	704,236	773,160	816,916	2,294,312
AGPC	909,903	881,542	741,142	2,513,982
Total Non-Operated Assets	**1,614,139**	**1,654,702**	**1,558,058**	**4,808,294**

*Q3 2025 & 9M 2025 data for the operated assets is from 13th September post recorded LTI at Oben.

During the quarter, we officially received the ISO 45001 certificate as we communicated in our 6M 2025 results. For ISO 14001, the focus during the quarter was preparations for the stage one audit which is now expected to take place in Q4 2025. Working to achieve these certifications further demonstrates our commitment to top-tier safety and environmental performance.

Yoho Production Platform Incident

On 27th September, there was a fire on the Yoho production platform (distinct and away from the Yoho FSO) with no injuries recorded. The fire was extinguished by the platform's safety systems which operated effectively. However, the fire caused damage to some electrical systems and adjoining piping, which will require repair before the platform can safely return to production. Force majeure has been declared for Yoho cargos, with production expected to be offline until year end. The impact on operations is the loss of approximately 10-12 kbopd working interest, against the group forecast in 4Q 2025, and is factored into our updated 2025 production guidance.

Petroleum Industry Act (PIA) Implementation Status

In our onshore business, we continue to make good progress on the PIA conversion process. During 3Q 2025, we focused on executing the legal and contractual phase of the conversion process following completion of technical milestones in 2Q 2025. We also secured JV alignment from our partners (NEPL & NUIMS). In October, we received the execution version of relevant contracts, in respect of the Seplat operated assets OML 4, 38, 41 and 53. In line with the Commission's guidance, we are progressing the execution of the contracts along with our JV partners, and expect to completely this imminently.

For our offshore assets, we have completed the commercial case for conversion, established the boundaries for technical delineation and minimum work programmes. The next step is to seek JV partner alignment and thereafter proceed with regulatory engagements. We retain guidance to complete the conversion process by the end of 2026.

Financial review

Our 9M 2025 financial results continue to reflect the significant step change in our financial performance following consolidation of our onshore and offshore operations. For 9M 2025, Brent crude fell 15% compared to the prior year, while our average realised oil price fell 13% YoY to $71.93/bbl. Our average realised NGL price was $46.64/bbl, while our blended realised gas price of $2.95/Mscf fell 7% YoY (9M 2024: $3.18/Mscf).

In 3Q 2025, the oil price environment improved, with average Brent crude price rising 2% QoQ to $68.05/bbl. Financial performance in the quarter was further aided by an increased premium to Brent in our realised oil price, as well as strong price realisations on both NGLs (+46% QoQ) and gas (+3% QoQ). This supported strong revenue growth and cashflow generation, enabling a further strengthening of our balance sheet and increased dividends to shareholders.

Revenue

Description	Units	Q3 2025	Q2 2025	Q1 2025	q/q change	9M 2025	9M 2024	y/y change
Oil volumes lifted	mmbbl	10.1	7.9	9.9	28 %	27.9	7.5	270 %
NGLs volumes lifted	kbbl	454.7	142.2	138.0	220 %	734.9	—	nm
Gas sales volume	Bscf	14.6	16.8	14.9	(13) %	46.3	28.4	63 %
Average realised oil price	US$/bbl	70.79	67.35	76.42	5 %	71.93	82.89	(13) %
Average Brent crude oil price	US$/bbl	68.05	66.45	74.87	2 %	69.73	81.79	(15) %
Premium (discount) to Brent	US$/bbl	2.74	0.90	1.55	204 %	2.20	1.10	100 %
Average realised NGL price	US$/bbl	50.92	34.77	35.88	46 %	46.64	—	nm
Average realised gas price	US$/mscf	3.06	2.98	3.01	3 %	2.95	3.18	(7) %
Crude oil revenue	US$m	711.2	533.4	759.8	33 %	2,004.4	625.2	221 %
Gas revenue	US$m	44.6	50.1	44.5	(11) %	139.2	90.2	54 %
NGLs revenue	US$m	23.2	4.9	5.0	373 %	33.0	—	nm
Total revenue	**US$m**	**779.0**	**588.4**	**809.3**	**32 %**	**2,176.6**	**715.3**	**204 %**
(Overlift)/underlift *	US$m	(38.8)	96.1	(53.5)	nm	3.8	8.2	(53) %
Total revenue adjusted for (overlift)/underlift	**US$m**	**740.2**	**684.5**	**755.8**	**8 %**	**2,180.5**	**723.5**	**201 %**
Crude oil & NGL revenue adjusted for (overlift)/underlift	US$m	695.6	634.4	711.3	10 %	2,041.3	633.4	222 %

*Overlift/Underlift balance in 9M 2025 comprised crude oil overlift valued at $9.2 million and NGL underlift valued at $13.1 million.

Total revenue for 9M 2025 rose 204% to $2,176.6 million from $715.3 million in 9M 2024. Of note, crude oil revenue contributed 92% of revenues in 9M 2025 compared to 87% in 9M 2024, reflecting the higher oil contribution from our offshore operations, while gas and NGL contributed 6% and 2% respectively.

In 3Q 2025, reported revenue rose 32% QoQ to $779.0 million. The growth was underpinned by higher crude oil liftings (up 28% QoQ to 10.1 MMbbls) and NGL liftings (up 220% QoQ to 454.7 kbbls). In addition, the business benefitted from an improved pricing environment, as average realised oil, gas and NGL prices rose 5%, 3%, and 46% QoQ respectively (details in the table). The higher NGL price realisation for 3Q 2025 was due to sale of a pentane cargo, which achieves the highest price realisation of the NGL products produced offshore.

Across product segments, oil revenue grew 33% QoQ, NGL revenue rose 373% QoQ, while gas revenue declined 11% QoQ reflective of lower gas sales volumes (down 13% QoQ to 14.6 Bcf) in 3Q 2025.

Cost of Sales

Description	Units	Q3 2025	Q2 2025	Q1 2025	q/q change	9M 2025	9M 2024	y/y change
Non-Production Cost:		**168.5**	**300.7**	**307.2**	**(44)%**	**776.3**	**228.5**	**240%**
Royalties	US$'m	129.2	121.8	130.2	6 %	381.2	107.6	254 %
Depletion, Depreciation, & Amortisation	US$'m	25.5	168.8	164.1	(85) %	358.3	114.1	214 %
Regulatory fees/levies*	US$'m	13.8	10.1	12.9	37 %	36.8	6.7	446 %
Production Cost:		**215.6**	**156.1**	**149.1**	**38 %**	**520.8**	**131.8**	**295%**
Crude Handling Fees	US$'m	20.6	19.7	18.8	5 %	59.2	49.5	20 %
Barging & Trucking	US$'m	7.1	7.8	5.7	(9) %	20.6	10.4	99 %
Operational & Maintenance Expenses	US$'m	187.9	128.6	124.6	46 %	441.0	72.0	513 %
Production Opex per boe	**US$/boe**	**17.0**	**12.5**	**12.6**	**36 %**	**14.1**	**10.1**	**39 %**
Cost of Sales	**US$'m**	**384.1**	**456.8**	**456.3**	**(16)%**	**1,297.2**	**360.3**	**260 %**

*Regulatory fees & levies include NDDC and NESS levies

Production costs, which encompass expenses related to crude-handling charges (CHC), barging/trucking, operations & maintenance, amounted to $520.8 million in 9M 2025 (9M 2024: $131.8 million). Onshore production costs account for 29% of the total ($157.5 million), reflecting higher production. Offshore production costs represent approximately 71% of the total ($351.5 million), reflecting the cost incurred in carrying out repairs and maintenance to improve asset integrity and reliability, laying the foundation for future growth.

On a QoQ basis, group production costs of $215.6 million were up 38%, primarily due to higher levels of offshore operating activities and a reclassification of offshore-related expenses to production costs as against G&A expenses in previous quarters, aligning reporting with our onshore methodology. As a result, 3Q 2025 unit operating costs rose to $17.0/boe and 9M 2025 unit operating costs settled at $14.1/boe, within our 2025 guidance ($14.0/boe - $15.0/boe).

9M 2025 Group non-production costs of $776.3 million, comprised of $381.2 million in royalties (9M 2024: $107.6 million), $358.3 million in depreciation, depletion, and amortisation (9M 2024: $114.1 million), and regulatory fees/levies of $36.8 million (9M 2024: $6.7 million). The significant increase in non-production costs compared to 9M 2024 reflects the impact of the offshore business consolidation.

Across asset categories, on our onshore operations, non-production costs in 9M 2025 increased to $306.2 million (9M 2024: $228.5 million) driven by increased DD&A, reflecting higher production compared to 9M 2024. Offshore, total non-production costs were $482.1 million.

On a QoQ basis group non-production costs fell 44% due to lower DD&A reflecting the adjustment to a new unit-of-production depreciation rate following conclusion of the new offshore Competent Persons Report (CPR).

Operating profit and Adjusted EBITDA

Description	Units	Q3 2025	Q2 2025	Q1 2025	q/q change	9M 2025	9M 2024	y/y change
Gross Profit	**US$'m**	**394.9**	**131.6**	**353.0**	**200 %**	**879.5**	**355.0**	**148 %**
Other Income	US$'m	(24.5)	95.4	(44.4)	nm	26.6	21.4	24 %
General and Administrative Expenses	US$'m	(34.7)	(70.2)	(64.9)	(51) %	(169.8)	(95.9)	77 %
Impairment Loss	US$'m	(5.8)	(2.5)	(0.5)	132 %	(8.9)	(2.7)	231 %
Fair Value Loss	US$'m	(6.7)	(4.6)	(5.1)	46 %	(16.3)	(3.2)	418 %
Operating Profit	US$'m	**323.2**	**149.7**	**238.1**	**116 %**	**711.0**	**274.8**	**159 %**
Adjusted EBITDA	US$'m	**376.9**	**334.4**	**400.6**	**13 %**	**1,111.9**	**383.0**	**190 %**

In 9M 2025, gross profit rose 148% to $879.5 million, from $355.0 million in 9M 2024, reflecting the impact of bigger operations. On a sequential basis, 3Q 2025 gross profit grew 200% QoQ to $394.9 million, primarily due to lower DD&A charge for our offshore assets driven by the reserves increase from the CPR update. Additionally, a combination of higher crude oil & NGL liftings as well as better price realisations during the quarter contributed to the growth.

General and Administrative ('G&A') expenses amounted to $169.8 million, versus $95.9 million in 9M 2024. G&A cost per boe for the group was lower at $4.6/boe (9M 2024: $7.4/boe). On a sequential basis, we note that G&A expenses per boe declined to $2.7/boe (1Q 2025 - $5.5/boe, 2Q 2025 - $5.6/boe) due to reclassification of some offshore-related cost items, as noted in the Cost of Sales section. On a YTD basis, G&A costs remain within plan, with a continued focus to drive costs lower.

The other income line item includes underlift adjustments of $3.8 million (9M 2024: $8.2 million) and foreign exchange gain of $11.4 million, reflecting gains from currency translation of monetary assets and liabilities. We also recorded tariff income of $5.9 million from third party usage of our pipelines.

Overall, we reported operating profit of $711.0 million in 9M 2025 (33% margin), from $274.8 million in 9M 2024 (38% margin). On a quarter on quarter basis operating profit rose 116% to $323.2 million, underpinned by lower offshore DD&A charge, higher liftings, and better price realisations.

After adjusting for non-cash items such as impairment, fair value, and exchange gains or losses, the adjusted EBITDA for 9M 2025 was $1,111.9 million (9M 2024: $383.0 million), resulting in a margin of 51%. 3Q 2025 Adj.EBITDA of $376.9 million was up 13% on the prior quarter.

Net result

Description	Units	Q3 2025	Q2 2025	Q1 2025	q/q change	9M 2025	9M 2024	y/y change
Profit before Tax	**US$'m**	**277.2**	**85.5**	**207.4**	**224 %**	**570.1**	**245.0**	**133 %**
Total Income tax expense:		209.5	81.4	184.1	157 %	475.0	209.7	126 %
Net Income	**US$'m**	**67.7**	**4.1**	**23.3**	**1551 %**	**95.1**	**35.3**	**170 %**
Profit Attributable to Holders of Equity	US$'m	68.5	3.4	20.2	1915 %	92.1	38.7	138 %
Earnings per Share	**US$c'shr**	**0.12**	**0.01**	**0.03**	**1100 %**	**0.16**	**0.07**	**129 %**

9M 2025 profit before tax rose 133% to $570.1 million, compared to $245.0 million in 9M 2024. On a QoQ basis, 3Q 2025 profit before tax rose 224% to $277.2 million (2Q 2025: $85.5 million), supported by better price realisations, lower overall costs, and higher liftings in the period. Profit after tax for 9M 2025 was $95.1 million (9M 2024: $35.3 million). Similarly, profit after tax in 3Q 2025 improved primarily due to significant reductions in DD&A following reserve updates from our recent Competent persons Report (CPR). This supported the lower effective tax rate of 76% compared to 89% and 95% in 1Q 2025 and 2Q 2025 respectively. Further details on taxation in the next section.

The profit attributable to equity holders of the parent Company, representing shareholders, was $92.1 million in 9M 2025, which resulted in basic earnings per share of $0.16 for the period (9M 2024: $0.07/share).

Taxation

The Company reported an income tax expense of $475.0 million (9M 2024: $209.7 million), representing an interim effective tax rate (ETR) of 83% (9M 2024: 86%). We note the improvement in ETR in 3Q 2025, falling to 76% (1Q 2025: 89%, 2Q 2025: 95%). The QoQ decline reflects the impact of adjustments to our Depletion, Depreciation & Amortisation calculation using a lower unit-of-production depreciation rate, following conclusion of the updated offshore CPR.

As we ramp up investment in our offshore operations, we expect to build capital allowances which will further aid our tax efficiency drive. Conversion to the Petroleum Industry Act (PIA) remains another upside to our efforts (more details in the Operating review).

We revise our FY 2025 effective tax rate projection to between 80% and 85%.

Cash flows from operating activities

Description	Units	Q3 2025	Q2 2025	Q1 2025	q/q change	9M 2025	9M 2024	y/y change
Profit before tax	US$'m	**277.2**	**85.5**	**207.4**	**224 %**	**570.1**	**245.0**	133 %
Non Cash Adjustments	US$'m	103.3	262.9	213.3	(61) %	579.5	163.6	254 %
Working Capital Changes	US$'m	248.8	111.2	(114.2)	124 %	245.8	14.8	1559 %
Pre-tax Cashflow from Operating Activities	**US$'m**	**629.3**	**459.6**	**306.5**	**37 %**	**1,395.4**	**423.3**	**230%**
Cash Taxes	US$'m	(90.9)	(177.3)	(36.2)	(49) %	(304.4)	(64.0)	375 %
Others*	US$'m	(14.4)	(12.1)	(53.7)	19 %	(80.2)	(1.5)	5215 %
Post-tax Cashflow from Operating Activities	**US$'m**	**524.0**	**270.3**	**216.6**	**94 %**	**1,010.8**	**357.8**	**183 %**

*Others include hedge premium, contribution to plan assets and restricted cash movements

Net (after-tax) cash flow from operating activities amounted to $1,010.8 million in 9M 2025, compared to $357.8 million in 9M 2024 and includes cash tax payments made year to date of $304.4 million, hedging premiums of $25.0 million and for the offshore business, a $52.0 million contribution for the defined benefit scheme paid during the current period. Overall, the cash taxes paid represents 22% of operating cashflow, an increase from 15% recorded in 9M 2024 as cash tax payments continued to reflect the tax paying position of the enlarged group. We expect estimates for cash taxes payable in 2025 to be approximately $500 million, around 25% higher than prior 2025 expectations. This reflects higher than planned realised commodity prices and production volumes, as well as timing of certain cost items, particularly related to capex offshore.

With respect to working capital, onshore cash call collections remained robust. On the OMLs 4, 38 & 41 and OML 40 JVs, we received $262.2 million in cash calls from our JV partner, bringing the receivables balance to $8.0 million (FY2024: $41.4 million). On OML 53, cash call obligations are fully paid up.

Similarly In our offshore business, cash call settlements remain positive as we work with the JV partners to receive all unsettled bills. The receivables balance on the SEPNU/NUIMS JV settled at $222.0 million at the end of 9M 2025, down from $384 million at 6M 2025.

Cash flows from investing activities

Description	Units	Q3 2025	Q2 2025	Q1 2025	q/q change	9M 2025	9M 2024	y/y change
Post-tax Cashflow from Operating Activities (A)	**US$'m**	**524.0**	**270.3**	**216.6**	**94 %**	**1,010.8**	**357.8**	**183 %**
Capital Expenditure (B)	US$'m	(83.6)	(56.2)	(40.2)	49 %	(180.1)	(157.0)	15 %
Additional Investment in Joint Venture	US$'m	—	(10.0)	(10.0)	nm	(20.0)	—	nm
Additional Payment to ExxonMobil	US$'m	(64.3)	—	—	nm	(64.3)	—	nm
Others*	US$'m	2.5	3.1	3.6	(19) %	9.3	30.2	(69) %
Net cash outflows used in investing activities	**US$'m**	**(145.4)**	**(63.1)**	**(46.6)**	**130 %**	**(255.1)**	**(126.8)**	**101 %**
Free Cashflow (A-B)	**US$'m**	**440.4**	**214.1**	**176.4**	**106 %**	**830.7**	**200.8**	**314 %**

*Others include Interest received, and deposit for asset held for sale.

In 9M 2025 the total net cash outflow from investing activities was $255.1 million, an increase on the $126.8 million reported in 9M 2024.

The cash capital expenditure on oil & gas assets during the period was $178.8 million (9M 2024: $153.6 million), up from the prior year given as drilling activities on our onshore operations ramped up, while replacement of the IGE on EAP commenced. Total capex (including other fixed assets) was $180.1 million (9M 2024: $157.0 million).

As a result of the strong operating performance in 9M 2025, the business generated $830.7 million of free cashflow, a material increase compared to the $200.7 million generated in 9M 2024. On a QoQ basis, free cashflow generation improved, up 106% to $440.3 million in 3Q 2025 (2Q 2025: $214.1 million).

As previously disclosed, the Company provided $20.0 million in equity funding to the AGPC IJV in 1H 2025 ($10.0 million in Q1 2025 and $10.0 million Q2 2025 respectively), in order to support delivery of the final project completion elements ahead of first gas.

In 3Q 2025 we made an additional payment to ExxonMobil of $64.3 million pursuant to the post completion reconciliation process agreed in the Sales & Purchase Agreement ('SPA') with ExxonMobil. The major component of the payment was a $57.0 million loan owed by MPNU for routine operations, which was settled by ExxonMobil at the time of the Change in Control (CiC). These costs were verified independently by an expert on behalf of Seplat. The reconciliation process remains ongoing as items remain under review, it is expected that we will complete payments in 4Q 2025. The quantum associated with these items is not significant relative to what was settled in 3Q 2025. We note that this process is separate from the $258.0 million deferred payment due to be paid in 4Q 2025.

Cash flows from financing activities

Description	Units	Q3 2025	Q2 2025	Q1 2025	q/q change	9M 2025	9M 2024	y/y change
Repayments of Loans and Borrowings	US$'m	(111.0)	—	(919.3)	nm	(1,030.3)	(38.5)	2575 %
Proceeds from Loans and Borrowings	US$'m	—	—	650.0	nm	650.0	—	nm
Interest paid on Loans and Borrowings	US$'m	(41.7)	(13.1)	(36.4)	(64) %	(91.2)	(62.5)	46 %
Other Finance Costs	US$'m	(0.9)	(35.4)	(5.1)	594 %	(41.4)	(6.9)	496 %
Lease Interest & Principal Payments	US$'m	(28.6)	—	—		(28.6)	(1.0)	2760 %
Dividends paid	US$'m	(27.6)	(67.7)	—	nm	(95.3)	(70.6)	35 %
Shares purchased for employees	US$'m	(10.0)	—	—	nm	(10.0)	(19.3)	(48) %
Net cash outflows used in financing activities	**US$'m**	**(219.8)**	**(116.2)**	**(310.8)**	**(63)%**	**(646.7)**	**(198.8)**	**225 %**

Net cash outflow from financing activities was $646.7 million in 9M 2025, compared to an outflow of $198.8 million in 9M 2024. The principal driver for the increase in outflow was reduction of the company's gross debt position. In 3Q 2025, we continued to reduce our gross debt position, paying down the outstanding amounts on our revolving credit facility as well as on the Westport Junior Reserve Based Lending (RBL) facility (more details in next section).

The increase in interest expense in 9M 2025 reflects increased drawn debt facilities (associated with the offshore assets acquisition) and higher interest rates on the newly issued Eurobond. The increase in Other finance costs relates to transaction costs on issuance of the $650.0 million Eurobond and withholding tax payment on bond coupon payment. The lease interest and principal payments of $28.6 million (9M 2024: $1.0 million) are related to our offshore operations, representing payments made for property and aircraft leases.

During the period, we paid $95.3 million in dividends to our shareholders, representing a 35% increase on 9M 2024's $70.6 million. We spent $10.0 million on shares which were purchased for the obligations under the Company's long-term incentive plan (9M 2024: $19.3 million).

Debt Movements

Westport Junior Reserve Based Lending ('RBL') offtake facility. During the quarter the Company repaid the $11 million outstanding under the Westport Junior RBL and subsequently cancelled the facility.

Westport Senior RBL facility. On 30th September the group refinanced its existing $110 million senior RBL facility into a new 5 year $80 million RBL facility. The new facility (Westport RBL facility) is supported by four lenders (previously three), and carries an interest rate of SOFR plus 6.5% for the first three years, increasing to SOFR plus 7.0% for the remainder of the term if more than 50% of the facility is drawn at that time. This is a c.176 bps improvement from SOFR plus CAS plus 8.0% on the previous Senior facility, and a c.426 bps improvement from SOFR plus CAS plus 10.5% on the now cancelled Junior facility. At quarter end $30.25 million was drawn under the facility.

Revolving credit facility ('RCF'). As previously disclosed, on 28th July the Company repaid the outstanding $100 million balance on its RCF. As of the reporting date the RCF remains undrawn and fully available.

Liquidity

The balance sheet continues to remain healthy with a solid liquidity position.

		Reported*	Reported*	Reported*
Description	Units	9M 2025	9M 2024	FY2024
Senior loan notes	US$'m	634.3	644.4	657.6
Senior Reserve Based Lending (RBL) facility	US$'m	28.5	49.7	51.1
$350 million Revolving credit facility	US$'m	0.0	0.0	351.5
Junior Reserve Based Lending (RBL) facility	US$'m	0.0	9.7	10.3
$300 million Advance payment facility	US$'m	302.8	0.0	297.0
Total borrowings	US$'m	**965.7**	**703.8**	**1,367.6**
Cash and cash equivalents (excluding restricted cash)	US$'m	**579.8**	**433.9**	**469.9**
Net Debt	US$'m	385.9	270.0	897.8
Adjusted Pro-Forma EBITDA **	US$'m	1,420.7	524.5	1,353.5
Net Debt-to-Trailing Twelve Months EBITDA	x	0.27	0.51	0.66

*Including amortised interest and accrual for the RCF (undrawn) commitment fee
**Adjusted EBITDA 2024 represents the FY2024 pro-forma adjusted EBITDA for onshore and offshore combined, 9M 2025 adjusted EBITDA includes pro-forma adjusted EBITDA from onshore and offshore between 4Q 2024 plus 9M 2025 adjusted EBITDA as reported.
***Restricted cash was $135 million at 9M 2025

Seplat Energy ended the period with gross debt of $965.7 million down 29% from YE 2024 ($1,376.6 million) and cash at bank of $579.8 million up 23% from YE 2024 ($469.9 million), resulting in net debt of $385.9 million down 57% from YE 2024 ($897.8 million). On a quarter-on-quarter basis net debt fell by 43% (2Q 2025: $676.3 million), given strong FCF generation in the quarter.

We continue to monitor the Net Debt-to-EBITDA ratio of the Company aiming to maintain a strong balance sheet through the cycle (Debt covenant - 3.0x). At the end of September 2025, proforma Net Debt-to-EBITDA ratio improved to 0.27x, from 0.66x at the end of 2024.

Dividend

The Board has approved a dividend of 7.5 US cents per share for 3Q 2025 (subject to appropriate WHT) comprised of the minimum quarterly base dividend (5.0 US cents per share) announced during the September capital markets day, and a special dividend of 2.5 US cents per share reflecting the strong cash generation year to date. We have updated our dividend policy to allow the board to consider special dividends twice per annum (at 9M in October and Full Year results in February). The total dividend is a 108% increase on 3Q 2024 dividend and a 63% increase on the equivalent dividend in 2Q 2025 (the QoQ base dividend increase is approximately 9%).

Reporting Period	Proposed Dividend (US cents per share)	Announcement Date	Qualification Date (LSE)	Qualification Date (NGX)	Payment Date
Q1 2025	4.6	28. April 2025	23. May 2025	23. May 2025	6. June 2025
Q2 2025	4.6	30. July 2025	12. August 2025	12. August 2025	28. August 2025
Q3 2025	7.5	30. October 2025	13. November 2025	13. November 2025	28. November 2025
Total 2025 YTD	**16.7**				

Hedging

Seplat Energy's hedging policy aims to guarantee appropriate levels of cash flow assurance in times of oil price weakness and volatility.

As previously disclosed, we completed our 2025 hedging programme during 2Q 2025. For 4Q 2025 we have hedged a total of 5.25 MMbbls, placed at a weighted average premium of $1.34/bbl and a weighted average strike price of $50.00/bbl.

During 3Q 2025 we completed our 1Q 2026 hedging programme. In 3 tranches we hedged 6.0 MMbbls upfront premium puts hedged at an average strike price of $52.5/bbl, at a cost of $1.21/bbl. We note that due to increased production, we increased hedged volumes by 14% versus the prior quarter. Our simple put option hedge strategy is unchanged.

2025 Oil Hedges (Brent Put Options)	Unit	Q1 2025	Q2 2025	Q3 2025	Q4 2025	Q1 2026
Volumes hedged	MMbbls	5.25	5.25	5.25	5.25	6.00
Price hedged	US$/bbl	55	55	55	50	52.5
Puts cost	US$/bbl	0.44	0.97	0.87	1.34	1.21

Credit ratings

Seplat maintains corporate credit ratings with Moody's Investor Services (Moody's), Standard & Poor's Rating Services (S&P) and Fitch Ratings (Fitch). The current corporate ratings are as follows: (i) Moody's B2 (stable); (ii) S&P B (stable); (iii) Fitch B (stable). During 2Q 2025 our corporate ratings were upgraded by Fitch and Moody's, while our rating was reaffirmed by S&P. There were no additional changes during 3Q 2025.

Outlook

We update our 2025 guidance reflecting year to date performance and expected outcome in 4Q 2025..

Production guidance

Seplat Energy's production operations were in the upper half of original guidance in the first 9M 2025, supported by continued strong performance onshore, which has delivered at the top end of expectations, and strong production performance in offshore. We therefore narrow our guidance to 130-140 kboepd (previously 120-140 kboepd), with the mid-point raised by ~4% and broadly in-line with YTD average daily production.

In 4Q 2025, onshore is expected to remain at the upper end of the original guidance, with potential upside via ANOH. Offshore is expected to be modestly weaker QoQ due to outage at Yoho and the downtime in the early part of the quarter for the IGE replacement works.

2025 production guidance narrowed to 130-140 kboepd (previously 120-140 kboepd). This includes:

- Onshore expected full year average production at the top end of original guidance.
- Offshore expected full year average production around the mid-point of original guidance.

Capex guidance

Cash capex in 9M 2025 of $180.0 million was limited to a number of smaller projects including final payments for 2024 wells, the delivery of the first set of 2025 wells and Sapele IGP construction costs. As expected, run rate capex increased in 3Q 2025 as the number of active drilling rigs increased to four. This level of drilling activity will continue in 4Q 2025, as well as certain capex payments for long lead items will be incurred in the final quarter of the year.

Working interest capital expenditure guidance is narrowed to $270 million - $290 million (previously $260-320 million).

- Onshore capex is expected in the upper half of original guidance range. A total of eight wells are targeting completion in 4Q 2025 (3 of which were drilling ahead at end September). Other capex involves the completion of end of routine flaring projects at Oben (completed in October) and Ohaji.
- Offshore capex is expected at the lower end of the original guidance range. The remaining work for 2025 includes completion of the Inlet Gas Exchange project on EAP, expenditure on the Oso-BRT gas projects and ordering of long lead items for the future drilling programme.

