**18 March 2026**

**ITHACA ENERGY PLC**

(“Ithaca Energy”, the "Company" or the “Group”)

**Full Year 2025 Results**

**A year of strong strategic and operational execution**

Ithaca Energy, a leading UK independent production and growth company, today announces its audited full year results for the year ended 31 December 2025.

**2025 Highlights:**

- Material UKCS resource holders with 2P reserves and 2C resources of 658 mmboe and attractive 2P reserves replacement ratio of over 130%
- Excellent operational performance supported average production of 119 kboe/d and 2025 exit rate of approx. 148 kboe/d, demonstrating increased installed production capacity into 2026
- Strong financial performance with adjusted EBITDAX of $2.0bn (2024: $1.4bn), net cash flow from operations of $1.7bn (2024: $0.9bn) and free cash flow of $683.3million (2024: 260.8 million)
- Enhanced liquidity position of $1.5bn (2024: $1.0bn) providing material financial firepower to support future growth
- Successful execution across the pillars of the Group’s growth strategy, supporting value creation and attractive shareholder returns:
    - Material targeted organic investment supporting increased production capacity, reliability enhancement and efficiency focus alongside incremental investment in high return wells
    - Material progression of West of Shetland development strategy with Rosebank entering the final stages of development towards first production in 2026/27, and the continued maturation of Cambo and Tornado through key regulatory milestones towards final investment decisions within 12 months
    - Continued execution of low-risk UKCS consolidation strategy and active and patient pursuit of international expansion strategy
- Attractive dividend distributions to shareholders of $500 million, with third interim 2025 dividend of $200 million, declared today, and payable in April 2026
- Refreshed capital allocation framework including upward revision of dividend policy, targeting shareholder returns in the range of 20-35% of post-tax CFFO, an increase from the previous range of 15–30%

**Yaniv Friedman, Executive Chairman,** commented: *“Ithaca Energy delivered another year of excellent operational and financial performance in 2025. Our acquisitions in Seagull and Cygnus contributed accretive growth, which along with organic investment in the period, achieved an exit rate of 148 kboe/d and allowed us to enter 2026 with significantly increased production capacity.*

*“In the West of Shetland, we saw material project activity, including at Rosebank where we are progressing in line with our development timeline towards first production in 2026/27. We also saw significant progress on the maturation of the Cambo and Tornado projects, with all activities supporting a potential FID within 12 months.*

*"We maintained our strong financial position throughout the year, supported by strong cash flow generation, a disciplined hedging strategy, and a successful bond issuance and an upsizing of the RBL facility, giving us an improved liquidity position. We remain committed to delivering attractive shareholder returns and I am pleased to announce the third tranche of our 2025 dividend of $200 million, taking our total return to shareholders for FY 2025 to $500 million, in line with our stated target. Moving forward, as a stronger business, we are raising the targeted shareholder returns range from 15-30% to 20-35% post-tax CFFO, with a 30% target ranging between $470-520 million in FY 2026, reflecting the strong continued performance of our diverse asset base which also supports our material capital programme as we continue to invest in organic growth opportunities.*

*"We enter 2026 with considerable momentum and strength, focused on upholding our strategic, operational and financial discipline, and well positioned to pursue value-driven growth and deliver sustainable returns."*

**Summary of key financial metrics**

| | **2025** | 2024 |
|---|---|---|
| Adjusted EBITDAX[1] ($m) | **2,030.8** | 1,405.0 |
| Net cash flow from operating activities ($m) | **1,745.3** | 853.3 |
| Available liquidity[1] ($m) | **1,470.1** | 1,015.1 |
| (Loss)/profit for the year[2] ($m) | **(84.1)** | 153.1 |
| Adjusted net income[1,2] ($m) | **289.2** | 323.6 |
| Basic EPS (Cents) | **(5.1)** | 13.2 |
| Unit operating expenditure[1] ($/boe) | **18.9** | 22.4 |

**Other KPIs**

| | | |
|---|---|---|
| Total production (kboe/d) | **119** | 80 |
| Tier 1 and Tier 2 process safety events | - | - |
| Serious injury and fatality frequency | - | - |
| Scope 1 and 2 emissions (kt$CO_2$e) | **437.5** | 448.2 |
| Greenhouse gas intensity (kg$CO_2$e/boe) | **17.2** | 23.9 |

1. Non-GAAP measure as set out on pages 66 to 67.
2. A one-off, non-cash deferred tax charge of $327.6 million in Q1 2025, reflecting the substantive enactment of the two-year extension of EPL to 31 March 2030, resulted in a reported loss of $84.1 million (2024: profit of $153.1 million). Adjusted net income of $289.2 million (2024: $323.6 million) better reflects underlying performance.

**2025 Corporate Highlights**

- Successful execution across our strategic pillars with a clear vision for 'scale, stability and strength' and continued high-grading of investment opportunities to maximise value creation and support attractive shareholder returns
- Material UKCS resource holders with 2P Reserves of 354 mmboe and 2C Resources of 304 mmboe as at 31 December 2025 (2024: 2P: 340 mmboe, 2C: 317 mmboe) and 2P reserves replacement ratio of over 130%

**Disciplined investment to sustain and optimise base production above > 120 kboe/d in the medium term**

- Very high levels of activity at Captain field in 2025, from execution of 13th well campaign to completion of significant summer shutdown supporting backlog reduction, optimisation and life extension activities. The Safe Caledonia flotel has subsequently left station having performed its activities to a high operational and safety standard, including an extension to its campaign to safeguard longer-term environmental and operational performance of the field
- Continued Cygnus infill well campaign, with well C12 achieving first production in December 2025, and three further wells sanctioned on Cygnus Alpha, and further investment opportunities for the field at Cygnus Bravo expected to reach final investment decision in 2026
- Fourth and final planned well at Seagull completed with start-up achieved in November 2025 and strong early well performance recorded
- Highest net average production rates in ten years achieved at the J Area of over 20 kboe/d, reflecting material value-led investment in short-cycle, high-return opportunities including three new wells in the area

**Unlocking material organic long-term growth opportunities**

- Material project activity executed at Rosebank in 2025 with project progressing in line with multi-year development timeline with estimated first production in 2026/27:
    - Successful delivery of offshore subsea installation scopes in 2025, ahead of drilling activities commencing
    - The FPSO Rosebank recently sailed away from Dubai having undertaken major refurbishment works over the past two and a half years. Remaining completion and commissioning scopes are planned during this year as part of the programme to moor and hook-up in field ahead of first production in 2026/27
    - Further environmental information was submitted for the development in 2025, and we await the decision on environmental consent
    - As we enter the final full year of development, maintaining disciplined execution will be critical to delivering the project safely, on schedule and within the project cost window
- Significant progress on the maturation of the Cambo project through key milestones toward potential FID in 2026/7, including:
    - Successful technical refresh in H1 2025 leveraging technical capabilities of Eni, via the Group's Technical Services Agreement, delivering meaningful optimisations and risk mitigations across both subsurface and facilities project scopes
    - Updated Field Development Plan and Environmental Statement submitted in Q1 2026
    - Completing tenders for the Engineering, Procurement, Construction and Commissioning (EPCC) of the FPSO and the Engineering, Procurement, Construction and Installation (EPCI) and entering market for drilling rig, with the objective of consolidating project costs and schedule, de-risking project execution
    - Farm-in process reinvigorated in early 2026, to reflect the project's enhanced maturity, associated derisking and the more stable fiscal and regulatory outlook
- Following NSTA approval of the Fotla and Tornado Development Concepts, Field Development Plans have been submitted, with both projects progressing towards FID

- Enhanced role as a strategic infrastructure partner in West of Shetland, with Tobermory 50% farm-in positioning the Group as part of a new northern gas hub and progression of Suilven project strengthening the Greater Tornado Area strategy, unlocking synergies and further exploration potential

**Track record of delivering value-accretive M&A and creating value from efficient integration**

- Continued execution of low-risk UKCS consolidation strategy with acquisitions from JAPEX UK of additional 15% stake in Seagull and 46.25% interest in the operated Cygnus field from Spirit Energy, adding equity in well-understood, high-quality assets with further upside potential
- Transactions completed at attractive valuations of approximately $10/boe (excluding tax losses) for JAPEX UK and $7/boe per 2P reserves for Cygnus
- The Group continues to maintain an active but patient pursuit of international M&A opportunities in line with our focused international expansion strategy
- Successfully concluded all integration activities in relation to our Business Combination with Eni UK in October 2024, demonstrating our strong integration capabilities

