

TULLOW OIL PLC - 2025 FULL YEAR RESULTS

Significant foundations laid in 2025, including comprehensive refinancing

Operational focus yielding strong performance in the first quarter of 2026

Significant opportunities for value creation through operational delivery and oil price leverage

28 April 2026 – Tullow Oil plc (Tullow), the independent oil and gas exploration and production group (Group), announces its Full Year Results for the year ended 31 December 2025. Details of a management presentation and webcast that will be held at 09:00 today are available on the [last page](#) of this announcement or visit the Group's website: www.tulloil.com

Ian Perks, Chief Executive Officer, Tullow Oil plc, commented:

“Throughout 2025 and into early 2026, we have delivered against a clear set of strategic priorities to position Tullow for long-term success. This began with the consolidation of our business to focus on our high-value assets in Ghana, with the sale of our non-core assets in Gabon and Kenya, alongside significant cost reductions. These efforts positioned the company strongly for the successful refinancing, which completed earlier this month with overwhelming support from our creditors. This transaction provides Tullow with the strong financial foundation and flexibility required to deliver value for stakeholders.

“Operationally, 2026 has started strongly, with momentum building across the business. We are particularly encouraged by the positive early results from our Ghana drilling campaign, which highlight the quality and potential of our world-class assets. A key milestone has been the agreement to purchase the TEN FPSO, a value-accretive acquisition that significantly improves the field's economics by eliminating lease costs and providing an opportunity to capture operating cost savings. Additionally extending the Jubilee and TEN petroleum agreements to 2040, and higher oil prices have further strengthened our platform for sustainable growth.

“Looking ahead, we have four more wells scheduled to come onstream in 2026, and the continued interpretation of 4D and Ocean Bottom Node (OBN) seismic data which will support future drilling campaigns at Jubilee and TEN, driving reserves growth and unlocking further value from our assets. Our focus remains on improving operational performance and executing our business plan.”

2025 FULL YEAR RESULTS¹

- Group working interest oil and gas production averaged 40.4 kboepd (2024: 51.5 kboepd).
- Revenue of \$847 million (2024: \$1,287 million), including \$19 million hedge costs (2024: \$74 million).
- Capital expenditure² of \$166 million (excluding \$29 million in Gabon) (2024: \$179 million, excluding \$52 million in Gabon) and decommissioning expenditure including cash provisioning for future decommissioning of \$17 million (2024: \$60 million).
- Sales of Tullow's Gabonese and Kenyan assets, completed in July and September, respectively, realising \$347 million proceeds during 2025.
- Adjusted EBITDAX² of \$586 million (2024: \$1,008 million); gross profit of \$247 million (2024: \$635 million); profit after tax for the year of \$7 million (2024: \$55 million); and loss from continuing operations after tax of \$129 million (2024: \$55 million).
- Free cash flow² (FCF) of \$99 million (2024: \$156 million).
- Net debt² at year end reduced to \$1,353 million (2024: \$1,452 million); cash gearing of net debt² to adjusted EBITDAX² of 2.3 times (2024: 1.4 times); liquidity headroom of \$322 million (2024: \$715 million).
- One new Jubilee well (J72-P) brought onstream in July 2025, which is currently producing c.8 kbopd.
- Average FPSO uptime at Jubilee and TEN of 97%.

2026 FIRST QUARTER PERFORMANCE

- Group working interest oil and gas production averaged 43.4 kboepd during the first quarter of 2026, underpinning expectations of delivering the higher end of full year guidance.
- The Petroleum Agreement extensions to 2040 for the Jubilee and TEN fields were ratified by the Ghanaian parliament in February 2026, unlocking the potential to book further material oil and gas reserves.
- Tullow secured revised terms for the supply of gas from the Jubilee field to the end of the extended period at an escalating price of \$2.50/mmbtu and agreed heads of terms for the potential supply of gas from the TEN fields.
- Tullow and the Government of Ghana have also agreed a gas payment security.
- 2025-26 Ghana drilling programme continues with J74-P onstream in January 2026 and J75-P onstream in March 2026.
- On 19 February 2026, Tullow signed a Sale and Purchase Agreement to acquire the TEN FPSO on behalf of the joint venture for a gross consideration of \$205 million (\$125.6 million net to Tullow), which is to be paid upon completion at the end of the first quarter of 2027. Following completion Tullow intends to maximise operational synergies with the adjacent Jubilee Field and drive further cost efficiencies which will underpin the longer-term development of the TEN and Jubilee fields.

2026 OUTLOOK AND GUIDANCE

- Group working interest production is expected to be at the higher end of the previously announced 34-42, including c.6 kboepd of gas.
- A further four Jubilee wells are expected onstream before the end of the year (three producers and one water injector).
- Capital expenditure² of c.\$200 million, allocated as follows: c.\$190 million in Ghana and c.\$10 million in Côte d'Ivoire.
- Decommissioning spend of c.\$5 million for UK; c.\$20 million cash provisioning for Ghana.
- Commodity hedge portfolio protecting c.60% of 2026 forecast sales volumes whilst retaining material oil price upside exposure.
- Pre-financing cash flow² guidance has increased to c.\$260-365 million at \$70-100/bbl, primarily due to year to date production performance being above expectations, higher oil price realisations and the higher oil price assumption used for guidance.
- Free cash flow² guidance of \$70-175 million at \$70-100/bbl.
- Cash flow would increase by c.\$40 million from \$70/bbl to \$80/bbl and then by a further c.\$30 million for every additional \$10/bbl increase, non-linear due to hedges in place.
- Free cash flow guidance includes recovery of 2025 cash call receivables and c.\$40 million gas revenues related to 2026 gas production, but excludes c.\$110 million historical gas receivables and the c.\$50 million receivable related to TEN development debt. Following execution of the Master Gas Agreement, Tullow has a payment security mechanism for gas. Tullow is working closely with the Government of Ghana and its agencies to resolve the historic receivables on a mutually acceptable basis.
- Interpretation of 4D and OBN seismic data ongoing to support well design and placement in the current drill programme and unlock future reserves growth in the Jubilee and TEN fields.
- On 27 April 2026, Tullow completed a comprehensive refinancing transaction, which includes an extension to its Senior Secured Notes and Glencore facility to November 2028 and May 2030 respectively, and a new \$100 million cargo pre-payment facility with Glencore to provide additional liquidity. The transaction provides a stable platform for Tullow to deliver its investment programme and realise the full value of its assets.
- Following completion of the comprehensive refinancing transaction, Tullow has liquidity headroom of free cash and undrawn facilities in excess of \$200 million.

1. All 2024 comparatives have been adjusted to remove Gabon following the sale of the Gabonese assets, effective from the start of 2025.
2. Alternative performance measures are reconciled on pages 36 to 39.

MANAGEMENT PRESENTATION - WEBCAST – 09:00 BST 28 APRIL 2026

To access the webcast please use the following link and follow the instructions provided:

<https://meetings.lumiconnect.com/100-007-059-118>

A replay will be available on the website from midday on 28 April 2026:

<https://www.tulloil.com/investors/results-reports-and-presentations/>

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Notes to editors

Tullow is an independent energy company committed to building a better future through the responsible oil and gas development of its core producing assets in Ghana. The Group is quoted on the London and Ghanaian stock exchanges (symbol: TLW). For further information, please refer to: www.tulloil.com.

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CHIEF EXECUTIVE OFFICER'S REVIEW

Overview

I was very pleased to be appointed CEO in September 2025. Tullow has many strengths including its reputation as a trusted partner and responsible operator on the continent of Africa, the drive and commitment of its people, and world class assets with significant growth potential. We also have a number of near-term operational catalysts with the potential to deliver value to stakeholders in the near term.

Priorities and achievements

I joined Tullow at a pivotal time. My immediate priorities were to work with the team and our stakeholders to put the Company on a long-term sustainable financial footing and create a strong foundation to drive operational and financial performance improvement.

In July, the sale of our assets in Gabon was completed for a total cash consideration of \$307 million net of tax and customary adjustments. In September we sold our interests in Kenya and have realised the first two tranches of proceeds, totalling \$80 million. A third tranche of \$40 million is due no later than 30 June 2033, subject to a payment schedule linked to the oil price. The proceeds from these strategic disposals materially reduced our net debt and strengthened our balance sheet. The successful completion of both transactions has also reshaped our asset portfolio and we now have a distinct Ghana-focused operating platform.

During 2025 we have further strengthened our position in Ghana by securing alignment with the Government on a suite of agreements that add value to our portfolio but more importantly provide a stable investment environment that paves the way for future growth opportunities. In June, together with our joint venture partners, we reached agreement with the Government of Ghana to extend our Jubilee and TEN petroleum agreements to 2040, which was ratified in February 2026. These extensions secure our ability to responsibly develop our assets in Ghana over the long-term. In addition, Tullow has secured revised terms for the supply of gas from the Jubilee field to the end of the extended period at an escalating price of \$2.50/mmbtu and agreed heads of terms for the potential supply of gas from the TEN fields. Tullow and the Government of Ghana have also agreed a gas payment security mechanism.

In February 2026 we signed an agreement to acquire the TEN FPSO on behalf of the joint venture for a gross consideration of \$205 million (\$125.6 million net). Our net consideration, which is equivalent to approximately one year of current net lease cost, is expected to be funded by in-year cash flow from TEN and to be paid upon completion at the end of the first quarter of 2027. In addition to the removal of the annual lease cost, assuming operatorship of the FPSO will result in cost savings similar to what has already been achieved at the adjacent Jubilee field and create further potential synergies which will underpin the longer-term development of the TEN fields.

The towed streamer 4D seismic and Ocean Bottom Node seismic surveys on the Jubilee and TEN fields were completed in the first and fourth quarters of 2025, respectively. Interpretation of the 4D seismic data continues to deliver informative reservoir insights supporting the well design and placement in the current drill programme and the identification of targets for future campaigns.

Our focus on capital efficiency and cost optimisation has continued. As a result, 2025 annual net G&A has reduced to c.\$45 million from c.\$52 million in 2024 and we are targeting savings of c.\$50 million over the three year period 2025-27.

In April 2026, we completed a comprehensive refinancing transaction; extending our Senior Secured Notes to November 2028 and the Glencore facility to May 2030, alongside a new \$100 million cargo pre-payment facility with Glencore to enhance liquidity. This pivotal milestone for the Company has secured a financial runway of over two years, reduced total cash interest and provides a stable platform for Tullow to deliver its investment programme and unlock the full potential of its assets.

Financial performance

In 2025, free cash flow of \$99 million was lower than expected due to lower realised revenue towards the end of the year, delayed receipt of the second Kenya disposal proceeds, which were received in March 2026, and delayed receipt of cash calls and gas payments from the Government of Ghana. Government of Ghana receivables at the end of 2025 were c.\$225 million net to Tullow (pre-tax), with c.\$65 million related to cash calls, c.\$110 million related to gas payments and c.\$50 million related to TEN development debt. We are working with the Government of Ghana and its agencies to resolve the historic receivables on a mutually acceptable basis.

Looking ahead, we expect to deliver free cash flow of \$70-175 million in 2026 at an oil price range of \$70-100/bbl. This cash flow guidance includes recovery of 2025 cash call receivables from the Government of Ghana and c.\$40 million pre-tax gas revenues from 2026 gas production; but excludes c.\$110 million in historical gas receivables and c.\$50 million receivables related to TEN development debt.

Operational performance

In 2025, the Group's working interest production averaged 40.4 kboepd, including 7.1 kboepd of gas. This figure reflects the sale of our Gabonese assets, which was effective from the beginning of the year. Overall production was in line with guidance, although towards the lower end, primarily due to operational challenges at Jubilee during the first half of the year.

Performance improved in the second half, supported by the good performance from the first new Jubilee production well, which was brought onstream in July and averaged c.10 kbopd in the second half of 2025. A second well (J74-P) was brought onstream in January 2026 and a third well (J75-P) in March 2026.

Group working interest production for 2026 is expected to be 32-42 kboepd, including c.6 kboepd of gas production. This range reflects the decline from existing well stock, which we are working hard to mitigate through improving waterflood and fluid lift optimisation, offset by additional production from the ongoing drill campaign. However, based on production performance in the first quarter, we expect to be at the high end of the production guidance range for the full year.

Ghana

In Ghana operational efficiency remained high with average facility uptime across the FPSOs averaging 97% and a combined average oil production rate of c.32.5 kbopd net in 2025. Production performance in the first quarter of 2026 has been strong, with Ghanaian oil production growing to 35.4 kbopd.

Gross oil production from the Jubilee field averaged 60.9 kbopd (net: 23.7 kbopd) in 2025. In the first half of the year, production was challenged by higher-than-expected water cut from certain wells, which affected riser stability on the eastern side of the field. To address this, riser based gas lift was introduced on the east side, successfully restoring and stabilising production in June. Looking ahead, riser based gas lift for the western side of Jubilee has been approved and is expected to deliver further support to production rates once fully implemented in 2027.