Opex guidance

Unit operating costs guidance maintained in the range of $14.0-15.0/boe.

- Unit production operating costs are expected to be in the original guidance range, benefitting from higher production, offset by classification of certain G&A items to opex.

Unaudited condensed consolidated interim financial statements for the nine months ended 30 September 2025 (NGN)

30 October 2025

Reliable energy, limitless potential

Condensed consolidated interim statement of profit or loss and other comprehensive income

For the nine months ended 30 September 2025

	Notes	9 months ended 30 Sept 2025 Unaudited ₦ million	9 months ended 30 Sept 2024 Unaudited ₦ million	3 Months ended 30 Sept 2025 Unaudited ₦ million	3 Months ended 30 Sept 2024 Unaudited ₦ million
Revenue from contracts with customers	7	**3,356,187**	1,070,897	**1,189,470**	495,845
Cost of sales	8	**(2,000,184)**	(539,379)	**(584,711)**	(211,814)
Gross profit		**1,356,003**	531,518	**604,759**	284,031
Other income/ (loss) -net	9	**40,944**	32,084	**(38,126)**	(88,526)
General and administrative expenses	10	**(261,880)**	(143,538)	**(52,438)**	(66,334)
Impairment loss on financial assets - net	11	**(13,654)**	(4,001)	**(8,936)**	(2,419)
Fair value loss	12	**(25,207)**	(4,723)	**(10,241)**	(589)
Operating profit		**1,096,206**	411,340	**495,018**	126,163
Finance income	13	**12,123**	11,702	**3,848**	4,295
Finance costs	13	**(223,485)**	(86,956)	**(72,936)**	(32,839)
Finance cost - net	13	**(211,362)**	(75,254)	**(69,088)**	(28,544)
Share of (loss)/profit from joint venture accounted for using the equity method		**(5,855)**	30,625	**(1,052)**	25,044
Profit before taxation		**878,989**	366,711	**424,878**	122,663
Income tax expense	14	**(732,350)**	(313,935)	**(320,758)**	(137,947)
Profit/(loss) for the period		**146,639**	52,776	**104,120**	(15,284)
Attributable to:					
Equity holders of the parent		**141,944**	57,888	**105,347**	2,303
Non-controlling interests		**4,695**	(5,112)	**(1,227)**	(17,587)
		146,639	52,776	**104,120**	(15,284)
Earnings per share for the period					
Basic earnings per share ₦	26	**240.18**	98.37	**178.25**	3.91
Diluted earnings per share ₦	26	**240.18**	98.37	**178.25**	3.91

	Notes	9 months ended 30 Sept 2025 Unaudited ₦ million	9 months ended 30 Sept 2024 Unaudited ₦ million	3 Months ended 30 Sept 2025 Unaudited ₦ million	3 Months ended 30 Sept 2024 Unaudited ₦ million
Profit/(loss) for the period		**146,639**	52,776	**104,120**	(15,284)
Other comprehensive income:					
Items that may be reclassified to profit or loss (net of tax):					
Foreign currency translation difference		**(129,587)**	1,253,259	**(118,950)**	231,232
Total comprehensive income/(loss) for the period (net of tax)		**17,052**	1,306,035	**(14,830)**	215,948
Attributable to:					
Equity holders of the parent		**83,630**	1,311,147	**51,819**	233,535
Non-controlling interests		**(66,578)**	(5,112)	**(66,649)**	(17,587)
		17,052	1,306,035	**(14,830)**	215,948

The above interim condensed consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

Condensed consolidated interim statement of financial position

As at 30 September 2025

	Notes	30 Sept 2025 Unaudited ₦ million	31 Dec 2024 Audited ₦ million
Assets			
Non-current assets			
Oil & gas properties		**4,685,768**	5,074,590
Other property, plant and equipment		**250,289**	346,574
Right-of-use assets		**180,807**	198,918
Intangible assets		**336,263**	383,257
Other assets		**133,061**	139,431
Investment accounted for using equity method		**381,266**	374,641
Long-term prepayments		**29,947**	48,018
Deferred tax assets	14.1	**326,745**	353,954
Defined benefit plan	24.1	**3,195**	—
Total non-current assets		**6,327,341**	6,919,383
Current assets			
Inventory		**677,072**	725,565
Trade and other receivables	17	**869,443**	1,156,593
Prepayments		**19,726**	52,596
Contract assets	18	**72,352**	23,918
Derivative financial assets	19.2	**21,000**	—
Restricted cash	20.2	**198,412**	202,983
Cash and cash equivalents	20	**849,502**	721,385
Total current assets		**2,707,507**	2,883,040
Asset held for sale	21	**17,978**	18,838
Total assets		**9,052,826**	9,821,261
Equity and liabilities			
Equity attributable to shareholders			
Issued share capital	22	**303**	297
Share premium	22	**150,399**	87,375
Share based payment reserve	22	**3,816**	15,558
Treasury shares	22	**(56,291)**	(3,570)
Capital contribution		**5,932**	5,932
Retained earnings		**314,054**	319,013
Foreign currency translation reserve		**2,334,937**	2,393,251
Non-controlling interest		**(55,451)**	11,127
Total shareholder's equity		**2,697,699**	2,828,983
Non-current liabilities			
Interest bearing loans and borrowings	23	**1,312,350**	1,409,480
Lease liabilities		**75,392**	88,530
Provision for decommissioning obligation		**1,181,160**	1,194,818
Deferred tax liability	14.1	**1,531,761**	1,615,677
Defined benefit plan	24.1	**—**	76,900
Total non-current liabilities		**4,100,663**	4,385,405
Current liabilities			
Interest bearing loans and borrowings	23	**102,583**	690,270
Lease liabilities		**31,421**	24,415
Derivative financial liability	19.1	**14,141**	6,073
Trade and other payables	25	**1,664,778**	1,684,706
Other provisions		**4,929**	5,088
Current tax liabilities		**436,612**	196,321
Total current liabilities		**2,254,464**	2,606,873
Total liabilities		**6,355,127**	6,992,278
Total shareholders' equity and liabilities		**9,052,826**	9,821,261

The financial statements of Seplat Energy Plc and its subsidiaries (The Group) for the nine months ended 30 September 2025 were authorised for issue in accordance with a resolution of the Directors on 30 October 2025 and were signed on its behalf by:

U. U. Udoma
FRC/2013/NBA/00000001796
Chairman
30 October 2025

R.T Brown
FRC/2014/PRO/DIR/00000017939
Chief Executive Officer
30 October 2025

E. Adaralegbe
FRC/2017/ICAN/006/00000017591
Chief Financial Officer
30 October 2025

Condensed consolidated interim statement of changes in equity

For the period ended 30 September 2025

	Issued share capital	Share premium	Share based payment reserve	Treasury shares	Capital contribution	Retained earnings	Foreign currency translation reserve	Non-controlling interest	Total equity
	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million
At 1 January 2024	**297**	**90,138**	**12,255**	**(1,612)**	**5,932**	**230,708**	**1,251,127**	**23,790**	**1,612,635**
Profit/(loss) for the period	–	–	–	–	–	57,888	–	(5,112)	52,776
Other comprehensive income	–	–	–	–	–	–	1,253,259	–	1,253,259
Total comprehensive income/(loss) for the period	**–**	**–**	**–**	**–**	**–**	**57,888**	**1,253,259**	**(5,112)**	**1,306,035**
Transactions with owners in their capacity as owners:									
Dividend paid	–	–	–	–	–	(105,712)	–	–	(105,712)
Share based payments	–	–	13,687	–	–	–	–	–	13,687
Vested shares	33	22,887	(22,920)	–	–	–	–	–	–
Issued vested shares	(33)	(22,887)	–	22,920	–	–	–	–	–
Shares re-purchased	–	–	–	(28,893)	–	–	–	–	(28,893)
Total	**–**	**–**	**(9,233)**	**(5,973)**	**–**	**(105,712)**	**–**	**–**	**(120,918)**
At 30 Sept 2024 (unaudited)	**297**	**90,138**	**3,022**	**(7,585)**	**5,932**	**182,884**	**2,504,386**	**18,678**	**2,797,752**
At 1 January 2025	**297**	**87,375**	**15,558**	**(3,570)**	**5,932**	**319,013**	**2,393,251**	**11,127**	**2,828,983**
Profit for the period	**–**	**–**	**–**	**–**	**–**	**141,944**	**–**	**4,695**	**146,639**
Other comprehensive loss	**–**	**–**	**–**	**–**	**–**	**–**	**(58,314)**	**(71,273)**	**(129,587)**
Total comprehensive income for the period	**–**	**–**	**–**	**–**	**–**	**141,944**	**(58,314)**	**(66,578)**	**17,052**
Transactions with owners in their capacity as owners:									
Dividend paid	**–**	**–**	**–**	**–**	**–**	**(146,903)**	**–**	**–**	**(146,903)**
Share based payments	**–**	**–**	**18,874**	**–**	**–**	**–**	**–**	**–**	**18,874**
Vested shares	**–**	**–**	**(25,728)**	**25,728**	**–**	**–**	**–**	**–**	**–**
Transfer to share based liability			**(4,888)**						**(4,888)**
Shares repurchased	**–**	**–**		**(15,419)**	**–**	**–**	**–**	**–**	**(15,419)**
Shares issued	**6**	**63,024**	**–**	**(63,030)**	**–**	**–**	**–**	**–**	**–**
Total	**6**	**63,024**	**(11,742)**	**(52,721)**	**–**	**(146,903)**	**–**	**–**	**(148,336)**
At 30 Sept 2025 (unaudited)	**303**	**150,399**	**3,816**	**(56,291)**	**5,932**	**314,054**	**2,334,937**	**(55,451)**	**2,697,699**

Condensed consolidated interim statement of cash flows

For the nine months ended 30 September 2025

	Notes	9 months ended 30 Sept 2025 ₦ million	9 months ended 30 Sept 2024 ₦ million
Cash flows from operating activities			
Cash generated from operations	15	**2,151,512**	633,757
Tax paid		**(469,325)**	(95,877)
Contribution to plan assets	24.1	**(80,189)**	–
Hedge premium paid		**(38,523)**	(6,190)
Restricted cash		**(4,948)**	3,931
Net cash inflows from operating activities		**1,558,527**	535,621
Cash flows from investing activities			
Payment for acquisition of oil and gas properties	16	**(275,723)**	(229,957)
Additional investment in Joint venture		**(30,838)**	–
Proceeds from the disposal of oil and gas properties		**–**	8,023
Payment for acquisition of other property, plant and equipment		**(1,920)**	(5,132)
Proceeds from the disposal of other property plant and equipment		**–**	9,196
Deposit from asset held for sale		**2,159**	–
Receipts from other asset		**–**	16,312
Payment for acquisition of subsidiary*		**(99,070)**	–
Interest received		**12,123**	11,702
Net cash outflows used in investing activities		**(393,269)**	(189,856)
Cash flows from financing activities			
Repayments of loans and borrowings		**(1,588,563)**	(57,650)
Proceeds from loans and borrowings		**1,002,248**	–
Dividend paid		**(146,903)**	(105,712)
Shares purchased for employees		**(15,419)**	(28,893)
Interest paid on lease liability		**(9,623)**	(1,362)
Lease payment - principal portion		**(34,534)**	(73)
Payment of financing charges from the issue of shares		**(176)**	–
Payments of other financing charges**		**(63,629)**	(10,400)
Interest paid on loans and borrowings		**(140,578)**	(93,590)
Net cash outflows used in financing activities		**(997,177)**	(297,680)
Net increase in cash and cash equivalents		**168,081**	48,085
Cash and cash equivalents at beginning of the period		**721,385**	404,825
Effects of exchange rate changes on cash and cash equivalents		**(39,964)**	241,699
Cash and cash equivalents at end of the period	20	**849,502**	694,609

*This relates to the reconciliation settlement paid to Exxon for the acquisition of SEPNU (formerly MPNU).

**Other financing charges of ₦63.6 billion (2024: ₦10.4 billion) largely relates to the transactional costs incurred on the new $650m bond issued during the period and withholding tax on bond coupon payment .

Notes to the condensed consolidated interim financial statements

For the nine months ended 30 September 2025

1. Corporate structure and business

Seplat Energy Plc (formerly called Seplat Petroleum Development Company Plc, hereinafter referred to as 'Seplat' or the 'Company'), the parent of the Group, was incorporated on 17 June 2009 as a private limited liability company and re-registered as a public company on 3 October 2014, under the Companies and Allied Matters Act, CAP C20, Laws of the Federation of Nigeria 2004. The Company commenced operations on 1 August 2010. The Company is principally engaged in oil and gas exploration and production and gas processing activities. The Company's registered address is: 16a Temple Road (Olu Holloway), Ikoyi, Lagos, Nigeria..

The Company acquired, pursuant to an agreement for assignment dated 31 January 2010 between the Company, SPDC, TOTAL and AGIP, a 45% participating interest in OML 4, OML 38 and OML 41 located in Nigeria.

On 7 November 2010, Newton Energy Limited ('Newton Energy'), an entity previously beneficially owned by the same shareholders as Seplat, became a subsidiary of the Company. On 1 June 2013, Newton Energy acquired from Pillar Oil Limited ('Pillar Oil') a 40% Participant interest in producing assets: the Umuseti/Igbuku marginal field area located within OPL 283 (the 'Umuseti/Igbuku Fields').

On 27 March 2013, the Group incorporated a subsidiary, MSP Energy Limited. The Company was incorporated for oil and gas exploration and production.

On 11 December 2013, the Group incorporated a new subsidiary, Seplat East Swamp Company Limited with the principal activity of oil and gas exploration and production.

On 11 December 2013, Seplat Gas Company Limited ('Seplat Gas') was incorporated as a private limited liability company to engage in oil and gas exploration and production and gas processing.

On 21 August 2014, the Group incorporated a new subsidiary, Seplat Energy UK Limited (formerly called Seplat Petroleum Development UK Limited). The subsidiary provides technical, liaison and administrative support services relating to oil and gas exploration activities.

In 2015, the Group purchased a 40% participating interest in OML 53, onshore northeastern Niger Delta (Seplat East Onshore Limited), from Chevron Nigeria Ltd for $259.4 million.

In 2017, the Group incorporated a new subsidiary, ANOH Gas Processing Company Limited. The principal activity of the Company is the processing of gas from OML 53 using the ANOH gas processing plant. The Group divested some of its ownership interest in this Company to Nigerian Gas Processing and Transportation Company (NGPTC) which was effective from 18 April 2019, hence this investment qualifies as a joint arrangement and has continued to be recognised as investment in joint venture.

On 16 January 2018, the Group incorporated a subsidiary, Seplat West Limited ('Seplat West'). Seplat West was incorporated to manage the producing assets of Seplat Plc.

On 31 December 2019, Seplat Energy Plc, acquired 100% of Eland Oil and Gas Plc's issued and yet to be issued ordinary shares. Eland is an independent oil and gas company that holds interest in subsidiaries and joint ventures that are into production, development and exploration in West Africa, particularly the Niger Delta region of Nigeria.

On acquisition of Eland Oil and Gas Plc (Eland), the Group acquired indirect interest in existing subsidiaries of Eland.

Eland Oil & Gas (Nigeria) Limited, is a subsidiary acquired through the purchase of Eland and is into exploration and production of oil and gas.

Westport Oil Limited, which was also acquired through purchase of Eland is a financing company.

Elcrest Exploration and Production Company Limited (Elcrest) who became an indirect subsidiary of the Group purchased a 45 percent interest in OML 40 in 2012. Elcrest is a Joint Venture between Eland Oil and Gas (Nigeria) Limited (45%) and Starcrest Nigeria Energy Limited (55%). It has been consolidated because Eland is deemed to have power over the relevant activities of Elcrest to affect variable returns from Elcrest at the date of acquisition by the Group. (See details in Note 4.1.v) The principal activity of Elcrest is exploration and production of oil and gas.

Wester Ord Oil & Gas (Nigeria) Limited, who also became an indirect subsidiary of the Group acquired a 40% stake in a licence, Ubima, in 2014 via a joint operations agreement. The principal activity of Wester Ord Oil & Gas (Nigeria) Limited is exploration and production of oil and gas. In 2022, Wester Ord Oil and Gas (Nigeria) divested it's interest in Ubima.

Other entities acquired through the purchase of Eland are Tarland Oil Holdings Limited (a holding company), Brineland Petroleum Limited (dormant company) and Destination Natural Resources Limited (dormant company).

On 1 January 2020, Seplat Energy Plc transferred its 45% participating interest in OML 4, OML 38 and OML 41 ("transferred assets") to Seplat West Limited. As a result, Seplat ceased to be a party to the Joint Operating Agreement in respect of the transferred assets and became a holding company. Seplat West Limited became a party to the Joint Operating Agreement in respect of the transferred assets and assumed its rights and obligations.

On 20 May 2021, following a special resolution by the Board in view of the Company's strategy of transitioning into an energy Company promoting renewable energy, sustainability, and new energy, the name of the Company was changed from Seplat Petroleum Development Company Plc to Seplat Energy Plc under the Companies and Allied Matters Act 2020.

On 7 February 2022, the Group incorporated a subsidiary, Seplat Energy Offshore Limited. The Company was incorporated for oil and gas exploration and production.

On 5 July 2022, the Group incorporated a subsidiary, Turnkey Drilling Services Limited. The Company was incorporated for the purpose of drilling chemicals, material supply, directional drilling, drilling support services and exploration services.

On 26 April 2023, Seplat Gas Company Limited was changed to Seplat Midstream Company Limited. This subsidiary was incorporated to engage in oil and gas exploration and production and gas processing. The company is yet commence operations.

On 14 June 2023, the Group entered into a joint venture agreement with Pol Gas Limited which birthed Pine Gas Processing Limited. Both parties subscribed to equal proportion of ordinary shares. The Company was incorporated for processing natural gas, storage, marketing, transportation, trading, supply and distribution of natural gas and petroleum products derived from natural gas. The company is yet to commence operations.

On 7 August 2024, the Group incorporated a subsidiary, Seplat Energy Investment Limited. The Company was incorporated for oil and gas exploration and production.

On 12 December 2024, the Group acquired 100% of Mobil Producing Nigeria Unlimited and later changed the name on 19 December 2024 to Seplat Energy Producing Nigeria Unlimited. The Company was acquired for the purpose of oil and gas exploration and production.

The Company together with its subsidiaries as shown below are collectively referred to as the Group.

Subsidiary	Date of incorporation	Country of incorporation and place of business	Percentage holding	Principal activities	Nature of holding
Eland Oil & Gas Limited	28 August 2009	United Kingdom	100%	Holding company	Direct
Eland Oil & Gas (Nigeria) Limited	11 August 2010	Nigeria	100%	Oil and Gas Exploration and Production	Indirect
Elcrest Exploration and Production Nigeria Limited	6 January 2011	Nigeria	45%	Oil and Gas Exploration and Production	Indirect
Westport Oil Limited	8 August 2011	Jersey	100%	Financing	Indirect
Brineland Petroleum Limited	18 February 2013	Nigeria	49%	Dormant	Indirect
MSP Energy Limited	27 March 2013	Nigeria	100%	Oil and Gas exploration and production	Direct
Newton Energy Limited	1 June 2013	Nigeria	99.9%	Oil & gas exploration and production	Direct
Seplat East Swamp Company Limited	11. December 2013	Nigeria	99.9%	Oil & gas exploration and production	Direct
Seplat Midstream Company Limited	11 December 2013	Nigeria	99.9%	Oil and Gas exploration and production and gas processing	Direct
Tarland Oil Holdings Limited	16 July 2014	Jersey	100%	Holding Company	Indirect
Wester Ord Oil and Gas Limited	16 July 2014	Jersey	100%	Holding Company	Indirect
Wester Ord Oil & Gas (Nigeria) Limited	18 July 2014	Nigeria	100%	Oil and Gas Exploration and Production	Indirect
Seplat Energy UK Limited	21 August 2014	United Kingdom	100%	Technical, liaison and administrative support services relating to oil & gas exploration and production	Direct
Seplat East Onshore Limited	12 December 2014	Nigeria	99.9%	Oil & gas exploration and production	Direct
Seplat West Limited	16 January 2018	Nigeria	99.9%	Oil & gas exploration and production	Direct
Seplat Energy Offshore Limited	7 February 2022	Nigeria	100%	Oil and Gas exploration and production	Direct
Turnkey Drilling Services Limited	5 July 2022	Nigeria	100%	Drilling services	Direct
Seplat Energy Investment Limited	7 August 2024	Nigeria	100%	Oil and Gas exploration and production	Direct
Seplat Energy Producing Nigeria Unlimited	19 December 2024	Nigeria	100%	Oil and Gas exploration and production	Direct

2. Significant changes in the current accounting period

There are no significant changes in the business during the current reporting period ending 30 Sept 2025.

3. Summary of significant accounting policies

3.1 Introduction to summary of significant accounting policies

This note provides a list of the significant accounting policies adopted in the preparation of these consolidated financial statements. These accounting policies have been applied to all the periods presented, unless otherwise stated. The Consolidated financial statements are for the Group consisting of Seplat Energy Plc and its subsidiaries.

3.2 Basis of preparation

The consolidated financial statements of the Group for the nine months ended 30 September 2025 have been prepared in accordance with International Financial Reporting Standards ("IFRS") and interpretations issued by the IFRS Interpretations Committee (IFRS IC). The financial statements comply with IFRS as issued by the International Accounting Standards Board (IASB). Additional information required by National regulations is included where appropriate.

The financial statements comprise the statement of profit or loss and other comprehensive income, the statement of financial position, the statement of changes in equity, the statement of cash flows and the notes to the financial statements.

The financial statements have been prepared under the going concern and historical cost convention, except for financial instruments measured at fair value on initial recognition, non-current asset held for sale, inventory, derivative financial instruments, and defined benefit plans – plan assets measured at fair value. The financial statements are presented in Nigerian Naira and United States Dollars, and all values are rounded to the nearest million (₦ million) and thousand ($'000) respectively, except when otherwise indicated.

Nothing has come to the attention of the directors to indicate that the Group will not remain a going concern for at least twelve months from the date of these financial statements.

The accounting policies adopted are consistent with those of the previous financial year end, except for the adoption of new and amended standard which are set out below.

3.3 New and amended standards adopted by the Group

The Group applied for the first-time certain standards and amendments, which are effective for annual periods beginning on or after 1 January 2025. The Group has not early adopted any other standard, interpretation or amendment that has been issued but is not yet effective.

a) Lack of exchangeability - Amendments to IAS 21

The amendments to IAS 21 The Effects of Changes in Foreign Exchange Rates specify how an entity should assess whether a currency is exchangeable and how it should determine a spot exchange rate when exchangeability is lacking. The amendments also require disclosure of information that enables users of its financial statements to understand how the currency not being exchangeable into the other currency affects, or is expected to affect, the entity's financial performance, financial position and cash flows.

The amendments are effective for annual reporting periods beginning on or after 1 January 2025. When applying the amendments, an entity cannot restate comparative information.

The amendments did not have a material impact on the Group's financial statements.

3.4 Standards issued but not yet effective

The new and amended standards and interpretations that are issued, but not yet effective, up to the date of issuance of the Group's financial statements are disclosed below. The Group intends to adopt these new and amended standards and interpretations, if applicable, when they become effective. Details of these new standards and interpretations are set out below:

a) Amendments to IFRS 10 and IAS 28: Selection or contribution of assets between an investor or joint venture

The IASB has made limited scope amendments to IFRS 10 Consolidated Financial Statements and IAS 28 Investments in Associates and Joint Ventures.

The amendments clarify the accounting treatment for sales or contribution of assets between an investor and their associates or joint ventures. They confirm that the accounting treatment depends on whether the non-monetary assets sold or contributed to an associate or joint venture constitute a "business' (as defined in IFRS 3 Business Combinations).

Where the non-monetary assets constitute a business, the investor will recognise the full gain or loss on the sale or contribution of assets. If the assets do not meet the definition of a business, the gain or loss is recognised by the investor only to the extent of the other investor's interests in the associate or joint venture. The amendments apply prospectively. There is currently no effective date for this amendment.

b) IFRS 18 - Presentation and Disclosure in Financial Statements

In April 2024, the IASB issued IFRS 18, which replaces IAS 1 Presentation of Financial Statements. IFRS 18 introduces new requirements for presentation within the statement of profit or loss, including specified totals and subtotals. Furthermore, entities are required to classify all income and expenses within the statement of profit or loss into one of five categories: operating, investing, financing, income taxes and discontinued operations, whereof the first three are new.

It also requires disclosure of newly defined management-defined performance measures, subtotals of income and expenses, and includes new requirements for aggregation and disaggregation of financial information based on the identified 'roles' of the primary financial statements (PFS) and the notes.

IFRS 18, and the amendments to the other standards, is effective for reporting periods beginning on or after 1 January 2027, but earlier application is permitted and must be disclosed. IFRS 18 will apply retrospectively.

c) IFRS 19 - Subsidiaries without Public Accountability: Disclosures

In May 2024, the IASB issued IFRS 19, which allows eligible entities to elect to apply its reduced disclosure requirements while still applying the recognition, measurement and presentation requirements in other IFRS accounting standards. To be eligible, at the end of the reporting period, an entity must be a subsidiary as defined in IFRS 10, cannot have public accountability and must have a parent (ultimate or intermediate) that prepares consolidated financial statements, available for public use, which comply with IFRS accounting standards.

d) Classification and Measurement of Financial Instruments—Amendments to IFRS 9 and IFRS 7

The Amendments include:

► A clarification that a financial liability is derecognised on the 'settlement date' and introduce an accounting policy choice (if specific conditions are met) to derecognise financial liabilities settled using an electronic payment system before the settlement date

► Additional guidance on how the contractual cash flows for financial assets with environmental, social and corporate governance (ESG) and similar features should be assessed

► Clarifications on what constitute 'non-recourse features' and what are the characteristics of contractually linked instruments

► The introduction of disclosures for financial instruments with contingent features and additional disclosure requirements for equity instruments classified at fair value through other comprehensive income (OCI)

The Amendments are effective for annual periods starting on or after 1 January 2026. Early adoption is permitted, with an option to early adopt the amendments for classification of financial assets and related disclosures only.

The Group is currently working to identify all impacts the amendments will have on the consolidated and separate financial statements.

e) Contracts Referencing Nature-dependent Electricity – Amendments to IFRS 9 and IFRS 7

In December 2024, the Board issued Contracts Referencing Nature-dependent Electricity (Amendments to IFRS 9 and IFRS 7). The amendments include:

- Clarifying the application of the 'own-use' requirements
- Permitting hedge accounting if these contracts are used as hedging instruments
- Adding new disclosure requirements to enable investors to understand the effect of these contracts on a company's financial performance and cash flows

The amendments will be effective for annual reporting periods beginning on or after 1 January 2026. Early adoption is permitted, but will need to be disclosed.

3.5 Basis of consolidation

The condensed consolidated interim financial statements comprise the financial statements of the Company and its subsidiaries as at 30 September 2025.

This basis of consolidation is the same adopted for the last audited financial statements as at 31 December 2024.

3.6 Functional and presentation currency

Items included in the financial statements are measured using the currency of the primary economic environment in which the Company operates ('the functional currency'), which is the US dollar. The financial statements are presented in Nigerian Naira and the US Dollars.

The Company has chosen to show both presentation currencies and this is allowable by the regulator.

a) Transaction and balances

Foreign currency transactions are translated into the functional currency using the exchange rates at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation of monetary assets and liabilities denominated in foreign currencies at year end are generally recognised in profit or loss. They are deferred in equity if attributable to net investment in foreign operations.

Foreign exchange gains and losses that relate to borrowings are presented in the statement of profit or loss, within finance costs. All other foreign exchange gains and losses are presented in the statement of profit or loss on a net basis within other income or other expenses.

Non-monetary items that are measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was determined. Translation differences on assets and liabilities carried at fair value are reported as part of the fair value gain or loss or other comprehensive income depending on where fair value gain or loss is reported.

b) Group companies

The results and financial position of foreign operations that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- assets and liabilities for each statement of financial position presented are translated at the closing rate at the date of the reporting date.
- income and expenses for statement of profit or loss and other comprehensive income are translated at average exchange rates (unless this is not - a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case income and expenses are translated at the dates of the transactions), and all resulting exchange differences are recognised in other comprehensive income.
- Equity items for each statement of financial position presented are translated at the historical rates.