**Maximising value creation and delivering attractive shareholder returns**

- Material dividend distributions to shareholders in 2025 of $500 million in line with our dividend target for the year, with third interim 2025 dividend of $200 million, declared today, and payable in April 2026

## 2025 Operational Highlights

**Safe and responsible operator**

- Positive trend in safety performance in 2025, with zero Tier 1 and Tier 2 process safety events recorded in the year and significant reduction in total recordable incident frequency
- Significant improvement across all key environmental performance in 2025 driven by "perfect day" focus, benefitting from the addition of lower-intensity assets, alongside continued investment in value-led decarbonisation activity
- Group gross operated emissions intensity decreased to 17.2 $kgCO_2e$/boe from 23.9 $kgCO_2e$/boe in 2025, comparing favourably against latest basin average of approx. 24 $kgCO_2e$/boe

**Strong Q4 performance, with positive production trend continuing into 2026**

- Pro forma 2025 production of 131 kboe/d reflects organic and inorganic investment and production growth, and positions Ithaca Energy as one of the largest operators in the basin (includes production from increased stakes in Seagull and Cygnus from 1 Jan 2025, through to completion)
- 2025 full year production of 119 kboe/d, at the lower end of previously upgraded guidance driven by strong core asset performance
    - Production split approximately 56% liquids and 44% gas
    - Reflects unprecedented levels of summer turnaround activity in the year
- Enhanced operational robustness of enlarged and diversified asset base, supported by continued operational improvements, optimisations and the consistent reliable delivery across the portfolio
- 2025 exit rate of approximately 148 kboe/d achieved, with peak daily production exceeding 150 kboe/d, following the successful delivery of new wells at Cygnus, Seagull and J Area in Q4

## 2025 Financial Highlights

- Material dividend distributions to shareholders of $500 million, with the announcement of the Group's third interim 2025 dividend declared today of $200 million payable in April 2026, in line with our stated target for the year
- Adjusted EBITDAX of $2.0bn (2024: $1.4bn), net cash flow from operations of $1.7bn (2024: $0.9bn) and free cash flow of $683.3 million (2024: 260.8 million)
- Profit before tax of $840.3 million (2024: $334.3 million). A one-off, non-cash deferred tax charge of $327.6 million in Q1 2025, reflecting enactment of two-year extension of EPL to 31 March 2030, resulted in a reported loss of $84.1 million (2024: profit of $153.1 million)
- Adjusted net income of $289.2 million (2024: $323.6 million), better reflecting underlying performance (see financial review)
- $184 million of hedge gains and other income in the year, reflecting a $4/boe contribution to adjusted EBITDAX. Average realised oil prices for 2025 were $70/boe before hedging results and $72/boe after hedging results (2024: $81/boe before hedging results and $82/boe after hedging results). Average realised gas prices for 2025 were $63/boe before hedging results and $66/boe after hedging results (2024: $64/boe before hedging results and $78/boe after hedging results)
- Significant available liquidity of $1.5bn (2024: $1.0bn) and low leverage position of 0.56x (2024: 0.45x), providing material financial firepower to support future growth
    - Adjusted net debt of $1.3bn (2024: $0.9bn)
    - Successful issuance of €450 million 5.5% senior notes, due 2031, and $300 million upsizing of the Group's Reserves Based Lending (RBL) facility via the accordion
    - Group RBL accordion facility of $435 million, secured as part of the 2024 refinancing, remains available, offering incremental liquidity potential from $1.5bn to approximately $1.9bn
- Adjusted net operating costs of $817 million (2024: $570 million), representing an adjusted net unit opex cost of less than $19/boe (2024: $22/boe), at the mid-point of management guidance of $790 million to $840 million, reflecting the high netback capability of the portfolio
- Total net producing asset capital expenditure of $629 million (2024: $448 million including six months of Eni UK capital costs), below the guidance range of $630 million to $670 million
- Net capital expenditure relating to the Rosebank development totaled $224 million (2024: $198 million), below the guidance range of $230 million to $270 million
- Group cash tax paid in the year of $263 million (2024: $351 million), below the guidance range of $270 million to $300 million, relating solely to the Energy Profits Levy

## Guidance and Outlook

### 2026

- **FY 2026 production guidance range of 120–130 kboe/d** reflecting enhanced installed operating capacity and full year contribution of increased stakes in the Cygnus and Seagull fields
- **FY 2026 net operating cost guidance range of $820-860 million**, normalised using USD: GBP exchange rate of 1.35
- **FY 2026 net producing asset capital cost guidance range of $600-700 million**, normalised using USD: GBP exchange rate of 1.35 (excludes pre-FID projects and Rosebank development)
- **FY 2026 net Rosebank project capital cost guidance range of $280-320 million**, reflecting increased activity in final phase of development
- **FY 2026 net decommissioning cost guidance range of $170-210 million**, based on USD: GBP exchange rate of 1.35
- **FY 2026 cash tax guidance of $290-340 million**

- Hedged position at 17 March 2026 of 63.8 mmboe (c.39% gas, c.61% oil) through the end of 2027 from 1 January 2026. The 2026 hedge book has been built to deliver oil price certainty with >80% of oil volumes in 2026 hedged using swaps at an average of c.$67 and with collars including some participating up to c.$90/bbl ceilings. Gas hedges in 2026 deliver material upside to the business with >40% of gas volumes in Q1 to Q3 either unhedged or hedged via collars with up to 130p/ therm average ceilings. The 2027 hedge book is expanding significantly during the current high price environment
- Refreshed capital allocation framework including increased medium-term production baseline of >120 kboe/d and upward revision of shareholder dividend return range to 20-35% of post-tax CFFO, from 15–30%, together with an equal dividend payment schedule with 50% following half year results and 50% following full year results, from a 1/3rd and 2/3rd schedule previously. These upward revisions reflect the strength of the Group's enhanced portfolio and increased scale which underpins the ability to deliver attractive sustainable returns, while continuing to invest for growth
- **2026 dividend commitment of 30% post-tax CFFO**, with a target range of **$470-520 million**

**Webcast and Conference call**

Ithaca Energy will host a virtual presentation and Q&A session for investors and analysts at 09:00 (GMT) today, 18 March 2026. Details are accessible via our website.

**Investors and Analysts – Webcast link**

https://www.investis-live.com/ithaca-energy/69b2a0005388a600223b4f5c/kyukk

**Investors and Analysts – Conference call**

Operator Assisted Dial-In: United Kingdom (Local): +44 20 3936 2999 United Kingdom (Toll-Free): +44 800 358 1035 Global Dial-In Numbers Access Code: 404300

## FY 2025 performance in review

### A year of strong strategic and operational execution

2025 has been another year of excellent operational delivery and disciplined strategic execution. With strong progress across all strategic pillars, the Group has delivered a significant increase in our installed production capacity, both through organic and inorganic investment, at the same time building momentum in unlocking material long-term growth opportunities through the advancement of our West of Shetland development strategy. Together, these achievements support our vision for 'Scale. Stability. Strength.' and position us to maximise long-term value creation for our shareholders.

With 2P reserves of 354 mmboe and 2C resources of 304 mmboe as at 31 December 2025 (2024: 2P: 340 mmboe; 2C: 317 mmboe), Ithaca Energy stands as one of the largest resource holders in the UKCS. Through continued organic and inorganic investment, we have delivered a 2P reserves replacement ratio of over 130%. Our own internal resources process which applies detailed Project Maturity Sub-classifications, enabling a more comprehensive assessment of the Group's resource base, has identified approximately 350 mmboe of unbooked contingent and prospective resource potential at year end, bringing our internal view of our resources to over 1bn barrels.

### Strong operational performance, delivering on upgraded production outlook for the year

2025 represents a year of outstanding operational performance, with significant improvements delivered across all key operational metrics and most notably a marked enhancement in our HSE performance. Our commitment to responsible operations and sustainable value creation, driven by a disciplined focus on achieving the 'perfect day' has delivered improvements in safety and environmental performance, higher production efficiency, and a reduction in operating cost per barrel.