Cumulative voidage replacement grew to 107% in the second half of 2025, as issues in the seawater lift system have been resolved. This will support improved reservoir pressure management and stabilise production going forward.

Gross oil production from the TEN fields averaged 16.0 kbopd (net: 8.8 kbopd) during 2025. This was above expectations supported by well zonal optimisation in Enyenra and water injection optimisation activities. The TEN FPSO flare tip was replaced in May, resulting in a c.50% reduction in routine flaring from July 2025 onwards.

As a result of the extension of our Ghanaian Petroleum Agreements to 2040, we expect to realise an increase in net 2P reserves of over 10 mmbœ. Furthermore, as part of this arrangement, from 20 July 2036 Ghana National Petroleum Corporation's share in the field will increase by a further 10% and the respective joint venture partners' shares will decrease pro rata.

Net gas production in Ghana averaged 6.8 kboepd in 2025.

Six Jubilee wells are expected onstream in 2026 (five producers and one water injector), two of which are already onstream (J74-P and J75-P). The next three producers are expected to come onstream in June and July, with the final well (water injector) due onstream in September.

To sustain production rates and counteract natural declines in reservoir output, waterflood operations are being optimised to maintain reservoir pressure and enhance oil recovery, and well production is being carefully managed via the riser system with the assistance of riser based gas lift.

Non-operated and exploration portfolios

As highlighted above, the sale of our Gabonese and Kenyan assets completed in July and September, respectively.

We are aware of a tax assessment for c.\$170 million from the Kenya Revenue Authority relating to alleged underpaid VAT and Capital Gains Tax on the disposal. Our clear and firm position is that the assessment is wholly without merit and we intend to contest it through the regular objection process. There will be no cash outflow in respect of lodging these objections, nor do we expect cash outflow on completion of the appeal process.

In Côte d'Ivoire, the Espoir field licence expiry is due in July 2026. Planning is under way to transfer the asset to Petroci.

We have taken the decision to exit exploration licences in Côte d'Ivoire (CI-524 and CI-703) and have completed our exit in Argentina (MLO 114, MLO 119 and MLO122).

Reserves and resources

At the end of 2025, audited 2P reserves were 100.4 mmbœ (2024: 164.5 mmbœ). The reserves reduction includes 14.7 mmbœ of Group production during 2025, the disposal of the Gabon assets (36.0 mmbœ), a downward revision on Jubilee reflecting production performance (11.8 mmbœ) and a minor reduction on TEN (1.6 mmbœ), which reflects rephasing of projects and an earlier assumed cessation of production due to a lower evaluation oil price.

Our asset base continues to have significant value, and as at 31 December 2025, the Group's audited 2P NPV10 was c.\$1.27 billion, at our independent reserves auditors price deck starting \$62.29/bbl in 2026 and rising to \$66.24/bbl in 2030 with 2% inflation applied from 2030 onwards.

The Group's audited 2C resources of c.200 mmbœ at the end of 2025 (2024: c.700 mmbœ) reflect the material opportunity we have to mature resources into reserves to realise sustained long-term production. A number of tangible near-term projects are being matured during 2026 to realise this, including opportunities to install subsea pumps and undertake further infill drilling on Jubilee and TEN and the potential monetisation of gas resources.

Sustainability

Sustainability underpins our business strategy and our approach focuses on three core themes: people, climate and nature.

Our Net Zero by 2030 commitment is a core aspect of our sustainable approach and following the implementation of process improvements and modifications on our FPSOs in Ghana during the year, we further reduced routine flaring by 22%.

Our community development programmes continue to focus on improving education and employability in our host communities and creating opportunities for local employment and entrepreneurship.

Governance

On 8 April 2026, we announced the appointment of four new independent Non-Executive Directors to enhance the Company's governance framework and to comply with the previously announced requirements of the refinancing transaction. The appointment of Henry Steel is with effect from 8 April 2026 and he will also serve as Senior Independent Director. The appointments of Garrett Soden, Euan Shirlaw and James Peterkin will become effective on 1 May 2026.

Outlook

In 2025 we laid the foundations for improved performance and created a number of potential growth opportunities. In the near term, we will focus on continuing to optimise our cash flow delivery, through better cash flow management, further cost reductions and reduction of the receivables from the Government of Ghana. Furthermore following the purchase of the TEN FPSO, we will look to capture synergies with the Jubilee FPSO whilst reducing costs and removing the significant annual lease payment.

Operationally, we are excited by the potential of the 4D seismic and OBN data to unlock future drilling campaigns in Jubilee and TEN. Nearer-term, we are encouraged by the positive start to the 2025-26 Jubilee drill campaign. There are a number of incremental opportunities beyond new wells that we are pursuing to improve production, including multi-phase pumps, riser based gas lift and workover campaigns. These projects have the potential for rapid payback with relatively low risk.

With the refinancing transaction completed and strong operational momentum across the business, Tullow is well positioned to deliver our Business Plan and target near-term upside. As we look to the year ahead we remain focused on improving the performance of our world-class assets and executing our Business Plan to deliver value for stakeholders.

1. Alternative performance measures are reconciled on pages 36 to 39.

FINANCE REVIEW

Income Statement

Income Statement (key metrics)	2025	2024 Restated ²
Revenue (\$m)		
Sales volume (boepd)	32,600	44,400
Realised oil price (\$/bbl)	66.2	75.9
Total revenue	847	1,287
Operating income/(costs) (\$m)		
Underlying cash operating costs ¹	(203)	(198)
Depreciation, Depletion and Amortisation (DD&A) of oil and gas and leased assets	(371)	(412)
DD&A before impairment charges (\$/bbl)	25.3	21.9
Overlift and oil stock movements	(28)	(42)
Administrative expenses	(45)	(52)
Exploration costs written off	(2)	(202)
Impairment reversal of property, plant and equipment (PP&E), net	5	12
Net financing costs	(263)	(275)
(Loss)/profit for the year from continuing activities before tax	(63)	174
Income tax expense	(67)	(229)
Loss for the year from continuing activities	(129)	(55)
Adjusted EBITDAX ¹	586	1,008
Basic loss per share (cents)	(8.8)	(3.8)

1. Alternative performance measures are reconciled on pages 36 to 39.

2. Amounts above are presented excluding discontinued operations in Gabon. Refer to note 8.

Revenue

Sales oil volumes

During the year, there were 32,600 boepd (2024: 44,400 boepd) of liftings. The decrease was driven by a reduction of 4.5 liftings in Ghana with 10 in Jubilee (2024: 13) and 3 in TEN (2024: 4.5).

Realised oil price (\$/bbl)

The Group's realised oil price after hedging for the period was \$66.2/bbl (2024: \$75.9/bbl) and before hedging \$67.8/bbl (2024: \$80.5/bbl). Lower oil prices and lower hedged volumes subject to price caps compared to 2024 have resulted in a lower hedge loss which decreased total revenue by \$19 million (2024: \$74 million).

Gas sales

Included in Total revenue of \$847 million are gas sales of \$59 million of which \$54 million relates to Ghana. During the year, the Group exported 44,503 mmscf (gross) of gas at an average price of \$3.08/mmbtu in Ghana (2024: 33,660 mmscf (gross) at \$2.97/mmbtu).

Cost of sales

Underlying cash operating costs

Underlying cash operating costs amounted to \$203 million; \$13.8/boe (2024: \$198 million; \$10.5/boe). This consists of Ghana \$166 million; \$11.6/boe (2024: \$157 million; \$8.6/boe), Côte d'Ivoire \$23 million; \$53.7/boe (2024: \$22 million; \$42.7/boe) and Corporate \$14 million (2024: \$18 million). The movement is primarily driven by Jubilee shutdown and FPSO Class related maintenance costs offset by a decrease in routine operating costs.

Depreciation, depletion and amortisation

DD&A charges before impairment on production and development assets amounted to \$371 million; \$25.3/boe (2024: \$412 million; \$21.9/boe). This decrease in DD&A is mainly attributable to lower Jubilee field production compared to the prior year.

Overlift and oil stock movements

The Group recognised an overlift expense of \$28 million (2024: \$42 million). The decrease in overlift expense is driven by timing of liftings and lower oil prices at the 2025 year end.

Administrative expenses

Administrative expenses of \$45 million (2024: \$52 million) have decreased in 2025 despite the inflationary environment. This is largely due to targeted cost optimisation initiatives undertaken in 2025 together with the broader Group restructuring following the disposal of the Gabon and Kenya assets. The full year impact of the cost optimisations is expected to realise in 2026, which together with additional cost optimisation initiatives is estimated to generate c.\$50 million savings over the next three years.

Impairment of property, plant and equipment

The Group recognised a net impairment reversal on PP&E of \$5 million in 2025 (2024: Net impairment reversal of \$12 million), mainly driven by changes to estimates on the cost of decommissioning for certain UK assets, partially offset by impairment of capital expenditure in Cote D'Ivoire. The \$35 million impairment in the TEN fields recognised in the 2025 half-year results has been fully reversed at the year end. This followed an assessment which determined that the net present value of TEN, reflecting the impact of the acquisition of the FPSO as disclosed in the Events since 31 December 2025 section, was equal to the carrying value of the PP&E, TEN FPSO net lease liability and associated deferred tax balances.

Net financing costs

Net financing costs for the year were \$263 million (2024: \$275 million). Lower net interest expense on borrowings and obligations under leases was partially offset by debt arrangement fees incurred in 2025 and a reduced interest income.

A reconciliation of net financing costs is included in note 6.

Taxation

The overall adjusted net tax expense of \$67 million (2024: \$229 million) primarily relates to tax charges in respect of the Group's production activities in West Africa, reduced by deferred tax credits associated with future UK decommissioning assets, exploration write-offs and impairments.

Based on a loss before tax for the period of \$63 million (2024: profit of \$174 million), the effective tax rate (ETR) is (106.0%) (2024:131.7%). After adjusting for non-recurring amounts related to exploration write-offs, disposals, impairments, provisions and their associated deferred tax benefit, the Group's adjusted tax rate is (125.5%) (2024: 71.1%). In the UK, there is net interest and hedging expense of \$162 million (2024: \$195 million), however, there is no UK tax benefit as in previous periods.

The Group has applied the exception from recognising and disclosing deferred tax assets and liabilities arising from the implementation of Pillar Two income taxes. Based on full year actuals, the Group has not identified any exposure to Pillar Two income taxes in jurisdictions where the safe harbour thresholds are not met. Accordingly, no Pillar Two income tax charges or related deferred tax effects have been recognised for the period.

Detailed analysis of ETR for underlying business - Continuing operations

Analysis of adjusted ETR (\$m)		Adjusted profit/(loss) before tax	Tax (expense)/credit	Adjusted effective tax rate
Ghana	2025	184.6	(70.3)	38.1%
	2024	580.3	(208.6)	35.9%
Corporate	2025	(205.3)	2.0	1.0%
	2024	(270.3)	(5.7)	(2.1%)
Other non-operated & exploration	2025	(33.1)	0.8	2.4%
	2024	(7.8)	(0.7)	(8.7%)
Total	2025	(53.8)	(67.5)	(125.5%)
	2024	302.2	(215.0)	71.1%

Detailed analysis of ETR - Discontinued operations

Analysis of adjusted ETR (\$m)		Adjusted profit/(loss) before tax	Tax (expense)/credit	Adjusted effective tax rate
Gabon	2025	62.0	(44.9)	72.5%
	2024	119.3	(38.2)	32.0%
Total	2025	62.0	(44.9)	72.5%
	2024	119.3	(38.2)	32.0%

Adjusted EBITDAX

Adjusted EBITDAX for the year was \$586 million (2024: \$1,008 million). The decrease in the period was mainly driven by lower revenue.

Loss for the year from continuing activities and loss per share

The loss for the year from continuing activities amounted to \$129 million (2024: \$55 million loss). The loss after tax was driven mainly by lower revenue, offset by lower income tax expense in the current year. Basic loss per share was 8.8 cents (2024: loss per share of 3.8 cents).

Balance sheet and liquidity management

Key metrics	2025	2024
Capital investment (\$m) ¹	195	231
Derivative financial instruments (\$m)	1	(12)
Borrowings (\$m)	(1,659)	(1,976)
Underlying operating cash flow (\$m) ¹	221	668
Free cash flow (\$m) ¹	99	156
Net debt (\$m) ¹	1,353	1,452
Gearing (times) ^{1,2}	2.3	1.4

1. Alternative performance measures are reconciled on pages 36 to 39.

2. Gearing presented above excludes discontinued operations in Gabon.

Capital investment

Capital expenditure amounted to \$195 million (2024: \$231 million) out of which \$191 million was invested in production and development activities (2024: \$206 million) with a \$146 million spend in Ghana (2024: \$148 million), \$28 million in Gabon (2024: \$40 million), \$14 million in Cote D'Ivoire (2024: \$12 million) and \$3 million in Kenya (2024: \$6 million). \$122 million of capital investment related to Jubilee (2024: \$134 million), mainly comprising \$85 million of drilling costs (2024: \$103 million). Investment in exploration and appraisal activities was \$4 million (2024: \$25 million).