On disposal of a foreign operation, the component of other comprehensive income relating to that particular foreign operation is recognised in profit or loss. Goodwill and fair value adjustments arising on the acquisition of a foreign operation are treated as assets and liabilities of the foreign operation and translated at the closing rate.

4. Significant accounting judgements, estimates and assumptions

The preparation of the Group's consolidated historical financial information requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the accompanying disclosures, and the disclosure of contingent liabilities. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

4.1 Judgements

In the process of applying the Group's accounting policies, management has made the following judgements, which have the most significant effect on the amounts recognised in the consolidated historical financial information:

I) OMLs 4, 38 and 41

OMLs 4, 38, 41 are grouped together as a cash generating unit for the purpose of impairment testing. These three OMLs are grouped together because they each cannot independently generate cash flows. They currently operate as a single block sharing resources for generating cash flows. Crude oil and gas sold to third parties from these OMLs are invoiced when the Group has an unconditional right to receive payment.

II) Deferred tax asset

Deferred income tax assets are recognised for tax losses carried forward to the extent that the realisation of the related tax benefit through future taxable profits is probable.

III) Foreign currency translation reserve

The Group has used the CBN rate to translate its Dollar currency to its Naira presentation currency. Management has determined that this rate is available for immediate delivery. If the rate was 10% higher or lower, revenue in Naira would have increased/decreased by ₦335.6 billion (2024: ₦29 billion). See Note 31 for the applicable translation rates.

IV) Consolidation of Elcrest

On acquisition of 100% shares of Eland Oil and Gas Plc, the Group acquired indirect holdings in Elcrest Exploration and Production (Nigeria) Limited. Although the Group has an indirect holding of 45% in Elcrest, Elcrest has been consolidated as a subsidiary for the following basis:

- Eland Oil and Gas Plc has controlling power over Elcrest due to its representation on the board of Elcrest, and clauses contained in the Share Charge agreement and loan agreement which gives Eland the right to control 100% of the voting rights of shareholders.
- Eland Oil and Gas Plc is exposed to variable returns from the activities of Elcrest through dividends and interests.
- Eland Oil and Gas Plc has the power to affect the amount of returns from Elcrest through its right to direct the activities of Elcrest and its exposure to returns.

V) Revenue recognition

Performance obligations

The judgments applied in determining what constitutes a performance obligation will impact when control is likely to pass and therefore when revenue is recognised i.e. over time or at a point in time. The Group has determined that only one performance obligation exists in oil contracts which is the delivery of crude oil to specified ports. Revenue is therefore recognised at a point in time.

For gas contracts, the performance obligation is satisfied through the delivery of a series of distinct goods. Revenue is recognised over time in this situation as gas customers simultaneously receive and consume the benefits provided by the Group's performance. The Group has elected to apply the 'right to invoice' practical expedient in determining revenue from its gas contracts. The right to invoice is a measure of progress that allows the Group to recognise revenue based on amounts invoiced to the customer. Judgement has been applied in evaluating that the Group's right to consideration corresponds directly with the value transferred to the customer and is therefore eligible to apply this practical expedient.

Significant financing component

The Group has entered into an advance payment contract with some of the customers for future crude oil to be delivered. The Group has considered whether the contract contains a financing component and whether that financing component is significant to the contract, including both of the following;

a) The difference, if any, between the amount of promised consideration and cash selling price and;

b) The combined effect of both the following:

- The expected length of time between when the Group transfers the crude to the customer and when payment for the crude is received and;
- The prevailing interest rate in the relevant market.

The advance period is greater than 12 months. In addition, the interest expense accrued on the advance is based on a comparable market rate. Interest expense has therefore been included as part of finance cost.

Transactions with Joint Operating arrangement (JOA) partners

The treatment of underlift and overlift transactions is judgmental and requires a consideration of all the facts and circumstances including the purpose of the arrangement and transaction. The transaction between the Group and its JOA partners involves sharing in the production of crude oil, and for which the settlement of the transaction is non-monetary. The JOA partners have been assessed to be partners not customers. Therefore, shortfalls or excesses below or above the Group's share of production are recognised in other income/ (expenses) - net.

VI Exploration and evaluation assets

The accounting for exploration and evaluation ('E&E') assets require management to make certain judgements and assumptions, including whether exploratory wells have discovered economically recoverable quantities of reserves. Designations are sometimes revised as new information becomes available. If an exploratory well encounters hydrocarbon, but further appraisal activity is required in order to conclude whether the hydrocarbons are economically recoverable, the well costs remain capitalised as long as sufficient progress is being made in assessing the economic and operating viability of the well. Criteria used in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected additional development activities, commercial evaluation and regulatory matters. The concept of 'sufficient progress' is an area of judgement, and it is possible to have exploratory costs remain capitalised for several years while additional drilling is performed or the Group seeks government, regulatory or partner approval of development plans.

VII Segment reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker.

The Board of directors has appointed a steering committee which assesses the financial performance and position of the Group and makes strategic decisions. The steering committee, which has been identified as being the chief operating decision maker, consists of the Chief Financial Officer, the General Manager (Finance), the Director (New Energy) and the Senior Financial Reporting Manager.. See further details in note 6.

VIII) Leases

Critical judgements in determining the lease term

In determining the lease term, management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not exercise a termination option. Extension options (or periods after termination options) are only included in the lease term if the lease is reasonably certain to be extended (or not terminated). For leases of warehouses, retail stores and equipment, the following factors are normally the most relevant

- If there are significant penalty payments to terminate (or not extend), the group is typically reasonably certain to extend (or not terminate).
- If any leasehold improvements are expected to have a significant remaining value, the group is typically reasonably certain to extend (or not terminate).
- Otherwise, the group considers other factors including historical lease durations and the costs and business disruption required to replace the leased asset.

Most extension options in offices and vehicles leases have not been included in the lease liability, because the group could replace the assets without significant cost or business disruption.

4.2 Estimates and assumptions

The key assumptions concerning the future and the other key source of estimation uncertainty at the reporting date that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are described below. The Group based its assumptions and estimates on parameters available when the consolidated financial statements were prepared. Existing circumstances and assumptions about future developments may change due to market changes or circumstances arising that are beyond the control of the Group. Such changes are reflected in the assumptions when they occur.

The following are some of the estimates and assumptions made:

I) Defined benefit plans

The cost of the defined benefit retirement plan and the present value of the retirement obligation are determined using actuarial valuations. An actuarial valuation involves making various assumptions that may differ from actual developments in the future. These include the determination of the discount rate, future salary increases, mortality rates and changes in inflation rates.

Due to the complexities involved in the valuation and its long-term nature, a defined benefit obligation is highly sensitive to changes in these assumptions. The parameter most subject to change is the discount rate. In determining the appropriate discount rate, management considers market yield on federal government bonds in currencies consistent with the currencies of the post-employment benefit obligation and extrapolated as needed along the yield curve to correspond with the expected term of the defined benefit obligation.

The rates of mortality assumed for employees are the rates published in 67/70 ultimate tables, published jointly by the Institute and Faculty of Actuaries in the UK.

II. Oil and gas reserves

Proved oil and gas reserves are used in the units of production calculation for depletion as well as the determination of the timing of well closure for estimating decommissioning liabilities and impairment analysis. There are numerous uncertainties inherent in estimating oil and gas reserves. Assumptions that are valid at the time of estimation may change significantly when new information becomes available. Changes in the forecast prices of commodities, exchange rates, production costs or recovery rates may change the economic status of reserves and may ultimately result in the reserves being restated.

III. Share-based payment reserve

Estimating fair value for share-based payment transactions requires determination of the most appropriate valuation model, which depends on the terms and conditions of the grant. This estimate also requires determination of the most appropriate inputs to the valuation model including the expected life of the share award or appreciation right, volatility and dividend yield and making assumptions about them. The Group measures the fair value of equity-settled transactions with employees at the grant date.

The Group makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, seldom equal the related actual results. Such estimates and assumptions are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

IV. Provision for decommissioning obligations

Provisions for environmental clean-up and remediation costs associated with the Group's drilling operations are based on current constructions, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

V. Property, plant and equipment

The Group assesses its property, plant and equipment, including exploration and evaluation assets, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable, or at least at every reporting date.

If there are low oil prices or natural gas prices during an extended period, the Group may need to recognise significant impairment charges. The assessment for impairment entails comparing the carrying value of the cash-generating unit with its recoverable amount, that is, higher of fair value less cost to dispose and value in use. Value in use is usually determined on the basis of discounted estimated future net cash flows. Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for regional market supply-and-demand conditions for crude oil and natural gas.

The Group uses the higher of the fair value less cost to dispose and the value in use in determining the recoverable amount of the cash-generating unit. In determining the value, the Group uses a forecast of the annual net cash flows over the life of proved plus probable reserves, production rates, oil and gas prices, future costs (excluding (a) future restructuring to which the entity is not yet committed; or (b) improving or enhancing the asset's performance) and other relevant assumptions based on the year-end Competent Persons Report (CPR). The pre-tax future cash flows are adjusted for risks specific to the forecast and discounted using a pre-tax discount rate which reflects both current market assessment of the time value of money and risks specific to the asset.

Management considers whether a reasonable possible change in one of the main assumptions will cause an impairment and believes otherwise.

VI. Useful life of other property, plant and equipment

The Group recognises depreciation on other property, plant and equipment on a straight-line basis in order to write-off the cost of the asset over its expected useful life. The economic life of an asset is determined based on existing wear and tear, economic and technical ageing, legal and other limits on the use of the asset, and obsolescence. If some of these factors were to deteriorate materially, impairing the ability of the asset to generate future cash flow, the Group may accelerate depreciation charges to reflect the remaining useful life of the asset or record an impairment loss.

VII. Income taxes

The Group is subject to income taxes by the Nigerian tax authority, which does not require significant judgement in terms of provision for income taxes, but a certain level of judgement is required for recognition of deferred tax assets. Management is required to assess the ability of the Group to generate future taxable economic earnings that will be used to recover all deferred tax assets. Assumptions about the generation of future taxable profits depend on management's estimates of future cash flows. The estimates are based on the future cash flow from operations taking into consideration the oil and gas prices, volumes produced, operational and capital expenditure.

VIII. Impairment of financial assets

he loss allowances for financial assets are based on assumptions about risk of default, expected loss rates and maximum contractual period. The Group uses judgement in making these assumptions and selecting the inputs to the impairment calculation, based on the Group's past history, existing market conditions as well as forward looking estimates at the end of each reporting period. Details of the key assumptions and inputs used are disclosed in note 5.1.3.

IX. Intangible assets

The contract based intangible assets (licence) were acquired as part of a business combination. They are recognised at their fair value at the date of acquisition and are subsequently amortised on a straight-line bases over their estimated remaining useful lives of the asset. The fair value of contract based intangible assets is estimated using the multi period excess earnings method. This requires a forecast of revenue and all cost projections throughout the useful life of the intangible assets. A contributory asset charge that reflects the return on assets is also determined and applied to the revenue but subtracted from the operating cash flows to derive the pre-tax cash flow. The post-tax cashflows are then obtained by deducting out the tax using the effective tax rate.

Discount rates represent the current market assessment of the risks specific to each CGU, taking into consideration the time value of money. The discount rate calculation is based on the specific circumstances of the Group and its operating segments and is derived from its weighted average cost of capital (WACC). The WACC takes into account both debt and equity. The cost of equity is derived from the expected return on investment by the Group's investors. The cost of debt is based on the interest-bearing borrowings the Group is obliged to service.

X. Inventories

The net realisable value of crude oil and refined products is based on the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale.

5. Financial risk management

5.1 Financial risk factors

The Group's activities expose it to a variety of financial risks such as market risk (including foreign exchange risk, interest rate risk and commodity price risk), credit risk and liquidity risk. The Group's risk management programme focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the Group's financial performance. The management of financial risks is carried out by the corporate finance team under policies approved by the Board of Directors. The Board provides written principles for overall risk management, as well as written policies covering specific areas, such as foreign exchange risk, interest rate risk, credit risk and investment of excess liquidity

Risk	Exposure arising from	Measurement	Management
Market risk – foreign exchange	Future commercial transactions Recognised financial assets and liabilities not denominated in US dollars.	Cash flow forecasting Sensitivity analysis	Match and settle foreign denominated cash inflows with the relevant cash outflows to mitigate any potential foreign exchange risk.
Market risk – interest rate	Long term borrowings at variable rate	Sensitivity analysis	None
Market risk – commodity prices	Derivative financial instruments	Sensitivity analysis	Oil price hedges
Credit risk	Cash and bank balances, trade receivables and derivative financial instruments.	Ageing analysis Credit ratings	Diversification of bank deposits
Liquidity risk	Borrowings and other liabilities	Rolling cash flow forecasts	Availability of committed credit lines and borrowing facilities

5.1.1 Credit risk

Credit risk refers to the risk of a counterparty defaulting on its contractual obligations resulting in financial loss to the Group. Credit risk arises from cash and bank balances as well as credit exposures to customers (i.e., Shell western, Pillar, Azura, Geregu Power, Sapele Power, ExxonMobil and Nigerian Gas Marketing Company (NGMC) receivables), and other parties (i.e., NUIMS receivables, NEPL receivables and other receivables)

a) Risk management

The Group is exposed to credit risk from its sale of crude oil to Exxonmobil, Waltersmith, Chevron and Shell western. The Groups's offstake agreements include payment terms ranging from 15 to 30 days post bill of lading date. The Group is exposed to further credit risk from outstanding cash calls from NEPL and NUIMS.

In addition, the Group is exposed to credit risk in relation to the sale of gas to its customers.

The credit risk on cash and bank balances is managed through the diversification of banks in which the balances are held. The risk is limited because the majority of deposits are with banks that have an acceptable credit rating assigned by an international credit agency. The Group's maximum exposure to credit risk due to default of the counterparty is equal to the carrying value of its financial assets.

b) Estimation uncertainty in measuring impairment loss

The table below shows information on the sensitivity of the carrying amounts of the Company's financial assets to the methods, assumptions and estimates used in calculating impairment losses on those financial assets at the end of the reporting period. These methods, assumptions and estimates have a significant risk of causing material adjustments to the carrying amounts of the Group's financial assets.

i. Significant unobservable inputs

The table below demonstrates the sensitivity of the Company's profit before tax to movements in the probability of default (PD) and loss given default (LGD) for financial assets, with all other variables held constant:

Increase/decrease in loss given default	**Effect on profit before tax** **30 Sept 2025** **₦ million**	**Effect on other components of equity before tax** **30 Sept 2025** **₦ million**
+10%	**(1,157)**	**—**
-10%	**1,157**	**—**

Increase/decrease in loss given default	Effect on profit before tax 31 Dec 2024 ₦ million	Effect on other components of equity before tax 31 Dec 2024 ₦ million
+10%	(208)	—
-10%	208	—

The table below demonstrates the sensitivity of the Group's profit before tax to movements in probabilities of default, with all other variables held constant:

Increase/decrease in probability of default	**Effect on profit before tax** **30 Sept 2025** **₦ million**	**Effect on other components of equity before tax** **30 Sept 2025** **₦ million**
+10%	**(1,365)**	**—**
-10%	**1,365**	**—**

Increase/decrease in probability of default	Effect on profit before tax 31 Dec 2024 ₦ million	Effect on other components of equity before tax 31 Dec 2024 ₦ million
+10%	(1,365)	—
-10%	1,365	—

The table below demonstrates the sensitivity of the Company's profit before tax to movements in the forward-looking macroeconomic indicators (Brent price and GDP Growth rate), with all other variables held constant:

Increase/decrease in forward looking macroeconomic indicators (Brent price)	Effect on profit before tax 30 Sept 2025 ₦ million	Effect on other components of equity before tax 30 Sept 2025 ₦ million
+10%	**(1,365)**	–
-10%	**1,365**	–

Increase/decrease in forward looking macroeconomic indicators (GDP Growth rate)	Effect on profit before tax 30 Sept 2025 ₦ million	Effect on other components of equity before tax 30 Sept 2025 ₦ million
+10%	**(1,298)**	–
-10%	**1,298**	–

Increase/decrease in forward looking macroeconomic indicators (Brent price)	Effect on profit before tax 31 Dec 2024 ₦ million	Effect on other components of equity before tax 31 Dec 2024 ₦ million
+10%	(63)	—
-10%	63	—

Increase/decrease in forward looking macroeconomic indicators (GDP Growth rate)	Effect on profit before tax 31 Dec 2024 ₦ million	Effect on other components of equity before tax 31 Dec 2024 ₦ million
+10%	(18)	—
-10%	18	—

5.1.2 Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet its financial obligations as they fall due. The Group manages liquidity risk by ensuring that sufficient funds are available to meet its commitments as they fall due.

The Group uses both long-term and short-term cash flow projections to monitor funding requirements for activities and to ensure there are sufficient cash resources to meet operational needs. Cash flow projections take into consideration the Group's debt financing plans and covenant compliance. Surplus cash held is transferred to the treasury department which invests in interest bearing current accounts and time deposits.

The following table details the Group's remaining contractual maturity for its non-derivative financial liabilities with agreed maturity periods. The table has drawn based on the undiscounted cash flows of the financial liabilities based on the earliest date on which the Group can be required to pay.

30 Sept 2025	Effective interest rate %	Less than 1 year ₦ million	1 – 2 year ₦ million	2 – 3 years ₦ million	3 – 5 years ₦ million	Total ₦ million
Non-derivatives						
Fixed interest rate borrowings						
$650 million Senior notes	9.125%	86,904	86,904	86,904	1,082,723	1,343,435
Variable interest rate borrowings						
Eland Wesport Loan						
The Mauritius Commercial Bank Ltd	6.5% + SOFR	1,125	1,505	1,509	16,321	20,460
Stanbic IBTC Bank Plc	6.5% + SOFR	1,012	1,354	1,358	14,688	18,412
Standard Bank of South Africa	6.5% + SOFR	563	753	755	8,160	10,231
First City Monument Ltd (FCMB)	6.5% + SOFR	541	722	724	7,834	9,821
Zenith Bank Plc	6.5% + SOFR	361	482	484	5,222	6,549
$300 million Advance Payment Facility (APF)						
ExxonMobil Financing	5% + SOFR + CAS	42,170	42,169	460,639	—	544,978
Total variable interest borrowings		45,772	46,985	465,469	52,225	610,451
Other non-derivatives						
Trade and other payables**		1,438,058	—	—	—	1,438,058
Lease liability		30,543	91,629	—	—	122,172
		1,468,601	91,629	—	—	1,560,230
Total		1,601,277	225,518	552,373	1,134,948	3,514,116

31 December 2024	Effective interest rate %	Less than 1 year ₦ million	1 – 2 year ₦ million	2 – 3 years ₦ million	Total ₦ million
Non-derivatives					
Fixed interest rate borrowings					
$650 million Senior notes	7.75%	77,342	1,036,629	—	1,113,971
Variable interest rate borrowings					
The Mauritius Commercial Bank Ltd	8% + SOFR	23,378	6,274	—	29,652
Stanbic IBTC Bank Plc	8% + SOFR	23,867	6,403	—	30,270
Standard Bank of South Africa	8% + SOFR	13,638	3,660	—	17,298
First City Monument Ltd (FCMB)	8% + SOFR	6,088	1,634	—	7,722
Shell Western Supply & Trading Limited	10.5% + SOFR	2,598	2,598	18,184	23,380
$350 million RCF					
Citibank N.A. London	5% + SOFR+CAS	15,354	—	—	15,354
Nedbank Limited, London Branch	5% + SOFR+CAS	69,090	—	—	69,090
Stanbic Ibtc Bank Plc	5% + SOFR+CAS	76,766	—	—	76,766
The Standard Bank of South Africa Limited		—	—	—	—
RMB International (Mauritius) Limited	5% + SOFR+CAS	99,796	—	—	99,796
The Mauritius Commercial Bank Ltd	5% + SOFR+CAS	69,090	—	—	69,090
JP Morgan Chase Bank, N.A London	5% + SOFR+CAS	46,060	—	—	46,060
Standard Chartered Bank	5% + SOFR+CAS	46,060	—	—	46,060
Natixis		—	—	—	—
Societe Generale Bank, London Branch		—	—	—	—
Zenith Bank Plc	5% + SOFR+CAS	23,030	—	—	23,030
Zenith Bank (UK) Limited	5% + SOFR+CAS	30,707	—	—	30,707
United Bank for Africa Plc	5% + SOFR+CAS	23,030	—	—	23,030
First City Monument Bank Limited	5% + SOFR+CAS	30,707	—	—	30,707
BP	5% + SOFR+CAS	7,677	—	—	7,677
$300 million Advance Payment Facility (APF)					
ExxonMobil Financing	5% + SOFR+CAS	44,547	44,547	504,533	593,627
Total variable interest borrowings		651,483	65,116	522,717	1,239,316
Other non-derivatives					
Trade and other payables**		1,428,884	—	—	1,428,884
Lease liability		24,415	—	—	24,415
		1,453,299	—	—	1,453,299
Total		2,182,124	1,101,745	522,717	3,806,586

1. Trade and other payables (exclude non-financial liabilities such as provisions, taxes, pension and other non-contractual payables)

5.1.3 Fair value measurements

Set out below is a comparison by category of carrying amounts and fair value of all financial instruments:

	Carrying amount		Fair value	
	30 Sept 2025	31 Dec 2024	**30 Sept 2025**	31 Dec 2024
	₦ million	₦ million	**₦ million**	₦ million
Financial assets measured at amortised cost				
Trade and other receivables*	**784,646**	1,148,171	**784,646**	1,148,171
Contract assets	**72,352**	23,918	**72,352**	23,918
Cash and cash equivalents	**849,502**	721,385	**849,502**	721,385
	1,706,500	1,893,474	**1,706,500**	1,893,474
Financial liabilities				
Interest bearing loans borrowings**	**1,414,933**	2,099,748	**1,391,150**	2,080,360
Trade and other payables***	**1,428,493**	1,428,884	**1,428,493**	1,428,884
	2,843,426	3,528,632	**2,819,643**	3,509,244
Financial liabilities at fair value				
Derivative financial instruments (Note 19)	**(14,141)**	(6,073)	**(14,141)**	(6,073)
	(14,141)	(6,073)	**(14,141)**	(6,073)

* Trade and other receivables exclude underlift, NGMC VAT receivables, cash advances and advance payments.

** In determining the fair value of the interest-bearing loans and borrowings, non-performance risks of the Group as at period-end were assessed to be insignificant.

*** Trade and other payables exclude non-financial liabilities such as taxes, overlift, pension and other non-contractual payables.

Trade and other receivables (excluding prepayments), contract assets and cash and bank balances are financial instruments whose carrying amounts as per the financial statements approximate their fair values. This is mainly due to their short-term nature.

5.1.4 Fair Value Hierarchy

As at the reporting period, the Group had classified its financial instruments into the three levels prescribed under the accounting standards. There were no transfers of financial instruments between fair value hierarchy levels during the period.

- Level 1 – Quoted (unadjusted) market prices in active markets for identical assets or liabilities.
- Level 2 – Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable.
- Level 3 – Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable.

The fair value of the financial instruments is included at the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The fair value of the Group's derivative financial instruments has been determined using a proprietary pricing model that uses marked to market valuation. The valuation represents the mid-market value and the actual close-out costs of trades involved. The market inputs to the model are derived from observable sources. Other inputs are unobservable but are estimated based on the market inputs or by using other pricing models. The derivative financial instruments are in level 2.

The fair value of the Group's interest-bearing loans and borrowings is determined by using discounted cash flow models that use market interest rates as at the end of the period. The interest-bearing loans and borrowings are in level 2.

The fair value of the property, plant and equipment (oil rig) held for sale is determined using the replacement cost of the asset and the actual values market participants are willing to pay for the asset. These assets are of specialised nature and has been recognised under level 2.

The valuation process

The finance & corporate planning teams of the Group perform the valuations of financial and non-financial assets required for financial reporting purposes, including level 3 fair values. The corporate planning team reports to the Director, Strategy, Planning and Business Development who reports directly to the Chief Executive Officer (CEO). Discussions on the valuation process and results are held between the Director and the valuation team at least twice every year.

6. Segment reporting

Business segments are based on the Group's internal organisation and management reporting structure. The Group's business segments are the two core businesses: Oil and Gas. The Oil segment deals with the exploration, development and production of crude oil while the Gas segment deals with the production and processing of gas. These two reportable segments make up the total operations of the Group.

For the nine months ended 30 September 2025, revenue from the gas segment of the business constituted 8% (2024: 13%) of the Group's revenue. Management is committed to continued growth of the gas segment of the business, including through increased investment to establish additional offices, create a separate gas business operational management team and procure the required infrastructure for this segment of the business. The gas business is positioned separately within the Group and reports directly to the chief operating decision maker. As the gas business segment's revenues, results and cash flows are largely independent of other business units within the Group, it is regarded

as a separate segment.The result is two reporting segments, Oil and Gas. There were no inter segment sales during the reporting periods under consideration, therefore all revenue was from external customers.
Amounts relating to the gas segment are determined using the gas cost centres, with the exception of depreciation. Depreciation relating to the gas segment is determined by applying a percentage which reflects the proportion of the Net Book Value of oil and gas properties that relates to gas investment costs (i.e., cost for the gas processing facilities).

The Group accounting policies are also applied in the segment reports.

6.1 Segment profit disclosure

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	**3 Months ended 30 Sept 2025**	3 Months ended 30 Sept 2024
	₦ million	₦ million	**₦ million**	₦ million
Oil	**80,319**	(29,642)	**64,804**	(39,791)
Gas	**66,320**	82,418	**39,316**	24,507
Total profit/(loss) for the period	**146,639**	52,776	**104,120**	(15,284)

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	**3 Months ended 30 Sept 2025**	3 Months ended 30 Sept 2024
Oil	**₦ million**	₦ million	**₦ million**	₦ million
Revenue from contracts with customers				
Crude oil sales (Note 7)	**3,090,596**	935,891	**1,085,876**	444,362
Cost of sales and general and administrative expenses	**(2,109,204)**	(660,436)	**(557,453)**	(256,130)
Other income/(loss)	**30,097**	54,767	**(43,790)**	(73,154)
Operating profit before impairment	**1,011,489**	330,222	**484,633**	115,078
Impairment reversal/(loss)	**1,320**	6,041	**1,891**	(893)
Fair value loss	**(25,207)**	(7,679)	**(10,241)**	(3,538)
Operating profit	**987,602**	328,584	**476,283**	110,647
Finance income (Note 13)	**12,123**	11,702	**3,848**	4,295
Finance expenses (Note 13)	**(223,485)**	(86,956)	**(72,936)**	(32,840)
Profit before taxation	**776,240**	253,330	**407,195**	82,102
Income tax expense (Note 14)	**(695,921)**	(282,972)	**(342,391)**	(121,893)
Profit/(loss) for the period	**80,319**	(29,642)	**64,804**	(39,791)

Other income in the Oil business largely relates to changes in underlift/overlift in the period.

The increase in the cost of sales and general and administrative expenses in the oil segment is driven mostly by the consolidation of the acquired SEPNU business.

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Gas	9 months ended 30 Sept 2025 ₦ million	9 months ended 30 Sept 2024 ₦ million	3 Months ended 30 Sept 2025 ₦ million	3 Months ended 30 Sept 2024 ₦ million
Revenue from contracts with customers				
Gas sales	**214,636**	135,006	**67,977**	51,483
Natural gas liquid	**50,955**	–	**35,617**	–
Cost of sales and general and administrative expenses	**(152,860)**	(19,523)	**(79,696)**	(19,068)
Other income/(losses)	**10,847**	(22,684)	**5,664**	(15,372)
Operating profit before impairment	**123,578**	92,799	**29,562**	17,043
Impairment losses	**(14,974)**	(10,042)	**(10,827)**	(1,526)
Operating profit	**108,604**	82,757	**18,735**	15,517
Share of (loss)/profit from joint venture accounted for using the equity method	**(5,855)**	30,625	**(1,052)**	25,044
Profit before taxation	**102,749**	113,382	**17,683**	40,561
Income tax (expenses) /credit (Note 14)	**(36,429)**	(30,964)	**21,633**	(16,054)
Profit for the period	**66,320**	82,418	**39,316**	24,507

Other income in the Gas business largely relates to foreign exchange differences in the period.