The Group recorded zero Tier 1 and Tier 2 process safety events and delivered sustained improvements in personal safety performance with a material reduction of over 25% in the Group's Total Recordable Injury Rate (TRIR) to 1.7 (2024: 2.3), continuing the positive trend since 2023, where the TRIR stood at 3.3.

The Group's strong production performance in 2025 reflects the enhanced operational robustness of our enlarged and diversified asset base, supported by continued operational improvements, optimisations and the consistent reliable delivery across our portfolio.  Average production for the year was 119 kboe/d (2024: 80 kboe/d), at the lower end of previously upgraded guidance driven by core asset performance in the first half of the year and reflecting unprecedented levels of summer turnaround activity in the year. Production for 2025 was split 56% oil and 44% gas, with the Group's operated assets accounting for 38% of total production.

Production efficiency performance in 2025 of 83% consistently exceeded the Group's 2024 average production efficiency of 80% and the industry average of 75% in 2024, including a sustained 4% improvement in unplanned production efficiency performance across our operated assets in the year.

The Group now enters 2026 with increased installed production capacity, having achieved a 2025 exit rate of approximately 148 kboe/d, and with peak daily production exceeding 150 kboe/d, following the successful delivery of new wells at Cygnus, Seagull and J Area in the final quarter of the year.

Adjusted net operating costs in 2025 of $817 million (2024: $570 million), representing an adjusted net unit opex cost of $19/boe (2024: $22/boe), was at the mid-point of management guidance of $790 million to $840 million, reflecting the high netback capability of the portfolio. Our aim is to maintain opex per boe in the low $20s in the medium-term to deliver resilient production in all commodity environments.

Total net producing asset capital expenditure of $629 million (2024: $448 million, including six months of Eni UK capital costs), came in at the lower end of the Group's management guidance range of $630 million to

$670 million. Net capital expenditure relating to the Rosebank development totalled $224 million (2024: $198 million), falling below management's guidance range of $230 million to $270 million.

Group cash tax paid in the year of $263 million (2024: $351 million) was below the Group's management guidance range of $270 million to $300 million, relating solely to the Energy Profits Levy.

**Significant progress across all strategic pillars in 2025, supporting our vision for further 'Scale. Stability. Strength.'**

The Group has successfully executed across its organic and inorganic growth strategy in the year, with a clear vision for further 'Scale. Stability. Strength'. As a disciplined and value-led business, we continued to high-grade investment in our diverse UK North Sea portfolio, sustaining and optimising our base production while investing to unlock material long-term growth opportunities and consolidating our positions in existing high-quality assets that offer upside potential.

**Organic growth – Disciplined investment to sustain and optimise base production while unlocking material long-term growth opportunities**

In 2025, we have seen the clear and immediate benefit of our strategy to invest in order to sustain and optimise our base production, with a significant increase in our installed production capacity as we exited the year. This was achieved through targeted investment toward new tie-in opportunities, asset optimisation and life extension initiatives, and infill drilling campaigns with material investment across our operated and non-operated asset base.

The Group's operated Captain field continued to see very high levels of activity in 2025 from the execution of the 13$^{th}$ well campaign to the completion of a significant summer shutdown with material backlog reduction, optimisation and life extension activities completed. In the first half of the year, the Group successfully delivered the drilling, completion and production start-up of wells C73 and C74, the work over of well C47 and in response to the Enhanced Oil Recovery Phase II project, production from the subsea wells has doubled, together contributing to the highest reported production rate for the asset in recent years.

Recognising the importance of Captain as a strategic operated asset, a major flotel campaign commenced in mid-2025 to support the long-term stability and operational performance of the asset, ensuring that the facility remains safe and reliable through its long-term field life. The decision to extend the Safe Caledonia flotel campaign was made later in the year, executing further critical scopes and investment into safeguarding longer-term environmental and operational performance. The flotel has subsequently left station having performed its activities to a high operational and safety standard.

The Cygnus infill well campaign continued through 2025, with well C12 achieving first production in late December. As we enter 2026 further investment activity has been sanctioned to sustain and optimise production at the Cygnus field, supporting the continuation of the long-term infill drilling campaign with commitments to the 14$^{th}$ and 15$^{th}$ wells on Cygnus Alpha. The previously sanctioned 13$^{th}$ well was spudded in Q4 2025, scheduled to be followed by the 14$^{th}$ well in Q2 2026, with the final firm well planned for a Q4 2026 spud. Further investment opportunities for the field, including two further infill wells at Cygnus Bravo, are expected to reach final investment decision in H1 2026.

At Seagull, the fourth and final planned well was completed, with start-up achieved in November 2025 after extended well completion operations, with strong early well performance recorded. Completion of the J4 well marks the transition of Ithaca Energy's role as development well operator, to a non-operated owner.

Average net production in 2025 from the J Area reached over 20 kboe/d, delivering its highest average production rates in ten years and making the area the most significant contributor to the Group's 2025 production. The area's significant production contribution reflects the Group's increased stakes in the area post Eni UK business combination, material value-led investment in short-cycle, high-return opportunities including three new wells in the area: Jocelyn South, a long-extended reach Judy infill well and a final well at Judy east flank delivered late December, together with strong performance of the recently brought online Talbot field and a successful well stimulation campaign at Joanne.

The Group executed unprecedented levels of turnaround activity during the summer window, with 12 out of the 15 turnarounds completed to plan or better. This major investment across our operated and non-operated base was critical to supporting the ongoing production efficiency of our diversified asset base.

The Group continues to make strong progress in unlocking material value across its long-life, high-value resource base, predominantly in the West of Shetland. The publication of the UK Government's Scope 3 guidance in June, the North Sea Future Plan and the EPL successor regime in November, has provided increased regulatory and fiscal clarity. This evolving certainty supports the progression of key development assets towards a final investment decision, aligned with the UK's long-term energy security objectives.

At Rosebank, material project activity was executed in 2025, including the successful delivery of offshore subsea installation scopes delivered on time and within budget, ahead of drilling activities. The FPSO Rosebank recently sailed away from Dubai having undertaken major refurbishment works over the past two and a half years. Remaining completion and commissioning scopes are planned during this year as part of the programme to moor and hook-up in field ahead of first production in 2026/27. Further environmental information was submitted for the development in 2025, and we await the decision on environmental consent. As we enter the final full year of development, maintaining disciplined execution will be critical to delivering the project safely, on schedule and within the project cost window.

We have made significant progress during 2025 in the maturation of the Cambo project toward a potential FID in 2026/27. In the first half of the year, the regulator granted an 18-month licence extension, supporting the continued progression of the project towards its licence milestones. A technical refresh of the Cambo project in H1 2025, leveraging the technical capabilities of Eni, delivered meaningful optimisation of the development concept, de-risking the project significantly and enabling the launch of tendering processes for major project packages including the FPSO Engineering, Procurement, Construction and Commissioning (EPCC) contract and EPCI contract for Subsea, Umbilicals, Risers and Flowlines package. In Q1 2026, the Group submitted an updated Field Development Plan and Environmental Statement, reflecting the project optimisations and reduction in environmental impact identified during the technical refresh. The farm-in process was reinvigorated in early 2026, to reflect the project's enhanced maturity, associated de-risking and the more stable fiscal and regulatory outlook, with a continued expectation that a farm-in agreement would be reached prior to project sanction.

Across the broader resource base, the Group continued to advance a number of projects through key regulatory milestones, with NSTA approval secured for the Fotla and Tornado Development Concepts, and the subsequent submission of the Field Development Plans for both projects in 2025. These projects have now reached a level of maturity that positions them close to final approval, demonstrating the robustness of the technical and regulatory work carried out to date. In support of the Group's West of Shetland gas strategy, Ithaca Energy announced its 50% farm-in to Tobermory, while continuing to progress the Suilven development, enabling potential synergies between the Tornado and Tobermory gas fields and infrastructure led exploration in the area and strengthening Ithaca Energy's position as a strategic infrastructure partner in the area. Together, Tornado, Tobermory and Suilven significantly strengthen our position and underpin the robustness of the Group's overall development strategy in the key West of Shetland Area.