The Group's 2026 capital expenditure is expected to be c.\$200 million, comprising c.\$190 million in Ghana and c.\$10 million in Cote D'Ivoire. Ghana capex is expected to include c.\$180 million relating to Jubilee, primarily drilling costs of c.\$150 million.

Decommissioning

Decommissioning expenditure was \$5 million (2024: \$49 million), and \$12 million of cash provisioning for future decommissioning in Ghana (2024: \$12 million). The Group's decommissioning budget in 2026 is c.\$25 million of which c.\$20 million is cash provisioning for future decommissioning in Ghana. Subject to programme scheduling, at the end of 2026 it is expected that c.\$12 million of decommissioning liabilities in the UK will remain.

Derivative financial instruments

The Group has a material hedge portfolio in place to protect against commodity price volatility and to ensure the availability of cash flow for re-investment in capital programmes that are driving business delivery, whilst retaining access to oil price upside.

At 31 December 2025, the Group's hedge portfolio provides downside protection for c.50% of forecast production entitlements in the first half of 2026 with c.\$58/bbl weighted average floors across all structures; while retaining strategic upside participation across for the same period, with only c.30% of forecast production entitlements capped with collars at a weighted average sold call of c.\$74/bbl, and c.7% of forecast production entitlements secured with three-way collars with \$70-\$80/bbl call spreads. To date, the Group's hedge portfolio in the second half of the year is comprised of collars providing downside protection for c.20% of forecast production entitlements with c.\$59/bbl weighted average floors, and upside capped at c.\$75/bbl.

All financial instruments that are initially recognised and subsequently measured at fair value have been classified in accordance with the hierarchy described in IFRS 13 Fair Value Measurement. Fair value is the amount for which the asset or liability could be exchanged in an arm's length transaction at the relevant date. Where available, fair values are determined using quoted prices in active markets (Level 1). To the extent that market prices are not available, fair values are estimated by reference to market-based transactions or using standard valuation techniques for the applicable instruments and commodities involved (Level 2).

All of the Group's derivatives are Level 2 (2024: Level 2). There were no transfers between fair value levels during the year.

At 31 December 2025, the Group's derivative instruments had a net positive fair value of \$1 million (2024: net negative \$12 million).

The following table demonstrates the timing, volumes and prices of the Group's commodity hedge portfolio at year end:

1H26 hedge portfolio at 31 December 2025	bopd	Bought put (floor)	Sold call	Bought call
Straight puts	3,750	\$58.20	–	–
Collars	10,200	\$58.48	\$75.17	–
Three-way collars (call spread)	2,224	\$57.99	\$69.90	\$79.90
Total/Weighted average	16,174	\$58.35	\$74.23	\$79.90

2H26 hedge portfolio at 31 December 2025	bopd	Bought put (floor)	Sold call	Bought call
Straight puts	–	–	–	–
Collars	7,500	\$58.97	\$74.88	–
Three-way collars (call spread)	–	–	–	–
Total/Weighted average	7,500	\$58.97	\$74.88	–

Since the balance sheet date, the Group has secured additional downside protection for 9,750 bopd, 12,000 bopd and 5,500 bopd for the periods 2H26, 1H27 and 2H27, respectively.

Borrowings

On 3 March 2025, the Group repaid in full its Senior Notes. The principal repayment of \$493 million and accrued interest to maturity were funded from a combination of drawing down the remaining balance of \$270 million under the Glencore Facility and cash on balance sheet.

On 29 April 2025, the Group made a drawdown under its Revolving Credit Facility (RCF) to manage near-term working capital.

On 15 May 2025, the Group made the annual prepayment of \$100 million of the Senior Secured Notes due 2026 (2026 Notes).

On 21 May 2025, the Group entered into an extension of its RCF to 31 October 2025 at reduced commitments of \$150 million. On 29 July 2025, the Group repaid and cancelled in full the \$150 million RCF.

As at 31 December 2025, the Group's total drawn debt reduced to \$1,685 million, consisting of \$1,285 million nominal value 2026 Notes and \$400 million outstanding under the Glencore facility.

Management regularly reviews options for optimising the Group's capital structure and may seek to refinance, retire or purchase any or all of its outstanding debt from time to time through new debt refinancings and/or cash purchases or exchanges in the open market, privately negotiated transactions or otherwise.

Credit ratings

The Group maintains credit ratings with Standard & Poor's (S&P's) and Moody's Investors Service (Moody's).

On 17 April 2025, S&P revised the Group's corporate credit rating and the rating of the 2026 Notes to CCC+ with negative outlook from B-.

On 2 October 2025, S&P revised the Group's corporate credit rating and the rating of the 2026 Notes to CCC with negative outlook.

On 28 November 2025, S&P revised the Group's corporate credit rating and the rating of the 2026 Notes to CCC- with negative outlook.

On 13 May 2025, Moody's revised the Group's corporate credit rating and the rating of the 2026 Notes to Caa2 with negative outlook from Caa1.

On 8 December 2025, Moody's revised the Group's corporate credit rating to Ca with negative outlook from Caa2 and the rating of the 2026 Notes to Caa3.

Underlying operating cash flow and free cash flow

Underlying operating cash flow for the year was \$221 million (2024: \$668 million), reflecting a decrease of \$447 million. This was primarily driven by \$620 million decline in cash revenue due to lower sales volumes and reduced oil prices, and higher cash operating costs and working capital of \$68 million. These factors were partially offset by lower cash and royalty taxes of \$241 million.

Free cash flow for the year decreased to \$99 million (2024: \$156 million). Underlying operating cashflow reduced by \$447 million, as outlined above. This decrease was largely offset by proceeds from disposals of \$334 million as well as lower net cash used in other investing activities, reduced lease payments related to capital activities and decommissioning costs, which decreased by \$28 million, \$22 million, and \$28 million, respectively. There was an increase in the finance costs of \$13 million, mainly due to debt arrangement fees, as well as an impact of foreign exchange loss of \$9 million.

Net debt and gearing

Reconciliation of net debt	\$m
FY 2024 net debt	1,452.3
Sales revenue	(962.4)
Operating costs	202.9
Other operating and administrative expenses	164.1
Operating cash flow before working capital movements	(595.4)
Movement in working capital	133.8
Tax paid	127.3
Purchases of intangible exploration and evaluation assets and property, plant and equipment	195.6
Other investing activities	(345.1)
Other financing activities	358.3
Debt arrangement fees	19.7
Foreign exchange loss on cash	6.5
FY 2025 net debt	1,353.0

1. Amounts above are presented including discontinued operations in Gabon.

Net debt reduced by \$99.3 million during the year to \$1,353.0 million on 31 December 2025 (2024: \$1,452.3 million), consisting of \$1,285 million Senior Secured Notes due 2026 and \$400 million Secured Notes Facility, less cash and cash equivalents.

The gearing ratio has increased to 2.3 times (2024: 1.4 times) due to a decrease in Adjusted EBITDAX from lower revenue in the current year as explained above.

Ghana tax assessments

The Group has two ongoing disputed tax assessments that relate to the disallowance of loan interest deductions for the fiscal years 2010 - 2020 and proceeds received by Tullow Oil plc under Tullow's corporate Business Interruption Insurance policy. Both were referred to international arbitration in 2023, with first hearings scheduled for 2025. The parties initially agreed a procedural timetable for the loan interest arbitration under which the first Tribunal hearing was due to have been held in the week commencing 30th June 2025. This has now been postponed to September 2026 allowing more time to conclude the negotiations. The hearing on the Business Interruption Insurance proceeds was held in November 2025, and a ruling can be expected during the first half of 2026. The Group continues to engage with the Government of Ghana, including the Ghana Revenue Authority (GRA), with the aim of resolving the assessments on a mutually acceptable basis.

Kenya tax assessments

The Group is aware of a tax assessment for c.\$170 million from the Kenya Revenue Authority relating to alleged underpaid VAT and Capital Gains Tax on the disposal of its 100% shareholding in its Kenyan subsidiary, Tullow Kenya BV, to the Gulf Energy Group for a minimum consideration of \$120 million. The Group's clear and firm position is that the assessment is wholly without merit, and it intends in conjunction with Gulf Energy to contest the assessment through the regular objection process. There will be no cash outflow in respect of lodging these objections, nor does the Group expect cash outflow on completion of its appeal process. Therefore, a provision for uncertain tax treatments in respect of this risk has not been recorded.

Liquidity risk management and going concern

The Directors consider the going concern assessment period to be up to 30 April 2027.

On 27 April 2026, the Group announced the completion of its refinancing transaction to address the maturity of \$1.285 billion senior secured notes (the 2026 Notes). Following a repayment of \$100 million of principal amount of the 2026 Notes at par, the Group issued \$1.185 billion new notes maturing 15 November 2028 to existing holders plus \$25 million fungible new notes to Glencore (together the New Notes) in exchange for the cancellation in full of the 2026 Notes. Further, a \$400 million loan provided by Glencore was extended by two years to mature on 15 May 2030, with \$21 million in accrued interest and \$2 million payment in kind fees added to the loan balance on completion.

The Group also entered into a revolving \$100 million cargo prepayment facility maturing on 15 November 2028 with Glencore which is undrawn and will be primarily used for working capital purposes and to provide a liquidity buffer in a downside scenario.

The New Notes, the Glencore loan and the cargo prepayment facility do not have any maintenance covenants. If a legally binding sale and purchase agreement has not been entered into within nine months of commencement of an M&A process (such process to commence before the end of 2026), the maturities of the New Notes and the cargo prepayment facility will be brought forward to 15 May 2028 (unless extended by approval of a Super Majority of holders of the New Notes), which is outside of the going concern assessment period. Governance will be enhanced with the addition of three new Independent Non-Executive Directors (INEDs) to Tullow's Board of Directors. The New Notes include a semi-annual forward-looking cash sweep whereby freely available cash will be required to repay the New Notes subject to the condition that rolling 15-month projected liquidity on the last date of each calendar month within the projection period (under certain downside assumptions) is equal to or exceeds \$100 million.

The Group closely monitors and manages its liquidity headroom. Cash forecasts are regularly produced, and sensitivities run for different scenarios covering key judgements and assumptions including, but not limited to, changes in commodity prices, different production rates from the Group's producing assets and different outcomes on ongoing disputes or litigations and the timing of any associated cash outflows.

Management has applied the following oil price assumptions for the going concern assessment based on forward prices and market forecasts:

Base Case: \$76/bbl for 2026; \$70/bbl for 2027.

Low Case: \$66/bbl for 2026; \$65/bbl for 2027.

To consider the principal risks to the cash flow projections, a sensitivity analysis has been performed which is represented in the Low Case, which management considers to be severe, but plausible, given the cumulative impact of the sensitivities applied. The most significant risk would be a sustained decline in oil prices. The analysis has been tested by including a 10% production decrease and a 5% increase in operating costs compared to the Base Case. Management has also considered additional outflows in respect of all ongoing disputes and litigations within the Low Case, with an additional \$33 million outflow included for the cases expected to progress in the going concern period. Based on the legal opinions received by management, the remaining disputes and litigations are not expected to conclude within the going concern period or have remote outcomes, therefore no outflows have been included in that respect in the Low Case. In the event of negative outcomes after the going concern period, management would use all available court processes to appeal such rulings, which, based on observable court timelines, would likely take in excess of a further year.

Following completion of the refinancing transaction the Directors have concluded that the material uncertainties noted in the 2024 Annual Report and Accounts, associated with implementing a refinancing proposal no longer exist. Upon completion of the refinancing transaction, the Group had in excess of \$200 million liquidity headroom of undrawn and available debt facilities and free cash. The Group's forecasts show that the Group will be able to operate within its current debt facilities and have sufficient financial headroom for the going concern assessment period under the Base Case and the Low Case. These forecasts assume full availability of the \$100 million cargo prepayment facility, which remains undrawn under the Base Case. Furthermore, management has performed a reverse stress test and the average oil price throughout the going concern period required to reduce headroom to zero during the assessment period is \$32/bbl.

Based on the analysis above, the Directors have a reasonable expectation that the Company has adequate resources to continue in operational existence for the going concern assessment period to 30 April 2027. On this basis the Board have prepared the Financial Statements on a going concern basis.

Events since 31 December 2025

TEN FPSO Purchase

On 19 February 2026, Tullow signed a Sale and Purchase Agreement (SPA) to acquire the TEN FPSO on behalf of the joint venture for a gross consideration of \$205.0 million (\$125.6 million net to Tullow), which is to be paid upon completion at the end of the first quarter of 2027.