The increase in the cost of sales and general and administrative expenses in the gas segment is driven mostly by the consolidation of the acquired SEPNU business.

6.1.1 Disaggregation of revenue from contracts with customers

The Group derives revenue from the transfer of commodities at a point in time or over time and from different geographical regions.

	9 months ended 30 Sept 2025 Oil ₦ million	9 months ended 30 Sept 2025 Gas ₦ million	9 months ended 30 Sept 2025 Natural Gas Liquid ₦ million	9 months ended 30 Sept 2025 Total ₦ million	9 months ended 30 Sept 2024 Oil ₦ million	9 months ended 30 Sept 2024 Gas ₦ million	9 months ended 30 Sept 2024 Total ₦ million
Geographical markets							
Bahamas	—	—	—	—	358,062	—	358,062
Barbados	—	—	—	—	55,229	—	55,229
Canada	112,460	—	—	112,460	—	—	—
Cote D'Ivoire	124,377	—	—	124,377	—	—	—
France	101,918	—	—	101,918	—	—	—
Germany	111,123	—	—	111,123	—	—	—
Ghana	—	—	36,096	36,096	—	—	—
India	639,581	—	—	639,581	—	—	—
Indonesia	317,814	—	—	317,814	—	—	—
Italy	203,017	—	—	203,017	94,511	—	94,511
Kenya	—	—	7,622	7,622	—	—	—
Malaysia	98,852	—	—	98,852	—	—	—
Netherlands	259,608	—	—	259,608	—	—	—
Nigeria	24,301	214,636	7,237	246,174	50,459	135,006	185,465
Portugal	192,808	—	—	192,808	—	—	—
South Africa	179,641	—	—	179,641	—	—	—
Spain	223,887	—	—	223,887	—	—	—
Switzerland	—	—	—	—	223,869	—	223,869
Turkey	132,425	—	—	132,425	—	—	—
UK	95,485	—	—	95,485	153,761	—	153,761
Uruguay	62,901	—	—	62,901	—	—	—
USA	206,984	—	—	206,984	—	—	—
Vietnam	3,414	—	—	3,414	—	—	—
Revenue from contracts with customers	3,090,596	214,636	50,955	3,356,187	935,891	135,006	1,070,897

	9 months ended 30 Sept 2025 Oil ₦ million	9 months ended 30 Sept 2025 Gas ₦ million	9 months ended 30 Sept 2025 Natural Gas Liquid ₦ million	9 months ended 30 Sept 2025 Total ₦ million	9 months ended 30 Sept 2024 Oil ₦ million	9 months ended 30 Sept 2024 Gas ₦ million	9 months ended 30 Sept 2024 Total ₦ million
Timing of revenue recognition							
At a point in time	3,090,596	—	—	3,090,596	935,891	—	935,891
Over time	—	214,636	50,955	265,591	—	135,006	135,006
Revenue from contracts with customers	3,090,596	214,636	50,955	3,356,187	935,891	135,006	1,070,897

	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024	3 Months ended 30 Sept 2024	3 Months ended 30 Sept 2024
	Oil	Gas	Natural gas liquid	Total	Oil	Gas	Total
	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million
Geographical markets							
Bahamas	**—**	**—**		**—**	183,542	—	183,542
Barbados	**—**	**—**	**—**	**—**	29,398	—	29,398
Canada	**16,727**	**—**	**—**	**16,727**	—	—	—
Cote D'lvoire	**47,224**	**—**	**—**	**47,224**	—	—	—
France	**(546)**	**—**	**—**	**(546)**	—	—	—
Germany	**(595)**	**—**	**—**	**(595)**	—	—	—
Ghana	**—**	**—**	**28,420**	**28,420**	—	—	—
India	**185,303**	**—**	**—**	**185,303**	—	—	—
Indonesia	**123,337**	**—**	**—**	**123,337**	—	—	—
Italy	**2,653**	**—**	**—**	**2,653**	8,409	—	8,409
Kenya	**—**	**—**	**(40)**	**(40)**	—	—	—
Malaysia	**(530)**	**—**	**—**	**(530)**	—	—	—
Netherlands	**103,911**	**—**	**—**	**103,911**	—	—	—
Nigeria	**5,436**	**67,977**	**7,237**	**80,650**	13,040	51,483	64,523
Portugal	**110,886**	**—**	**—**	**110,886**	—	—	—
South Africa	**107,225**	**—**	**—**	**107,225**	—	—	—
Spain	**63,700**	**—**	**—**	**63,700**	—	—	—
Switzerland	**—**	**—**	**—**	**—**	125,011	—	125,011
Turkey	**128,978**	**—**	**—**	**128,978**	—	—	—
UK	**93,279**	**—**	**—**	**93,279**	84,962	—	84,962
Uruguay	**(337)**	**—**	**—**	**(337)**	—	—	—
USA	**99,243**	**—**	**—**	**99,243**	—	—	—
Vietnam	**(18)**	**—**	**—**	**(18)**	—	—	—
Revenue from contracts with customers	**1,085,876**	**67,977**	**35,617**	**1,189,470**	444,362	51,483	495,845

	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024	3 Months ended 30 Sept 2024	3 Months ended 30 Sept 2024
	Oil	Gas	Natural gas	Total	Oil	Gas	Total
	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million	₦ million
Timing of revenue recognition							
At a point in time	**1,085,876**	**—**	**—**	**1,085,876**	444,362	—	444,362
Over time	**—**	**67,977**	**35,617**	**103,594**	—	51,483	51,483
Revenue from contracts with customers	**1,085,876**	**67,977**	**35,617**	**1,189,470**	444,362	51,483	495,845

The Group's transactions with its major customers, Shell Western, Chevron, and ExxonMobil, constitute about 92% (₦2.9 trillion) (9M 2024: 20%, ₦223.9 billion) of the total revenue from oil segment and the Group as a whole. Also, the Group's transactions with Geregu Power, Sapele Power, NGMC, MSNE and Azura (₦155.6 billion) (9M 2024: ₦135 billion) accounted for most of the revenue from gas segment.

The current period data reflects location of the final buyers based on information extracted from bill of lading, while 2024 data reflected the country of location of the crude oil traders/offtakers.

6.1.2 Impairment (losses)/reversal on financial assets by reportable segments

	9 months ended 30 Sept 2025			9 months ended 30 Sept 2024		
	Oil	**Gas**	**Total**	Oil	Gas	Total
	₦ million	**₦ million**	**₦ million**	₦ million	₦ million	₦ million
Impairment reversal/(losses) recognised during the period	**1,320**	**(14,974)**	**(13,654)**	6,041	(10,042)	(4,001)

	3 Months ended 30 Sept 2025			3 Months ended 30 Sept 2024		
	Oil	**Gas**	**Total**	Oil	Gas	Total
	₦ million	**₦ million**	**₦ million**	₦ million	₦ million	₦ million
Impairment reversal/(losses) recognised during the period	**1,891**	**(10,827)**	**(8,936)**	(893)	(1,526)	(2,419)

6.2 Segment assets

Segment assets are measured in a manner consistent with that of the financial statements. These assets are allocated based on the operations of the reporting segment and the physical location of the asset. The Group had no non-current assets domiciled outside Nigeria.

	Oil	Gas	Total
Total segment assets	₦ million	₦ million	₦ million
30 September 2025	**7,677,614**	**1,375,212**	**9,052,826**
31 December 2024	8,744,398	1,076,863	9,821,261

6.3 Segment liabilities

Segment liabilities are measured in a manner consistent with that of the financial statements. These liabilities are allocated based on the operations of the segment.

	Oil	Gas	Total
Total segment liabilities	₦ million	₦ million	₦ million
30 September 2025	**5,525,577**	**829,550**	**6,355,127**
31 December 2024	6,407,278	585,000	6,992,278

7. Revenue from contract with customers

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	**3 Months ended 30 Sept 2025**	3 Months ended 30 Sept 2024
	₦ million	₦ million	**₦ million**	₦ million
Crude oil sales	**3,090,596**	935,891	**1,085,876**	444,362
Gas sales	**214,636**	135,006	**67,977**	51,483
Natural gas liquid	**50,955**	–	**35,617**	–
	3,356,187	1,070,897	**1,189,470**	495,845

The major off-takers for crude oil are Shell West, Chevron and ExxonMobil. The major off-takers for gas are MSN, Sapele Power, Nigerian Gas Marketing Company and Azura. The major off-taker for natural gas liquid is ExxonMobil.

8. Cost of Sales

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	**3 Months ended 30 Sept 2025**	3 Months ended 30 Sept 2024
	₦ million	₦ million	**₦ million**	₦ million
Royalties	**587,750**	161,106	**197,087**	64,274
Depletion, depreciation and amortisation	**525,761**	170,805	**33,659**	62,845
Depreciation of right of use assets	**26,754**	–	**2,878**	–
Crude handling fees	**91,328**	74,154	**31,536**	30,800
Nigeria Export Supervision Scheme (NESS) fee	**3,083**	635	**1,097**	301
Niger Delta Development Commission Levy	**53,692**	9,465	**19,986**	3,727
Barging/Trucking	**31,712**	15,495	**10,725**	4,532
Operational & Maintenance expenses	**680,104**	107,719	**287,743**	45,335
	2,000,184	539,379	**584,711**	211,814

Operational & maintenance expenses relates mainly to maintenance costs, warehouse operations expenses, security expenses, community expenses, clean-up costs, fuel supplies and catering services. Also included in operational and maintenance expenses is gas flare penalty of ₦55.5 billion (9M 2024: ₦29.8 billion). The Group is working through projects in the onshore business to end routine flaring by the end of 2025 and we expect a significant reduction in gas flare penalty from 2026

Barging and Trucking costs relates to costs on the OML 40 Gbetiokun field.

The increase in the cost of sales is largely driven by the consolidation of the acquired business SEPNU.

9. Other income - net

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	**3 Months ended 30 Sept 2025**	3 Months ended 30 Sept 2024
	₦ million	₦ million	**₦ million**	₦ million
Underlift/(Overlift)	**5,900**	12,285	**(60,124)**	(63,793)
Gain/(loss) on foreign exchange	**17,570**	25,562	**14,908**	(15,768)
Loss on disposal of property, plant & equipment	**–**	(11,150)	**–**	(11,150)
Tariffs	**9,020**	4,696	**3,234**	1,885
Others	**8,454**	691	**3,856**	300
	40,944	32,084	**(38,126)**	(88,526)

Underlifts/Overlifts) are shortfalls/(surplus) of crude lifted below/(above) the share of production. It may exist when the crude oil lifted by the Group during the period is (more)/less than its ownership share of production. The (surplus)/shortfall is initially measured at the market price of oil at the date of lifting and recognised as other (loss)/income. At each reporting period, the (surplus)/shortfall is remeasured at the current market value. The resulting change, as a result of the remeasurement, is also recognised in profit or loss as other (loss)/income.

Gain/(loss) on foreign exchange is principally due to the translation of Naira, Pounds and Euro denominated monetary assets and liabilities.

Tariffs which is a form of crude handling fee, relate to income generated from the use of the Group's pipeline by others.

Others represents joint venture billing interest and joint venture billing finance fees.

10. General and administrative expenses

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024
	₦ million	₦ million	**₦ million**	₦ million
Depreciation and amortisation	**38,617**	8,453	**11,744**	6,420
Depreciation of right of use assets	**21,916**	5,911	**7,387**	2,586
Professional & Consulting Fees	**31,728**	37,209	**16,967**	15,100
Auditor's remuneration	**408**	891	**176**	577
Directors Emoluments (Executives)	**3,574**	4,678	**1,110**	1,480
Directors Emoluments (Non - Executives)	**4,829**	5,527	**1,296**	1,805
Employee benefits	**67,563**	43,203	**(3,549)**	15,901
Share-based benefits	**23,546**	13,687	**7,624**	6,670
Donation	**102**	112	**20**	48
Flights and other travel costs	**11,445**	9,862	**(1,377)**	3,761
Other general expenses	**58,152**	14,005	**11,040**	11,986
	261,880	143,538	**52,438**	66,334

Included in the other general expenses are IT\Communications Consumables of ₦13.58 billion (9M 2024: ₦1.4 billion), Contract Labour ₦23.13 billion (9M 2024: ₦4.7 billion), Repairs and Maintenance Expenses of 14.75 billion (9M 2024: ₦0.32 billion) Software License/Maintenance Fees of ₦3.70 billion (9M 2024: ₦1.2 billion) and office/guest house rental of ₦1.6 billion (9M 2024: ₦0.5 billion)

The increase in the general and administrative expenses is driven by the consolidation of the acquired business SEPNU

The decrease in emoluments for Executive and Non-Executive Directors in the current period, when compared to the prior period is attributed to exit payments made to retired Executive and Non-Executive Directors in the prior period .

10.1 Below are details of non-audit services provided by the auditors:

Entity	Service	PwC office	Fees (₦'million)	Year
Seplat Energy Plc	Review of financial information in offering memorandum and provision of comfort letter and opinion on unaudited proforma financial information for $650 million bond issuance	PwC Nigeria	1,639	2025

11. Impairment losses

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024
	₦ million	₦ million	**₦ million**	₦ million
Impairment losses on financial assets-net (Note 11.1)	**(13,654)**	(4,001)	**(8,936)**	(2,419)
	(13,654)	(4,001)	**(8,936)**	(2,419)

11.1 Impairment losses on financial assets - net

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024
	₦ million	₦ million	**₦ million**	₦ million
Impairment (losses)/reversal on:				
NUIMS receivables	**–**	1,139	**258**	897
NEPL receivables	**248**	5,449	**560**	483
Trade receivables (Geregu power, Sapele Power and NGMC)	**(13,516)**	(10,909)	**(9,510)**	(3,747)
Contract asset	**(128)**	–	**14**	—
Other receivables	**(258)**	320	**(258)**	(52)
Total impairment loss	**(13,654)**	(4,001)	**(8,936)**	(2,419)

12. Fair value loss

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024
	₦ million	₦ million	**₦ million**	₦ million
Hedge premium expenses	**(16,088)**	(6,288)	**(4,624)**	(2,319)
Fair value (loss)/gain on derivatives	**(9,119)**	1,565	**(5,617)**	1,730
	(25,207)	(4,723)	**(10,241)**	(589)

Fair value loss on derivatives represents changes in the fair value of hedging receivables charged to profit or loss.

13. Finance income/(cost)

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024
	₦ million	₦ million	**₦ million**	₦ million
Finance income				
Interest income	**12,123**	11,702	**3,848**	4,295
Finance charges				
Interest on debt factoring	**–**	–	**–**	
Interest on loans and borrowings	**(170,790)**	(75,405)	**(55,553)**	(29,472)
Other financing charges	**–**	(4,137)	**–**	(369)
Interest on lease liabilities	**(9,624)**	(1,363)	**(3,180)**	(558)
Unwinding of discount on provision for decommissioning	**(43,071)**	(6,051)	**(14,203)**	(2,440)
	(223,485)	(86,956)	**(72,936)**	(32,839)
Finance cost - net	**(211,362)**	(75,254)	**(69,088)**	(28,544)

Finance income represents interest on short-term fixed deposits.

14. Taxation

The Income tax expense is recognised based on management's estimate of the weighted average effective annual income tax rate expected for the full financial year in line with the requirements of the standard. The annual tax rate used for the nine months ended 30 September 2025 is 85% for crude oil activities and 30% for gas activities.

The major components of income tax expense for the period ended 30 September 2025 and 2024 are:

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024
	₦ million	₦ million	**₦ million**	₦ million
Current tax:				
Current tax expense/(credit) on profit for the period	**704,413**	82,843	**167,579**	(3,311)
Education Tax	**24,546**	14,475	**7,089**	9,718
NASENI Levy	**2,358**	960	**1,129**	308
Police Levy	**51**	15	**23**	4
Total current tax	**731,368**	98,293	**175,820**	6,719
Deferred tax:				
Deferred tax (credit)/expense in profit or loss (Note 14.1)	**982**	215,642	**144,938**	131,228
Total tax expense in statement of profit or loss	**732,350**	313,935	**320,758**	137,947
Total tax charged for the period	**732,350**	313,935	**320,758**	137,947
Effective tax rate	**83 %**	86 %	**76 %**	122 %

The income tax expense of ₦732.4 billion for the interim period includes a current tax charge of ₦731.4 billion and a deferred tax credit of ₦0.98 billion based on the 2025 9M projected effective tax rate (ETR) of 83%. This approach is in line with IAS 34 30c which states: "Income tax expense is recognized in each interim period based on the best estimate of the weighted average annual income tax rate expected for the full financial year. Amounts accrued for income tax expenses in one interim period may have to be adjusted in a subsequent interim period of that financial year if the estimate of the annual income tax rate changes".

The split between current and deferred tax charge was determined using management's estimate of the full year weighted average effective annual income tax rate expected for individual taxable entities within the group.

14.1 Deferred tax

The analysis of deferred tax assets and deferred tax liabilities is as follows:

	Balance as at 1 January 2025	(Charged) / credited to profit or loss	Credited to other comprehensive income	Exchange difference	Balance as at 30 Sept 2025
	₦ million	₦ million	₦ million	₦ million	₦ million
Deferred tax assets	353,954	(11,617)	—	(15,592)	326,745
Deferred tax liabilities	(1,615,677)	10,635	—	73,281	(1,531,761)
	(1,261,723)	(982)	—	57,689	(1,205,016)

In line with the requirements of IAS 12, the Group offset the deferred tax assets against the deferred tax liabilities arising from similar transactions.

15. Computation of cash generated from operations

	Notes	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024
		₦ million	₦ million
Profit before tax		878,989	366,711
Adjusted for:			
Depletion, depreciation and amortisation		564,378	179,258
Depreciation of right-of-use asset		48,669	5,912
Impairment losses on financial assets	11.1	13,654	4,000
Loss on disposal of other property, plant and equipment		–	11,150
Interest income	13	(12,122)	(11,702)
Interest expense on bank loans	13	170,790	79,541
Interest on lease liabilities	13	9,624	1,362
Unwinding of discount on provision for decommissioning	13	43,072	6,053
Unrealised fair value loss/(gain) on derivatives financial instruments	12	9,119	(1,564)
Realised fair value loss on derivatives		16,089	6,288
Unrealised foreign exchange loss/(gain)		8,181	(25,562)
Share based payment expenses		23,546	13,688
Share of loss/(profit) from joint venture		5,855	(30,625)
Defined benefit plan		(7,251)	7,074
Changes in working capital: (excluding the effects of exchange differences)			
Trade and other receivables		233,053	105,443
Inventories		16,150	4,823
Prepayments		48,774	8,613
Contract assets		(52,248)	1,264
Trade and other payables		133,190	(97,970)
Net cash from operating activities		2,151,512	633,757

16. Oil and gas properties

During the nine months ended 30 Sept 2025, the Group acquired assets amounting to ₦275.7 billion (Dec 2024: ₦362.8 billion)

17. Trade and other receivables

	30 Sept 2025	31 Dec 2024
Financial Assets	**₦ million**	₦ million
Trade receivables (Note 17.1)	**389,749**	534,917
NEPL receivables (Note 17.2)	**11,712**	63,615
NUIMS receivables (Note 17.3)	**310,875**	454,571
Receivables from ANOH (Note 17.5)	**4,476**	2,589
Other receivables (Note 17.4)	**67,834**	92,479
Non-financial assets		
Other receivables (Note 17.4)*	**1,989**	961
Underlift	**28,522**	–
Advances to suppliers-others	**54,286**	7,461
	869,443	1,156,593

The Group applies the IFRS 9 simplified approach to measuring expected credit losses which uses a lifetime expected loss allowance for all trade receivables and contract assets while it estimated the expected credit loss on NEPL receivables, NUIMS receivables, Receivables from Anoh and Other receivables by applying the general model.

- The other receivables relates to withholding tax.

17.1 Trade receivables

Included in the trade receivables are:

	30 Sept 2025	31 Dec 2024
Financial Assets	**₦ million**	₦ million
Geregu	**17,964**	18,001
Waltersmith	**5,095**	8,079
Sapele Power	**12,227**	11,271
NGMC	**373**	1,274
MSN ENERGY	**36,243**	25,526
Pillar	**8,216**	7,634
Shell Western	**30,568**	50,503
Azura	**11,109**	3,359
Transcorp Power	**6,347**	2,555
Exxon Mobil	**292,735**	438,326
Others	**12,770**	523
Impairment allowance	**(43,898)**	(32,134)
Total	**389,749**	534,917

Seplat Energy

Reconciliation of trade receivables

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Balance as at 1 January	**567,051**	107,871
Additions during the period	**3,147,730**	1,703,543
Receipt for the period	**(3,429,044)**	(1,393,036)
Acquired from business combination	**–**	141,601
Exchange difference	**147,910**	7,072
Gross carrying amount	**433,647**	567,051
Less: Impairment allowance	**(43,898)**	(32,134)
Balance as at	**389,749**	534,917

Reconciliation of impairment allowance on trade receivables

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Loss allowance as at 1 January	**32,134**	15,130
Increase in loss allowance during the period	**13,516**	14,137
Revaluation impact	**409**	–
Exchange difference	**(2,161)**	2,867
Loss allowance as at	**43,898**	32,134

17.2 NEPL receivables

The outstanding cash calls due to Seplat from its JOA partner, NEPL is ₦12 billion (Dec 2024:₦63.6 billion)

Reconciliation of NEPL receivables

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Balance as at 1 January	**67,954**	116,421
Addition during the period	**384,183**	495,804
Receipts during the period	**(382,020)**	(601,059)
AMT Net-off	**(73,947)**	–
Exchange difference	**19,535**	56,788
Gross carrying amount	**15,705**	67,954
Less: impairment allowance	**(3,993)**	(4,339)
Balance as at	**11,712**	63,615

Reconciliation of impairment allowance on NEPL receivables

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Loss allowance as at 1 January	**4,339**	4,367
Decrease in loss allowance during the period	**(248)**	(2,473)
Foreign exchange revaluation impact	**—**	—
Exchange difference	**(98)**	2,445
Loss allowance as at period end	**3,993**	4,339

17.3 NUIMS receivables

Reconciliation of NUIMS receivables

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Balance as at 1 January	**454,571**	19,099
Addition during the period	**1,052,084**	386,723
Receipts during the period	**(1,250,579)**	(246,960)
Acquired on business combination	**–**	300,562
Exchange difference	**54,799**	(4,853)
Gross carrying amount	**310,875**	454,571
Less: impairment allowance	**–**	–
Balance as at	**310,875**	454,571

Reconciliation of impairment allowance on NUIMS receivables

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Loss allowance as at 1 January	**–**	684
Decrease in loss allowance during the period	**–**	(1,126)
Exchange difference	**–**	442
Loss allowance as at	**–**	–

During the period, the Group have started receiving the legacy cash call from our JV partner in the SEPNU asset and this has resulted in the downward trend in the receivable account.

17.4 Other receivables

Reconciliation of other receivables

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Balance as at 1 January	**173,107**	74,727
Addition during the period	**7,454**	49,908
Receipts for the period	**(15,803)**	(16,491)
Acquired from business combination	**–**	6,583
Exchange difference	**(8,180)**	58,380
Gross carrying amount	**156,578**	173,107
Less: impairment allowance	**(86,755)**	(79,667)
Balance as at period end	**69,823**	93,440

Other receivables includes receivables from 3rd party injectors (tariff income) of ₦15.5 billion, employee receivables of ₦10.9 billion, sundry receivables of ₦4 billion, advances to Belema for OML 55 crude evacuation of ₦5.4 billion, receivable from All Grace for Ubima Disposal of ₦24.1 billion, receivable from Naptha for Abiala Marginal field of ₦4 billion and Pillar Cash Call of ₦14 billion.

Reconciliation of impairment allowance on other receivables

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Loss allowance as at 1 January	**79,667**	48,564
Increase in loss allowance during the period	**258**	9,711
Foreign exchange revaluation impact	**1,212**	—
Exchange difference	**5,618**	21,392
Loss allowance as at	**86,755**	79,667

17.5 Receivables from joint venture (ANOH)

Receivables from joint venture (ANOH)	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Balance as at 1 January	**7,252**	5,992
Additions during the period	**1,537**	775
Receipts for the period	**–**	(616)
Exchange difference	**138**	1,101
Gross carrying amount	**8,927**	7,252
Less: impairment allowance	**(4,451)**	(4,664)
Balance as at period end	**4,476**	2,588

Reconciliation of impairment allowance on receivables from joint venture (ANOH)

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Loss allowance as at 1 January	**4,664**	5,427
Decrease in loss allowance during the period	**–**	(4,433)
Exchange difference	**(213)**	3,670
Loss allowance as at	**4,451**	4,664

18. Contract assets

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Revenue on gas sales	**7,761**	12,622
Revenue on oil sales	**64,956**	11,551
Impairment loss on contract assets	**(365)**	(255)
	72,352	23,918

A contract asset is an entity's right to consideration in exchange for goods or services that the entity has transferred to a customer. The Group has recognised a contract asset in relation to contracts with Sapele Power, Azura, NGMC, Transcorp Power, MSN Energy, Waltersmith and Pillar for the delivery of oil and gas supplies which these customers have received but which have not been invoiced as at the end of the reporting period.

The terms of payments relating to the contract is between 30- 45 days from the invoice date. However, invoices are raised after delivery between 14-21 days when the receivable amount has been established and the right to the receivables crystalises. The right to the unbilled receivables is recognised as a contract asset. At the point where the gas receipt certificates and crude invoices are obtained from the customers (Sapele Power, Azura, NGMC, Transcorp Power, MSN Energy, Waltersmith and Pillar) upon volumes reconciliation with offtakers authorising the quantities, this will be reclassified from contract assets to trade receivables.

18.1 Reconciliation of contract assets

The movement in the Group's contract assets is as detailed below:

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Balance as at 1 January	**24,173**	7,496
Additions during the period	**522,150**	167,015
Amount billed during the period	**(469,926)**	(156,049)
Foreign exchange revaluation impact	**(3,680)**	5,711
Gross contract assets on gas and oil	**72,717**	24,173
Impairment charge	**(365)**	(255)
Balance as at 30 Sept	**72,352**	23,918

Reconciliation of impairment allowance on contract assets

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Loss allowance as at 1 January	**255**	256
Decrease in loss allowance during the period	**(128)**	–
Exchange difference	**238**	(1)
Loss allowance as at	**365**	255

19. Derivative financial instruments

The Group uses its derivatives for economic hedging purposes and not as speculative investments. Derivatives are measured at fair value through profit or loss. They are presented as current liability to the extent they are expected to be settled within 12 months after the reporting period.

The fair value has been determined using a proprietary pricing model which generates results from inputs. The market inputs to the model are derived from observable sources. Other inputs are unobservable but are estimated based on the market inputs or by using other pricing models.

19.1 Derivative financial liabilities

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Opening Balance	**(6,073)**	(1,444)
Reversal of prior period unrealised fair value gain	**5,763**	1,836
Prior year premium paid	**335**	540
Premium Accrued	**–**	(322)
Unrealised fair value loss	**(14,882)**	(5,531)
Exchange difference	**716**	(1,152)
	(14,141)	(6,073)

As at 30 September 2025, the Group entered into economic crude oil hedge contracts with an average strike price of ₦82,493/bbl (Dec 2024: ₦81,382/bbl) for 27 million barrels (Dec 2024: 3 million barrels) at a cost of ₦405.5 billion (Dec 2024: ₦7.6 billion).

19.2 Derivative financial assets

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Opening Balance	**–**	–
Increase in derivative financial assets	**22,100**	–
Exchange difference	**(1,100)**	–
	21,000	–

20. Cash and cash equivalents

Cash and cash equivalents in the statement of financial position comprise of cash at bank, cash on hand and short-term deposits with a maturity of three months or less.

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Short-term fixed deposits	**275**	202,123
Cash at bank	**849,586**	519,638
Gross cash and cash equivalents	**849,861**	721,761
Loss allowance	**(359)**	(376)
Net cash and cash equivalents	**849,502**	721,385

20.1 Reconciliation of impairment allowance on cash and cash equivalents

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Loss allowance as at 1 January	**376**	221
Increase/ (decrease) in loss allowance during the period	**–**	–
Exchange difference	**(17)**	155
Loss allowance as at the end of the period	**359**	376

20.2 Restricted cash

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Restricted cash	**198,412**	202,983
	198,412	202,983

20.3 Movement in restricted cash

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Opening balance	**202,983**	24,311
Increase in restricted cash	**4,948**	155,630
Exchange difference	**(9,519)**	23,042
Closing balance	**198,412**	202,983

Included in the restricted cash is ₦159.6 billion (Dec 2024: ₦159.9 billion), which relates to SEPNU's decommissioning and abandonment deposit, as well as the host community fund.