**Inorganic growth: Disciplined execution of M&A strategy**

The Group successfully executed against its inorganic growth strategy, pursuing low-risk consolidation in its core UKCS basin through the acquisitions from JAPEX and Spirit Energy of an additional 15% stake in Seagull and 46.25% interest in the Group's operated Cygnus fields respectively. The bolt-on transactions enhanced the Group's stakes in well-understood, high-quality, long-life assets delivering near-term production growth and cash flow generation, increasing pro forma 2025 production by 17 kboe/d and adding 44 mmboe of 2P reserves and 2C resources as at 1 January 2025.

The Cygnus acquisition enhances the Group's stake in the UKCS's largest producing gas field, adding additional operated high-margin, low-emission gas production to its portfolio and strengthening the Group's position as a leading UKCS gas producer, providing critical domestic energy security.

These strategic acquisitions reinforce the Group's position as a leading consolidator in the UKCS, delivering growth through targeted, value-accretive transactions that offer tangible near-term benefits and long-term potential. Both transactions met the Group's disciplined investment criteria and were completed at attractive valuations of approximately $10/boe (excluding tax losses) for Japex E&P UK and $7/boe per 2P reserves for Cygnus.

In line with the Group's focused international expansion strategy, we continued to assess global M&A opportunities in an active but patient manner during 2025. Our priority as we enter 2026, is to target regions that offer meaningful follow-on consolidation potential, allowing us to build scalable positions and maximise returns. This selective approach ensures capital is allocated to markets where we can replicate our proven model for value creation.

Following completion of the Business Combination with Eni UK in October 2024, integration activities were completed by the end of H1 2025, including a restructuring process aimed at creating an optimised organisation to support our next phase of growth. The integration process, set the enlarged business up for success, realising operational synergies as efficiently as possible, including the relocation of our workforce to our Aberdeen headquarters.

**Responsible operator**

Our commitment to ESG serves as our licence to operate and guides the way we create long-term sustainable value. We recognise the need to balance the reliable long-term supply of hydrocarbons, critical to delivering domestic energy security and affordability for the end user, with the necessity to lower our emissions footprint. In 2025, we supplied over 10% of the UK's oil and gas production, highlighting both the scale of our contribution and the material imbalance between domestic supply and consumption. In a period of heightened geopolitical tension and global energy uncertainty, this reinforces the strategic importance of developing and sustaining the UK's own resources to support energy resilience.

Our ESG mindset drives a clear commitment to value-led decarbonisation taking progressive, economically disciplined steps that strengthen the sustainability of our business. Our well-defined ESG strategy is built around three key pillars: acquiring assets that enhance our overall emissions; investing in low emission intensity assets capable of driving the meaningful long-term transition of our portfolio; while delivering targeted, economically-viable optimisation activities across our existing operations in the short-term.

In 2025, we delivered strong performance across all three pillars of our ESG strategy. Our M&A activity directly supported significant improvements to our medium-term emission profile through the acquisition of increased stakes in low-intensity assets, Cygnus and Seagull. In parallel, the progression of Rosebank towards first production alongside the continued maturation of low emission intensity developments, such as Cambo and Tornado toward FID, in addition to preparing the high-intensity Greater Stella Area and Alba fields as planned for cessation of production and decommissioning, positions the Group to materially transform the emission intensity of our portfolio in the long-term. Across our portfolio, we also made significant progress on emissions reduction initiatives aimed at optimising our footprint in the short to medium-term, including flare gas recovery projects at Captain and Cygnus and pump replacement projects and export compressor projects at Captain, supported by the extension of the Safe Caledonia flotel campaign.

The Group delivered a significant improvement in its environmental performance in 2025, reflecting changes in portfolio composition post Business Combination with Eni UK, and through further consolidation activity in 2025, with the portfolio benefitting from the addition of lower-intensity assets, alongside continued investment in value-led decarbonisation activity. The Group's gross operated emissions intensity decreased to 17.2 $kgCO_2e$/boe from 23.9 $kgCO_2e$/boe in 2024, marking material progress towards its decarbonisation objectives and comparing favourably against the latest basin average of approximately 24 $kgCO_2e$/boe. The Group also reported a material reduction in the number of reportable releases to sea (spills). A reduction of 67% was recorded in the year driven by clearer procedures, asset integrity investment, training and vendor oversight.

**Evolving UK regulatory and fiscal landscape**

2025 has been characterised by continued fiscal and regulatory uncertainty, marked by three significant industry consultations covering the treatment of Scope 3 emissions, the Future of the North Sea and the design of a successor regime to the energy profits levy ahead of its scheduled sunset in 2030. The significance of these consultations understandably placed the sector into a holding pattern throughout the year, contributing to a continued hiatus of material long-term investment activity across the sector.

Throughout the year, we welcomed significant engagement with His Majesty's Treasury (HMT) and His Majesty's Revenue & Customs (HMRC) in relation to the EPL successor regime, culminating in the announcement of the Oil and Gas Price Mechanism (OGPM) as part of the Chancellor's Autumn Statement. The revenue-based OGPM aims to establish a framework for future price shock environments, taxing windfalls at an increased commodity threshold rate of $90 per barrel for oil and 90 pence per therm for gas (inflation adjusted). The introduction of the OGPM represents an important and welcome step in providing greater fiscal certainty necessary for making long-term investment decisions. We will continue to work collaboratively with HMT and HMRC as the mechanism progresses through the legislative process, while continuing to advocate for an earlier introduction to stimulate investment in the basin.

Alongside the OGPM announcement, the UK Government also published the North Sea Future plan, setting out its response to the Future of the North Sea consultation, which closed in early 2025. Following publication of the North Sea Future Plan, we expect significant engagement with the UK Government through the legislative phase, primarily the Department of Energy Security and Net Zero, to ensure policy development reflects the significant economic and strategic value our industry brings to the UK, while supporting a just and orderly energy transition.

**Material financial firepower to support growth aspirations and attractive shareholder returns**

We remain firmly focused on maintaining a strong and flexible balance sheet as the foundation of our capital allocation priorities. Our enhanced financial position supports continued investment in sustaining base production, protects our low leverage profile, and enables disciplined hedging through the cycle. This approach ensures we continue to deliver attractive shareholder returns while preserving the financial agility to evolve our business by pursuing both organic and inorganic growth opportunities.

The Group further enhanced its liquidity position in the year, increasing available liquidity to $1.5bn (2024: $1.0bn), providing material financial firepower to support future growth. Our strong credit credentials were highlighted by the successful issuance of €450 million 5.5% senior notes, due 2031, which attracted significant investor demand. The proceeds were subsequently swapped to US Dollars at an effective all-in USD interest rate of approximately 6.7%.

Liquidity was strengthened further through a $300 million upsizing of the Group's RBL facility via the accordion, with the participation of all new lending institutions. Combined, the notes issuance and RBL upsizing have optimised the Group's financial structure and extending its debt maturity profile. The Group's unused RBL accordion facility of $435 million, secured as part of the 2024 refinancing, also remains available, offering incremental liquidity potential from $1.5bn, up to approximately $1.9bn.

Following the bond issuance, adjusted net debt increased to $1,258.2 million (2024: $884.9 million), with the Group's RBL facility of $1,300 million (excluding letters of credit) remaining fully undrawn at year-end. Pro forma leverage increased modestly to 0.56x (2024: 0.45x) and remains low, providing a robust financial foundation for disciplined future growth.

Our enlarged portfolio delivered strong financial results, generating adjusted EBITDAX of $2.0bn (2024: $1.4bn), net cash flow from operations of $1.7bn (2024: $0.9bn) and free cash flow of $683.3 million (2024: 260.8 million). This step change in performance, despite a softening commodity price environment, reflects both the transformational Business Combination with Eni UK, which created a diversified and scaled portfolio, and the enhanced outlook reported mid-year as a result of sustained strong operational performance and continued optimisations and efficiencies being realised across the business.

Profit before tax for the year was $840.3 million (2024: $334.3 million). A one-off, non-cash deferred tax charge of $327.6 million in Q1 2025, reflecting the substantive enactment of the two-year extension of EPL to 31 March 2030, resulted in a reported loss of $84.1 million (2024: profit of $153.1 million). Adjusted net income of $289.2 million (2024: $323.6 million) better reflects underlying performance.

The Group's net current liability position has improved to $303.9 million (2024: $456.5 million) largely as a result of deferred consideration payments made in 2025. The Group expects that the net current liability position will be addressed through a combination of operating cash flows and available liquidity.