The lease modification to include an obligation to purchase the FPSO, together with the update to the lease term, constitutes a lease remeasurement in accordance with IFRS 16 Leases. As at the date of the SPA, the remeasurement will result in a reduction in the lease liability, a reduction in the right-of-use asset, and a corresponding decrease in the receivable from the joint venture partners, as the value of the gross undiscounted lease payments will decrease from \$716.7 million to \$424.9 million. As the assessment of the financial impacts is ongoing, these cannot be disclosed in the Annual Report and Accounts. Accordingly, the relevant disclosure will be made in the 2026 half-year results.

Extension of the Petroleum Agreements in Ghana

On 20 February 2026, Tullow announced that the extension of its West Cape Three Points and Deep Water Tano Petroleum Agreements, which cover the Jubilee and TEN fields, was ratified by the Ghanaian Parliament. Accordingly, these agreements have been extended to 31 December 2040, and from 20 July 2036 Ghana National Petroleum Corporation's share in the field will increase by a further 10% interest and the joint venture partners' shares will decrease pro rata.

In addition, Tullow has secured revised terms for the supply of gas from the Jubilee field to the end of the extended period at an escalating price of \$2.50/mmbtu and heads of terms for the potential supply of gas from TEN. Tullow and the Government of Ghana have also agreed a gas payment security mechanism.

Refinancing transaction

On 20 February 2026, Tullow announced that it had entered into a binding Lock-Up Agreement to implement a refinancing transaction with holders of c.66% 10.25% senior secured notes due May 2026 (the Senior Secured Notes) and with Glencore Energy UK Limited (Glencore). Key features of the transaction included:

- Release of Senior Secured Notes and issuance of new Extended Notes maturing 15 November 2028, together with a paydown of \$100 million, extending the Company's debt maturity profile.
- Glencore's existing \$400 million Secured Notes Facility released and issuance of new Glencore Junior Notes of an equal amount maturing 15 May 2030.
- Strengthened liquidity position through a new \$100 million super senior Cargo Prepayment Facility provided by Glencore, complemented by a reduced all-in cash interest profile through Payment-In-Kind (PIK) only interest on the Glencore Junior Notes.
- Existing equity remains in place and no new shares are anticipated to be issued in connection with the refinancing transaction.

On 26 February 2026, Tullow announced that holders of over 90% of its Senior Secured Notes have acceded to the Lock-Up Agreement in support of the Company's refinancing transaction, meeting the necessary threshold required to implement it by way of consent solicitation.

On 25 March 2026, Tullow launched a consent solicitation to obtain formal consents from the holders of the Notes required in connection with the implementation of the refinancing transaction.

On 8 April 2026, Tullow announced that holders representing over 97% of the outstanding principal amount of its existing notes had provided consents to approve amendments to the indenture and intercreditor agreement, the release and exchange of the existing notes for new notes, and related waivers to permit the release of collateral, in each case in connection with the proposed refinancing transaction.

On 27 April 2026, Tullow announced the completion of the refinancing transaction. As the assessment of the financial impacts is ongoing, these cannot be disclosed in the Annual Report and Accounts. Accordingly, the relevant disclosure will be made in the 2026 half-year results.

Receipt of Tranche B payment for sale of Kenya assets

On 9 March 2026, Tullow received \$36 million proceeds of the Tranche B payment under the terms of the SPA announced on 21 July 2025 for the sale of its entire working interest in Kenya. The final 10% of Tranche B proceeds (\$4 million), was received on 1 April 2026 following completion of transition support services.

Board of Directors appointments

On 8 April 2026, Tullow has announced the appointment of four independent Non-Executive Directors (Henry Steel, Garrett Soden, Euan Shirlaw and James Peterkin) to its Board of Directors. Henry Steel's appointment was effective immediately. The other appointments were conditional on completion of the refinancing, which closed on 27 April 2026, and will become effective on 1 May 2026. The appointments will be subject to election by shareholders at the Annual General Meeting in June.

These are all non-adjusting events as at 31 December 2025 as defined by IAS 10 Events after the Reporting Period.

There have not been any other events since 31 December 2025 that have resulted in a material impact on the year end results.

Group income statement

Year ended 31 December 2025

\$m	Notes	2025	2024 Restated ¹
Revenue		847.0	1,287.2
Other operating income – insurance proceeds		4.2	–
Cost of sales	5	(603.9)	(652.5)
Gross profit		247.3	634.7
Administrative expenses	5	(45.0)	(52.2)
Restructuring provisions	5	(7.2)	(7.1)
Expected credit loss reversal/(charge) on trade receivables	5	6.6	(6.6)
Loss on disposal	8	(4.5)	–
Exploration costs written off	9	(2.1)	(202.3)
Impairment reversal of property, plant and equipment, net	10	4.8	11.8
Provisions reversal	5	–	70.4
Operating profit		199.9	448.7
Finance income	6	63.4	69.2
Finance costs	6	(326.0)	(344.2)
(Loss)/Profit for the year from continuing operations before tax		(62.7)	173.7
Income tax expense	7	(66.5)	(228.7)
Loss for the year from continuing operations		(129.2)	(55.0)
Discontinued operations			
Profit after tax from discontinued operations		135.7	109.6
Profit for the year		6.5	54.6
<i>Attributable to</i>			
Owners of the Company		6.5	54.6
Earnings per ordinary share		¢	¢
Basic		0.4	3.7
Diluted		0.4	3.6
Loss per ordinary share from continuing operations		¢	¢
Basic		(8.8)	(3.8)
Diluted		(8.8)	(3.8)

1. Comparative amounts have been restated to present Gabon as a discontinued operation. Refer to note 8.

Group statement of comprehensive income and expense

Year ended 31 December 2025

\$m	2025	2024
Profit for the year	6.5	54.6
Items that may be reclassified to the income statement in subsequent periods		
Cash flow hedges		
Gain/(losses) arising in the year	0.3	(28.5)
Losses arising in the year – time value	(5.8)	(21.9)
Reclassification adjustments for items included in profit on realisation	–	47.5
Reclassification adjustments for items included in loss on realisation – time value	18.8	26.1
Exchange differences on translation of foreign operations	(7.7)	2.0
Net other comprehensive income for the year	5.6	25.2
Total comprehensive income for the year	12.1	79.8
<i>Attributable to</i>		
Owners of the Company	12.1	79.8

Group balance sheet

As at 31 December 2025

\$m	Notes	2025	2024
Assets			
Non-current asset			
Goodwill	12	–	44.9
Intangible exploration and evaluation assets	9	–	109.1
Property, plant and equipment	10	1,894.3	2,324.1
Other non-current assets	11	300.2	340.8
Deferred tax assets		5.0	8.3
		2,199.5	2,827.2
Current assets			
Inventories		90.1	132.4
Trade receivables		179.2	137.9
Other current assets	11	472.9	391.9
Current tax assets		2.9	6.9
Derivative financial instruments		2.0	0.1
Cash and cash equivalents		332.2	555.1
		1,079.3	1,224.3
Total assets		3,278.8	4,051.5
Liabilities			
Current liabilities			
Trade and other payables	13	(638.4)	(736.5)
Borrowings		(1,277.9)	(589.4)
Provisions	15	(5.5)	(24.3)
Current tax liabilities		(140.5)	(175.3)
Derivative financial instruments		(0.6)	(11.9)
		(2,062.9)	(1,537.4)
Non-current liabilities			
Trade and other payables	13	(493.0)	(665.9)
Borrowings		(381.0)	(1,386.4)
Provisions	15	(257.3)	(321.5)
Deferred tax liabilities		(337.5)	(413.0)
		(1,468.8)	(2,786.8)
Total liabilities		(3,531.7)	(4,324.2)
Net liabilities		(252.9)	(272.7)
Equity			
Called-up share capital		218.6	217.5
Share premium		1,294.7	1,294.7
Foreign currency translation reserve		(250.1)	(242.4)
Hedge reserve		0.4	0.1
Hedge reserve – time value		0.9	(12.1)
Merger reserve		755.2	755.2
Retained earnings		(2,272.6)	(2,285.7)
Equity attributable to equity holders of the Company		(252.9)	(272.7)
Total equity		(252.9)	(272.7)

Group statement of changes in equity

Year ended 31 December 2025

\$m	Share capital	Share premium	Foreign currency translation reserve ¹	Hedge reserve ²	Hedge reserve – time value ²	Merger reserve ³	Retained earnings	Total
At 1 January 2024	216.7	1,294.7	(244.4)	(18.9)	(16.3)	755.2	(2,346.4)	(359.4)
Profit for the period	–	–	–	–	–	–	54.6	54.6
Hedges, net of tax	–	–	–	19.0	4.2	–	–	23.2
Currency translation adjustments	–	–	2.0	–	–	–	–	2.0
Total comprehensive income	–	–	2.0	19.0	4.2	–	54.6	79.8
Exercise of employee share options	0.8	–	–	–	–	–	(0.8)	–
Share-based payment charges	–	–	–	–	–	–	6.9	6.9
At 1 January 2025	217.5	1,294.7	(242.4)	0.1	(12.1)	755.2	(2,285.7)	(272.7)
Profit for the period	–	–	–	–	–	–	6.5	6.5
Hedges, net of tax	–	–	–	0.3	13.0	–	–	13.3
Currency translation adjustments	–	–	(7.7)	–	–	–	–	(7.7)
Total comprehensive income	–	–	(7.7)	0.3	13.0	–	6.5	12.1
Exercise of employee share options	1.1	–	–	–	–	–	(1.1)	–
Share-based payment charges	–	–	–	–	–	–	7.7	7.7
At 31 December 2025	218.6	1,294.7	(250.1)	0.4	0.9	755.2	(2,272.6)	(252.9)

1. The foreign currency translation reserve represents exchange gains and losses arising on translation of foreign currency subsidiaries, monetary items receivable from or payable to a foreign operation for which settlement is neither planned nor likely to occur, which form part of the net investment in a foreign operation.

2. The hedge reserve represents gains and losses on derivatives classified as effective cash flow hedges.

3. The merger reserve represents the premium on shares issued in relation to acquisitions.

Group cash flow statement

Year ended 31 December 2025

\$m	Notes	2025	2024
Cash flows from operating activities			
(Loss)/Profit for the year from continuing operations before tax		(62.7)	173.7
Profit for the year from discontinued operations before tax		221.9	147.8
Profit for the year before tax		159.2	321.5
Adjustments for:			
Depreciation, depletion and amortisation	10	376.0	444.2
Asset revaluation	12	–	(38.9)
Gain on disposals, net	8	(160.8)	–
Taxes paid in kind	7	(3.8)	(6.3)
Exploration costs written off	9	7.4	212.6
Impairment reversal of property, plant and equipment, net	10	(4.8)	(11.8)
Provisions/(Provisions reversal), net		7.2	(63.3)
Payment for provisions	15	(37.9)	(0.7)
Decommissioning expenditure	15	(17.6)	(45.0)
Share-based payment charge		7.7	6.9
Finance income	6	(64.1)	(71.5)
Finance costs	6	326.9	345.6
Operating cash flow before working capital movements		595.4	1,093.3
(Increase)/decrease in trade and other receivables		(78.5)	0.7
Decrease/(increase) in inventories		20.5	(25.1)
(Decrease)/increase in trade payables		(75.8)	49.9
Cash generated from operating activities		461.6	1,118.8
Income taxes paid		(127.3)	(360.3)
Net cash from operating activities		334.3	758.5
Cash flows from investing activities			
Proceeds from disposals, net of transaction costs		334.2	–
Purchase of additional interests in a joint operation		–	(8.1)
Purchase of intangible exploration and evaluation assets		(7.6)	(27.8)
Purchase of property, plant and equipment		(188.0)	(196.7)
Interest received		10.9	19.5
Net cash from/(used in) investing activities		149.5	(213.1)
Cash flows from financing activities			
Debt arrangement fees		(19.7)	–
Repayment of borrowings		(742.5)	(100.0)
Drawdown of borrowings		420.3	–
Payment of obligations under leases	14	(142.1)	(169.0)
Finance costs paid		(216.2)	(223.2)
Net cash used in financing activities		(700.2)	(492.2)
Net (decrease)/increase in cash and cash equivalents		(216.4)	53.2
Cash and cash equivalents at beginning of year		555.1	499.0
Foreign exchange (loss)/gain		(6.5)	2.9
Cash and cash equivalents at end of year		332.2	555.1

NOTES TO THE FINANCIAL STATEMENTS

Year ended 31 December 2025

1. Basis of preparation and presentation of financial information

The Financial Statements have been prepared in accordance with United Kingdom adopted international accounting standards (UK-adopted IFRSs) and International Financial Reporting Standards adopted pursuant to Regulation (EC) No. 1606/2002 as it applies in the European Union. The financial reporting framework that has been applied in the preparation of the Parent Company Financial Statements is applicable law and United Kingdom Accounting Standards, including FRS 101 Reduced Disclosure Framework (United Kingdom Generally Accepted Accounting Practice).