Also Included in the restricted cash balance is ₦3.6 billion (Dec 2024: ₦3.7 billion) and ₦33.9 billion (Dec 2024: ₦32.8 billion) set aside in the stamping reserve account and debt service reserve account respectively for the revolving credit facility. The stamping reserve amount is to be used for the settlement of all fees and costs payable for the purposes of stamping and registering the Security Documents at the stamp duties office and at the Corporate Affairs Commission (CAC).

A garnishee order of ₦0.8 billion (Dec 2024: ₦0.7 billion is included in the restricted cash balance as at the end of the reporting period.

Also included in the restricted cash balance is ₦0.5 billion (Dec 2024: ₦0.6 billion) for unclaimed dividend.

These amounts are subject to legal restrictions and are therefore not available for general use by the Group.

21. Asset held for sale

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Opening balance	**18,838**	–
Additions	**–**	18,838
Exchange difference	**(860)**	–
Closing balance	**17,978**	18,838

As at the reporting date, the Group has classified certain non-current assets as held for sale. These assets primarily consist of Turnkey rigs and accessories. The assets have been classified as held for sale following the decision by management to sell the assets.

22. Share capital

22.1 Authorised and issued share capital

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Authorised ordinary share capital		
$599,944,561 (Dec 2024: $588,444,561) issued shares denominated in Naira of 50 kobo per share	**303**	297
Issued and fully paid		
599,944,561 (Dec 2024: 588,444,561) issued shares denominated in Naira of 50 kobo per share	**303**	297

Fully paid ordinary shares carry one vote per share and the right to dividends. There were no restrictions on the Group's share capital.

22.2 Movement in share capital and other reserves

	Number of shares Shares	Issued share capital ₦ million	Share premium ₦ million	Share based payment reserve ₦ million	Treasury shares ₦ million	Total ₦ million
Opening balance as at 1 January 2025	**588,444,561**	**297**	**87,375**	**15,558**	**(3,570)**	**99,660**
Vested shares during the period	**–**	**–**	**–**	**(25,728)**	**25,728**	**–**
Share based payments	**–**	**–**	**–**	**18,874**	**–**	**18,874**
Transfer to share based liability*	**–**	**–**	**–**	**(4,888)**	**–**	**(4,888)**
Share repurchased	**–**	**–**	**–**	**–**	**(15,419)**	**(15,419)**
Shares issued	**11,500,000**	**6**	**63,024**	**–**	**(63,030)**	**–**
Closing balance as at 30 Sept 2025	**599,944,561**	**303**	**150,399**	**3,816**	**(56,291)**	**98,227**

22.3 Employee share-based payment scheme

As at 30 September 2025, the Group had 50,537,292 shares (Dec 2024: 53,305,512 shares). which are yet to fully vest. These shares have been assigned to certain employees and senior executives in line with its share-based incentive scheme. During the nine months ended 30 September 2025 13,856,482 shares were vested (Dec 2024: 17,567,776 shares).

*The Group in the current period changed the classification of the 2024 LTIP shares awards to employees below the board level, from equity settled to cash settled share based payment.

22.4 Treasury shares

This relates to shares purchased from the market to fund the Group's Long-Term Incentive Plan. The programme commenced from 1 March 2021 and are held by the Trustees under the Trust for the benefit of the Group's employee beneficiaries covered under the Trust.

23. Interest bearing loans and borrowings

23.1 Reconciliation of interest bearings loans and borrowings

Below is the reconciliation on interest bearing loans and borrowings for 30 September 2025:

	Borrowings within 1 year ₦ million	Borrowings above 1 year ₦ million	Total ₦ million
Balance as at 1 January 2025	**690,270**	**1,409,480**	**2,099,750**
Interest accrued	**170,790**	**–**	**170,790**
Principal paid	**(1,588,563)**	**–**	**(1,588,563)**
Interest repayment	**(140,578)**	**–**	**(140,578)**
Other financing charges	**(63,629)**	**–**	**(63,629)**
Proceeds from loan financing	**1,002,248**	**–**	**1,002,248**
Transfers	**34,453**	**(34,453)**	**–**
Exchange differences	**(2,408)**	**(62,677)**	**(65,085)**
Carrying amount as at 30 Sept 2025	**102,583**	**1,312,350**	**1,414,933**

Below is the reconciliation on interest bearing loans and borrowings for 31 December 2024:

	Borrowings within 1 year ₦ million	Borrowings due above 1 year ₦ million	Total ₦ million
Balance as at 1 January 2024	80,265	599,434	679,699
Additions	517,888	443,904	961,792
Interest accrued	118,896	–	118,896
Borrowing cost capitalized	5,985	–	5,985
Principal paid	(56,981)	–	(56,981)
Interest repayment	(92,504)	–	(92,504)
Other financing charges	(31,775)	–	(31,775)
Transfers	71,692	(71,692)	–
Exchange differences	76,804	437,834	514,638
Carrying amount as at 31 Dec 2024	690,270	1,409,480	2,099,750

Other financing charges include term loan arrangement and commitment fees, annual bank charges, technical bank fee, agency fee and analytical services in connection with annual service charge. These costs do not form an integral part of the effective interest rate. As a result, they are not included in the measurement of the interest-bearing loan.

23.2 Amortised cost of borrowings

	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Senior loan notes	**929,409**	1,009,628
Revolving loan facilities	**–**	15,868
Senior reserve based lending (RBL) facility	**41,810**	78,522
$350 million RCF	**–**	539,722
$300 million advance payment facility	**443,714**	456,010
	1,414,933	2,099,750

$650 million Senior notes

On 21 March 2025, the Group refinanced the $650m notes due 2026 with a new $650m issuance maturing in 2030. The newly issued $650m notes due in 2030 carry a coupon rate of 9.125%, reflecting prevailing global market volatility. The $650 million bond issuance was used exclusively to redeem the maturing $650 million note, with transaction costs covered from the company's cash reserves.The amortised cost for the senior notes as at the reporting period is ₦929 billion (Dec 2024: ₦1,009 billion).

$80 million Senior reserve-based lending (RBL) facility - refinanced facility

On 30 September 2025, the Group, through its subsidiary Westport, successfully completed the refinancing of the Westport RBL Facility. The new facility is an $80M RBL facility with Standard Bank (USD 35 million), Mauritius Commercial Bank (USD 25 million), First City Monument Bank (USD 12 million), and Zenith Bank (USD 8 million). Zenith Bank represents a new participant in this financing.

The refinancing resulted in improved pricing terms, with the facility now carrying a margin of 6.5% for the first three years, increasing to 7.0% from year four onwards should the facility remain drawn. These margins are more favourable than those under the previous senior (8.0% plus a CAS of 0.25%) and junior (10.5% plus a CAS of 0.25%) facilities. The final maturity date is five years from the effective date, with an 18-month moratorium. The amortised cost for the $80 million senior reserve-based lending facility as at the reporting period is ₦41.8 billion.

$50 million Reserved based lending (RBL) facility

The $50M junior offtake facility was fully repaid and cancelled on 25 August 2025. The facility was only drawn to $11M and had a headroom of $37.5M.

$350 million Revolving credit facility

The $350m Seplat RCF was amended and restated on 20 August 2024. The facility has a bullet repayment and incurs a total interest of SOFR (incl. CAS) + 5% margin. Due to the refinancing of the $650m notes that occurred on 21 March 2025, the final maturity of the RCF was automatically extended to 31 December 2026 from 30 June 2025, an extension of 18 months. The RCF was fully drawn for the completion of the MPNU transaction in December 2024, $250m was prepaid on 31 March 2025, and the remaining $100m was prepaid on 28 July 2025. The amortised cost for the RCF as at the reporting period is nil (Dec 2024: ₦539.7 billion).

$300 million Advance payment facility

On 6 December 2024, Seplat Energy Offshore Limited entered into an up to $300m Advance Payment Facility ("APF") with ExxonMobil Financial Investment Company Limited ("EMFICL"), a fully owned subsidiary of ExxonMobil. The APF can be used for general corporate purposes and was used to provide financing in the completion of the MPNU acquisition.

The security package of the APF covers shares in Seplat Energy Offshore Limited ("SEOL") and Seplat Energy Investment Limited ("SEIL"), as well as, security over the onshore collection account and the offshore proceeds account, and an assignment by way of security of SEPNU's rights as seller under the offtake agreement.

The APF is currently fully drawn and will bear interest at a rate of the aggregate of Term SOFR (including a credit adjustment spread of 0.25% per annum) plus 5% per annum. This is the same pricing as our RCF.

Financial covenants under the APF include a forward-looking DSCR of 1.20x, with a cure period of 30 business days.

The amortised cost for the APF as at the reporting period is ₦444 billion (Dec 2024: ₦456 billion) although the principal is ₦459 billion. Final maturity is three years following the date of the agreement, i.e., December 2027. EMFICL concluded the syndication of the APF on 30 May 2025 and four additional bank lenders have entered the financing, namely, First Abu Dhabi Bank ($100M), Standard Bank ($75M), Mauritius Commercial Bank ($50M) and Rand Merchant Bank ($45M).

24. Employee benefit obligation

24.1 Defined benefit plan

During the reporting period, the defined benefit plan was presented as a net plan asset of ₦3.2 billion compared to a net defined benefit liability of (Dec. 2024: ₦76.9 billion) as at year end. This change in position is due to the consolidation of SEPNU's financials where the defined benefit asset stood at ₦16.92 billion as at the end of the current period.

Net defined benefit assets/(liabilities) recognised in the financial position	30 Sept 2025 ₦ million	Movement during the period ₦ million	31 Dec 2024 ₦ million
Present value of defined benefit obligation	**(206,584)**	**(411,621)**	205,037
Fair value of plan assets	**209,779**	**337,916**	(128,137)
	3,195	**(73,705)**	76,900

Movement during the period for the defined benefit assets/(liabilities):	Movement during the period ₦ million
Opening balance	–
Employer contribution	**80,189**
Income on plan asset	**11,888**
Current service cost	**(8,302)**
Exchange differences	**(10,070)**
	73,705

25. Trade and other payables

Financial Liabilities	30 Sept 2025 ₦ million	31 Dec 2024 ₦ million
Trade payable	**616,999**	562,913
Accruals and other payables	**811,499**	865,971
Share based payment liability	**9,560**	–
Non-Financial Liabilities		
NDDC levy	**41,202**	11,716
Royalties payable	**128,144**	174,932
Overlift	**57,374**	69,174
	1,664,778	1,684,706

Included in accruals and other payables are field accruals of ₦418.9 billion (Dec 2024: ₦147.8 billion), deposit received for asset held for sale of ₦15.3 billion (Dec 2024: ₦12.6 billion) and deferred consideration from the business consideration of ₦377.3 billion (Dec 2024: ₦394.5 billion) Royalties payable include accruals in respect of crude oil and gas production for which payment is outstanding at the end of the period.

Overlifts are excess crude lifted above the share of production. It may exist when the crude oil lifted by the Group during the period is above its ownership share of production. Overlifts are initially measured at the market price of oil at the date of lifting and recognised in profit or loss. At each reporting period, overlifts are remeasured at the current market value. The resulting change, as a result of the remeasurement, is also recognised in profit or loss and any amount unpaid at the end of the year is recognised in overlift payable.

26. Earnings per share EPS

Basic

Basic EPS is calculated on the Group's profit after taxation attributable to the parent entity, which is based on the weighted average number of issued and fully paid ordinary shares at the end of the period.

Diluted

Diluted EPS is calculated by dividing the profit after taxation attributable to the parent entity by the weighted average number of ordinary shares outstanding during the period plus all the dilutive potential ordinary shares (arising from outstanding share awards in the share-based payment scheme) into ordinary shares.

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	**3 Months ended 30 Sept 2025**	3 Months ended 30 Sept 2024
	₦ million	₦ million	**₦ million**	₦ million
Profit/(loss) attributable to equity holders of the parent	**141,944**	57,888	**105,347**	2,303
Profit/(loss) attributable to non-controlling interests	**4,695**	(5,112)	**(1,227)**	(17,587)
Profit/(loss) for the period	**146,639**	52,776	**104,120**	(15,284)

	Shares '000	Shares '000	**Shares '000**	Shares '000
Weighted average number of ordinary shares in issue	**591,001**	588,445	**591,001**	588,445
Outstanding share based payments (shares)	**–**	–	**–**	–
Weighted average number of ordinary shares adjusted for the effect of dilution	**591,001**	588,445	**591,001**	588,445

Basic earnings per share for the period	**₦**	₦	**₦**	₦
Basic earnings per share	**240.18**	98.37	**178.25**	3.91
Diluted earnings per share	**240.18**	98.37	**178.25**	3.91
Profit used in determining basic/diluted earnings per share	**141,944**	57,888	**105,347**	2,303

The weighted average number of issued shares was calculated as a proportion of the number of months in which they were in issue during the reporting period.

27. Proposed dividend

For the period ended 30 September 2025, the Group's directors proposed an interim dividend of 5 cents per share and a special dividend of 2.5 cents per share for the reporting period (3Q 2024: 3.6 cents per share).

28. Related party relationships and transactions

There was no related party transactions in the period.

29. Commitments and contingencies

29.1 Contingent liabilities

The Group is involved in a number of legal suits as defendant. The estimated value of the contingent liabilities for the year ended 30 September 2025 is ₦512,183 million, (Dec 2024: ₦724 million). The contingent liability for the year is determined based on possible occurrences, though unlikely to occur. No provision has been made for this potential liability in these financial statements. Management and the Group's solicitors are of the opinion that the Group will suffer no loss from these claims.

30. Events after the reporting period

Subsequent to 30 September 2025 and up to the date of authorisation of the consolidated interim financial statements, there were no events that had a material impact on the Group's financial position or performance, or that require disclosure in these financial statements.

31. Exchange rates used in translating the accounts to Naira

The table below shows the exchange rates used in translating the accounts into Naira

	Basis	30 Sept 2025 N/$	30 Sept 2024 N/$	31 Dec. 2024 N/$
Property, plant & equipment – opening balances	Historical rate	**Historical**	Historical	Historical
Property, plant & equipment – additions	Average rate	**1,541.92**	1,497.05	1,479.68
Property, plant & equipment - closing balances	Closing rate	**1,465.18**	1,601.03	1,535.32
Current assets	Closing rate	**1,465.18**	1,601.03	1,535.32
Current liabilities	Closing rate	**1,465.18**	1,601.03	1,535.32
Equity	Historical rate	**Historical**	Historical	Historical
Income and Expenses:	Overall Average rate	**1,541.92**	1,497.05	1,479.68

Unaudited condensed consolidated interim financial statements for the nine months ended 30 September 2025 (USD)

30 October 2025

Reliable energy,
limitless potential

Condensed consolidated interim statement of profit or loss and other comprehensive income

For the nine months ended 30 September 2025

	Notes	9 months ended 30 Sept 2025 Unaudited $'000	9 months ended 30 Sept 2024 Unaudited $'000	3 Months ended 30 Sept 2025 Unaudited $'000	3 Months ended 30 Sept 2024 Unaudited $'000
Revenue from contracts with customers	7	**2,176,629**	715,339	**778,908**	293,697
Cost of sales	8	**(1,297,176)**	(360,294)	**(384,068)**	(120,118)
Gross profit		**879,453**	355,045	**394,840**	173,579
Other income/ (loss) -net	9	**26,553**	21,431	**(24,454)**	(67,003)
General and administrative expenses	10	**(169,840)**	(95,881)	**(34,731)**	(39,275)
Impairment loss on financial assets - net	11	**(8,855)**	(2,672)	**(5,811)**	(1,512)
Fair value loss	12	**(16,348)**	(3,155)	**(6,694)**	(124)
Operating profit		**710,963**	274,768	**323,150**	65,665
Finance income	13	**7,862**	7,817	**2,524**	2,386
Finance costs	13	**(144,939)**	(58,085)	**(47,822)**	(18,405)
Finance cost - net	13	**(137,077)**	(50,268)	**(45,298)**	(16,019)
Share of (loss)/profit from joint venture accounted for using the equity method		**(3,797)**	20,457	**(699)**	16,365
Profit before taxation		**570,089**	244,957	**277,153**	66,011
Income tax expense	14	**(474,960)**	(209,703)	**(209,447)**	(80,665)
Profit/(loss) for the period		**95,129**	35,254	**67,706**	(14,654)
Attributable to:					
Equity holders of the parent		**92,084**	38,668	**68,481**	(2,093)
Non-controlling interests		**3,045**	(3,414)	**(775)**	(12,561)
		95,129	35,254	**67,706**	(14,654)
Earnings per share for the period					
Basic earnings per share $	26	**0.16**	0.07	**0.12**	—
Diluted earnings per share $	26	**0.16**	0.07	**0.12**	—

The above interim condensed consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

	Notes	9 months ended 30 Sept 2025 Unaudited $'000	9 months ended 30 Sept 2024 Unaudited $'000	3 Months ended 30 Sept 2025 Unaudited $'000	3 Months ended 30 Sept 2024 Unaudited $'000
Profit/(loss) for the period		**95,129**	35,254	**67,706**	(14,654)
Other comprehensive income:					
Total comprehensive income/(loss) for the period (net of tax)		**95,129**	35,254	**67,706**	(14,654)
Attributable to:					
Equity holders of the parent		**92,084**	38,668	**68,481**	(2,093)
Non-controlling interests		**3,045**	(3,414)	**(775)**	(12,561)
		95,129	35,254	**67,706**	(14,654)

The above interim condensed consolidated statement of profit or loss and other comprehensive income should be read in conjunction with the accompanying notes.

Condensed consolidated interim statement of financial position

As at 30 September 2025

	Notes	30 Sept 2025 Unaudited $'000	31 Dec 2024 Audited $'000
Assets			
Non-current assets			
Oil & gas properties		**3,198,083**	3,305,233
Other property, plant and equipment		**170,824**	225,734
Right-of-use assets		**123,403**	129,561
Intangible assets		**229,503**	249,627
Other assets		**90,815**	90,815
Investment accounted for using equity method		**260,218**	244,015
Long-term prepayments		**20,439**	31,276
Deferred tax assets	14.1	**223,007**	230,541
Defined benefit plan	24.1	**2,180**	—
Total non-current assets		**4,318,472**	4,506,802
Current assets			
Inventory		**462,108**	472,582
Trade and other receivables	17	**593,404**	753,321
Prepayments		**13,462**	34,257
Contract assets	18	**49,381**	15,579
Derivative financial assets	19.2	**14,333**	—
Restricted cash	20.2	**135,418**	132,209
Cash and cash equivalents	20	**579,794**	469,862
Total current assets		**1,847,900**	1,877,810
Asset held for sale	21	**12,270**	12,270
Total assets		**6,178,642**	6,396,882
Equity and liabilities			
Equity attributable to shareholders			
Issued share capital	22	**1,868**	1,864
Share premium	22	**559,438**	518,564
Share based payment reserve	22	**28,807**	36,747
Treasury shares	22	**(39,801)**	(5,609)
Capital contribution		**40,000**	40,000
Retained earnings		**1,229,939**	1,233,128
Foreign currency translation reserve		**2,233**	2,233
Non-controlling interest		**18,724**	15,679
Total shareholder's equity		**1,841,208**	1,842,606
Non-current liabilities			
Interest bearing loans and borrowings	23	**895,692**	918,036
Lease liabilities		**51,456**	57,663
Provision for decommissioning obligation		**806,153**	778,221
Deferred tax liability	14.1	**1,045,442**	1,052,339
Defined benefit plan	24.1	**—**	50,087
Total non-current liabilities		**2,798,743**	2,856,346
Current liabilities			
Interest bearing loans and borrowings	23	**70,014**	449,593
Lease liabilities		**21,445**	15,902
Derivative financial liability	19.1	**9,652**	3,955
Trade and other payables	25	**1,136,224**	1,097,297
Other provisions		**3,364**	3,314
Current tax liabilities		**297,992**	127,869
Total current liabilities		**1,538,691**	1,697,930
Total liabilities		**4,337,434**	4,554,276
Total shareholders' equity and liabilities		**6,178,642**	6,396,882

The financial statements of Seplat Energy Plc and its subsidiaries (The Group) for the nine months ended 30 September 2025 were authorised for issue in accordance with a resolution of the Directors on 30 October 2025 and were signed on its behalf by:

U. U. Udoma	**R.T Brown**	**E. Adaralegbe**
FRC/2013/NBA/00000001796	FRC/2014/PRO/DIR/00000017939	FRC/2017/ICAN/006/00000017591
Chairman	Chief Executive Officer	Chief Financial Officer
30 October 2025	30 October 2025	30 October 2025

Condensed consolidated interim statement of changes in equity

For the nine months ended 30 September 2025

	Issued share capital	Share premium	Share based payment reserve	Treasury shares	Capital contribution	Retained earnings	Foreign currency translation reserve	Non-controlling interest	Total equity
	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000	$'000
At 1 January 2024	**1,864**	**520,431**	**34,515**	**(4,286)**	**40,000**	**1,173,450**	**2,816**	**24,237**	**1,793,027**
Profit/(loss) for the period	–	–	–	–	–	38,668	–	(3,414)	35,254
Total comprehensive income/(loss) for the period	**–**	**–**	**–**	**–**	**–**	**38,668**	**–**	**(3,414)**	**35,254**
Transactions with owners in their capacity as owners:									
Dividend paid						(70,613)			(70,613)
Share based payments	–	–	9,143	–	–	–	–	–	9,143
Vested shares	22	15,288	(15,310)	–	–	–	–	–	–
Issued vested shares	(22)	(15,288)	–	15,310	–	–	–	–	–
Shares re-purchased	–	–	–	(19,300)	–	–	–	–	(19,300)
Total	**–**	**–**	**(6,167)**	**(3,990)**	**–**	**(70,613)**	**–**	**–**	**(80,770)**
At 30 Sept 2024 (unaudited)	**1,864**	**520,431**	**28,348**	**(8,276)**	**40,000**	**1,141,505**	**2,816**	**20,823**	**1,747,511**
At 1 January 2025	**1,864**	**518,564**	**36,747**	**(5,609)**	**40,000**	**1,233,128**	**2,233**	**15,679**	**1,842,606**
Profit for the period	**–**	**–**	**–**	**–**	**–**	**92,084**	**–**	**3,045**	**95,129**
Total comprehensive income for the period	**–**	**–**	**–**	**–**	**–**	**92,084**	**–**	**3,045**	**95,129**
Transactions with owners in their capacity as owners:									
Dividend paid	**–**	**–**	**–**	**–**	**–**	**(95,273)**	**–**	**–**	**(95,273)**
Share based payments	**–**	**–**	**12,082**	**–**	**–**	**–**	**–**	**–**	**12,082**
Vested shares	**–**	**–**	**(16,686)**	**16,686**	**–**	**–**	**–**	**–**	**–**
Transfer to share based liability	**–**	**–**	**(3,336)**	**–**	**–**	**–**	**–**		**(3,336)**
Shares repurchased	**–**	**–**	**–**	**(10,000)**	**–**	**–**	**–**	**–**	**(10,000)**
Shares issued	**4**	**40,874**	**–**	**(40,878)**	**–**	**–**	**–**	**–**	**–**
Total	**4**	**40,874**	**(7,940)**	**(34,192)**	**–**	**(95,273)**	**–**	**–**	**(96,527)**
At 30 Sept 2025 (unaudited)	**1,868**	**559,438**	**28,807**	**(39,801)**	**40,000**	**1,229,939**	**2,233**	**18,724**	**1,841,208**

Condensed consolidated interim statement of cash flows

For the nine months ended 30 September 2025

	Notes	9 months ended 30 Sept 2025 $'000	9 months ended 30 Sept 2024 $'000
Cash flows from operating activities			
Cash generated from operations	15	**1,395,374**	423,337
Tax paid		**(304,377)**	(64,044)
Contribution to plan assets	24.1	**(52,006)**	–
Hedge premium paid		**(24,984)**	(4,135)
Restricted cash		**(3,209)**	2,626
Net cash inflows from operating activities		**1,010,798**	357,784
Cash flows from investing activities			
Payment for acquisition of oil and gas properties	16	**(178,818)**	(153,607)
Additional investment in Joint venture		**(20,000)**	–
Proceeds from the disposal of oil and gas properties		**–**	5,359
Proceeds from the disposal of other property plant and equipment		**–**	6,143
Payment for acquisition of other property, plant and equipment		**(1,245)**	(3,428)
Deposit from asset held for sale		**1,400**	–
Receipts from other asset		**–**	10,896
Payment for acquisition of subsidiary*		**(64,251)**	–
Interest received		**7,862**	7,817
Net cash outflows used in investing activities		**(255,052)**	(126,820)
Cash flows from financing activities			
Repayments of loans and borrowings		**(1,030,250)**	(38,509)
Dividend paid		**(95,273)**	(70,613)
Proceeds from loans and borrowings		**650,000**	–
Shares purchased for employees		**(10,000)**	(19,300)
Interest paid on lease liability		**(6,241)**	(910)
Lease payment - principal portion		**(22,397)**	(49)
Payments of other financing charges**		**(41,266)**	(6,947)
Payment of financing charges from the issue of shares		**(114)**	–
Interest paid on loans and borrowings		**(91,171)**	(62,516)
Net cash outflows used in financing activities		**(646,712)**	(198,844)
Net increase in cash and cash equivalents		**109,034**	32,120
Cash and cash equivalents at beginning of the period		**469,862**	450,109
Effects of exchange rate changes on cash and cash equivalents		**898**	(48,370)
Cash and cash equivalents at end of the period	20	**579,794**	433,859

*This relates to the reconciliation settlement paid to Exxon for the acquisition of SEPNU (formerly MPNU).

**Other financing charges of $41.3 million, (2024: $6.9 million) largely relates to the transactional costs incurred on the new $650m bond issued during the period and withholding tax on bond coupon payment ..

Notes to the condensed consolidated interim financial statements

For the nine months ended 30 September 2025

1. Corporate structure and business

Seplat Energy Plc (formerly called Seplat Petroleum Development Company Plc, hereinafter referred to as 'Seplat' or the 'Company'), the parent of the Group, was incorporated on 17 June 2009 as a private limited liability company and re-registered as a public company on 3 October 2014, under the Companies and Allied Matters Act, CAP C20, Laws of the Federation of Nigeria 2004. The Company commenced operations on 1 August 2010. The Company is principally engaged in oil and gas exploration and production and gas processing activities. The Company's registered address is: 16a Temple Road (Olu Holloway), Ikoyi, Lagos, Nigeria..

The Company acquired, pursuant to an agreement for assignment dated 31 January 2010 between the Company, SPDC, TOTAL and AGIP, a 45% participating interest in OML 4, OML 38 and OML 41 located in Nigeria.

On 7 November 2010, Newton Energy Limited ('Newton Energy'), an entity previously beneficially owned by the same shareholders as Seplat, became a subsidiary of the Company. On 1 June 2013, Newton Energy acquired from Pillar Oil Limited ('Pillar Oil') a 40% Participant interest in producing assets: the Umuseti/Igbuku marginal field area located within OPL 283 (the 'Umuseti/Igbuku Fields').

On 27 March 2013, the Group incorporated a subsidiary, MSP Energy Limited. The Company was incorporated for oil and gas exploration and production.

On 11 December 2013, the Group incorporated a new subsidiary, Seplat East Swamp Company Limited with the principal activity of oil and gas exploration and production.

On 11 December 2013, Seplat Gas Company Limited ('Seplat Gas') was incorporated as a private limited liability company to engage in oil and gas exploration and production and gas processing.

On 21 August 2014, the Group incorporated a new subsidiary, Seplat Energy UK Limited (formerly called Seplat Petroleum Development UK Limited). The subsidiary provides technical, liaison and administrative support services relating to oil and gas exploration activities.

In 2015, the Group purchased a 40% participating interest in OML 53, onshore northeastern Niger Delta (Seplat East Onshore Limited), from Chevron Nigeria Ltd for $259.4 million.

In 2017, the Group incorporated a new subsidiary, ANOH Gas Processing Company Limited. The principal activity of the Company is the processing of gas from OML 53 using the ANOH gas processing plant. The Group divested some of its ownership interest in this Company to Nigerian Gas Processing and Transportation Company (NGPTC) which was effective from 18 April 2019, hence this investment qualifies as a joint arrangement and has continued to be recognised as investment in joint venture.