The effectiveness of the Group's disciplined hedging strategy was demonstrated during the year, with hedge gains and other income of $184 million recorded, reflecting a $4/boe contribution to adjusted EBITDAX. Our proactive approach to commodity risk management is designed to strike the right balance between maintaining exposure to commodity price upside while ensuring strong downside protection of cash flows to support planned investment and uphold commitments to shareholder returns through the cycle. Following significant proactive hedging activity in Q1 2026, taking advantage of market volatility, the Group has built a material hedge position as at 17 March 2026 of 63.8 mmboe (c.39% gas, c.61% oil) through the end of 2027 from 1 January 2026.  The 2026 hedge book has been built to deliver oil price certainty with >80% of oil volumes in 2026 hedged using swaps at an average of c.$67 and with collars including some participating up to c.$90/bbl ceilings. Gas hedges in 2026 deliver material upside to the business with >40% of gas volumes in Q1 to Q3 either unhedged or hedged via collars with up to 130p/ therm average ceilings. The 2027 hedge book is expanding significantly during the current high price environment.

Our commitment to delivering attractive and sustainable shareholder returns remains unwavering. In 2025, our strong operational and cash flow performance has supported total cash dividend distributions of $500 million, including the first interim 2025 dividend of $167 million declared and paid in September 2025, and the acceleration of a second interim dividend of $133 million declared and paid in December. The Board has today declared a third interim dividend of $200 million in respect of the 2025 financial year to be paid in April 2026, bringing our total 2025 dividends declared to $500 million, in line with our stated target for the year. Since our IPO in November 2022, we have built a strong track record of delivering material returns to shareholders with $1.4bn of dividends declared and returned to shareholders across three financial years.

Looking ahead, the Board has reviewed the dividend policy, as part of the broader capital allocation framework, and increased the targeted shareholder return range to 20-35% of post-tax CFFO, up from the previous range of 15–30%. This upward revision reflects the strength of the Group's enhanced portfolio and underpins our ability to deliver attractive sustainable returns, while continuing to invest in growth.

## Outlook

Following a year of exceptional strategic and operational delivery, we enter 2026 from a position of considerable strength. We will continue to uphold our strategic, operational and financial discipline as we pursue value-driven growth, high-grading investment across our strategic pillars and operating within the parameters of our refreshed capital allocation policy to maximise value creation and deliver attractive, sustainable shareholder returns.

Management provides the following guidance for the year and medium-term outlook:

**Our 2026 production guidance of 120-130 kboe/d** reflects the Group's enhanced installed operating capacity at year end and the full-year contribution of increased stakes in the Cygnus and Seagull field following continued consolidation in the year. Beyond 2026, the Group expects to maintain production above 120 kboe/d in the medium-term from its existing producing asset base, the start-up of the Rosebank development and other project investments.

**Our operating cost guidance for 2026 of $820-860 million,** based on USD: GBP exchange rate of 1.35, reflects a reduction in opex per barrel driven by the high netback capability of the portfolio. In the medium-term, we expect to maintain a relatively flat unit operating cost per barrel of approximately $20/boe.

**Our producing asset capital cost guidance for 2026 of $600-700 million,** based on USD: GBP exchange rate of 1.35, (excluding capital investment for projects awaiting FID and Rosebank), reflects our continued high levels of organic investment activity to sustain and optimise production at Captain, Cygnus, J-Area and Mariner in support of our medium-term outlook.

**Rosebank development costs to be in the range of $280-320 million** reflecting increased activity in the final phase of the project development, including completion of FPSO modification, drilling and hook-up and commissioning works.

**Net decommissioning cost guidance of $170-210 million**, based on USD: GBP exchange rate of 1.35, reflects the cessation of production of the Group's operated Alba field and the Greater Stella Area in 2026.

**Estimated 2025 cash tax payments of $290-340 million,** primarily EPL related.

**Our material hedge position at 17 March of 63.8 mmboe provides strong cash flow coverage into 2027**, following significant proactive hedging through Q1, taking advantage of upside market volatility.

**Our 2026 dividend commitment** is 30% post-tax CFFO with a target range of $470-520 million.

**Enquiries**

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**Notes:**

[1] Non-GAAP measure

**About Ithaca Energy plc**

Ithaca Energy is a leading UK independent exploration and production company with a strong track record of material value creation. In recent years, the Company has been focused on growing its portfolio of assets through both organic investment programmes and acquisitions and has seen a period of significant M&A driven growth centred upon three transformational acquisitions in recent years, including the recent Business Combination with Eni UK. Today, Ithaca Energy is one of the largest independent oil and gas companies in the United Kingdom Continental Shelf (the “UKCS”), by production and resources.

With stakes in six of the ten largest fields in the UKCS and two of UKCS’s largest pre-development fields, and with energy security currently being a key focus of the UK Government, the Group believes it can utilise its significant reserves and operational capabilities to play a key role in delivering security of domestic energy supply from the UKCS.

Ithaca Energy serves today’s needs for domestic energy through operating sustainably. The Group achieves this by harnessing Ithaca Energy’s deep operational expertise and innovative minds to collectively challenge the norm, continually seeking better ways to meet evolving demands.

Ithaca Energy’s commitment to delivering attractive and sustainable returns is supported by a well-defined emissions-reduction strategy with a target of achieving net zero ahead of targets set out in the North Sea Transition Deal.

Ithaca Energy plc was admitted to trading on the London Stock Exchange (LON: ITH) on 14 November 2022.

-ENDS-

### Adjusted EBITDAX analysis

| | 2025 | | 2024 | |
|---|---|---|---|---|
| **Production** | **kboe/d** | **mmboe** | **kboe/d** | **mmboe** |
| Oil | **61** | **22** | 41 | 15 |
| Gas | **52** | **19** | 25 | 9 |
| Condensate | **6** | **2** | 3 | 1 |
| **Total production** | **119** | **43** | **69** | **25** |
| **Revenues**[1] | **$/boe** | **$m** | **$/boe** | **$m** |
| Oil revenue | **70** | **1,534** | 81 | 1,176 |
| Gas revenue | **63** | **1,117** | 64 | 599 |
| Condensate revenue | **44** | **81** | 48 | 47 |
| Oil and gas hedging gains/other income | **4** | **184** | 5 | 135 |
| **Total** | **67** | **2,916** | **77** | **1,957** |
| Movement in oil and gas inventory | **–** | **12** | 3 | 84 |
| Tanker costs | **–** | **(20)** | (1) | (18) |
| Stella royalties | **–** | **(2)** | – | (2) |
| **Total value from production** | **67** | **2,906** | **79** | **2,021** |
| **Costs** | | | | |
| Operating costs excluding restructuring costs, tanker costs and net of tariff income | **(19)** | **(817)** | (22) | (570) |
| Administrative expenses excluding restructuring costs and business combination costs | **(1)** | **(43)** | (2) | (41) |
| Foreign exchange losses/materials inventory provisions | **–** | **(15)** | – | (5) |
| **Other operating costs in arriving at adjusted EBITDAX** | **(20)** | **(875)** | **(24)** | **(616)** |
| **Adjusted EBITDAX**[2] | **47** | **2,031** | **55** | **1,405** |

1 Revenues in the above table exclude principally tariff income and premium payments on oil and gas derivative contracts.
2 Non-GAAP measure.

### Financial performance: revenue, costs and charges and adjusted EBITDAX

Adjusted EBITDAX is a key measure of operational performance delivery in the business and amounted to $2,030.8 million (2024: $1,405.0 million), mainly reflecting the higher production principally due to the Eni UK Business Combination, JAPEX UK and Cygnus acquisitions, and improved operational performance partly offset by lower realised commodity prices net of hedging.

Average realised oil prices for 2025 were $70/boe before hedging results and $72/boe after hedging results (2024: $81/boe before hedging results and $82/boe after hedging results). Average realised gas prices for 2025 were $63/boe before hedging results and $66/boe after hedging results (2024: $64/boe before hedging results and $78/boe after hedging results).

Movement on oil and gas inventory was a credit of $11.7 million (2024: $84.2 million) representing movements in underlift/overlift entitlements.