The financial information for the year ended 31 December 2025 does not constitute statutory accounts as defined in sections 435 (1) and (2) of the Companies Act 2006. Statutory accounts for the year ended 31 December 2024 have been delivered to the Registrar of Companies and those for 2025 will be delivered following the Company's annual general meeting. The auditor's report on these accounts was unqualified, did not include a reference to any matters to which the auditor drew attention by way of emphasis of matter and did not contain a statement under section 498 (2) or (3) of the Companies Act 2006.

The Financial Statements have been prepared on the historical cost basis, except for derivative financial instruments and contingent consideration, which have been measured at fair value which are carried at fair value less cost to sell. The Financial Statements are presented in US dollars and all values are rounded to the nearest \$0.1 million, except where otherwise stated.

The accounting policies applied are consistent with those adopted and disclosed in the Group's Financial Statements for the year ended 31 December 2024. There have been a number of amendments to accounting standards and new interpretations issued by the International Accounting Standards Board which were applicable from 1 January 2025, however, these have not any impact on the accounting policies, methods of computation or presentation applied by the Group. Further details on new International Financial Reporting Standards adopted will be disclosed in the 2025 Annual Report and Accounts.

Certain new accounting standards and interpretations have been published that are not mandatory for 31 December 2025 reporting periods and have not been early adopted by the Group. These standards are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

2. Earnings/(loss) per ordinary share

Basic earnings/(loss) per ordinary share amounts are calculated by dividing net profit/(loss) for the year attributable to ordinary equity holders of the Parent by the weighted average number of ordinary shares outstanding during the year.

Diluted earnings per ordinary share amounts are calculated by dividing net profit/(loss) for the year attributable to ordinary equity holders of the Parent by the weighted average number of ordinary shares outstanding during the year plus the weighted average number of dilutive ordinary shares that would be issued if employee and other share options were converted into ordinary shares.

3. 2025 Annual Report and Accounts

The 2025 Annual Report and Accounts will be mailed in May 2026 only to those shareholders who have elected to receive it. Otherwise, shareholders will be notified that the Annual Report and Accounts are available on the Group's website (www.tulloil.com). Copies of the Annual Report and Accounts will also be available from the Company's registered office at Building 9, Chiswick Park, 566 Chiswick High Road, London, W4 5XT.

4. Segmental Reporting

Following the disposals of operations in Gabon and Kenya in 2025 (refer to note 8), the information reported to the Group's Chief Executive Officer for the purposes of resource allocation and assessment of segment performance is now focused on two Business Units: Ghana and Other, which contain non-operated producing assets in Cote D'Ivoire, decommissioning assets and exploration activities. Therefore, the Group's reportable segments under IFRS 8 are Ghana and Other.

The following tables present revenue, profit and certain asset and liability information regarding the Group's reportable business segments for the years ended 31 December 2025 and 31 December 2024. The table for the year ended 31 December 2024 has been restated to reflect the new reportable segments of the business.

\$m	Ghana	Other ⁴	Corporate	Total
2025				
Sales revenue by origin	833.0	32.8	(18.8)	847.0
Other operating income	–	–	4.2	4.2
Segment result ¹	285.4	(9.2)	(26.2)	250.0
Loss on disposal				(4.5)
Unallocated expenses ²				(45.6)
Operating profit				199.9
Finance income				63.4
Finance costs				(326.0)
Loss before tax				(62.7)
Income tax expense				(66.5)
Loss after tax				(129.2)
Total assets	2,852.1	33.0	393.7	3,278.8
Total liabilities ³	(1,733.8)	(81.0)	(1,716.9)	(3,531.7)
Other segment information				
Capital expenditure:				
Property, plant and equipment	115.6	37.6	0.2	153.4
Intangible exploration and evaluation assets	–	6.8	–	6.8
Depletion, depreciation and amortization	(359.3)	(12.6)	(4.1)	(376.0)
Impairment reversal of property, plant and equipment, net	–	2.8	2.0	4.8
Exploration costs written off	–	(2.1)	–	(2.1)

1. Segment result is a non-IFRS measure which includes gross profit, exploration costs written off and impairment of property, plant and equipment. See reconciliation below.

2. Unallocated expenditure relates to general and administrative expenses not specifically attributable to a geographic area.

3. Total liabilities – Corporate comprise the Group's external debt and other non-attributable liabilities.

4. Other excludes results attributable to Gabon, which is classified as discontinued operations (refer to note 8).

Reconciliation of segment result

\$m	2025	2024
Segment result	250.0	444.2
<i>Add back</i>		
Exploration costs written off	2.1	202.3
Impairment reversal of property, plant and equipment	(4.8)	(11.8)
Gross profit	247.3	634.7

4. Segmental reporting continued

\$m	Ghana	Other ⁴	Corporate	Total
2024 (restated)				
Sales revenue by origin	1,325.4	35.4	(73.6)	1,287.2
Segment result ¹	722.6	(186.8)	(91.6)	444.2
Provisions reversal				70.4
Unallocated expenses ²				(65.9)
Operating profit				448.7
Finance income				69.2
Finance costs				(344.2)
Profit before tax				173.7
Income tax expense				(228.7)
Loss after tax				(55.0)
Total assets	3,164.3	422.1	465.1	4,051.5
Total liabilities ³	(1,978.4)	(266.2)	(2,079.6)	(4,324.2)
Other segment information				
Capital expenditure:				
Property, plant and equipment	126.4	124.5	2.6	253.5
Intangible exploration and evaluation assets	0.2	34.5	–	34.7
Depletion, depreciation and amortisation	(401.4)	(39.7)	(3.1)	(444.2)
Impairment reversal of property, plant and equipment, net	–	11.8	–	11.8
Exploration costs written off	–	(212.6)	–	(212.6)

1. Segment result is a non-IFRS measure which includes gross profit, exploration costs written off and impairment of property, plant and equipment. See reconciliation above.

2. Unallocated expenditure relates to general and administrative expenses not specifically attributable to a geographic area.

3. Total liabilities - Corporate comprise of the Group's external debt, derivative financial instruments and other non-attributable liabilities.

4. Other excludes results attributable to Gabon, which is classified as discontinued operations (refer to note 8).

5. Other costs

\$m	2025	2024 Restated ³
Cost of sales		
Operating costs	202.9	197.8
Depletion and amortisation of oil and gas and leased assets ¹	371.4	412.1
Overlift, underlift and oil stock movements	28.3	42.1
Share-based payment charge included in cost of sales	0.5	0.4
Other cost of sales	0.8	0.1
Total cost of sales	603.9	652.5
Administrative expenses		
Share-based payment charge included in administrative expenses	7.2	6.5
Depreciation of other fixed assets	4.6	6.5
Other administrative costs	33.2	39.2
Total administrative expenses	45.0	52.2
Provisions/(provisions reversal)²	7.2	(63.3)

1. Depreciation expense on leased assets of \$67.7 million (2024: \$91.4 million) as per note 10 includes a charge of \$2.1 million (2024: \$4.1 million) on leased administrative assets, which is presented in administrative expenses in the income statement. The remaining balance of \$65.6 million (2024: \$87.3 million) relates to other leased assets and is included in cost of sales.

2. This includes a provision for restructuring and redundancy costs of \$7.2 million (2024: \$7.1 million). The prior year balance includes reduction in other provisions of \$70.4 million.

3. Comparative amounts have been restated to present Gabon as a discontinued operation. Refer to note 8.

6. Net financing costs

\$m	2025	2024 Restated ¹
Interest on bank overdrafts and borrowings	206.3	211.5
Interest on obligations for leases	97.0	119.7
Total borrowing costs	303.3	331.2
Finance and arrangement fees ²	10.7	3.0
Other interest expense	0.6	–
Unwinding of discount on decommissioning provisions ³	11.4	10.0
Total finance costs	326.0	344.2
Interest income on amounts due from joint venture partners for leases	(37.9)	(48.1)
Other finance income	(25.5)	(21.1)
Total finance income	(63.4)	(69.2)
Net financing costs	262.6	275.0

1. Comparative amounts have been restated to present Gabon as a discontinued operation. Refer to note 8.

2. Finance and arrangement fees mostly relate to costs incurred in unsuccessful refinancing activities. Costs relating to the refinancing transaction announced in February 2026 are recognised in Prepayments (note 11) and will be capitalised on completion of the transaction in 2026.

3. This is excluding \$0.8 million of unwinding of discount on decommissioning provisions in Gabon (2024: \$1.4 million).

7. Taxation on profit on continuing activities

\$m	2025	2024 Restated ¹
Current tax on profits for the year		
Foreign tax	96.6	259.1
Adjustments in respect of prior periods	(0.3)	(1.6)
Total corporate tax	96.3	257.5
UK petroleum revenue tax	–	(2.4)
Total current tax	96.3	255.1
Deferred tax		
Origination and reversal of temporary differences		
UK corporation tax	(24.9)	(19.1)
Foreign tax	(5.5)	(11.1)
Adjustments in respect of prior periods	2.8	(0.1)
Total deferred corporate tax	(27.6)	(30.3)
Deferred UK petroleum revenue tax	(2.2)	3.9
Total deferred tax	(29.8)	(26.4)
Total income tax expense	66.5	228.7

1. Comparative amounts have been restated to present Gabon as a discontinued operation. Refer to note 8.

\$m	2025	2024 Restated ¹
(Loss)/ Profit from continuing activities before tax	(62.7)	173.7
Tax on (loss)/ profit from continuing activities at the standard UK corporation tax rate of 25% (2024: 25%)	(15.7)	43.4
Effects of:		
Non-deductible exploration expenditure	0.4	50.3
Other non-deductible expenses	5.3	(3.5)
Net deferred tax asset not recognised	56.4	78.2
Utilisation of tax losses not previously recognised	(0.2)	(0.6)
Adjustment relating to prior years	2.5	(1.7)
Other tax rates applicable outside the UK	16.6	62.6
Tax impact of acquisitions and disposals	1.2	–
Total income tax expense for the year	66.5	228.7

1. Comparative amounts have been restated to present Gabon as a discontinued operation. Refer to note 8.

Uncertain tax treatments

The Group is subject to various material claims which arise in the ordinary course of its business in various jurisdictions, including cost recovery claims, claims from regulatory bodies and both corporate income tax and indirect tax claims. The Group is in formal dispute proceedings regarding a number of these tax claims. The resolution of tax positions, through negotiation with the relevant tax authorities or litigation, can take several years to complete. In assessing whether these claims should be provided for in the Financial Statements, management has considered them in the context of the applicable laws and relevant contracts for the countries concerned. Management has applied judgement in assessing the likely outcome of the claims and has estimated the financial impact based on external tax and legal advice and prior experience of such claims.

Provisions for uncertain tax treatments of \$78.3 million (2024: \$80.8 million) are included in income tax payable of \$76.7 million (2024: \$79.0 million) and provisions of \$1.7 million (2024: \$1.8 million). Where these matters relate to expenditure which is capitalised within intangible exploration and evaluation assets and property, plant and equipment, any difference between the amounts accrued and the amounts settled is capitalised in the relevant asset balance, subject to applicable impairment indicators. Where these matters relate to producing activities or historical issues, any differences between the accrued and settled amounts are taken to the Group income statement.

Due to the uncertainty of such tax items, it is possible that on conclusion of an open tax matter at a future date, the outcome may differ significantly from management's estimate. If the Group was unsuccessful in defending itself from all these claims, the result would be additional liabilities of \$582.7 million (2024: \$608.7 million) excluding interest and penalties. In management's view the likelihood of the crystallisation of these liabilities and the associated interest and penalties is remote.

7. Taxation on profit on continuing activities continued

The provisions and contingent liabilities relating to uncertain tax treatments have decreased following the conclusion of tax authority challenges and matters lapsing under the statute of limitations, but have increased, following new claims being initiated and extrapolation of exposures through to 31 December 2025, giving rise to an overall decrease in provision of \$2.5 million and decrease in contingent liability of \$26.0 million.

Ghana tax assessments

In October 2021, Tullow Ghana Limited (TGL) filed a Request for Arbitration with the International Chamber of Commerce (ICC) disputing the \$320.3 million Branch Profits Remittance Tax (BPRT) assessment issued as part of the direct tax audit for the financial years 2014 to 2016. The Ghana Revenue Authority (GRA) is seeking to apply BPRT under a law which the Group considers is not applicable to TGL, since it falls outside the tax regime provided for in the Petroleum Agreements and relevant double tax treaties. Two hearings took place in November 2023 and June 2024. On 24 December 2024, the BPRT Tribunal issued its ruling to the ICC, which delivered its award on 2 January 2025 with regard to the BPRT arbitration with the Government of Ghana. The Tribunal determined that BPRT is not applicable to Tullow Ghana since it falls outside the tax regime provided for in the Petroleum Agreements. This means that Tullow Ghana is not liable to pay the \$320.3 million BPRT assessment issued by the GRA, and Tullow has no future exposure to BPRT in respect of its operations under the Petroleum Agreements.