On 16 January 2018, the Group incorporated a subsidiary, Seplat West Limited ('Seplat West'). Seplat West was incorporated to manage the producing assets of Seplat Plc.

On 31 December 2019, Seplat Energy Plc, acquired 100% of Eland Oil and Gas Plc's issued and yet to be issued ordinary shares. Eland is an independent oil and gas company that holds interest in subsidiaries and joint ventures that are into production, development and exploration in West Africa, particularly the Niger Delta region of Nigeria.

On acquisition of Eland Oil and Gas Plc (Eland), the Group acquired indirect interest in existing subsidiaries of Eland.

Eland Oil & Gas (Nigeria) Limited, is a subsidiary acquired through the purchase of Eland and is into exploration and production of oil and gas.

Westport Oil Limited, which was also acquired through purchase of Eland is a financing company.

Elcrest Exploration and Production Company Limited (Elcrest) who became an indirect subsidiary of the Group purchased a 45 percent interest in OML 40 in 2012. Elcrest is a Joint Venture between Eland Oil and Gas (Nigeria) Limited (45%) and Starcrest Nigeria Energy Limited (55%). It has been consolidated because Eland is deemed to have power over the relevant activities of Elcrest to affect variable returns from Elcrest at the date of acquisition by the Group. (See details in Note 4.1.v) The principal activity of Elcrest is exploration and production of oil and gas.

Wester Ord Oil & Gas (Nigeria) Limited, who also became an indirect subsidiary of the Group acquired a 40% stake in a licence, Ubima, in 2014 via a joint operations agreement. The principal activity of Wester Ord Oil & Gas (Nigeria) Limited is exploration and production of oil and gas. In 2022, Wester Ord Oil and Gas (Nigeria) divested it's interest in Ubima.

Other entities acquired through the purchase of Eland are Tarland Oil Holdings Limited (a holding company), Brineland Petroleum Limited (dormant company) and Destination Natural Resources Limited (dormant company).

On 1 January 2020, Seplat Energy Plc transferred its 45% participating interest in OML 4, OML 38 and OML 41 ("transferred assets") to Seplat West Limited. As a result, Seplat ceased to be a party to the Joint Operating Agreement in respect of the transferred assets and became a holding company. Seplat West Limited became a party to the Joint Operating Agreement in respect of the transferred assets and assumed its rights and obligations.

On 20 May 2021, following a special resolution by the Board in view of the Company's strategy of transitioning into an energy Company promoting renewable energy, sustainability, and new energy, the name of the Company was changed from Seplat Petroleum Development Company Plc to Seplat Energy Plc under the Companies and Allied Matters Act 2020.

On 7 February 2022, the Group incorporated a subsidiary, Seplat Energy Offshore Limited. The Company was incorporated for oil and gas exploration and production.

On 5 July 2022, the Group incorporated a subsidiary, Turnkey Drilling Services Limited. The Company was incorporated for the purpose of drilling chemicals, material supply, directional drilling, drilling support services and exploration services.

On 26 April 2023, Seplat Gas Company Limited was changed to Seplat Midstream Company Limited. This subsidiary was incorporated to engage in oil and gas exploration and production and gas processing. The company is yet commence operations.

On 14 June 2023, the Group entered into a joint venture agreement with Pol Gas Limited which birthed Pine Gas Processing Limited. Both parties subscribed to equal proportion of ordinary shares. The Company was incorporated for processing natural gas, storage, marketing, transportation, trading, supply and distribution of natural gas and petroleum products derived from natural gas. The company is yet to commence operations.

On 7 August 2024, the Group incorporated a subsidiary, Seplat Energy Investment Limited. The Company was incorporated for oil and gas exploration and production.

On 12 December 2024, the Group acquired 100% of Mobil Producing Nigeria Unlimited and later changed the name on 19 December 2024 to Seplat Energy Producing Nigeria Unlimited. The Company was acquired for the purpose of oil and gas exploration and production.

The Company together with its subsidiaries as shown below are collectively referred to as the Group.

Subsidiary	Date of incorporation	Country of incorporation and place of business	Percentage holding	Principal activities	Nature of holding
Eland Oil & Gas Limited	28 August 2009	United Kingdom	100%	Holding company	Direct
Eland Oil & Gas (Nigeria) Limited	11 August 2010	Nigeria	100%	Oil and Gas Exploration and Production	Indirect
Elcrest Exploration and Production Nigeria Limited	6 January 2011	Nigeria	45%	Oil and Gas Exploration and Production	Indirect
Westport Oil Limited	8 August 2011	Jersey	100%	Financing	Indirect
Brineland Petroleum Limited	18 February 2013	Nigeria	49%	Dormant	Indirect
MSP Energy Limited	27 March 2013	Nigeria	100%	Oil and Gas exploration and production	Direct
Newton Energy Limited	1 June 2013	Nigeria	99.9%	Oil & gas exploration and production	Direct
Seplat East Swamp Company Limited	11. December 2013	Nigeria	99.9%	Oil & gas exploration and production	Direct
Seplat Midstream Company Limited	11 December 2013	Nigeria	99.9%	Oil and Gas exploration and production and gas processing	Direct
Tarland Oil Holdings Limited	16 July 2014	Jersey	100%	Holding Company	Indirect
Wester Ord Oil and Gas Limited	16 July 2014	Jersey	100%	Holding Company	Indirect
Wester Ord Oil & Gas (Nigeria) Limited	18 July 2014	Nigeria	100%	Oil and Gas Exploration and Production	Indirect
Seplat Energy UK Limited	21 August 2014	United Kingdom	100%	Technical, liaison and administrative support services relating to oil & gas exploration and production	Direct
Seplat East Onshore Limited	12 December 2014	Nigeria	99.9%	Oil & gas exploration and production	Direct
Seplat West Limited	16 January 2018	Nigeria	99.9%	Oil & gas exploration and production	Direct
Seplat Energy Offshore Limited	7 February 2022	Nigeria	100%	Oil and Gas exploration and production	Direct
Turnkey Drilling Services Limited	5 July 2022	Nigeria	100%	Drilling services	Direct
Seplat Energy Investment Limited	07 August , 2024	Nigeria	100%	Oil and Gas exploration and production	Direct
Seplat Energy Producing Nigeria Unlimited	19 December , 2024	Nigeria	100%	Oil and Gas exploration and production	Direct

2. Significant changes in the current accounting period

There are no significant changes in the business during the current reporting period ending 30 Sept 2025.

3. Summary of significant accounting policies

3.1 Introduction to summary of significant accounting policies

This note provides a list of the significant accounting policies adopted in the preparation of these consolidated financial statements. These accounting policies have been applied to all the periods presented, unless otherwise stated. The Consolidated financial statements are for the Group consisting of Seplat Energy Plc and its subsidiaries.

3.2 Basis of preparation

The consolidated financial statements of the Group for the nine months ended 30 September 2025 have been prepared in accordance with International Financial Reporting Standards ("IFRS") and interpretations issued by the IFRS Interpretations Committee (IFRS IC). The financial statements comply with IFRS as issued by the International Accounting Standards Board (IASB). Additional information required by National regulations is included where appropriate.

The financial statements comprise the statement of profit or loss and other comprehensive income, the statement of financial position, the statement of changes in equity, the statement of cash flows and the notes to the financial statements.

The financial statements have been prepared under the going concern and historical cost convention, except for financial instruments measured at fair value on initial recognition, non-current asset held for sale, inventory, derivative financial instruments, and defined benefit plans – plan assets measured at fair value. The financial statements are presented in Nigerian Naira and United States Dollars, and all values are rounded to the nearest million (₦ million) and thousand ($'000) respectively, except when otherwise indicated.

Nothing has come to the attention of the directors to indicate that the Group will not remain a going concern for at least twelve months from the date of these financial statements.

The accounting policies adopted are consistent with those of the previous financial year end, except for the adoption of new and amended standard which are set out below.

3.3 New and amended standards adopted by the Group

The Group applied for the first-time certain standards and amendments, which are effective for annual periods beginning on or after 1 January 2025. The Group has not early adopted any other standard, interpretation or amendment that has been issued but is not yet effective.

a) Lack of exchangeability - Amendments to IAS 21

The amendments to IAS 21 The Effects of Changes in Foreign Exchange Rates specify how an entity should assess whether a currency is exchangeable and how it should determine a spot exchange rate when exchangeability is lacking. The amendments also require disclosure of information that enables users of its financial statements to understand how the currency not being exchangeable into the other currency affects, or is expected to affect, the entity's financial performance, financial position and cash flows.

The amendments are effective for annual reporting periods beginning on or after 1 January 2025. When applying the amendments, an entity cannot restate comparative information.

The amendments did not have a material impact on the Group's financial statements.

3.4 Standards issued but not yet effective

The new and amended standards and interpretations that are issued, but not yet effective, up to the date of issuance of the Group's financial statements are disclosed below. The Group intends to adopt these new and amended standards and interpretations, if applicable, when they become effective. Details of these new standards and interpretations are set out below:

a) Amendments to IFRS 10 and IAS 28: Selection or contribution of assets between an investor or joint venture

The IASB has made limited scope amendments to IFRS 10 Consolidated Financial Statements and IAS 28 Investments in Associates and Joint Ventures.

The amendments clarify the accounting treatment for sales or contribution of assets between an investor and their associates or joint ventures. They confirm that the accounting treatment depends on whether the non-monetary assets sold or contributed to an associate or joint venture constitute a "business' (as defined in IFRS 3 Business Combinations).

Where the non-monetary assets constitute a business, the investor will recognise the full gain or loss on the sale or contribution of assets. If the assets do not meet the definition of a business, the gain or loss is recognised by the investor only to the extent of the other investor's interests in the associate or joint venture. The amendments apply prospectively. There is currently no effective date for this amendment.

b) IFRS 18 - Presentation and Disclosure in Financial Statements

In April 2024, the IASB issued IFRS 18, which replaces IAS 1 Presentation of Financial Statements. IFRS 18 introduces new requirements for presentation within the statement of profit or loss, including specified totals and subtotals. Furthermore, entities are required to classify all income and expenses within the statement of profit or loss into one of five categories: operating, investing, financing, income taxes and discontinued operations, whereof the first three are new.

It also requires disclosure of newly defined management-defined performance measures, subtotals of income and expenses, and includes new requirements for aggregation and disaggregation of financial information based on the identified 'roles' of the primary financial statements (PFS) and the notes.

IFRS 18, and the amendments to the other standards, is effective for reporting periods beginning on or after 1 January 2027, but earlier application is permitted and must be disclosed. IFRS 18 will apply retrospectively.

c) IFRS 19 - Subsidiaries without Public Accountability: Disclosures

In May 2024, the IASB issued IFRS 19, which allows eligible entities to elect to apply its reduced disclosure requirements while still applying the recognition, measurement and presentation requirements in other IFRS accounting standards. To be eligible, at the end of the reporting period, an entity must be a subsidiary as defined in IFRS 10, cannot have public accountability and must have a parent (ultimate or intermediate) that prepares consolidated financial statements, available for public use, which comply with IFRS accounting standards.

IFRS 19 will become effective for reporting periods beginning on or after 1 January 2027, with early application permitted.

d) Classification and Measurement of Financial Instruments—Amendments to IFRS 9 and IFRS 7

The Amendments include:

► A clarification that a financial liability is derecognised on the 'settlement date' and introduce an accounting policy choice (if specific conditions are met) to derecognise financial liabilities settled using an electronic payment system before the settlement date
► Additional guidance on how the contractual cash flows for financial assets with environmental, social and corporate governance (ESG) and similar features should be assessed

► Clarifications on what constitute 'non-recourse features' and what are the characteristics of contractually linked instruments

► The introduction of disclosures for financial instruments with contingent features and additional disclosure requirements for equity instruments classified at fair value through other comprehensive income (OCI)

The Amendments are effective for annual periods starting on or after 1 January 2026. Early adoption is permitted, with an option to early adopt the amendments for classification of financial assets and related disclosures only.

The Group is currently working to identify all impacts the amendments will have on the consolidated and separate financial statements.

e) Contracts Referencing Nature-dependent Electricity – Amendments to IFRS 9 and IFRS 7

In December 2024, the Board issued Contracts Referencing Nature-dependent Electricity (Amendments to IFRS 9 and IFRS 7). The amendments include:

- Clarifying the application of the 'own-use' requirements
- Permitting hedge accounting if these contracts are used as hedging instruments
- Adding new disclosure requirements to enable investors to understand the effect of these contracts on a company's financial performance and cash flows

The amendments will be effective for annual reporting periods beginning on or after 1 January 2026. Early adoption is permitted, but will need to be disclosed..

3.5 Basis of consolidation

The condensed consolidated interim financial statements comprise the financial statements of the Company and its subsidiaries as at 30 September 2025.

This basis of consolidation is the same adopted for the last audited financial statements as at 31 December 2024.

3.6 Functional and presentation currency

Items included in the financial statements are measured using the currency of the primary economic environment in which the Company operates ('the functional currency'), which is the US dollar. The financial statements are presented in Nigerian Naira and the US Dollars.

The Company has chosen to show both presentation currencies and this is allowable by the regulator.

a) Transaction and balances

Foreign currency transactions are translated into the functional currency using the exchange rates at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation of monetary assets and liabilities denominated in foreign currencies at year end are generally recognised in profit or loss. They are deferred in equity if attributable to net investment in foreign operations.

Foreign exchange gains and losses that relate to borrowings are presented in the statement of profit or loss, within finance costs. All other foreign exchange gains and losses are presented in the statement of profit or loss on a net basis within other income or other expenses.

Non-monetary items that are measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was determined. Translation differences on assets and liabilities carried at fair value are reported as part of the fair value gain or loss or other comprehensive income depending on where fair value gain or loss is reported.

b) Group companies

The results and financial position of foreign operations that have a functional currency different from the presentation currency are translated into the presentation currency as follows:

- assets and liabilities for each statement of financial position presented are translated at the closing rate at the date of the reporting date.
- income and expenses for statement of profit or loss and other comprehensive income are translated at average exchange rates (unless this is not - a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case income and expenses are translated at the dates of the transactions), and all resulting exchange differences are recognised in other comprehensive income.
- Equity items for each statement of financial position presented are translated at the historical rates.

On disposal of a foreign operation, the component of other comprehensive income relating to that particular foreign operation is recognised in profit or loss. Goodwill and fair value adjustments arising on the acquisition of a foreign operation are treated as assets and liabilities of the foreign operation and translated at the closing rate.

4. Significant accounting judgements, estimates and assumptions

The preparation of the Group's consolidated historical financial information requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the accompanying disclosures, and the disclosure of contingent liabilities. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

4.1 Judgements

In the process of applying the Group's accounting policies, management has made the following judgements, which have the most significant effect on the amounts recognised in the consolidated historical financial information:

I) OMLs 4, 38 and 41

OMLs 4, 38, 41 are grouped together as a cash generating unit for the purpose of impairment testing. These three OMLs are grouped together because they each cannot independently generate cash flows. They currently operate as a single block sharing resources for generating cash flows. Crude oil and gas sold to third parties from these OMLs are invoiced when the Group has an unconditional right to receive payment.

II) Deferred tax asset

Deferred income tax assets are recognised for tax losses carried forward to the extent that the realisation of the related tax benefit through future taxable profits is probable.

III) Foreign currency translation reserve

The Group has used the CBN rate to translate its Dollar currency to its Naira presentation currency. Management has determined that this rate is available for immediate delivery. If the rate was 10% higher or lower, revenue in Naira would have increased/decreased by ₦335.6 billion (2024: ₦29 billion). See Note 31 for the applicable translation rates.

IV) Consolidation of Elcrest

On acquisition of 100% shares of Eland Oil and Gas Plc, the Group acquired indirect holdings in Elcrest Exploration and Production (Nigeria) Limited. Although the Group has an indirect holding of 45% in Elcrest, Elcrest has been consolidated as a subsidiary for the following basis:

- Eland Oil and Gas Plc has controlling power over Elcrest due to its representation on the board of Elcrest, and clauses contained in the Share Charge agreement and loan agreement which gives Eland the right to control 100% of the voting rights of shareholders.
- Eland Oil and Gas Plc is exposed to variable returns from the activities of Elcrest through dividends and interests.
- Eland Oil and Gas Plc has the power to affect the amount of returns from Elcrest through its right to direct the activities of Elcrest and its exposure to returns.

V) Revenue recognition

Performance obligations

The judgments applied in determining what constitutes a performance obligation will impact when control is likely to pass and therefore when revenue is recognised i.e. over time or at a point in time. The Group has determined that only one performance obligation exists in oil contracts which is the delivery of crude oil to specified ports. Revenue is therefore recognised at a point in time.

For gas contracts, the performance obligation is satisfied through the delivery of a series of distinct goods. Revenue is recognised over time in this situation as gas customers simultaneously receive and consume the benefits provided by the Group's performance. The Group has elected to apply the 'right to invoice' practical expedient in determining revenue from its gas contracts. The right to invoice is a measure of progress that allows the Group to recognise revenue based on amounts invoiced to the customer. Judgement has been applied in evaluating that the Group's right to consideration corresponds directly with the value transferred to the customer and is therefore eligible to apply this practical expedient.

Significant financing component

The Group has entered into an advance payment contract with some of the customers for future crude oil to be delivered. The Group has considered whether the contract contains a financing component and whether that financing component is significant to the contract, including both of the following;

a) The difference, if any, between the amount of promised consideration and cash selling price and;

b) The combined effect of both the following:

- The expected length of time between when the Group transfers the crude to the customer and when payment for the crude is received and;
- The prevailing interest rate in the relevant market.

The advance period is greater than 12 months. In addition, the interest expense accrued on the advance is based on a comparable market rate. Interest expense has therefore been included as part of finance cost.

Transactions with Joint Operating arrangement (JOA) partners

The treatment of underlift and overlift transactions is judgmental and requires a consideration of all the facts and circumstances including the purpose of the arrangement and transaction. The transaction between the Group and its JOA partners involves sharing in the production of crude oil, and for which the settlement of the transaction is non-monetary. The JOA partners have been assessed to be partners not customers. Therefore, shortfalls or excesses below or above the Group's share of production are recognised in other income/ (expenses) - net.

VI Exploration and evaluation assets

The accounting for exploration and evaluation ('E&E') assets require management to make certain judgements and assumptions, including whether exploratory wells have discovered economically recoverable quantities of reserves. Designations are sometimes revised as new information becomes available. If an exploratory well encounters hydrocarbon, but further appraisal activity is required in order to conclude whether the hydrocarbons are economically recoverable, the well costs remain capitalised as long as sufficient progress is being made in assessing the economic and operating viability of the well. Criteria used in making this determination include evaluation of the reservoir characteristics and hydrocarbon properties, expected additional development activities, commercial evaluation and regulatory matters. The concept of 'sufficient progress' is an area of judgement, and it is possible to have exploratory costs remain capitalised for several years while additional drilling is performed or the Group seeks government, regulatory or partner approval of development plans.

VII Segment reporting

Operating segments are reported in a manner consistent with the internal reporting provided to the chief operating decision maker.

The Board of directors has appointed a steering committee which assesses the financial performance and position of the Group and makes strategic decisions. The steering committee, which has been identified as being the chief operating decision maker, consists of the Chief Financial Officer, the General Manager (Finance), the Director (New Energy) and the Senior Financial Reporting Manager.. See further details in note 6.

VIII) Leases

Critical judgements in determining the lease term

In determining the lease term, management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not exercise a termination option. Extension options (or periods after termination options) are only included in the lease term if the lease is reasonably certain to be extended (or not terminated). For leases of warehouses, retail stores and equipment, the following factors are normally the most relevant

- If there are significant penalty payments to terminate (or not extend), the group is typically reasonably certain to extend (or not terminate).
- If any leasehold improvements are expected to have a significant remaining value, the group is typically reasonably certain to extend (or not terminate).
- Otherwise, the group considers other factors including historical lease durations and the costs and business disruption required to replace the leased asset.

Most extension options in offices and vehicles leases have not been included in the lease liability, because the group could replace the assets without significant cost or business disruption.

4.2 Estimates and assumptions

The key assumptions concerning the future and the other key source of estimation uncertainty at the reporting date that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are described below. The Group based its assumptions and estimates on parameters available when the consolidated financial statements were prepared. Existing circumstances and assumptions about future developments may change due to market changes or circumstances arising that are beyond the control of the Group. Such changes are reflected in the assumptions when they occur.

The following are some of the estimates and assumptions made:

I) Defined benefit plans

The cost of the defined benefit retirement plan and the present value of the retirement obligation are determined using actuarial valuations. An actuarial valuation involves making various assumptions that may differ from actual developments in the future. These include the determination of the discount rate, future salary increases, mortality rates and changes in inflation rates.

Due to the complexities involved in the valuation and its long-term nature, a defined benefit obligation is highly sensitive to changes in these assumptions. The parameter most subject to change is the discount rate. In determining the appropriate discount rate, management considers market yield on federal government bonds in currencies consistent with the currencies of the post-employment benefit obligation and extrapolated as needed along the yield curve to correspond with the expected term of the defined benefit obligation.

The rates of mortality assumed for employees are the rates published in 67/70 ultimate tables, published jointly by the Institute and Faculty of Actuaries in the UK.

II. Oil and gas reserves

Proved oil and gas reserves are used in the units of production calculation for depletion as well as the determination of the timing of well closure for estimating decommissioning liabilities and impairment analysis. There are numerous uncertainties inherent in estimating oil and gas reserves. Assumptions that are valid at the time of estimation may change significantly when new information becomes available. Changes in the forecast prices of commodities, exchange rates, production costs or recovery rates may change the economic status of reserves and may ultimately result in the reserves being restated.

III. Share-based payment reserve

Estimating fair value for share-based payment transactions requires determination of the most appropriate valuation model, which depends on the terms and conditions of the grant. This estimate also requires determination of the most appropriate inputs to the valuation model including the expected life of the share award or appreciation right, volatility and dividend yield and making assumptions about them. The Group measures the fair value of equity-settled transactions with employees at the grant date.

The Group makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, seldom equal the related actual results. Such estimates and assumptions are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

IV. Provision for decommissioning obligations

Provisions for environmental clean-up and remediation costs associated with the Group's drilling operations are based on current constructions, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

V. Property, plant and equipment

The Group assesses its property, plant and equipment, including exploration and evaluation assets, for possible impairment if there are events or changes in circumstances that indicate that carrying values of the assets may not be recoverable, or at least at every reporting date.

If there are low oil prices or natural gas prices during an extended period, the Group may need to recognise significant impairment charges. The assessment for impairment entails comparing the carrying value of the cash-generating unit with its recoverable amount, that is, higher of fair value less cost to dispose and value in use. Value in use is usually determined on the basis of discounted estimated future net cash flows. Determination as to whether and how much an asset is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for regional market supply-and-demand conditions for crude oil and natural gas.

The Group uses the higher of the fair value less cost to dispose and the value in use in determining the recoverable amount of the cash-generating unit. In determining the value, the Group uses a forecast of the annual net cash flows over the life of proved plus probable reserves, production rates, oil and gas prices, future costs (excluding (a) future restructuring to which the entity is not yet committed; or (b) improving or enhancing the asset's performance) and other relevant assumptions based on the year-end Competent Persons Report (CPR). The pre-tax future cash flows are adjusted for risks specific to the forecast and discounted using a pre-tax discount rate which reflects both current market assessment of the time value of money and risks specific to the asset.

Management considers whether a reasonable possible change in one of the main assumptions will cause an impairment and believes otherwise.

VI. Useful life of other property, plant and equipment

The Group recognises depreciation on other property, plant and equipment on a straight-line basis in order to write-off the cost of the asset over its expected useful life. The economic life of an asset is determined based on existing wear and tear, economic and technical ageing, legal and other limits on the use of the asset, and obsolescence. If some of these factors were to deteriorate materially, impairing the ability of the asset to generate future cash flow, the Group may accelerate depreciation charges to reflect the remaining useful life of the asset or record an impairment loss.

VII. Income taxes

The Group is subject to income taxes by the Nigerian tax authority, which does not require significant judgement in terms of provision for income taxes, but a certain level of judgement is required for recognition of deferred tax assets. Management is required to assess the ability of the Group to generate future taxable economic earnings that will be used to recover all deferred tax assets. Assumptions about the generation of future taxable profits depend on management's estimates of future cash flows. The estimates are based on the future cash flow from operations taking into consideration the oil and gas prices, volumes produced, operational and capital expenditure.

VIII. Impairment of financial assets

The loss allowances for financial assets are based on assumptions about risk of default, expected loss rates and maximum contractual period. The Group uses judgement in making these assumptions and selecting the inputs to the impairment calculation, based on the Group's past history, existing market conditions as well as forward looking estimates at the end of each reporting period. Details of the key assumptions and inputs used are disclosed in note 5.1.3.

IX. Intangible assets

The contract based intangible assets (licence) were acquired as part of a business combination. They are recognised at their fair value at the date of acquisition and are subsequently amortised on a straight-line bases over their estimated remaining useful lives of the asset. The fair value of contract based intangible assets is estimated using the multi period excess earnings method. This requires a forecast of revenue and all cost projections throughout the useful life of the intangible assets. A contributory asset charge that reflects the return on assets is also determined and applied to the revenue but subtracted from the operating cash flows to derive the pre-tax cash flow. The post-tax cashflows are then obtained by deducting out the tax using the effective tax rate.

Discount rates represent the current market assessment of the risks specific to each CGU, taking into consideration the time value of money. The discount rate calculation is based on the specific circumstances of the Group and its operating segments and is derived from its weighted average cost of capital (WACC). The WACC takes into account both debt and equity. The cost of equity is derived from the expected return on investment by the Group's investors. The cost of debt is based on the interest-bearing borrowings the Group is obliged to service.

X. Inventories

The net realisable value of crude oil and refined products is based on the estimated selling price in the ordinary course of business, less the estimated costs of completion and the estimated costs necessary to make the sale.

5. Financial risk management

5.1 Financial risk factors

The Group's activities expose it to a variety of financial risks such as market risk (including foreign exchange risk, interest rate risk and commodity price risk), credit risk and liquidity risk. The Group's risk management programme focuses on the unpredictability of financial markets and seeks to minimise potential adverse effects on the Group's financial performance. The management of financial risks is carried out by the corporate finance team under policies approved by the Board of Directors. The Board provides written principles for overall risk management, as well as written policies covering specific areas, such as foreign exchange risk, interest rate risk, credit risk and investment of excess liquidity

Risk	Exposure arising from	Measurement	Management
Market risk – foreign exchange	Future commercial transactions Recognised financial assets and liabilities not denominated in US dollars.	Cash flow forecasting Sensitivity analysis	Match and settle foreign denominated cash inflows with the relevant cash outflows to mitigate any potential foreign exchange risk.
Market risk – interest rate	Long term borrowings at variable rate	Sensitivity analysis	None
Market risk – commodity prices	Derivative financial instruments	Sensitivity analysis	Oil price hedges
Credit risk	Cash and bank balances, trade receivables and derivative financial instruments.	Ageing analysis Credit ratings	Diversification of bank deposits
Liquidity risk	Borrowings and other liabilities	Rolling cash flow forecasts	Availability of committed credit lines and borrowing facilities

5.1.1 Credit risk

Credit risk refers to the risk of a counterparty defaulting on its contractual obligations resulting in financial loss to the Group. Credit risk arises from cash and bank balances as well as credit exposures to customers (i.e., Shell western, Pillar, Azura, Geregu Power, Sapele Power, ExxonMobil and Nigerian Gas Marketing Company (NGMC) receivables), and other parties (i.e., NUIMS receivables, NEPL receivables and other receivables)

a) Risk management

The Group is exposed to credit risk from its sale of crude oil to Exxonmobil, Waltersmith, Chevron and Shell western. The Groups's offstake agreements include payment terms ranging from 15 to 30 days post bill of lading date. The Group is exposed to further credit risk from outstanding cash calls from NEPL and NUIMS.

In addition, the Group is exposed to credit risk in relation to the sale of gas to its customers.