During the year, operating costs (excluding over/underlift) including tariff expenses but excluding restructuring costs, tanker costs and net of tariff income were $817.3 million (2024: $569.6 million) and unit operating expenditure was $18.9/boe (2024: $22.4/boe). The reduction in unit operating expenditure per boe compared to 2024 reflects both the Group's continued focus on cost control and the high netback capability of the enlarged protfolio.

Administrative expenses, excluding business combination costs of $0.3 million (2024: $16.3 million) and restructuring costs of $3.5 million (2024: $nil), were $43.5 million (2024: $41.0 million) with the increase principally due to the ongoing administrative costs of the former Eni UK businesses.

### Adjusted EBITDAX to profit before tax

| | 2025 $m | 2024 $m |
|---|---|---|
| Adjusted EBITDAX | **2,030.8** | 1,405.0 |
| Depletion, depreciation and amortisation (DDA) | **(840.6)** | (600.2) |
| Impairment charges on oil and gas assets | **(77.5)** | (263.0) |
| Exploration and evaluation expenses | **(2.1)** | (24.6) |
| Net finance costs | **(254.8)** | (189.4) |
| Oil and gas put premiums | **(0.3)** | (4.9) |
| Fair value remeasurement of contingent consideration | **(22.8)** | 27.3 |
| Restructuring costs | **(8.0)** | – |
| Revaluation of derivative contracts | **15.9** | 0.4 |
| Business combination costs | **(0.3)** | (16.3) |
| **Profit before tax** | **840.3** | **334.3** |

DDA charges were $840.6 million (2024: $600.2 million). The year-on-year increase was principally due to the higher production partly offset by most of the Group's new assets acquired in the last two years having a significantly lower DDA charge per boe than legacy Ithaca Energy assets. DDA per barrel was $19.4 (2024: $23.6).

Impairment charges on oil and gas assets of $77.5 million (2024: $263.0 million) principally reflects a charge of $8.2 million for Alder which ceased production during the year (2024: a charge of $116.4 million for the Greater Stella Area and a charge of $32.4 million in respect of Pierce), and a charge of $69.3 million (2024: $114.2 million) principally relating to decommissioning cost estimate changes on assets that have either been fully written off or have ceased production.

Exploration and evaluation expenses amounted to $2.1 million (2024: $24.6 million) and principally relate to licence relinquishments during the year.

Net finance costs were $254.8 million (2024: $189.4 million) with the increase due to higher drawings on the RBL, a full year of the increased borrowing under the senior notes 2029, the incremental senior notes due 2031 and higher accretion charges on decommissioning liabilities as a result of the Eni UK Business Combination. These items were partly offset by certain one-off charges in 2024. In the year to 31 December 2024, net finance costs included an early repayment charge of $14.1 million on the senior notes due 2026 and the write-off of unamortised fees of $5.3 million on the refinancing of the RBL and $2.6 million on the refinancing of the senior notes due 2026.

Change in fair value of contingent consideration was a charge of $22.8 million (2024: credit of $27.3 million), mainly due to an updated view from management of the likelihood of certain milestones being achieved.

Restructuring costs of $8.0 million (2024: $nil) were incurred on reorganising and streamlining the organisational structure following the Eni UK Business Combination and comprise operational costs of $4.5 million and administrative expenses of $3.5 million.

Revaluation of derivative financial instruments was a credit of $15.9 million (2024: $0.4 million), principally reflecting gains on revaluation of foreign exchange forward contracts and foreign exchange collar contracts.

Transaction costs of $0.3 million (2024: $16.3 million) reflect principally professional fees and other cost directly related to acquisitions made in 2025.

**Financial performance: (loss)/profit for the year and adjusted net income**

| | **2025 $m** | 2024 $m |
|---|---|---|
| Profit before tax | **840.3** | 334.3 |
| Tax | **(924.4)** | (181.2) |
| **(Loss)/profit for the year** | **(84.1)** | **153.1** |
| Impairment charges on oil and gas assets | **77.5** | 263.0 |
| Tax credit on impairment charges on oil and gas assets | **(33.6)** | (160.3) |
| Restructuring costs | **8.0** | – |
| Business combination costs | **0.3** | 16.3 |
| One-off finance charges related to refinancing | **–** | 22.0 |
| Tax credit on restructuring costs, business combination costs and one-off finance charges | **(6.5)** | (28.6) |
| Deferred tax impact of EPL changes substantively enacted during the year | **327.6** | 58.1 |
| **Adjusted net income[1]** | **289.2** | **323.6** |

1 Non-GAAP measure.

The reduction in adjusted net income year-on-year was principally due to higher taxable profits attracting tax at 78% as well as higher underlying finance costs and a charge for fair value remeasurements of contingent consideration in 2025 compared to a credit in 2024.

**Taxation**

The tax charge for the year was $924.4 million (2024: $181.1 million) with the increase mainly due to a deferred tax charge of $327.6 million for the extension of EPL to 31 March 2030, higher taxable profits attracting tax at 78% and a higher level of non-deductible expenditure such as contingent consideration compared to 2024. The year to 31 December 2024 included a charge of $58.1 million on the enactment of the increase in the EPL rate from 35% to 38%.

**Earnings per share (EPS)**

Statutory EPS was (5.1) cents (2024: 13.2 cents) and adjusted EPS was 17.5 cents (2024: 27.8 cents). Adjusted EPS is a non-GAAP measure which eliminates items which distort year-on-year comparisons such as impairment charges on oil and gas assets, restructuring costs, business combination costs, one-off finance charges related to refinancing, the tax effect of such items and deferred tax charges due to the substantive enactment of changes to EPL during the year.

**Shares in issue**

At 31 December 2025, there were 1,653.7 million (2024: 1,653.7 million) shares in issue. The weighted average number of shares during the year for EPS calculations, excluding shares held by the Employee Benefit Trust, was 1,648.8 million (2024: 1,164.3 million).

**Dividends**

Dividends paid during the year amounted to $497.7 million (2024: $432.7 million), reflecting the third interim dividend for 2024 of $199.3 million and the first and second interim dividends for 2025 of $298.4 million. A further interim dividend for 2025 of $200.0 million will be paid in April 2026.

**Goodwill headroom**

At 31 December 2025, Goodwill amounted to $1,339 million (2024: $1,129 million). Due to declines in future commodity prices, goodwill headroom reduced to $125 million (2024: $419 million). Commodity prices would have to be 2% lower than those assumed in the base case impairment testing for there to be no goodwill headroom left. Further details are set out in notes 18 and 19.

**Financial position: assets, liabilities and shareholders' equity**

| | **2025 $m** | 2024 $m |
|---|---|---|
| Total assets | **8,447.0** | 8,275.0 |
| Total liabilities | **(5,875.2)** | (5,234.6) |
| **Net assets and shareholders' equity** | **2,571.8** | **3,040.4** |

### Assets

At 31 December 2025, total assets amounted to $8,447.0 million (2024: $8,275.0 million) and comprised current assets of $1,152.5 million (2024: $976.2 million) and non-currents assets of $7,292.7 million (2024: $7,300.6 million). The increase in total assets of $172.0 million was primarily due to:

- Derivative financial instruments being $328.3 million higher mainly reflecting gas trades which have moved from a liability position due to lower than previously forecast future prices;
- Property, plant and equipment increasing by $557.1 million as asset additions, acquired assets and revisions to decommissioning cost estimates exceeded the depreciation charge for the year;
- Goodwill was higher by $209.3, million reflecting the JAPEX UK and Cygnus acquisitions as well as revisions to the Eni UK fair values; partly offset by:
- Deferred tax was $862.2 million lower principally due to the tax charge for the two-year extension of EPL, tax on cash flow hedges which go through the statement of comprehensive income and the utilisation of historic tax losses; and
- Trade and other recievables were $62.0 million lower mainly due to reduced accrued income on lower liftings year-on-year.