In December 2022, TGL received a \$190.5 million corporate income tax assessment and payment demand from the GRA relating to the disallowance of loan interest for the financial years 2010 to 2020. The Group has previously disclosed assessments by the GRA relating to the same issue; this revised assessment supersedes all previous claims. The Group considers the assessment to breach TGL's rights under its Petroleum Agreements. In February 2023, TGL filed a Request for Arbitration with the ICC disputing the assessment, with the suspension of TGL's obligation to pay any amount in relation to the assessment until the dispute is formally resolved. The parties initially agreed a procedural timetable for the arbitration under which the first Tribunal hearing was to be held in July 2025. This has now been postponed to September 2026 allowing more time to continue settlement negotiations.

In December 2022, TGL received a \$196.5 million corporate income tax assessment and payment demand from the GRA relating to proceeds received by Tullow during the financial years 2016 to 2019 under Tullow's corporate Business Interruption insurance policy. The Group considers the assessment to breach TGL's rights under its Petroleum Agreements. In February 2023, TGL filed a Request for Arbitration to the ICC disputing the assessment, with the suspension of TGL's obligation to pay any amount in relation to the assessment until the dispute is formally resolved. The first Tribunal hearing was held in November 2025 and a ruling is expected mid-year 2026.

The Group continues to engage with the Government of Ghana with the aim of resolving these tax disputes on a mutually acceptable basis.

Kenya tax assessments

The Group is aware of a tax assessment for c.\$170 million from the Kenya Revenue Authority relating to alleged underpaid VAT and Capital Gains Tax on the disposal of its 100% shareholding in its Kenyan subsidiary, Tullow Kenya BV, to the Gulf Energy Group for a minimum consideration of \$120 million. The Group's clear and firm position is that the assessment is wholly without merit, and it intends in conjunction with Gulf Energy to contest the assessment through the regular objection process. There will be no cash outflow in respect of lodging these objections, nor does the Group expect cash outflow on completion of its appeal process. Therefore, a provision for uncertain tax treatments in respect of this risk has not been recorded.

Bangladesh litigation

The National Board of Revenue (NBR) is seeking to disallow \$118 million of tax relief in respect of development costs incurred by Tullow Bangladesh Limited (TBL). The NBR subsequently issued a payment demand to TBL in February 2020 for Taka 3,094 million requesting payment by 15 March 2020. The amount in USD including legal costs is c.\$29 million. However, under the Production Sharing Contract (PSC), the government is required to indemnify TBL against all taxes levied by any public authority, and the share of production paid to Petrobangla (PB), Bangladesh's national oil company, is deemed to include all taxes due, which PB is then obliged to pay to the NBR. TBL sent the payment demand to PB and the government requesting the payment or discharge of the payment demand under their respective PSC indemnities. On 14 June 2021, TBL issued a formal notice of dispute under the PSC to the government and PB. A further request for payment was received from NBR on 28 October 2021 demanding settlement by 15 November 2021. Arbitration proceedings were initiated under the PSC on 29 December 2021, and a hearing of the merits of the case were heard by the Tribunal on 20 May 2024. Final written submissions were made to the Tribunal in September 2024. The Tribunal has informed both parties that a ruling can be expected during the first half of 2026.

Other items

Other items totalling \$166.6 million (2024: \$192.3 million) comprise exposures in respect of claims for corporation tax from disallowed expenditure or withholding taxes that are either currently under discussion with the tax authorities or which arise from known issues for periods not yet under audit.

Timing of cash-flows

While it is not possible to estimate the timing and amount of tax cash flows in relation to possible outcomes with certainty, management anticipates that there will not be material cash taxes paid in excess of the amounts provided for uncertain tax treatments.

8. Asset disposals and discontinued operations

Gabon

On 29 July 2025, Tullow completed the sale of Tullow Oil Gabon SA to the Gabon Oil Company for a total cash consideration of \$307 million, net of tax and customary adjustments. The transaction was a corporate sale of Tullow's entire Gabonese portfolio of assets, representing c.10 kbopd of production and c.36 million barrels of 2P reserves. The transaction was subject to a capital gains tax of \$51.7 million as agreed with the Gabon Tax Authority, payable by the Gabon Oil Company. This was recorded as an income tax expense with a corresponding pre-tax gain on disposal and no deferred tax recognised.

This represents a disposal of a separate major geographical area of operations under IFRS 5 Non-current Assets Held for Sale and Discontinued Operation, and as such the results of operations in Gabon have been presented as a discontinued operation for the years ended 31 December 2025 and 2024.

The results from discontinued operations for the year are presented below:

\$m	2025	2024
Discontinued operations		
Revenue	115.4	247.7
Cost of sales	(53.1)	(128.4)
Gross profit	62.3	119.3
Administrative expenses	(0.2)	(1.0)
Asset revaluation	–	38.9
Exploration costs written off	(5.3)	(10.3)
Operating profit	56.8	146.9
Finance income	0.7	2.3
Finance costs	(0.9)	(1.4)
Profit before tax	56.6	147.8
Income tax expense	(34.5)	(38.2)
Profit after tax	22.1	109.6
Gain on disposal	165.3	–
Tax on gain on disposal	(51.7)	–
Profit after tax from discontinued operations	135.7	109.6
Earnings per share from discontinued operations, ¢	2025	2024
Basic	9.3	7.5
Diluted	9.0	7.1

The net cash flows generated/(incurred) by Tullow Oil Gabon SA are as follows:

\$m	2025	2024
Cash flows from operating activities	(24.2)	21.4
Cash flows from investing activities	(87.7)	(45.7)
Cash flows from financing activities	114.9	22.2
Net cash inflow/(outflow)	3.0	(2.1)

8. Asset disposals and discontinued operations continued

The net assets disposed from the transaction and the subsequent gain on disposal for the year ended 31 December 2025 are as follows:

\$m	2025
Goodwill	44.9
Intangible exploration and evaluation assets	6.1
Property, plant and equipment	204.5
Inventories	21.8
Trade receivables	26.0
Other current assets	0.1
Cash and cash equivalents	0.9
Total assets disposed	304.3
Trade and other payables	(16.1)
Current tax liabilities	(18.9)
Provisions	(35.9)
Deferred tax liabilities	(48.4)
Total liabilities disposed	(119.3)
Net assets disposed	185.0

\$m	2025
Cash consideration	307.1
Capital gains tax paid by Gabon Oil Company	51.7
Net assets disposed	(185.0)
Transaction costs	(8.5)
Gain on disposal	165.3

8. Asset disposals and discontinued operations continued

Kenya

On 25 September 2025, Tullow completed the sale of Tullow Kenya BV, which holds Tullow's entire working interest in Kenya, to Auron Energy E&P Limited, an affiliate of Gulf Energy Limited, for a total consideration of at least \$120 million. The consideration is split into \$40 million payment received on completion (Tranche A), \$40 million receivable at the earlier of Field Development Plan (FDP) approval or 30 June 2026 (Tranche B), and \$40 million receivable no later than 2033 (Tranche C), subject to the following payment schedule:

- Payments of \$2 million per quarter starting in the third quarter of 2028, provided Dated Brent oil price averaged at least \$65/bbl during the preceding quarter.
- If \$40 million in aggregate has not been paid by 30 June 2033, the remainder will be due as a bullet payment at that point irrespective of the prevailing oil price.

In addition, Tullow is entitled to royalty payments subject to subject to oil price, resource, and production related conditions. Tullow also retains a back-in right for a 30% participation in potential future development phases at no cost.

\$36 million proceeds of the Tranche B was received on 9 March 2026. The final 10% of Tranche B proceeds (\$4 million), was received on 1 April following completion of transition support services.

Tullow Kenya BV is not presented as a discontinued operation for the year ended 31 December 2025 as it is not a major line of business for the Group.

The net assets disposed from the transaction and the subsequent loss on disposal for the year ended 31 December 2025 are as follows:

\$m	2025
Intangible exploration and evaluation assets	107.7
Trade receivables	8.4
Other current assets	0.4
Cash and cash equivalents	1.8
Total assets disposed	118.3
Trade and other payables	(5.1)
Total liabilities disposed	(5.1)
Net assets disposed	113.2

\$m	2025
Consideration ¹	110.5
Net assets disposed	(113.2)
Transaction costs	(1.8)
Loss on disposal	(4.5)

1. Consideration relates to \$40 million cash received (Tranche A) and the present value of Tranches B-C. No amount has been recognised with respect to the royalty payments and the back-in right as their fair value cannot be reliably estimated as of the reporting date.

Net proceeds from disposals of \$334.2 million were received during the year, comprising cash consideration of \$347.0 million, less transaction cost of \$10.3 million and cash disposed of \$2.7 million relating to disposals in Kenya and Gabon, as well as \$0.2 million of other disposals.

9. Intangible exploration and evaluation assets

\$m	2025	2024
At 1 January	109.1	287.0
Additions	6.8	34.7
Exploration costs written off	(2.1)	(212.6)
Disposals ¹	(113.8)	–
At 31 December	–	109.1

1. This balance relates to assets in Gabon and Kenya. Refer to note 8.

The below table provides a summary of the exploration costs written off on a pre-tax basis by country.

Country	CGU	Rationale for 2025 write-off	2025 Write-off \$m	2025 Remaining recoverable amount \$m
Argentina	MLO114, MLO119 and MLO122	a	1.2	–
Côte d'Ivoire	Block 524 and Block 803	b	0.5	–
Other	Various	c	0.4	–
Total write-off			2.1	

a. Licence period concluded in October 2025.

b. Licence periods concluded in May 2025 for Block 803 and August 2025 for Block 524.

c. Current year expenditure on assets previously written off.

d. In addition to the exploration costs written off stated above, \$5.3 million has been recognised in Gabon relating to uncommercial well costs incurred in DE8 and Simba cash-generating units (CGUs). This is presented as discontinued operations in note 8.

Country	CGU	Rationale for 2024 write-off	2024 Write-off restated ^e \$m	2024 Remaining recoverable amount \$m
Argentina	MLO114, MLO119 and MLO122	a	38.8	–
Côte d'Ivoire	Block 524 and Block 803	a	15.5	–
Kenya	Blocks 10BB and 13T	b	145.4	103.2
New Ventures	Various	c	1.3	–
Uganda	Exploration areas 1, 1A, 2 and 3A	d	0.8	–
Other	Various		0.5	–
Total write-off			202.3	

a. No further activity planned following unsuccessful farm-down efforts.

b. Delay in farm-down and extension of Field Development Plan review period.

c. New Ventures expenditure is written off as incurred.

d. Indirect tax movement on previously disposed or written-off assets.

e. In addition to the exploration costs written off stated above, \$10.3 million has been recognised in Gabon relating to uncommercial well costs incurred in Simba CGU. This is presented as discontinued operations in note 8.

10. Property, plant and equipment

\$m	2025 Oil and gas assets	2025 Other fixed assets	2025 Right-of-use assets	2025 Total	2024 Oil and gas assets	2024 Other fixed assets	2024 Right-of-use assets	2024 Total
Cost								
At 1 January	11,513.8	23.4	1,124.4	12,661.6	11,282.1	21.9	1,268.8	12,572.8
Additions	153.1	0.3	–	153.4	151.6	3.1	1.4	156.1
Acquisitions	–	–	–	–	97.4	–	–	97.4
Disposal	(718.0)	(2.4)	–	(720.4)	–	–	–	–
Asset retirement	–	–	–	–	–	(1.3)	(145.3)	(146.6)
Currency translation adjustments	78.0	0.9	2.2	81.1	(17.3)	(0.3)	(0.5)	(18.1)
At 31 December	11,026.9	22.2	1,126.6	12,175.7	11,513.8	23.4	1,124.4	12,661.6
Depreciation, depletion and amortization and impairment								
At 1 January	(9,698.9)	(18.6)	(620.0)	(10,337.5)	(9,377.7)	(17.5)	(644.8)	(10,040.0)
Charge for the year	(305.8)	(2.5)	(67.7)	(376.0)	(350.3)	(2.5)	(91.4)	(444.2)
Impairment reversal	2.8	–	2.0	4.8	11.8	–	–	11.8
Capitalised depreciation	–	–	(8.3)	(8.3)	–	–	(29.5)	(29.5)
Disposal	513.6	2.3	–	515.9	–	–	–	–
Asset retirement	–	–	–	–	–	1.3	145.3	146.6
Currency translation adjustments	(78.0)	(0.6)	(1.7)	(80.3)	17.3	0.1	0.4	17.8
At 31 December	(9,566.3)	(19.4)	(695.7)	(10,281.4)	(9,698.9)	(18.6)	(620.0)	(10,337.5)
Net book value at 31 December	1,460.6	2.8	430.9	1,894.3	1,814.9	4.8	504.4	2,324.1

The Group applied the following nominal oil price assumption for impairment assessments:

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 onwards
2025	\$60/bbl	\$64/bbl	\$70/bbl	\$70/bbl	\$70/bbl	\$70/bbl inflated at 2%
2024	\$74/bbl	\$71/bbl	\$75/bbl	\$75/bbl	\$75/bbl	\$75/bbl inflated at 2%

	Trigger for 2025 Impairment/ (reversal)	2025 Impairment/ (reversal) \$m	Pre-tax discount rate assumption	2025 Remaining recoverable amount ^e \$m
Espoir (Cote D'Ivoire)	a	4.5	n/a	–
Mauritania	b	0.2	n/a	–
UK CGU	b,c	(7.5)	n/a	–
UK Corporate	d	(2.0)	n/a	–
Impairment reversal		(4.8)		–

a. Impairment of capital expenditure in excess of accumulated depreciation as the NPV of the asset is nil.

b. Change to decommissioning estimate.

c. The fields in the UK are grouped into one CGU as all fields share critical gas infrastructure.

d. Partial reversal of previously recognised impairment of right-of-use asset relating to office space.

e. The remaining recoverable amount of the asset is its value in use.