The credit risk on cash and bank balances is managed through the diversification of banks in which the balances are held. The risk is limited because the majority of deposits are with banks that have an acceptable credit rating assigned by an international credit agency. The Group's maximum exposure to credit risk due to default of the counterparty is equal to the carrying value of its financial assets.

b) Estimation uncertainty in measuring impairment loss

The table below shows information on the sensitivity of the carrying amounts of the Company's financial assets to the methods, assumptions and estimates used in calculating impairment losses on those financial assets at the end of the reporting period. These methods, assumptions and estimates have a significant risk of causing material adjustments to the carrying amounts of the Group's financial assets.

i. Significant unobservable inputs

The table below demonstrates the sensitivity of the Company's profit before tax to movements in the probability of default (PD) and loss given default (LGD) for financial assets, with all other variables held constant:

Increase/decrease in loss given default	**Effect on profit before tax 30 Sept 2025 $'000**	**Effect on other components of equity before tax 30 Sept 2025 $'000**
+10%	**(264)**	**—**
-10%	**264**	**—**

Increase/decrease in loss given default	Effect on profit before tax 31 Dec 2024 $'000	Effect on other components of equity before tax 31 Dec 2024 $'000
+10%	(141)	—
-10%	141	—

The table below demonstrates the sensitivity of the Group's profit before tax to movements in probabilities of default, with all other variables held constant:

Increase/decrease in probability of default	**Effect on profit before tax 30 Sept 2025 $'000**	**Effect on other components of equity before tax 30 Sept 2025 $'000**
+10%	**(886)**	**—**
-10%	**886**	**—**

Increase/decrease in probability of default	Effect on profit before tax 31 Dec 2024 $'000	Effect on other components of equity before tax 31 Dec 2024 $'000
+10%	(886)	—
-10%	886	—

The table below demonstrates the sensitivity of the Company's profit before tax to movements in the forward-looking macroeconomic indicators, (Brent price and GDP Growth rate) with all other variables held constant:

Increase/decrease in forward looking macroeconomic indicators (Brent price)	Effect on profit before tax 30 Sept 2025 $'000	Effect on other components of equity before tax 30 Sept 2025 $'000
+10%	**(886)**	–
-10%	**886**	–

Increase/decrease in forward looking macroeconomic indicators (GDP Growth rate)	Effect on profit before tax 30 Sept 2025 $'000	Effect on other components of equity before tax 30 Sept 2025 $'000
+10%	**(886)**	–
-10%	**886**	–

Increase/decrease in forward looking macroeconomic indicators (Brent price)	Effect on profit before tax 31 Dec 2024 $'000	Effect on other components of equity before tax 31 Dec 2024 $'000
+10%	(42)	—
-10%	42	—

Increase/decrease in forward looking macroeconomic indicators (GDP Growth rate)	Effect on profit before tax 31 Dec 2024 $'000	Effect on other components of equity before tax 31 Dec 2024 $'000
+10%	(12)	—
-10%	12	—

5.1.2 Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet its financial obligations as they fall due. The Group manages liquidity risk by ensuring that sufficient funds are available to meet its commitments as they fall due.

The Group uses both long-term and short-term cash flow projections to monitor funding requirements for activities and to ensure there are sufficient cash resources to meet operational needs. Cash flow projections take into consideration the Group's debt financing plans and covenant compliance. Surplus cash held is transferred to the treasury department which invests in interest bearing current accounts and time deposits.

The following table details the Group's remaining contractual maturity for its non-derivative financial liabilities with agreed maturity periods. The table has drawn based on the undiscounted cash flows of the financial liabilities based on the earliest date on which the Group can be required to pay.

30 Sept 2025	Effective interest rate %	Less than 1 year $'000	1 – 2 year $'000	2 – 3 years $'000	3 – 5 years $'000	Total $'000
Non-derivatives						
Fixed interest rate borrowings						
$650 million Senior notes	9.125%	59,313	59,313	59,313	738,969	916,908
Variable interest rate borrowings						
Eland Wesport Loan						
The Mauritius Commercial Bank Ltd	6.5% + SOFR	768	1,027	1,030	11,139	13,964
Stanbic IBTC Bank Plc	6.5% + SOFR	691	924	927	10,025	12,567
Standard Bank of South Africa	6.5% + SOFR	384	514	515	5,569	6,982
First City Monument Ltd (FCMB)	6.5% + SOFR	369	493	494	5,347	6,703
Zenith Bank Plc	6.5% + SOFR	246	329	330	3,564	4,469
$300 million Advance Payment Facility (APF)						
ExxonMobil Financing	5% + SOFR + CAS	28,781	28,781	314,391	—	371,953
Total variable interest borrowings		31,239	32,068	317,687	35,644	416,638
Other non-derivatives						
Trade and other payables*		981,485	—	—	—	981,485
Lease liability		20,846	62,538	—	—	83,384
		1,002,331	62,538	—	—	1,064,869
Total		1,092,883	153,919	377,000	774,613	2,398,415

31 December 2024	Effective interest rate %	Less than 1 year $'000	1 – 2 year $'000	2 – 3 years $'000	Total $'000
Non-derivatives					
Fixed interest rate borrowings					
$650 million Senior notes	7.75%	50,375	675,188	—	725,563
Variable interest rate borrowings					
The Mauritius Commercial Bank Ltd	8% + SOFR	15,227	4,086	—	19,313
Stanbic IBTC Bank Plc	8% + SOFR	15,545	4,171	—	19,716
Standard Bank of South Africa	8% + SOFR	8,883	2,384	—	11,267
First City Monument Ltd (FCMB)	8% + SOFR	3,965	1,064	—	5,029
Shell Western Supply & Trading Limited	10.5% + SOFR	1,692	1,692	11,844	15,228
350 million Seplat RCF					
Citibank N.A. London	5% + SOFR+CAS	10,000	—	—	10,000
Nedbank Limited, London Branch	5% + SOFR+CAS	45,000	—	—	45,000
Stanbic Ibtc Bank Plc	5% + SOFR+CAS	50,000	—	—	50,000
The Standard Bank of South Africa Limited		—	—	—	—
RMB International (Mauritius) Limited	5% + SOFR+CAS	65,000	—	—	65,000
The Mauritius Commercial Bank Ltd	5% + SOFR+CAS	45,000	—	—	45,000
JP Morgan Chase Bank, N.A London	5% + SOFR+CAS	30,000	—	—	30,000
Standard Chartered Bank	5% + SOFR+CAS	30,000	—	—	30,000
Natixis		—	—	—	—
Societe Generale Bank, London Branch		—	—	—	—
Zenith Bank Plc	5% + SOFR+CAS	15,000	—	—	15,000
Zenith Bank (UK) Limited	5% + SOFR+CAS	20,000	—	—	20,000
United Bank for Africa Plc	5% + SOFR+CAS	15,000	—	—	15,000
First City Monument Bank Limited	5% + SOFR+CAS	20,000	—	—	20,000
BP	5% + SOFR+CAS	5,000	—	—	5,000
$300 million Advance Payment Facility (ADF)					—
ExxonMobil Financing	5% + SOFR + CAS	29,015	29,015	328,617	386,647
Total variable interest borrowings		424,327	42,412	340,461	807,200
Other non-derivatives					
Trade and other payables*		930,674	—	—	930,674
Lease liability		15,902	—	—	15,902
		946,576	—	—	946,576
Total		1,421,278	717,600	340,461	2,479,339

- Trade and other payables (exclude non-financial liabilities such as provisions, taxes, pension and other non-contractual payables)

5.1.3 Fair value measurements

Set out below is a comparison by category of carrying amounts and fair value of all financial instruments:

	Carrying amount		Fair value	
	30 Sept 2025	31 Dec 2024	**30 Sept 2025**	31 Dec 2024
	$'000	$'000	**$'000**	$'000
Financial assets at amortised cost				
Trade and other receivables*	**535,529**	747,836	**535,529**	747,836
Contract assets	**49,381**	15,579	**49,381**	15,579
Cash and cash equivalents	**579,794**	469,862	**579,794**	469,862
	1,164,704	1,233,277	**1,164,704**	1,233,277
Financial liabilities				
Interest bearing loans and borrowings**	**965,706**	1,367,629	**949,474**	1,355,001
Trade and other payables***	**981,485**	930,674	**981,485**	930,674
	1,947,191	2,298,303	**1,930,959**	2,285,675
Financial liabilities at fair value				
Derivative financial instruments (Note 19)	**(9,652)**	(3,955)	**(9,652)**	(3,955)
	(9,652)	(3,955)	**(9,652)**	(3,955)

* Trade and other receivables exclude underlift, NGMC VAT receivables, cash advances and advance payments.

** In determining the fair value of the interest-bearing loans and borrowings, non-performance risks of the Group as at period-end were assessed to be insignificant.

*** Trade and other payables exclude non-financial liabilities such as taxes, overlift, pension and other non-contractual payables.

Trade and other receivables (excluding prepayments), contract assets and cash and bank balances are financial instruments whose carrying amounts as per the financial statements approximate their fair values. This is mainly due to their short-term nature.

5.1.4 Fair Value Hierarchy

As at the reporting period, the Group had classified its financial instruments into the three levels prescribed under the accounting standards. There were no transfers of financial instruments between fair value hierarchy levels during the period.

- Level 1 – Quoted (unadjusted) market prices in active markets for identical assets or liabilities.
- Level 2 – Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly or indirectly observable.
- Level 3 – Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable.

The fair value of the financial instruments is included at the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The fair value of the Group's derivative financial instruments has been determined using a proprietary pricing model that uses marked to market valuation. The valuation represents the mid-market value and the actual close-out costs of trades involved. The market inputs to the model are derived from observable sources. Other inputs are unobservable but are estimated based on the market inputs or by using other pricing models. The derivative financial instruments are in level 2.

The fair value of the Group's interest-bearing loans and borrowings is determined by using discounted cash flow models that use market interest rates as at the end of the period. The interest-bearing loans and borrowings are in level 2.

The fair value of the property, plant and equipment (oil rig) held for sale is determined using the replacement cost of the asset and the actual values market participants are willing to pay for the asset. These assets are of specialised nature and has been recognised under level 2.

The valuation process

The finance & corporate planning teams of the Group perform the valuations of financial and non-financial assets required for financial reporting purposes, including level 3 fair values. The corporate planning team reports to the Director, Strategy, Planning and Business Development who reports directly to the Chief Executive Officer (CEO). Discussions on the valuation process and results are held between the Director and the valuation team at least twice every year.

6. Segment reporting

Business segments are based on the Group's internal organisation and management reporting structure. The Group's business segments are the two core businesses: Oil and Gas. The Oil segment deals with the exploration, development and production of crude oil while the Gas segment deals with the production and processing of gas. These two reportable segments make up the total operations of the Group.

For the nine months ended 30 September 2025, revenue from the gas segment of the business constituted 8% (2024: 13%) of the Group's revenue. Management is committed to continued growth of the gas segment of the business, including through increased investment to establish additional offices, create a separate gas business operational management team and procure the required infrastructure for this segment of the business. The gas business is positioned separately within the Group and reports directly to the chief operating decision maker. As the gas business segment's revenues, results and cash flows are largely independent of other business units within the Group, it is regarded as a separate segment.The result is two reporting segments, Oil and Gas. There were no inter segment sales during the reporting periods under consideration, therefore all revenue was from external customers.

Amounts relating to the gas segment are determined using the gas cost centres, with the exception of depreciation. Depreciation relating to the gas segment is determined by applying a percentage which reflects the proportion of the Net Book Value of oil and gas properties that relates to gas investment costs (i.e., cost for the gas processing facilities).

The Group accounting policies are also applied in the segment reports.

6.1 Segment profit disclosure

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	**3 Months ended 30 Sept 2025**	3 Months ended 30 Sept 2024
	$'000	$'000	**$'000**	$'000
Oil	**52,116**	(17,825)	**42,113**	(31,513)
Gas	**43,013**	53,079	**25,593**	16,859
Total profit/(loss) for the period	**95,129**	35,254	**67,706**	(14,654)

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	**3 Months ended 30 Sept 2025**	3 Months ended 30 Sept 2024
Oil	**$'000**	$'000	**$'000**	$'000
Revenue from contracts with customers				
Crude oil sales (Note 7)	**2,004,381**	625,157	**711,162**	264,756
Cost of sales and general and administrative expenses	**(1,367,880)**	(441,157)	**(366,860)**	(150,953)
Other income/(loss)	**19,518**	36,583	**(28,145)**	(57,212)
Operating profit before impairment	**656,019**	220,583	**316,157**	56,591
Impairment reversal/(loss)	**856**	4,035	**1,224**	(1,048)
Fair value loss	**(16,348)**	(3,155)	**(6,694)**	(124)
Operating profit	**640,527**	221,463	**310,687**	55,419
Finance income (Note 13)	**7,862**	7,817	**2,524**	2,385
Finance expenses (Note 13)	**(144,939)**	(58,085)	**(47,822)**	(18,404)
Profit before taxation	**503,450**	171,195	**265,389**	39,400
Income tax expense (Note 14)	**(451,334)**	(189,020)	**(223,276)**	(70,913)
Profit/(loss) for the period	**52,116**	(17,825)	**42,113**	(31,513)

Other income in the Oil business largely relates to changes in underlift/overlift in the period.

The increase in the cost of sales and general and administrative expenses in the oil segment is driven mostly by the consolidation of the acquired SEPNU business.

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Gas	9 months ended 30 Sept 2025 $'000	9 months ended 30 Sept 2024 $'000	3 Months ended 30 Sept 2025 $'000	3 Months ended 30 Sept 2024 $'000
Revenue from contracts with customers				
Gas sales	**139,201**	90,182	**44,593**	28,941
Natural gas liquid	**33,047**	–	**23,153**	–
Cost of sales and general and administrative expenses	**(99,136)**	(15,018)	**(51,939)**	(8,440)
Other income/(losses)	**7,035**	(15,152)	**3,691**	(9,791)
Operating profit before impairment	**80,147**	60,012	**19,498**	10,710
Impairment losses	**(9,711)**	(6,707)	**(7,035)**	(464)
Operating profit	**70,436**	53,305	**12,463**	10,246
Share of (loss)/profit from joint venture accounted for using the equity method	**(3,797)**	20,457	**(699)**	16,365
Profit before taxation	**66,639**	73,762	**11,764**	26,611
Income tax (expenses) /credit (Note 14)	**(23,626)**	(20,683)	**13,829**	(9,752)
Profit for the period	**43,013**	53,079	**25,593**	16,859

Other income in the Gas business largely relates to foreign exchange differences in the period.

The increase in the cost of sales and general and administrative expenses in the gas segment is driven mostly by the consolidation of the acquired SEPNU business.

6.1.1 Disaggregation of revenue from contracts with customers

The Group derives revenue from the transfer of commodities at a point in time or over time and from different geographical regions.

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	9 months ended 30 Sept 2024	9 months ended 30 Sept 2024
	Oil	**Gas**	**Natural Gas Liquid**	**Total**	Oil	Gas	Total
	$'000	**$'000**	**$'000**	**$'000**	$'000	$'000	$'000
Geographical markets							
Bahamas	**—**	**—**	**—**	**—**	239,179	—	239,179
Barbados	**—**	**—**	**—**	**—**	36,892	—	36,892
Canada	**72,935**	**—**	**—**	**72,935**	—	—	—
Cote D'Ivoire	**80,664**	**—**	**—**	**80,664**	—	—	—
France	**66,098**	**—**	**—**	**66,098**	—	—	—
Germany	**72,068**	**—**	**—**	**72,068**	—	—	—
Ghana	**—**	**—**	**23,410**	**23,410**	—	—	—
India	**414,795**	**—**	**—**	**414,795**	—	—	—
Indonesia	**206,116**	**—**	**—**	**206,116**	—	—	—
Italy	**131,665**	**—**	**—**	**131,665**	63,132	—	63,132
Kenya	**—**	**—**	**4,943**	**4,943**	—	—	—
Malaysia	**64,110**	**—**	**—**	**64,110**	—	—	—
Netherlands	**168,367**	**—**	**—**	**168,367**	—	—	—
Nigeria	**15,759**	**139,201**	**4,694**	**159,654**	33,704	90,182	123,886
Portugal	**125,044**	**—**	**—**	**125,044**	—	—	—
South Africa	**116,505**	**—**	**—**	**116,505**	—	—	—
Spain	**145,200**	**—**	**—**	**145,200**	—	—	—
Switzerland	**—**	**—**	**—**	**—**	149,540	—	149,540
Turkey	**85,883**	**—**	**—**	**85,883**	—	—	—
UK	**61,926**	**—**	**—**	**61,926**	102,710	—	102,710
Uruguay	**40,794**	**—**	**—**	**40,794**	—	—	—
USA	**134,238**	**—**	**—**	**134,238**	—	—	—
Vietnam	**2,214**	**—**	**—**	**2,214**	—	—	—
Revenue from contracts with customers	**2,004,381**	**139,201**	**33,047**	**2,176,629**	625,157	90,182	715,339

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	9 months ended 30 Sept 2024	9 months ended 30 Sept 2024
	Oil	**Gas**	**Natural Gas Liquid**	**Total**	Oil	Gas	Total
	$'000	**$'000**	**$'000**	**$'000**	$'000	$'000	$'000
Timing of revenue recognition							
At a point in time	**2,004,381**	**—**	**—**	**2,004,381**	625,157	—	625,157
Over time	**—**	**139,201**	**33,047**	**172,248**	—	90,182	90,182
Revenue from contracts with customers	**2,004,381**	**139,201**	**33,047**	**2,176,629**	625,157	90,182	715,339

Seplat Energy

	3 Months ended 30 Sept 2025 Oil $'000	3 Months ended 30 Sept 2025 Gas $'000	3 Months ended 30 Sept 2025 Natural Gas Liquid $'000	3 Months ended 30 Sept 2025 Total $'000	3 Months ended 30 Sept 2024 Oil $'000	3 Months ended 30 Sept 2024 Gas $'000	3 Months ended 30 Sept 2024 Total $'000
Geographical markets							
Bahamas	**—**	**—**	**—**	**—**	111,217	—	111,217
Barbados	**—**	**—**	**—**	**—**	17,952	—	17,952
Canada	**11,179**	**—**	**—**	**11,179**	—	—	—
Cote D'Ivoire	**30,893**	**—**	**—**	**30,893**	—	—	—
England	**—**	**—**	**—**	**—**	—	—	—
Ghana	**—**	**—**	**18,459**	**18,459**	—	—	—
India	**121,746**	**—**	**—**	**121,746**	—	—	—
Indonesia	**80,662**	**—**	**—**	**80,662**	—	—	—
Italy	**2,413**	**—**	**—**	**2,413**	—	—	—
Kenya	**—**	**—**		**—**	—	—	—
Malaysia	**—**	**—**	**—**	**—**	—	—	—
Netherlands	**67,929**	**—**	**—**	**67,929**	—	—	—
Nigeria	**3,589**	**44,593**	**4,694**	**52,876**	6,269	28,941	35,210
Portugal	**72,197**	**—**	**—**	**72,197**	—	—	—
South Africa	**69,790**	**—**	**—**	**69,790**	—	—	—
Spain	**41,865**	**—**	**—**	**41,865**	—	—	—
Switzerland	**—**	**—**	**—**	**—**	77,055	—	77,055
Turkey	**83,660**	**—**	**—**	**83,660**	—	—	
UK	**60,503**	**—**	**—**	**60,503**	52,263	—	52,263
Uruguay	**—**	**—**	**—**	**—**	—	—	—
USA	**64,736**	**—**	**—**	**64,736**	—	—	—
Revenue from contracts with customers	**711,162**	**44,593**	**23,153**	**778,908**	**264,756**	**28,941**	**293,697**

	3 Months ended 30 Sept 2025 Oil $'000	3 Months ended 30 Sept 2025 Gas $'000	3 Months ended 30 Sept 2025 Natural Gas Liquid $'000	3 Months ended 30 Sept 2025 Total $'000	3 Months ended 30 Sept 2024 Oil $'000	3 Months ended 30 Sept 2024 Gas $'000	3 Months ended 30 Sept 2024 Total $'000
Timing of revenue recognition							
At a point in time	**711,162**	**—**	**—**	**711,162**	264,756	—	264,756
Over time	**—**	**44,593**	**23,153**	**67,746**	—	28,941	28,941
Revenue from contracts with customers	**711,162**	**44,593**	**23,153**	**778,908**	**264,756**	**28,941**	**293,697**

The Group's transactions with its major customers, Shell Western, Chevron, and ExxonMobil, constitute about 92% ($1.85 billion), (9M 2024: 20%, $149.5 million) of the total revenue from oil segment and the Group as a whole. Also, the Group's transactions with Geregu Power, Sapele Power, NGMC, MSNE and Azura ($100.9 million) (9M 2024: $90 million) accounted for most of the revenue from the gas segment.

The current period data reflects location of the final buyers based on information extracted from bill of lading, while 2024 data reflected the country of location of the crude oil traders/offtakers.

6.1.2 Impairment (losses)/reversal on financial assets by reportable segments

	9 months ended 30 Sept 2025			9 months ended 30 Sept 2024		
	Oil	**Gas**	**Total**	Oil	Gas	Total
	$'000	**$'000**	**$'000**	$'000	$'000	$'000
Impairment reversal/(losses) recognised during the period	**856**	**(9,711)**	**(8,855)**	4,035	(6,707)	(2,672)

	3 Months ended 30 Sept 2025			3 Months ended 30 Sept 2024		
	Oil	**Gas**	**Total**	Oil	Gas	Total
	$'000	**$'000**	**$'000**	$'000	$'000	$'000
Impairment reversal/(losses) recognised during the period	**1,224**	**(7,035)**	**(5,811)**	(1,048)	(464)	(1,512)

6.2 Segment assets

Segment assets are measured in a manner consistent with that of the financial statements. These assets are allocated based on the operations of the reporting segment and the physical location of the asset. The Group had no non-current assets domiciled outside Nigeria.

	Oil	Gas	Total
Total segment assets	$'000	$'000	$'000
30 September 2025	**5,240,046**	**938,596**	**6,178,642**
31 December 2024	5,695,489	701,393	6,396,882

6.3 Segment liabilities

Segment liabilities are measured in a manner consistent with that of the financial statements. These liabilities are allocated based on the operations of the segment.

	Oil	Gas	Total
Total segment liabilities	$'000	$'000	$'000
30 September 2025	**3,771,258**	**566,176**	**4,337,434**
31 December 2024	4,173,248	381,028	4,554,276

7. Revenue from contract with customers

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	**3 Months ended 30 Sept 2025**	3 Months ended 30 Sept 2024
	$'000	$'000	**$'000**	$'000
Crude oil sales	**2,004,381**	625,157	**711,162**	264,756
Gas sales	**139,201**	90,182	**44,593**	28,941
Natural gas liquid	**33,047**	–	**23,153**	–
	2,176,629	715,339	**778,908**	293,697

The major off-takers for crude oil are Shell West, Chevron and ExxonMobil. The major off-takers for gas are MSN, Sapele Power, Nigerian Gas Marketing Company and Azura. The major off-taker for natural gas liquid is ExxonMobil.

8. Cost of Sales

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	**3 Months ended 30 Sept 2025**	3 Months ended 30 Sept 2024
	$'000	$'000	**$'000**	$'000
Royalties	**381,181**	107,616	**129,169**	36,617
Depletion, depreciation and amortisation	**340,978**	114,094	**23,529**	34,935
Depreciation of right of use assets	**17,351**	–	**1,949**	–
Crude handling fees	**59,230**	49,534	**20,659**	17,746
Nigeria Export Supervision Scheme (NESS) fee	**2,000**	424	**719**	179
Niger Delta Development Commission Levy	**34,822**	6,322	**13,079**	2,115
Barging/Trucking	**20,567**	10,350	**7,029**	2,312
Operational & Maintenance expenses	**441,047**	71,954	**187,935**	26,214
	1,297,176	360,294	**384,068**	120,118

Operational & maintenance expenses relates mainly to maintenance costs, warehouse operations expenses, security expenses, community expenses, clean-up costs, fuel supplies and catering services. Also included in operational and maintenance expenses is gas flare penalty of $36.0 million (9M 2024: $19.9 million). The Group is working through projects in the onshore business to end routine flaring by the end of 2025 and we expect a significant reduction in gas flare penalty from 2026

Barging and Trucking costs relates to costs on the OML 40 Gbetiokun field.

The increase in the cost of sales is largely driven by the consolidation of the acquired business SEPNU.

9. Other income - net

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	**3 Months ended 30 Sept 2025**	3 Months ended 30 Sept 2024
	$'000	$'000	**$'000**	**$'000**
Underlift/(Overlift)	**3,826**	8,206	**(38,765)**	(47,576)
Gain/(loss) on foreign exchange	**11,395**	17,075	**9,678**	(13,229)
Loss on disposal of property, plant & equipment	**–**	(7,448)	**–**	(7,448)
Tariffs	**5,850**	3,137	**2,117**	1,076
Others	**5,482**	461	**2,516**	174
	26,553	21,431	**(24,454)**	(67,003)

Underlifts/(Overlifts) are shortfalls/(surplus) of crude lifted below/(above) the share of production. It may exist when the crude oil lifted by the Group during the period is (more)/less than its ownership share of production. The (surplus)/shortfall is initially measured at the market price of oil at the date of lifting and recognised as other (loss)/income. At each reporting period, the (surplus)/shortfall is remeasured at the current market value. The resulting change, as a result of the remeasurement, is also recognised in profit or loss as other (loss)/income.

Gain/(loss) on foreign exchange is principally due to the translation of Naira, Pounds and Euro denominated monetary assets and liabilities.

Tariffs which is a form of crude handling fee, relate to income generated from the use of the Group's pipeline by others.

Others represents joint venture billing interest and joint venture billing finance fees.

10. General and administrative expenses

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024
	$'000	$'000	**$'000**	$'000
Depreciation and amortisation	**25,045**	5,647	**7,710**	4,157
Depreciation of right of use assets	**14,213**	3,949	**4,841**	1,511
Professional & Consulting Fees	**20,577**	24,855	**11,055**	8,644
Auditor's remuneration	**265**	595	**116**	365
Directors Emoluments (Executives)	**2,318**	3,125	**728**	780
Directors Emoluments (Non - Executives)	**3,132**	3,692	**853**	963
Employee benefits	**43,817**	28,859	**(2,056)**	8,841
Share-based benefits	**15,271**	9,143	**5,000**	3,998
Donation	**66**	75	**14**	32
Flights and other travel costs	**7,422**	6,588	**(849)**	2,114
Other general expenses	**37,714**	9,353	**7,319**	7,870
	169,840	95,881	**34,731**	39,275

Included in the other general expenses are IT\Communications Consumables of $8.81 million (9M 2024: $0.92 million), Contract Labour $15.00 million (9M 2024: $3.10 million), Repairs and Maintenance Expenses of $9.56 million (9M 2024: $0.21 million) Software License/Maintenance Fees of $2.39 million (9M 2024: $0.80 million) and office/guest house rental of $1.03 million (9M 2024: $0.40 million)

The increase in the general and administrative expenses is driven by the consolidation of the acquired business SEPNU

The decrease in emoluments for Executive and Non-Executive Directors in the current period, when compared to the prior period is attributed to exit payments made to retired Executive and Non-Executive Directors in the prior period .

10.1 Below are details of non-audit services provided by the auditors:

Entity	Service	PwC office	Fees ($'000)	Year
Seplat Energy Plc	Review of financial information in offering memorandum and provision of comfort letter and opinion on unaudited proforma financial information for $650 million bond issuance	PwC Nigeria	1,063	2025

11. Impairment losses

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024
	$'000	$'000	**$'000**	$'000
Impairment losses on financial assets-net (Note 11.1)	**(8,855)**	(2,672)	**(5,811)**	(1,512)
	(8,855)	(2,672)	**(5,811)**	(1,512)

11.1 Impairment losses on financial assets - net

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024
	$'000	$'000	**$'000**	$'000
Impairment (losses)/reversal on:				
NUIMS receivables	**—**	761	**167**	583
NEPL receivables	**161**	3,640	**362**	—
Trade receivables (Geregu power, Sapele Power and NGMC)	**(8,766)**	(7,287)	**(6,182)**	(2,036)
Contract assets	**(83)**	–	**9**	—
Other receivables	**(167)**	214	**(167)**	(59)
Total impairment loss	**(8,855)**	(2,672)	**(5,811)**	(1,512)

12. Fair value loss

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024
	$'000	$'000	**$'000**	$'000
Hedge premium expenses	**(10,434)**	(4,200)	**(3,039)**	(1,290)
Fair value (loss)/gain on derivatives	**(5,914)**	1,045	**(3,655)**	1,166
	(16,348)	(3,155)	**(6,694)**	(124)

Fair value loss on derivatives represents changes in the fair value of hedging receivables charged to profit or loss.