### Liabilities

At 31 December 2025, total liabilities amounted to $5,875.2 million (2024: $5,234.6 million). The increase in total liabilities during the year of $640.6 million was mainly due to:

- Decommissioning provisions increased by $426.8 million primarily due to $266.5 million of revisions to cost estimates principally at Elgin Franklin, Captain, Heather, Strathspey, J-block and Cynus. In addition $125.4 miilion of liabilities were acquired through JAPEX UK and Cygnus;
- Borrowings were $396.9 million higher due to the issuance of the senior unsecured notes, due 2031, party offet by lower drawings under the RBL;
- Lease liabilities increased by $72.1 million due to the addition of a drilling rig for Cygnus, a decommissioning vessel for Alba and a two-year extension to the Skandi Gamma contract;
- Current tax payable was $69.8 million higher principally due to higher current EPL charges on higher taxable profits; partly offset by:
- Contingent and deferred consideration was $202.2 million lower mainly due to Eni UK and Marubeni deferred consideration payements of $164.0 million and $70.0 million, respectively; and
- Derivative financial instruments liabilities reduced by $141.6 million reflecting the gas trades which, as noted above, have moved to asset positions at 31 December 2025.

### Equity and reserves

At 31 December 2025, total equity and reserves amounted to $2,571.8 million (2024: $3,040.4 million). The reduction in equity and reserves during the year of $468.6 million was primarily due to:

- Dividends paid of $497.7 million;
- The loss for the year of $84.1 million; partly offset by:
- Favourable post-tax hedging reserve movements of $95.1 million.

### Financial position: cash

| | 2025 $m | 2024 $m |
|---|---|---|
| **Opening cash** | **165.1** | **153.2** |
| Operating cash flows | **1,745.3** | 853.3 |
| Investing cash flows | **(1,451.6)** | (390.9) |
| Financing cash flows | **(292.2)** | (449.5) |
| Foreign exchange | **3.5** | (1.0) |
| Net cash flow | **5.0** | 11.9 |
| **Closing cash** | **170.1** | **165.1** |
| Undrawn borrowing facilities | **1,300.0** | 850.0 |
| Available liquidity | **1,470.1** | 1,015.1 |

### Operating cash flows

Net cash from operating activities amounted to $1,745.3 million (2024: $853.3 million), including favourable working capital movements of $64.0 million (2024: adverse movements of $124.2 million) and tax payments of $262.9 million (2024: $351.3 million). The increase in net cash flow from operating activities was largely driven by the higher production in the year.

### Investing cash flows

Cash flow used in investing activities amounted to $1,451.6 million (2024: $390.9 million), an increase of $1,060.7 million principally due to:

- Capital expenditure was $420.2 million higher than 2024 reflecting drilling and workover activities at Captain, FPSO modifications and subsurface scopes on Rosebank and well work on Cygnus, Seagull and Judy/Joanne;
- Acquisition payments, net of cash acquired, were $400.9 million higher due to the JAPEX UK and Cygnus acquisitions in 2025; and
- Deferred consideration payments were $234.0 million higher due to the payments to Eni S.p.A and Marubeni.

### Financing cash flows

Cash outflow from financing activities of $292.2 million (2024: $449.5 million), a decrease of $157.3 million mainly due to:

- Proceeds of the senior notes, due 2031, of $523.9 million were received in 2025;
- A loan from bp of $100.0 million was repaid in the year to 31 December 2024; partly offset by:
- Net movements on the RBL facility, including fees paid on the 2024 refinancing, were $268.4 million adverse year-on-year, reflecting repayments in 2025 compared to drawdowns in 2024;
- There was a net receipt of $86.8 million in the year to 31 December 2024 on the refinancing of the senior notes due 2026 with the senior notes due 2029;
- Dividend payments were $65.0 million higher year-on-year under our dividend policy; and
- Leases, interest and charges paid were $45.8 million higher year-on-year because of new leases entered into and higher levels of debt following the refinancing in 2024 and the issuance of the senior notes due 2031.

Cash balances were $170.1 million (2024: $165.1 million) at 31 December 2025 and available liquidity was $1,470.1 million (2024: $1,015.1 million).

### Derivative financial instruments

Derivative financial instruments are utilised to manage commodity price risk in a substantive financial hedging programme for future oil and gas production volumes. As at 31 December 2025, the following hedges were in place:

| | 2026 | 2027 |
|---|---|---|
| **Oil** | | |
| Volume hedged (mmboe) | 16.7 | 3.1 |
| Weighted average floor hedged price ($/bbl) | 63 | 66 |
| **Gas** | | |
| Volume hedged (mmboe) | 12.0 | 2.0 |
| Weighted average floor hedged price (p/therm) | 86 | 82 |

### Going concern

Management closely monitor the funding position of the Group, including monitoring compliance with covenants and available facilities to ensure sufficient headroom is maintained to fund operations. Management have considered a number of risks applicable to the Group that may have an impact on the Group's ability to continue as a going concern. Short-term and long-term cash forecasts are prepared on a weekly and quarterly basis, respectively, along with any related sensitivity analysis. This allows proactive management of any business risk including liquidity risk.

The Directors consider the preparation of the financial statements on a going concern basis to be appropriate. This is due to the following key factors:

- A well-hedged portfolio over the next 12 months;
- Reserves Based Lending (RBL) facility is undrawn providing liquidity headroom of $1,300 million, plus $214 million of cash at the end of February 2026; and
- Robust operational performance and a well-diversified portfolio.

**Cash flow forecast – base case assumptions**

| | | 2026 | H1 2027 |
|---|---|---|---|
| Average oil price | $/bbl | 68 | 66 |
| Average gas price | p/therm | 83 | 72 |
| Average hedged oil price (including floor price for zero cost collars) | $/bbl | 63 | 66 |
| Average hedged gas price (including floor price for zero cost collars) | p/therm | 84 | 76 |

The oil and gas price assumptions used in the going concern and viability assessments represent management's current best estimates at the date of approval of the Annual Report and Accounts, as supported by data from third-party analysis, of future commodity prices whereas the commodity prices used in impairment testing (see note 19) are based on market conditions at 31 December 2025.

Owing to the ongoing fluctuations in commodity demand and price volatility, management prepared sensitivity analyses to the forecasts and applied a number of plausible downside scenarios including: decreases in production of 10%, reduced sales prices of 20% and increases in operating and capital expenditures of 10%. Management aggregated these scenarios to create a reasonable combined worst-case scenario. The sensitivity analysis showed that, without any consideration of the mitigation strategies within management's control, there was no reasonably possible scenario that would result in the business being unable to meets its liabilities as they fall due. The analysis demonstrated that the Group would still continue to comply with financial covenants and have sufficient liquidity throughout the period to 30 June 2027 to continue trading.

In addition, reverse stress tests have been performed reflecting further reductions in commodity prices, prior to any mitigating actions, to determine what levels they would have to reach such that either lending covenants are breached or there is no liquidity headroom left. This stress test demonstrated that the likelihood of the fall in price required to cause a breach of covenants or liquidity issue, is considered sufficiently remote in the context of the mitigation strategies available to management. The mitigation strategies within the control of management include the reduction in uncommitted capital expenditure and variable opex savings in the low production scenario.

Notwithstanding the Group having net current liabilities at 31 December 2025 of $303.9 million (2024: $456.5 million), there are sufficient undrawn facilities available to enable current liabilities to be settled as they fall due.

Based on their assessment of the Group's financial position over the period to 30 June 2027, the Directors believe that the Group will be able to continue in operational existence for the foreseeable future. Accordingly, they continue to adopt the going concern basis of accounting in preparing the consolidated financial statements.

## Consolidated statement of profit or loss

**For the year ended 31 December**

| | Note | **2025 $m** | 2024 $m |
|---|---|---|---|
| Revenue | 5 | **2,900.2** | 1,981.8 |
| Other income | 5 | **46.3** | – |
| **Revenue and other income** | | **2,946.5** | 1,981.8 |
| Cost of sales | 6 | **(1,710.9)** | (1,139.6) |
| **Gross profit** | | **1,235.6** | 842.2 |
| Impairment charges on oil and gas assets | 19 | **(77.5)** | (263.0) |
| Exploration and evaluation expenses | 14 | **(2.1)** | (24.6) |
| Administrative expenses | 7 | **(47.3)** | (57.3) |
| Other (losses)/gains | 8 | **(13.6)** | 26.4 |
| **Profit from operations before tax, finance income and finance costs** | | **1,095.1** | 523.7 |
| Finance income | 9 | **9.8** | 11.2 |
| Finance costs | 9 | **(264.6)** | (200.6) |
| **Profit before tax** | | **840.3** | 334.3 |
| Income tax | 28 | **(924.4)** | (181.2) |
| **(Loss)/profit for the year** | | **(84.1)** | 153.1 |

| **Earnings per share (EPS)** | Note | **2025 Cents** | 2024 Cents |
|---|---|---|---|
| Basic | 10 | **(5.1)** | 13.2 |
| Diluted | 10 | **(5.1)** | 13.0 |

The results above are entirely derived from continuing operations.