The \$35.0 million impairment in the TEN fields recognised at 30 June 2025 has been fully reversed at the year end. This change has been recognised following an assessment which determined that the fair value less cost of disposal (FVLCD) of TEN of \$41.4 million was materially equal to the total carrying value of the CGU. FVLCD reflects the impact of the acquisition of the FPSO, as a market participant would have assumed the successful completion of the purchase transaction when pricing the asset. A pre-tax discount rate of 14% was applied in the assessment.

Oil prices stated above are benchmark prices to which an individual field price differential is applied. All impairment assessments are prepared on a VIU or FVLCD basis using discounted future cash flows based on 2P reserves profiles. A reduction or increase in the two-year forward curve of \$5/bbl, based on the approximate range of annualised average oil price over recent history, and a reduction or increase in the medium and long-term price assumptions of \$5/bbl, based on the range of annualised average historical prices, are considered to be reasonably possible changes for the purposes of sensitivity analysis. Decreases to oil prices specified above would result in an impairment charge for TEN of \$41.4 million, reducing the remaining carrying value of the CGU to \$nil, whilst increases to oil prices specified above would lead to an impairment reversal of \$43.6 million. A 1% increase in the post-tax discount rate would result in an impairment charge of \$8.5 million. The Group believes a 1% increase in the post-tax discount rate to be a reasonable possibility based on historical analysis of the Group's and peer group of companies' impairments. The above scenarios would not have an impact on the carrying value of Jubilee.

10. Property, plant and equipment continued

	Trigger for 2024 Impairment/ (reversal)	2024 Impairment/ (reversal) \$m	Pre-tax discount rate assumption	2024 Remaining recoverable amount ^e \$m
Espoir (Cote D'Ivoire)	a	2.5	14%	–
Mauritania	b	(19.7)	n/a	–
UK CGU	c,d	5.4	n/a	–
Impairment reversal		(11.8)		

a. Change to decommissioning discount rate.

b. Impairment reversal driven by operational efficiencies and scope revision.

c. Change to decommissioning estimate.

d. The fields in the UK are grouped into one CGU as all fields share critical gas infrastructure.

e. The remaining recoverable amount of the asset is its value in use.

11. Other assets

\$m	2025	2024
Non-current		
Amounts due from joint venture partners	269.7	333.1
VAT recoverable	–	7.7
Deferred consideration	30.5	–
	300.2	340.8
Current		
Amounts due from joint venture partners	404.7	350.2
Underlifts	–	20.9
Prepayments	20.1	17.1
Deferred consideration	40.0	–
Other current assets	8.1	3.7
	472.9	391.9
	773.1	732.7

Non-current receivables from joint venture partners include the Ghana decommissioning fund, which relates to the requirement for joint venture partners of the Unitisation and Unit Operating Agreement (UUOA) to establish a trust fund in which the estimated cost of decommissioning and abandonment are accrued to cover decommissioning obligations in respect of the Jubilee Field Unit when the trigger date occurs. As at 31 December 2025, Tullow has contributed \$23.2 million (2024: \$11.6 million) into the decommissioning trust fund.

The increase in current receivables from joint venture partners compared to 31 December 2024 relates to net increase in GNPC (Ghana National Petroleum Corporation) receivable and other working capital movements.

GNPC receivables as at 31 December 2025 were \$223.1 million net to Tullow (2024: \$110.8 million), with \$64.9 million related to cash calls (2024: \$6.7 million), \$107.8 million related to gas receivable (2024: \$56.2 million) and \$50.4 million related to TEN development debt (2024: \$47.9 million). Tullow is working with the Government of Ghana and its agencies to resolve these outstanding balances.

Deferred consideration relates to Tranche B and C, adjusted for time value of money, from disposal of assets in Kenya (refer to note 8).

12. Business combination

On 29 February 2024, the Group completed the asset swap agreement (ASA) transaction with Perenco Oil and Gas Gabon S.A (Perenco). The rationale for the transaction was the simplification of the Group's equity ownership across key fields in Gabon, creating better alignment between the participating interest partners and streamlining processes such as budgeting, cost management and capital allocation. The revised portfolio of assets has enabled Tullow to leverage its technical skills and focus on more material positions in key fields.

The transaction was an asset swap achieved through the exchange of participating interests held by both parties in certain licences in Gabon. The exchange represented the acquisition of an additional interest in a joint operation that constitutes a business, and therefore IFRS 11 Joint Arrangements required the application of the principles in IFRS 3 Business Combinations.

In line with the requirements of IFRS 3, the interests transferred as part of the consideration, which comprised mainly of property, plant, and equipment of \$54.4 million, were remeasured to the acquisition date fair value of \$93.3 million. This resulted in an asset revaluation gain of \$38.9 million recognised in the income statement at 31 December 2024.

The fair values of the identifiable assets and liabilities acquired were:

	Fair value recognised on acquisition \$m
Intangible assets	1.0
Property, plant and equipment	97.4
Other current assets	0.7
Goodwill	44.9
Total assets acquired	144.0
Provisions	(5.8)
Deferred tax liabilities	(44.9)
Total liabilities assumed	(50.7)
Net identifiable assets acquired	93.3
Total purchase consideration	(93.3)
Consideration satisfied by exchange of assets	(85.2)
Consideration satisfied by cash	(8.1)
Purchase of additional interest in joint operation per the cash flow statement	(8.1)

The fair value of the purchase consideration of \$93.3 million reflected the discounted future cash flows of the assets and liabilities exchanged as part of the swap as the transaction was intended to be value neutral. However, as the transaction completed more than a year later, the ASA included provisions to ensure the neutrality of the transaction via cash adjustments for the period between the economic date and the completion date, the agreed adjustment upon completion was \$8.1 million, which has been included in investing activities in the cash flow statement.

IAS 12 Income Taxes requires recognition of a deferred tax asset or liability for the difference between the fair value of the assets acquired and liabilities assumed, and their respective tax bases. Goodwill of \$44.9 million was recognised as a direct result of the recognition of the deferred tax liability.

The assets and liabilities acquired from the transaction, including the goodwill, were part of the disposal group in the sale of Tullow Oil Gabon SA in the year ending 31 December 2025. Refer to note 8.

13. Trade and other payables

\$m	2025	2024
Current		
Trade payables	92.7	75.7
Other payables	63.3	96.8
Overlifts	15.3	38.3
Accruals	305.4	373.8
Current portion of leases	161.7	151.9
	638.4	736.5
Non-current		
Other non-current liabilities ¹	56.1	84.9
Non-current portion of leases	436.9	581.0
	493.0	665.9

1. Other non-current liabilities include balances related to joint venture partners.

Accruals relate to operating and administrative expenditure of \$147.1 million (2024: \$196.3 million), capital expenditure of \$124.1 million (2024: \$119.6 million), interest expense on bonds of \$24.0 million (2024: \$35.3 million) and staff-related expenses of \$10.2 million (2024: \$22.6 million). The movement in the operating and administrative expenditure is driven by efficiencies in cost management and optimised contractual arrangements with suppliers.

Trade and other payables are non-interest bearing except for leases (note 14). The change in trade payables and in other payables represents timing differences and levels of work activity, particularly the ongoing drilling campaign in Jubilee which commenced in late 2025.

Payables related to operated joint ventures (primarily in Ghana) are recorded gross with the amount representing the partners' share recognised in amounts due from joint venture partners (note 11).

The movement in current and non-current lease liabilities is mainly driven by the level of drilling activity in Ghana (note 14).

14. Leases

This note provides information for leases where the Group is a lessee. The Group did not enter into any material contracts acting as a lessor.

i) Amounts recognised in the balance sheet

\$m	Right-of-use assets		Lease liabilities	
	2025	2024	2025	2024
Right-of-use assets (included within property, plant and equipment) and lease liabilities				
Property leases	15.9	18.2	21.4	26.1
Oil and gas production and support equipment leases	400.5	466.4	541.4	661.9
Transportation equipment leases	14.5	19.8	35.8	44.9
Total	430.9	504.4	598.6	732.9
Current provisions			161.7	151.9
Non-current			436.9	581.0
Total			598.6	732.9

There were no additions and disposals of right-of-use assets during the 2025 financial year (2024: \$1.4 million and \$145.3 million). Refer to note 10.

14. Leases continued

TEN FPSO

The Group's leases balance includes the TEN FPSO. As at 31 December 2025, the present value of the TEN FPSO right-of-use asset was \$398.3 million (2024: \$466.3 million).

The present value of the TEN FPSO gross lease liability was \$534.4 million (2024: \$650.0 million).

A receivable from the joint venture partners of \$200.5 million (2024: \$244.9 million) was recognised in other assets (note 11) to reflect the value of future payments that will be met by cash calls from partners relating to the TEN FPSO lease. The present value of the receivable from the joint venture partners unwinds over the expected life of the lease and the unwinding of the discount is reported in the finance income.

On 19 February 2026, Tullow announced that it signed a Sale and Purchase Agreement to acquire the TEN FPSO on behalf of the joint venture.

Carrying amounts of the lease liabilities and joint venture leases receivables and the movements during the period:

\$m	Lease liabilities	Joint venture lease receivables	Total
At 1 January 2024	(906.7)	349.5	(557.2)
Additions and changes in lease estimates	1.6	1.2	2.8
Payments/(receipts)	291.6	(122.6)	169.0
Interest (expense)/income	(119.7)	48.1	(71.6)
Currency translation adjustments	0.3	–	0.3
At 1 January 2025	(732.9)	276.2	(456.7)
Payments/(receipts)	232.3	(90.2)	142.1
Interest (expense)/income	(97.0)	37.9	(59.1)
Currency translation adjustments	(1.0)	–	(1.0)
At 31 December 2025	(598.6)	223.9	(374.7)

ii) Amounts recognised in the statement of profit or loss

\$m	2025	2024
Depreciation charge of right-of-use assets		
Property leases	4.4	8.5
Oil and gas production and support equipment leases	63.3	82.9
Total	67.7	91.4
Interest expense on lease liabilities (included in finance costs)	97.0	119.7
Interest income on amounts due from joint venture partners	(37.9)	(48.1)
Expense relating to short-term leases	57.2	0.8
Expense relating to leases of low-value assets	0.6	0.6
Total	184.6	164.4

The total net cash outflow for leases in 2025 was \$142.1 million (2024: \$169.0 million).

15. Provisions

\$m	Decommissioning 2025	Other provisions 2025	Total 2025	Decommissioning 2024	Other provisions 2024	Total 2024
At 1 January	306.4	39.4	345.8	377.9	93.7	471.6
New provisions	–	16.5	16.5	–	22.4	22.4
Changes in estimate	(32.1)	(2.1)	(34.2)	(39.3)	(75.9)	(115.2)
Acquisitions	–	–	–	5.8	–	5.8
Disposal of subsidiaries	(31.6)	(4.3)	(35.9)	–	–	–
Payments	(5.9)	(37.9)	(43.8)	(49.0)	(0.7)	(49.7)
Unwinding of discount	12.2	–	12.2	11.4	–	11.4
Currency translation adjustment	1.9	0.3	2.2	(0.4)	(0.1)	(0.5)
At 31 December	250.9	11.9	262.8	306.4	39.4	345.8
Current provisions	3.3	2.2	5.5	9.8	14.5	24.3
Non-current provisions	247.6	9.7	257.3	296.6	24.9	321.5

Other provisions include non-income tax provisions of \$5.7 million (2024: \$7.1 million) and \$6.2 million (2024: \$32.3 million) of disputed cases and claims. Management estimates non-current other provisions would fall due between two and five years.

New other provisions of \$16.5 million mainly relate to redundancy and restructuring costs incurred during the year.

The decommissioning provision represents the present value of decommissioning costs relating to the UK and African oil and gas interests. The Group has assumed cessation of production as the estimated timing for outflow of expenditure. However, expenditure could be incurred prior to cessation of production or after and actual timing will depend on a number of factors, including underlying cost environment, availability of equipment and services, and allocation of capital.