13. Finance income/(cost)

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024
	$'000	$'000	**$'000**	$'000
Finance income				
Interest income	**7,862**	7,817	**2,524**	2,386
Finance charges				
Interest on loans and borrowings	**(110,764)**	(50,369)	**(36,426)**	(16,690)
Other financing charges	**–**	(2,763)	**–**	–
Interest on lease liabilities	**(6,241)**	(910)	**(2,084)**	(320)
Unwinding of discount on provision for decommissioning	**(27,934)**	(4,043)	**(9,312)**	(1,395)
	(144,939)	(58,085)	**(47,822)**	(18,405)
Finance cost - net	**(137,077)**	(50,268)	**(45,298)**	(16,019)

Finance income represents interest on short-term fixed deposits.

14. Taxation

The Income tax expense is recognised based on management's estimate of the weighted average effective annual income tax rate expected for the full financial year in line with the requirements of the standard. The annual tax rate used for the nine months ended 30 September 2025 is 85% for crude oil activities and 30% for gas activities.

The major components of income tax expense for the period ended 30 September 2025 and 2024 are:

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	**3 Months ended 30 Sept 2025**	3 Months ended 30 Sept 2024
	$'000	$'000	**$'000**	$'000
Current tax:				
Current tax expense/(credit) on profit for the period	**456,842**	55,339	**110,537**	(7,831)
Education Tax	**15,919**	9,669	**4,657**	6,181
NASENI Levy	**1,529**	641	**736**	163
Police Levy	**33**	10	**15**	2
Total current tax	**474,323**	65,659	**115,945**	(1,485)
Deferred tax:				
Deferred tax (credit)/expense in profit or loss (Note 14.1)	**637**	144,044	**93,502**	82,150
Total tax expense in statement of profit or loss	**474,960**	209,703	**209,447**	80,665
Total tax charged for the period	**474,960**	209,703	**209,447**	80,665
Effective tax rate	**83 %**	86 %	**76 %**	122 %

The income tax expense of $475 million for the interim period includes a current tax charge of $456.8 million and a deferred tax credit of $0.64 million based on the 2025 full year projected effective tax rate (ETR) of 83%. This approach is in line with IAS 34 30c which states: "Income tax expense is recognized in each interim period based on the best estimate of the weighted average annual income tax rate expected for the full financial year. Amounts accrued for income tax expenses in one interim period may have to be adjusted in a subsequent interim period of that financial year if the estimate of the annual income tax rate changes".

The split between current and deferred tax charge was determined using management's estimate of the full year weighted average effective annual income tax rate expected for individual taxable entities within the group.

14.1 Deferred tax

The analysis of deferred tax assets and deferred tax liabilities is as follows:

	Balance as at 1 January 2025	**(Charged) /credited to profit or loss**	**Credited to other comprehensive income**	**Balance as at 30 Sept 2025**
	$'000	**$'000**	**$'000**	**$'000**
Deferred tax assets	230,541	**(7,534)**	**—**	**223,007**
Deferred tax liabilities	(1,052,339)	**6,897**	**—**	**(1,045,442)**
	(821,798)	**(637)**	**—**	**(822,435)**

In line with the requirements of IAS 12, the Group offset the deferred tax assets against the deferred tax liabilities arising from similar transactions.

15. Computation of cash generated from operations

	Notes	9 months ended 30 Sept 2025 $'000	9 months ended 30 Sept 2024 $'000
Profit before tax		**570,089**	244,957
Adjusted for:			
Depletion, depreciation and amortisation		**366,023**	119,741
Depreciation of right-of-use asset		**31,564**	3,949
Impairment losses on financial assets	11.1	**8,855**	2,672
Loss on disposal of other property, plant and equipment		**–**	7,448
Interest income	13	**(7,862)**	(7,817)
Interest expense on bank loans	13	**110,764**	53,132
Interest on lease liabilities	13	**6,241**	910
Unwinding of discount on provision for decommissioning	13	**27,934**	4,043
Unrealised fair value loss/(gain) on derivatives financial instruments	12	**5,914**	(1,045)
Realised fair value loss on derivatives		**10,434**	4,200
Unrealised foreign exchange loss/(gain)		**5,306**	(17,075)
Share based payment expenses		**15,271**	9,143
Share of loss/(profit) from joint venture		**3,797**	(20,457)
Defined benefit plan		**(4,702)**	4,725
Changes in working capital: (excluding the effects of exchange differences)			
Trade and other receivables		**151,145**	70,434
Inventories		**10,474**	3,222
Prepayments		**31,632**	5,753
Contract assets		**(33,885)**	844
Trade and other payables		**86,380**	(65,442)
Net cash from operating activities		**1,395,374**	423,337

16. Oil and gas properties

During the nine months ended 30 Sept 2025, the Group acquired assets amounting to $178.8million (Dec 2024: $245.2 million).

17. Trade and other receivables

	30 Sept 2025 $'000	31 Dec 2024 $'000
Financial Assets		
Trade receivables (Note 17.1)	**266,007**	348,407
NEPL receivables (Note 17.2)	**7,994**	41,434
NUIMS receivables (Note 17.3)	**212,175**	296,075
Receivables from ANOH (Note 17.5)	**3,055**	1,686
Other receivables (Note 17.4)	**46,298**	60,234
Non-financial assets		
Other receivables (Note 17.4)*	**1,358**	626
Underlift	**19,467**	–
Advances to suppliers-others	**37,050**	4,859
	593,404	753,321

The Group applies the IFRS 9 simplified approach to measuring expected credit losses which uses a lifetime expected loss allowance for all trade receivables and contract assets while it estimated the expected credit loss on NEPL receivables, NUIMS receivables, Receivables from Anoh and Other receivables by applying the general model.

- The other receivables relates to withholding tax.

17.1 Trade receivables

Included in the trade receivables are:

	30 Sept 2025 $'000	31 Dec 2024 $'000
Geregu	**12,261**	11,725
Waltersmith	**3,478**	5,262
Sapele Power	**8,345**	7,341
NGMC	**255**	830
MSN ENERGY	**24,736**	16,626
Pillar	**5,607**	4,972
Shell Western	**20,863**	32,894
Azura	**7,582**	2,188
Transcorp Power	**4,332**	1,665
Exxon Mobil	**199,793**	285,495
Others	**8,716**	339
Impairment allowance	**(29,961)**	(20,930)
Total	**266,007**	348,407

Reconciliation of trade receivables

	30 Sept 2025 $'000	31 Dec 2024 $'000
Balance as at 1 January	**369,337**	119,939
Additions during the period	**2,148,356**	1,109,569
Receipt for the period	**(2,223,879)**	(941,444)
Acquired from business combination	**–**	92,229
Exchange difference	**2,154**	(10,956)
Gross carrying amount	**295,968**	369,337
Less: Impairment allowance	**(29,961)**	(20,930)
Balance as at	**266,007**	348,407

Reconciliation of impairment allowance on trade receivables

	30 Sept 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 January	**20,930**	16,822
Increase in loss allowance during the period	**8,766**	9,554
Revaluation impact	**265**	(5,446)
Loss allowance as at	**29,961**	20,930

17.2 NEPL receivables

The outstanding cash calls due to Seplat from its JOA partner, NEPL is $8.0 million (Dec 2024: $41.4 million).

Reconciliation of NEPL receivables

	30 Sept 2025 $'000	31 Dec 2024 $'000
Balance as at 1 January	**44,260**	129,444
Addition during the period	**262,210**	322,932
Receipts during the period	**(247,756)**	(406,209)
AMT Net-off	**(47,958)**	–
Exchange difference	**(37)**	(1,907)
Gross carrying amount	**10,719**	44,260
Less: impairment allowance	**(2,725)**	(2,826)
Balance as at	**7,994**	41,434

Reconciliation of impairment allowance on NEPL receivables

	30 Sept 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 January	**2,826**	4,856
Decrease in loss allowance during the period	**(161)**	(1,671)
Foreign exchange revaluation impact	**60**	(359)
Loss allowance as at period end	**2,725**	2,826

17.3 NUIMS receivables

Reconciliation of NUIMS receivables

	30 Sept 2025 $'000	31 Dec 2024 $'000
Balance as at 1 January	**296,075**	21,236
Addition during the period	**718,058**	251,884
Receipts during the period	**(811,053)**	(166,901)
Acquired on business combination	**–**	196,189
Exchange difference	**9,095**	(6,333)
Gross carrying amount	**212,175**	296,075
Less: impairment allowance	**–**	–
Balance as at	**212,175**	296,075

Reconciliation of impairment allowance on NUIMS receivables

	30 Sept 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 January	**–**	761
Decrease in loss allowance during the period	**–**	(761)
Loss allowance as at	**–**	–

During the period, the Group have started receiving the legacy cash call from our JV partner in the SEPNU asset and this has resulted in the downward trend in the receivable account.

17.4 Other receivables

Reconciliation of other receivables

	30 Sept 2025 $'000	31 Dec 2024 $'000
Balance as at 1 January	**119,118**	83,086
Addition during the period	**5,082**	38,875
Receipts for the period	**(10,249)**	(11,145)
Acquired from business combination	**–**	4,297
Exchange difference	**(7,084)**	4,005
Gross carrying amount	**106,867**	119,118
Less: impairment allowance	**(59,211)**	(58,258)
Balance as at period end	**47,656**	60,860

Other receivables includes receivables from 3rd party injectors (tariff income) of $10.6 million, employee receivables of $7.5 million, sundry receivables of $2.7 million, advances to Belema for OML 55 crude evacuation of $3.7 million, receivable from All Grace for Ubima Disposal of $16.5 million, receivable from Naptha for Abiala Marginal field of $2.7 million and Pillar Cash Call of $9.5 million.

Reconciliation of impairment allowance on other receivables

	30 Sept 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 January	**58,258**	53,996
Increase in loss allowance during the period	**167**	6,563
Foreign exchange revaluation impact	**786**	(2,301)
Loss allowance as at	**59,211**	58,258

17.5 Receivables from joint venture (ANOH)

Receivables from joint venture (ANOH)	30 Sept 2025 $'000	31 Dec 2024 $'000
Balance as at 1 January	**4,724**	6,662
Additions during the period	**1,050**	505
Receipts for the period	**–**	(416)
Exchange difference	**319**	(2,027)
Gross carrying amount	**6,093**	4,724
Less: impairment allowance	**(3,038)**	(3,038)
Balance as at period end	**3,055**	1,686

Reconciliation of impairment allowance on receivables from joint venture (ANOH)

	30 Sept 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 January	**3,038**	6,034
Decrease in loss allowance during the period	**–**	(2,996)
Loss allowance as at	**3,038**	3,038

18. Contract assets

	30 Sept 2025 $'000	31 Dec 2024 $'000
Revenue on gas sales	**5,297**	8,221
Revenue on oil sales	**44,333**	7,524
Impairment loss on contract assets	**(249)**	(166)
	49,381	15,579

A contract asset is an entity's right to consideration in exchange for goods or services that the entity has transferred to a customer. The Group has recognised a contract asset in relation to contracts with Sapele Power, Azura, NGMC, Transcorp Power, MSN Energy, Waltersmith and Pillar for the delivery of oil and gas supplies which these customers have received but which have not been invoiced as at the end of the reporting period.

The terms of payments relating to the contract is between 30- 45 days from the invoice date. However, invoices are raised after delivery between 14-21 days when the receivable amount has been established and the right to the receivables crystalises. The right to the unbilled receivables is recognised as a contract asset. At the point where the gas receipt certificates and crude invoices are obtained from the customers (Sapele Power, Azura, NGMC, Transcorp Power, MSN Energy, Waltersmith and Pillar) upon volumes reconciliation with offtakers authorising the quantities, this will be reclassified from contract assets to trade receivables.

18.1 Reconciliation of contract assets

The movement in the Group's contract assets is as detailed below:

	30 Sept 2025 $'000	31 Dec 2024 $'000
Balance as at 1 January	**15,745**	8,334
Additions during the period	**338,636**	112,872
Amount billed during the period	**(304,767)**	(105,461)
Foreign exchange revaluation impact	**16**	–
Gross contract assets on gas and oil	**49,630**	15,745
Impairment charge	**(249)**	(166)
Balance as at 30 Sept	**49,381**	15,579

Reconciliation of impairment allowance on contract assets

	30 Sept 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 January	**166**	285
Increase/(decrease) in loss allowance during the period	**83**	(119)
Loss allowance as at	**249**	166

19. Derivative financial instruments

The Group uses its derivatives for economic hedging purposes and not as speculative investments. Derivatives are measured at fair value through profit or loss. They are presented as current liability to the extent they are expected to be settled within 12 months after the reporting period.

The fair value has been determined using a proprietary pricing model which generates results from inputs. The market inputs to the model are derived from observable sources. Other inputs are unobservable but are estimated based on the market inputs or by using other pricing models.

19.1 Derivative financial liabilities

	30 Sept 2025 $'000	31 Dec 2024 $'000
Opening Balance	**(3,955)**	(1,606)
Reversal of prior period unrealised fair value gain	**3,738**	1,241
Prior year premium paid	**217**	365
Premium Accrued	**–**	(217)
Unrealised fair value loss	**(9,652)**	(3,738)
	(9,652)	(3,955)

As at 30 September 2025, the Group entered into economic crude oil hedge contracts with an average strike price of $53.5/bbl (Dec 2024: $55/bbl) for 27 million barrels (Dec 2024: 3 million barrels) at a cost of $263 million (Dec 2024: $4.9 million).

19.2 Derivative financial assets

	30 Sept 2025 $'000	31 Dec 2024 $'000
Opening Balance	**–**	–
Increase in derivative financial assets	**14,333**	–
	14,333	–

20. Cash and cash equivalents

Cash and cash equivalents in the statement of financial position comprise of cash at bank, cash on hand and short-term deposits with a maturity of three months or less.

	30 Sept 2025 $'000	31 Dec 2024 $'000
Short-term fixed deposits	**188**	131,649
Cash at bank	**579,851**	338,458
Gross cash and cash equivalents	**580,039**	470,107
Loss allowance	**(245)**	(245)
Net cash and cash equivalents	**579,794**	469,862

20.1 Reconciliation of impairment allowance on cash and cash equivalents

	30 Sept 2025 $'000	31 Dec 2024 $'000
Loss allowance as at 1 January	**245**	245
Increase/ (decrease) in loss allowance during the period	**–**	–
Loss allowance as at the end of the period	**245**	245

20.2 Restricted cash

	30 Sept 2025 $'000	31 Dec 2024 $'000
Restricted cash	**135,418**	132,209
	135,418	132,209

20.3 Movement in restricted cash

	30 Sept 2025 $'000	31 Dec 2024 $'000
Opening balance	**132,209**	27,031
Increase in restricted cash	**3,209**	105,178
Closing balance	**135,418**	132,209

Included in the restricted cash is $108.9 million (Dec 2024: $104.1 million), which relates to SEPNU's decommissioning and abandonment deposit, as well as the host community fund.

Also Included in the restricted cash balance is $2.4 million (Dec 2024: $2.4 million) and $23.2 million (Dec 2024: $21.4 million) set aside in the stamping reserve account and debt service reserve account respectively for the revolving credit facility. The stamping reserve amount is to be used for the settlement of all fees and costs payable for the purposes of stamping and registering the Security Documents at the stamp duties office and at the Corporate Affairs Commission (CAC).

A garnishee order of $0.5 million (Dec 2024: $0.5 million) is included in the restricted cash balance as at the end of the reporting period.

Also included in the restricted cash balance is $0.4 million (Dec 2024: $0.4 million) for unclaimed dividend.

These amounts are subject to legal restrictions and are therefore not available for general use by the Group.

21. Asset held for sale

	30 Sept 2025 $'000	31 Dec 2024 $'000
Opening balance	**12,270**	–
Addition	**–**	12,270
Closing balance	**12,270**	12,270

As at the reporting date, the Group has classified certain non-current assets as held for sale. These assets primarily consist of Turnkey rigs and accessories. The assets have been classified as held for sale following the decision by management to sell the assets.

22. Share capital

22.1 Authorised and issued share capital

	30 Sept 2025 $'000	31 Dec 2024 $'000
Authorised ordinary share capital		
599,944,561 (Dec 2024: 588,444,561) ordinary shares denominated in Naira of 50 kobo per share	**1,868**	1,864
Issued and fully paid		
599,944,561 (Dec 2024: 588,444,561) issued shares denominated in Naira of 50 kobo per share	**1,868**	1,864

Fully paid ordinary shares carry one vote per share and the right to dividends. There were no restrictions on the Group's share capital.

22.2 Movement in share capital and other reserves

	Number of shares Shares	Issued share capital $'000	Share premium $'000	Share based payment reserve $'000	Treasury shares $'000	Total $'000
Opening balance as at 1 January 2025	**588,444,561**	**1,864**	**518,564**	**36,747**	**(5,609)**	**551,566**
Vested shares during the period	**–**	**–**	**–**	**(16,686)**	**16,686**	**–**
Share based payments	**–**	**–**	**–**	**12,082**	**–**	**12,082**
Transfer to share based liability*				**(3,336)**		**(3,336)**
Share repurchased	**–**	**–**	**–**	**–**	**(10,000)**	**(10,000)**
Shares issued	**11,500,000**	**4**	**40,874**	**–**	**(40,878)**	**–**
Closing balance as at 30 Sept 2025	**599,944,561**	**1,868**	**559,438**	**28,807**	**(39,801)**	**550,312**

22.3 Employee share-based payment scheme

As at 30 September 2025, the Group had 50,537,292 shares (Dec 2024: 53,305,512 shares). which are yet to fully vest. These shares have been assigned to certain employees and senior executives in line with its share-based incentive scheme. During the nine months ended 30 September 2025, 13,856,482 shares were vested (Dec 2024: 17,567,776 shares).

*The Group in the current period changed the classification of the 2024 LTIP shares awards to employees below the board level, from equity settled to cash settled share based payment.

22.4 Treasury shares

This relates to shares purchased from the market to fund the Group's Long-Term Incentive Plan. The programme commenced from 1 March 2021 and are held by the Trustees under the Trust for the benefit of the Group's employee beneficiaries covered under the Trust.

23. Interest bearing loans and borrowings

23.1 Reconciliation of interest bearings loans and borrowings

Below is the reconciliation on interest bearing loans and borrowings for 30 September 2025:

	Borrowings within 1 year	Borrowings above 1 year	Total
	$'000	$'000	$'000
Balance as at 1 January 2025	**449,593**	**918,036**	**1,367,629**
Interest accrued	**110,764**	**–**	**110,764**
Principal paid	**(1,030,250)**	**–**	**(1,030,250)**
Interest repayment	**(91,171)**	**–**	**(91,171)**
Other financing charges	**(41,266)**	**–**	**(41,266)**
Proceeds from loan financing	**650,000**	**–**	**650,000**
Transfers	**22,344**	**(22,344)**	**–**
Carrying amount as at 30 Sept 2025	**70,014**	**895,692**	**965,706**

Below is the reconciliation on interest bearing loans and borrowings for 31 December 2024:

	Borrowings within 1 year	Borrowings above 1 year	Total
	$'000	$'000	$'000
Balance as at 1 January 2024	89,244	666,487	755,731
Additions	350,000	300,000	650,000
Interest accrued	80,352	–	80,352
Borrowing cost capitalized	4,045	–	4,045
Principal paid	(38,509)	–	(38,509)
Interest repayment	(62,516)	–	(62,516)
Other financing charges	(21,474)	–	(21,474)
Transfers	48,451	(48,451)	–
Carrying amount as at 31 Dec 2024	449,593	918,036	1,367,629

Other financing charges include term loan arrangement and commitment fees, annual bank charges, technical bank fee, agency fee and analytical services in connection with annual service charge. These costs do not form an integral part of the effective interest rate. As a result, they are not included in the measurement of the interest-bearing loan.

23.2 Amortised cost of borrowings

	30 Sept 2025	31 Dec 2024
	$'000	$'000
Senior loan notes	**634,331**	657,601
Revolving loan facilities	**–**	10,335
Senior reserve based lending (RBL) facility	**28,536**	51,143
$350 million RCF	**–**	351,537
$300 million advance payment facility	**302,839**	297,013
	965,706	1,367,629

$650 million Senior notes

On 21 March 2025, the Group refinanced the $650m notes due 2026 with a new $650m issuance maturing in 2030. The newly issued $650m notes due in 2030 carry a coupon rate of 9.125%, reflecting prevailing global market volatility. The $650 million bond issuance was used exclusively to redeem the maturing $650 million note, with transaction costs covered from the company's cash reserves. The amortised cost for the senior notes as at the reporting period is $634 million (Dec 2024: $657.6 million).

$80 million Senior reserve-based lending (RBL) facility – refinanced facility

On 30 September 2025, the Group, through its subsidiary Westport, successfully completed the refinancing of the Westport RBL Facility. The new facility is an $80M RBL facility with Standard Bank (USD 35 million), Mauritius Commercial Bank (USD 25 million), First City Monument Bank (USD 12 million), and Zenith Bank (USD 8 million). Zenith Bank represents a new participant in this financing.

The refinancing resulted in improved pricing terms, with the facility now carrying a margin of 6.5% for the first three years, increasing to 7.0% from year four onwards should the facility remain drawn. These margins are more favourable than those under the previous senior (8.0% plus a CAS of 0.25%) and junior (10.5% plus a CAS of 0.25%) facilities. The final maturity date is five years from the effective date, with an 18-month moratorium. The amortised cost for the senior notes as at the reporting period is $28.5 million.

$50 million Reserved based lending (RBL) facility

The $50M junior offtake facility was fully repaid and cancelled on 25 August 2025. The facility was only drawn to $11M and had a headroom of $37.5M.

$350 million Revolving credit facility

The $350m Seplat RCF was amended and restated on 20 August 2024. The facility has a bullet repayment and incurs a total interest of SOFR (incl. CAS) + 5% margin. Due to the refinancing of the $650m notes that occurred on 21 March 2025, the final maturity of the RCF was automatically extended to 31 December 2026 from 30 June 2025, an extension of 18 months. The RCF was fully drawn for the completion of the MPNU transaction in December 2024, $250m was prepaid on 31 March 2025, and the remaining $100m was prepaid on 28 July 2025. The amortised cost for the RCF as at the reporting period is nil (Dec 2024: $351.5 million).

$300 million Advance payment facility

On 6 December 2024, Seplat Energy Offshore Limited entered into an up to $300m Advance Payment Facility ("APF") with ExxonMobil Financial Investment Company Limited ("EMFICL"), a fully owned subsidiary of ExxonMobil. The APF can be used for general corporate purposes and was used to provide financing in the completion of the MPNU acquisition.

The security package of the APF covers shares in Seplat Energy Offshore Limited ("SEOL") and Seplat Energy Investment Limited ("SEIL"), as well as, security over the onshore collection account and the offshore proceeds account, and an assignment by way of security of SEPNU's rights as seller under the offtake agreement.

The APF is currently fully drawn and will bear interest at a rate of the aggregate of Term SOFR (including a credit adjustment spread of 0.25% per annum) plus 5% per annum. This is the same pricing as our RCF.

Financial covenants under the APF include a forward-looking DSCR of 1.20x, with a cure period of 30 business days.

The amortised cost for the APF as at the reporting period is $303 million, (Dec 2024: $297 million) although the principal is $300 million. Final maturity is three years following the date of the agreement, i.e., December 2027. EMFICL concluded the syndication of the APF on 30 May 2025 and four additional bank lenders have entered the financing, namely, First Abu Dhabi Bank ($100M), Standard Bank ($75M), Mauritius Commercial Bank ($50M) and Rand Merchant Bank ($45M).

Seplat Energy

24. Employee benefit obligation

24.1 Defined benefit plan

During the reporting period, the defined benefit plan was presented as a net plan asset of $2.2 million, compared to a net defined benefit liability of (Dec. 2024: $50.1 million) as at year end. This change in position is due to the consolidation of SEPNU's financials where the defined benefit asset stood at $11.5 million, as at the end of the current period.

Net defined benefit assets/(liabilities) recognised in the financial position	**30 Sept 2025 $'000**	**Movement $'000**	31 Dec 2024 $'000
Present value of defined benefit obligation	**(140,996)**	**(7,449)**	(133,547)
Fair value of plan assets	**143,176**	**59,716**	83,460
	2,180	**52,267**	(50,087)

Movement during the period for the defined benefit assets/(liabilities):	**30 Sept 2025 $'000**
Opening balance	**–**
Employer contribution	**52,006**
Income on plan asset	**7,710**
Current service cost	**(5,384)**
Exchange differences	**(2,065)**
	52,267

25. Trade and other payables

Financial Liabilities	**30 Sept 2025 $'000**	31 Dec 2024 $'000
Trade payable	**421,108**	366,642
Accruals and other payables	**553,852**	564,032
Share based payment liability	**6,525**	–
Non-Financial Liabilities		
NDDC levy	**28,121**	7,630
Royalties payable	**87,460**	113,938
Overlift	**39,158**	45,055
	1,136,224	1,097,297

Included in accruals and other payables are field accruals of $286.5 million (Dec 2024:$96.3 million), deposit received for asset held for sale of $9.9 million (Dec 2024: $8.5 million) and deferred consideration from the business combination of $257.5 million (Dec 2024: $257.5 million). Royalties payable include accruals in respect of crude oil and gas production for which payment is outstanding at the end of the period. Overlifts are excess crude lifted above the share of production. It may exist when the crude oil lifted by the Group during the period is above its ownership share of production. Overlifts are initially measured at the market price of oil at the date of lifting and recognised in profit or loss. At each reporting period, overlifts are remeasured at the current market value. The resulting change, as a result of the remeasurement, is also recognised in profit or loss and any amount unpaid at the end of the year is recognised in overlift payable.

26. Earnings per share EPS

Basic

Basic EPS is calculated on the Group's profit after taxation attributable to the parent entity, which is based on the weighted average number of issued and fully paid ordinary shares at the end of the period.

Diluted

Diluted EPS is calculated by dividing the profit after taxation attributable to the parent entity by the weighted average number of ordinary shares outstanding during the period plus all the dilutive potential ordinary shares (arising from outstanding share awards in the share-based payment scheme) into ordinary shares.

	9 months ended 30 Sept 2025	9 months ended 30 Sept 2024	3 Months ended 30 Sept 2025	3 Months ended 30 Sept 2024
	$'000	$'000	$'000	$'000
Profit/(loss) attributable to equity holders of the parent	**92,084**	38,668	**68,481**	(2,093)
Profit/(loss) attributable to non-controlling interests	**3,045**	(3,414)	**(775)**	(12,561)
Profit/(loss) for the period	**95,129**	35,254	**67,706**	(14,654)

	Shares '000	Shares '000	Shares '000	Shares '000
Weighted average number of ordinary shares in issue	**591,001**	588,445	**591,001**	588,445
Outstanding share based payments (shares)	**–**	–	**–**	
Weighted average number of ordinary shares adjusted for the effect of dilution	**591,001**	588,445	**591,001**	588,445

Basic earnings per share for the period	$	$	$	$
Basic earnings per share	**0.16**	0.07	**0.12**	–
Diluted earnings per share	**0.16**	0.07	**0.12**	–
Profit used in determining basic/diluted earnings per share	**92,084**	38,668	**68,481**	(2,093)

The weighted average number of issued shares was calculated as a proportion of the number of months in which they were in issue during the reporting period.

27. Proposed dividend

For the period ended 30 September 2025, the Group's directors proposed an interim dividend of 5 cents per share and a special dividend of 2.5 cents per share for the reporting period (3Q 2024: 3.6 cents per share)

28. Related party relationships and transactions

There was no related party transactions in the period.

29. Commitments and contingencies

29.1 Contingent liabilities

The Group is involved in a number of legal suits as defendant. The estimated value of the contingent liabilities for the year ended 30 Sept 2025 is $349.57 million, (Dec 2024: $0.47 million). The contingent liability for the year is determined based on possible occurrences, though unlikely to occur. No provision has been made for this potential liability in these financial statements. Management and the Group's solicitors are of the opinion that the Group will suffer no loss from these claims.

30. Events after the reporting period

Subsequent to 30 September 2025 and up to the date of authorisation of the consolidated interim financial statements, there were no events that had a material impact on the Group's financial position or performance, or that require disclosure in these financial statements