Decommissioning provisions	Inflation assumption ¹	Discount rate assumption 2025	Cessation of production assumption 2025	Total 2025 \$m	Discount rate assumption 2024	Cessation of production assumption 2024	Total 2024 \$m
Côte d'Ivoire	n/a	n/a	2026	54.8	4.5%	2026	50.0
Gabon	n/a	n/a	n/a	-	4.5-5.0%	2030-2047	30.7
Ghana	2.0%	4.0%	2035-2036	177.0	4.5%	2033-2036	195.6
Mauritania	n/a	n/a	2018	0.8	n/a	2018	1.1
UK	n/a	3.5%	2018	18.3	n/a	2018	29.0
				250.9			306.4

1. Short-term inflation rate assumption has increased from 2.5% to 3% in 2026. Long-term rates of 2% remained unchanged from 31 December 2024.

The Group is in discussions with the regulator in respect of the impact of the intended transfer of operatorship to the PetroCi (upon expiry of the license effective July 2026) on the decommissioning obligation for the Espoir field in Côte d'Ivoire. Inflation and discounting adjustments have not been applied to the decommissioning estimate.

The Group's decommissioning activities are ongoing in the UK and Mauritania, with \$3.3 million of the future costs expected to be incurred in 2026. The remaining activities are planned to continue through to 2030, with an associated expenditure of \$15.8 million, mostly in the UK.

16. Commercial reserves and contingent resources summary working interest basis

	Ghana		Other		Total		
	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Oil mmbbl	Gas bcf	Petroleum mmboe ⁶
COMMERCIAL RESERVES¹							
1 January 2025	104.8	138.4	36.4	1.1	141.2	139.5	164.5
Revisions ³	(14.7)	7.8	-	-	(14.7)	7.8	(13.4)
Production	(11.9)	(14.8)	(0.3)	(0.8)	(12.2)	(15.6)	(14.8)
Acquisitions	-	-	-	-	-	-	-
Disposals ^{4,5}	-	-	(36.0)	-	(36.0)	-	(36.0)
31 December 2025	78.2	131.4	0.1	0.3	78.3	131.7	100.3
CONTINGENT RESOURCES²							
1 January 2025	126.4	438.8	509.2	13.9	635.6	452.7	711.0
Revisions ³	(11.2)	(8.9)	-	-	(11.2)	(8.9)	(12.7)
Acquisitions	-	-	-	-	-	-	-
Disposals ^{4,5}	-	-	(494.7)	-	(494.7)	-	(494.7)
31 December 2025	115.2	429.9	14.5	13.9	129.7	443.8	203.6
TOTAL							
31 December 2025	193.4	561.3	14.6	14.2	208.0	575.5	303.9

1. Reserves presented are 'proven and probable'. They are as audited and reported by the independent third-party reserves auditor as at year end 2025.

2. Contingent resources are 'best estimate'. For Ghana, they are as audited and reported by the independent third-party reserves auditor as at year end 2025.

3. Reserves and resources revisions in Ghana are primarily related to a technical re-evaluation based on Jubilee production performance during 2025.

4. Reserve and resource changes in the non-operated portfolio primarily reflect the disposal of the Gabon assets at the start of 2025, with only the Espoir asset remaining at the end of 2025.

5. The sale of S.Lokichar assets in Kenya have contributed the most significant reduction in contingent resources.

6. A gas conversion factor of 6 mscf/boe is used to calculate the total petroleum mmboe.

The Group provides for depletion and amortisation of tangible fixed assets on a net entitlements basis, which reflects the terms of the Production Sharing Contracts related to each field. Total working interest reserves were 100.4 mmboe at 31 December 2025 (31 December 2024: 161.5 mmboe).

Contingent resources are discovered resources for which development plans are either in the course of preparation, on hold or further evaluation is under way with a view to future development.

Alternative performance measures

The Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. These non-IFRS measures include capital investment, net debt, gearing, adjusted EBITDAX, underlying cash operating costs, free cash flow, underlying operating cash flow and pre-financing cash flow.

Capital investment

Capital investment is defined as additions to property, plant and equipment and intangible exploration and evaluation assets less decommissioning asset additions, right-of-use asset additions, lease payments related to capital activities, additions to administrative assets, and certain other adjustments. The Directors believe that capital investment is a useful indicator of the Group's organic expenditure on exploration and evaluation assets and oil and gas assets incurred during a period because it eliminates certain accounting adjustments such as decommissioning and administrative asset additions.

\$m	2025	2024
Additions to property, plant and equipment	153.1	249.0
Additions to intangible exploration and evaluation assets	6.8	34.7
Less		
Changes to decommissioning asset estimates	(32.1)	(39.3)
Right-of-use asset additions	–	1.4
Lease payments related to capital activities	–	(21.9)
Additions to administrative assets	0.3	3.1
Other non-cash capital movements ¹	(3.7)	109.3
Capital investment	195.4	231.1
Movement in working capital	(0.1)	(1.6)
Additions to administrative assets	0.3	3.1
Cash capital expenditure per the cash flow statement	195.6	232.6

1. In 2024, Other Non-cash capital movements includes \$95 million of additions in relation to asset swap with Perenco in Gabon.

Net debt

Net debt is a useful indicator of the Group's indebtedness, financial flexibility and capital structure because it indicates the level of cash borrowings after taking account of cash and cash equivalents in the Group's business that could be utilised to pay down the outstanding cash borrowings. Net debt is defined as current and non-current borrowings plus non-cash adjustments, less cash and cash equivalents. Non-cash adjustments include unamortised arrangement fees and other adjustments. The Group's definition of net debt does not include the Group's leases as the Group's focus is the management of cash borrowings and a lease is viewed as deferred capital investment. The value of the Group's lease liabilities as at 31 December 2025 was \$161.7 million current and \$436.9 million non-current; it should be noted that these balances are recorded gross for operated assets and are therefore not representative of the Group's net exposure under these contracts.

\$m	2025	2024
Current borrowings	1,277.9	589.4
Non-current borrowings	381.0	1,386.4
Non-cash adjustments ¹	26.3	31.6
Less cash and cash equivalents ²	(332.2)	(555.1)
Net debt	1,353.0	1,452.3

1. Non-cash adjustments include unamortised arrangement fees which are incurred on creation or amendment of borrowing facilities.

2. Cash and cash equivalents include an amount of \$6.8 million (2024: \$83.5 million) which the Group holds as operator in joint venture bank accounts. Included in cash at bank is \$3.0 million (2024: \$6.5 million) held in restricted bank accounts. This mainly consists of \$2.3 million pledged as collateral for a Letter of Credit Facility. In the prior year, \$6.5 million was held as security for performance bonds relating to work commitments on exploration licences.

Gearing and Adjusted EBITDAX

Gearing is a useful indicator of the Group's indebtedness, financial flexibility and capital structure and can assist securities analysts, investors and other parties to evaluate the Group. Gearing is defined as net debt divided by adjusted EBITDAX. Adjusted EBITDAX is defined as profit/(loss) from continuing activities adjusted for income tax expense, finance costs, finance revenue, loss on disposal, depreciation, depletion and amortisation, share-based payment charge, provision reversal, exploration costs written off, impairment reversal of property, plant and equipment net, expected credit loss (reversal)/charge on trade receivables and restructuring provision.

\$m	2025	2024 Restated ¹
Loss for the year from continuing activities	(129.2)	(55.0)
Adjusted for		
Income tax expense	66.5	228.7
Finance costs	326.0	344.2
Finance revenue	(63.4)	(69.2)
Loss on disposal	4.5	–
Depreciation, depletion and amortisation	376.0	418.7
Share-based payment charge	7.7	6.9
Provision reversal	–	(70.4)
Exploration costs written off	2.1	202.3
Impairment reversal of property, plant and equipment, net	(4.8)	(11.8)
Expected credit loss (reversal)/charge on trade receivables	(6.6)	6.6
Restructuring provision	7.2	7.1
Adjusted EBITDAX³	586.0	1,008.1
Net debt	1,353.0	1,452.3
Gearing (times)	2.3	1.4

1. Comparative adjusted EBITDAX and gearing have been restated to present Gabon as a discontinued operation. Refer to note 8.

Balances above are presented excluding discontinued operations in Gabon.

Adjusted EBITDAX including results from discontinued operations in Gabon is \$648.1 million (2024: \$1,151.9 million).

Underlying cash operating costs

Underlying cash operating costs is a useful indicator of the Group's costs incurred to produce oil and gas. Underlying cash operating costs eliminates certain non-cash accounting adjustments to the Group's cost of sales to produce oil and gas. Underlying cash operating costs is defined as cost of sales less operating lease expense, depletion and amortisation of oil and gas assets, underlift, overlift and oil stock movements, share-based payment charge included in cost of sales, royalties and certain other cost of sales. Underlying cash operating costs are divided by production to determine underlying cash operating costs per boe.

In 2024 and 2025, Tullow incurred abnormal non-recurring costs, which are presented separately below. The adjusted normalised cash operating costs are a helpful indicator to the forward underlying costs of the business.

\$m	2025	2024 Restated ⁵
Cost of sales	603.9	652.5
Add		
Lease payments related to operating activity	11.6	11.6
Less		
Depletion and amortisation of oil and gas and leased assets ¹	371.4	412.1
Underlift, overlift and oil stock movements ²	28.3	42.1
Share-based payment charge included in cost of sales	0.5	0.4
Other cost of sales ³	12.4	11.7
Underlying cash operating costs	202.9	197.8
Non-recurring costs ⁴	(24.4)	(8.3)
Total normalised cash operating costs	178.5	189.5
Production (MMboe)	14.7	18.9
Underlying cash operating costs per boe (\$/boe)	13.8	10.5
Normalised cash operating costs per boe (\$/boe)	12.1	10.0

1. Depletion and amortisation of oil and gas assets is the depreciation and amortisation of the Group's oil and gas assets over the life of an asset on a unit of production basis.

2. Under lifting or offtake arrangements for oil and gas produced in certain operations in which the Group has interests with other commercial partners, each participant may not receive and sell its precise share of the overall production in each period. The resulting imbalance between cumulative entitlement and cumulative production less stock constitutes "underlift" or "overlift". Underlift and overlift are valued at market value and included within other current assets and other current payables on the Group's balance sheet, respectively. Movements during an accounting period are charged to cost of sales rather than charged through revenue, and as a result gross profit is recognised on an entitlements basis.

3. Other cost of sales includes purchases of gas from third parties to fulfil gas sales contracts and royalties paid in cash.

4. Non-recurring costs include vessel Class maintenance related works and shutdown preparation costs.

5. Comparative balances have been restated to present Gabon as a discontinued operation. Refer to note 8.

6. Balances above are presented excluding discontinued operations in Gabon.

Free cash flow

Free cash flow is a useful indicator of the Group's ability to generate cash flow to fund the business and strategic acquisitions, reduce borrowings and provide returns to shareholders through dividends. Free cash flow is defined as net cash from operating activities, and net cash from/ (used in) investing activities, repayment of obligations under leases, finance costs and debt arrangement fees paid and foreign exchange (loss)/ gain.

\$m	2025	2024
Net cash from operating activities	334.3	758.5
Net cash from/ (used in) investing activities	149.5	(213.1)
Repayment of obligations under leases	(142.1)	(169.0)
Finance costs paid	(216.2)	(223.2)
Debt arrangement fees	(19.7)	–
Foreign exchange (loss)/gain	(6.5)	2.9
Free cash flow	99.3	156.1

Underlying operating cash flow

This is a useful indicator of the Group's assets' ability to generate cash flow to fund further investment in the business, reduce borrowings and provide returns to shareholders. Underlying operating cash flow is defined as net cash from operating activities less repayment of obligations under leases plus decommissioning expenditure.

Pre-financing cash flow

This is a useful indicator of the Group's ability to generate cash flow to reduce borrowings and provide returns to shareholders through dividends. Pre-financing free cash flow is defined as net cash from operating activities, and net cash used in investing activities, less repayment of obligations under leases and foreign exchange gain.

\$m	2025	2024
Net cash from operating activities	334.3	758.5
Add		
Decommissioning expenditure	17.6	45.0
Lease payments related to capital activities	–	21.9
Payments to decommissioning escrow fund	11.6	11.6
Less		
Repayment of obligations under leases	(142.1)	(169.0)
Underlying operating cash flow	221.4	668.0
Net cash used in investing activities	149.5	(213.1)
Decommissioning expenditure	(17.6)	(45.0)
Lease payments related to capital activities	–	(21.9)
Payments to decommissioning escrow fund	(11.6)	(11.6)
Pre-financing cash flow	341.7	376.4

MANAGEMENT PRESENTATION - WEBCAST – 09:00 BST 28 APRIL 2026

To access the webcast please use the following link and follow the instructions provided:

<https://meetings.lumiconnect.com/100-007-059-118>

A replay will be available on the website from midday on 28 April 2026:

<https://www.tulloil.com/investors/results-reports-and-presentations/>

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Notes to editors

Tullow is an independent energy company committed to building a better future through the responsible oil and gas development of its core producing assets in Ghana. The Group is quoted on the London and Ghanaian stock exchanges (symbol: TLW). For further information, please refer to: www.tulloil.com.

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