The year to 31 December 2025 includes the results of the JAPEX UK acquisition from 7 July 2025, the Cygnus acquisition from 1 October 2025 and the Eni UK business combination for the full year. The year to 31 December 2024 includes the results of the Eni UK business combination from 3 October 2024 (see note 17 for further details).

The accompanying notes on pages 26 to 65 are an integral part of the financial statements.

## Consolidated statement of comprehensive income

**For the year ended 31 December**

| | Note | 2025 $m | 2024 $m |
|---|---|---|---|
| **(Loss)/profit for the year** | | **(84.1)** | 153.1 |
| **Items that may be reclassified to profit and loss** | | | |
| Fair value gains/(losses) on cash flow hedges | 30 | **363.9** | (213.6) |
| Fair value gains/(losses) on cost of hedging | 30 | **68.1** | (50.8) |
| Fair value gains on investments in listed oil and gas shares | | **10.7** | – |
| Deferred tax (charge)/credit on cash flow hedges, cost of hedging and fair value through OCI reserve movements | 28 | **(336.9)** | 195.6 |
| **Other comprehensive income/(expense)** | | **105.8** | (68.8) |
| **Total comprehensive income for the year** | | **21.7** | 84.3 |

The accompanying notes on pages 26 to 65 are an integral part of the financial statements.

## Consolidated statement of financial position
As at 31 December

| | Note | 2025 $m | 2024 Restated[1] $m |
|---|---|---|---|
| **Assets** | | | |
| **Current assets** | | | |
| Inventories | 13 | **253.4** | 283.8 |
| Other financial assets | | **11.3** | 11.3 |
| Trade and other receivables | 11 | **355.6** | 417.6 |
| Decommissioning reimbursements | 11 | **64.9** | 23.2 |
| Prepayments | 12 | **29.4** | 42.2 |
| Derivative financial instruments | 31 | **267.8** | 33.0 |
| Cash and cash equivalents | | **170.1** | 165.1 |
| | | **1,152.5** | 976.2 |
| **Non-current assets** | | | |
| Goodwill | 18 | **1,338.8** | 1,129.5 |
| Exploration and evaluation assets | 14 | **606.0** | 612.5 |
| Property, plant and equipment | 15 | **4,745.5** | 4,188.4 |
| Deferred tax assets | 28 | **362.0** | 1,224.2 |
| Investments in listed oil and gas shares | | **49.0** | – |
| Decommissioning reimbursements | 11 | **99.7** | 144.2 |
| Derivative financial instruments | 31 | **93.5** | – |
| | | **7,294.5** | 7,298.8 |
| **Total assets** | | **8,447.0** | 8,275.0 |
| **Liabilities and equity** | | | |
| **Current liabilities** | | | |
| Borrowings | 20 | **(14.1)** | (13.0) |
| Trade and other payables | 22 | **(610.3)** | (566.5) |
| Other provisions | 24 | **(7.6)** | – |
| Current tax payable | | **(316.9)** | (247.1) |
| Decommissioning liabilities | 23 | **(328.0)** | (152.7) |
| Lease liabilities | 25 | **(59.1)** | (19.4) |
| Contingent and deferred consideration | 26 | **(111.1)** | (303.5) |
| Derivative financial instruments | 31 | **(9.3)** | (130.5) |
| | | **(1,456.4)** | (1,432.7) |

**Consolidated statement of financial position** continued
**As at 31 December**

| | Note | 2025 $m | 2024 Restated[1] $m |
|---|---|---|---|
| **Non-current liabilities** | | | |
| Borrowings | 20 | **(1,407.7)** | (1,011.9) |
| Decommissioning liabilities | 23 | **(2,753.9)** | (2,502.4) |
| Lease liabilities | 25 | **(53.1)** | (20.7) |
| Other provisions | 24 | **(3.6)** | (36.2) |
| Contingent and deferred consideration | 26 | **(199.9)** | (209.7) |
| Derivative financial instruments | 31 | **(0.6)** | (21.0) |
| | | **(4,418.8)** | (3,801.9) |
| **Total liabilities** | | **(5,875.2)** | (5,234.6) |
| **Net assets** | | **2,571.8** | 3,040.4 |
| **Shareholders' equity** | | | |
| Share capital | 27 | **20.0** | 20.0 |
| Share premium | 27 | **308.8** | 308.8 |
| Merger reserve | 27 | **852.8** | 852.8 |
| Capital contribution reserve | 27 | **181.9** | 181.9 |
| Own shares | 27 | **(4.7)** | (9.6) |
| Share-based payment reserve | 27 | **21.3** | 18.8 |
| Cash flow hedge reserve | 30 | **64.3** | (15.7) |
| Cost of hedging reserve | 30 | **6.0** | (9.1) |
| Fair value through OCI reserve | | **10.7** | – |
| Retained earnings | | **1,110.7** | 1,692.5 |
| **Total equity** | | **2,571.8** | 3,040.4 |

1 The excess over the nominal value of the shares issued on the completion of the Eni UK business combination on 3 October 2024 of $852.8 million has been reclassified from share premium to merger reserve (see note 2 for further details).

The accompanying notes on pages 26 to 65 are an integral part of the financial statements.

Approved on behalf of the Board on 17 March 2026:

**Iain C S Lewis**
Director

## Consolidated statement of changes in equity
**For the year ended 31 December**

| | Note | Share capital $m | Share premium $m | Merger reserve $m | Capital contribution reserve $m | Own shares $m | Share-based payment reserve $m | Cash flow hedge reserve $m | Cost of hedging reserve $m | Fair value through OCI reserve $m | Retained earnings $m | Total $m |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Balance at 1 January 2024** | | 11.5 | 308.8 | – | 181.9 | (12.4) | 15.5 | 39.9 | 4.1 | – | 1,972.1 | 2,521.4 |
| Dividends paid | 34 | – | – | – | – | – | – | – | – | – | (432.7) | (432.7) |
| Issuance of shares | 27 | 8.5 | 852.8 | – | – | – | – | – | – | – | – | 861.3 |
| Share-based payments | 27 | – | – | – | – | 2.8 | 3.3 | – | – | – | – | 6.1 |
| *Comprehensive income for the year:* | | | | | | | | | | | | |
| Profit for the year | | – | – | – | – | – | – | – | – | – | 153.1 | 153.1 |
| Other comprehensive expense | | – | – | – | – | – | – | (55.6) | (13.2) | – | – | (68.8) |
| *Total comprehensive income/(expense) for the year* | | – | – | – | – | – | – | (55.6) | (13.2) | – | 153.1 | 84.3 |
| **Balance at 31 December 2024 as previously stated** | | **20.0** | **1,161.6** | – | **181.9** | **(9.6)** | **18.8** | **(15.7)** | **(9.1)** | – | **1,692.5** | **3,040.4** |
| Reclassification[1] | | – | **(852.8)** | **852.8** | – | – | – | – | – | – | – | – |
| **Balance at 31 December 2024 and 1 January 2025 as restated** | | **20.0** | **308.8** | **852.8** | **181.9** | **(9.6)** | **18.8** | **(15.7)** | **(9.1)** | – | **1,692.5** | **3,040.4** |
| Dividends paid | 34 | – | – | – | – | – | – | – | – | – | **(497.7)** | **(497.7)** |
| Share-based payments | 27 | – | – | – | – | **4.9** | **2.5** | – | – | – | – | **7.4** |
| *Comprehensive income for the year:* | | | | | | | | | | | | |
| Loss for the year | | – | – | – | – | – | – | – | – | – | **(84.1)** | **(84.1)** |
| Other comprehensive income | | – | – | – | – | – | – | **80.0** | **15.1** | **10.7** | – | **105.8** |
| *Total comprehensive income/(expense) for the year* | | – | – | – | – | – | – | **80.0** | **15.1** | **10.7** | **(84.1)** | **21.7** |
| **Balance at 31 December 2025** | | **20.0** | **308.8** | **852.8** | **181.9** | **(4.7)** | **21.3** | **64.3** | **6.0** | **10.7** | **1,110.7** | **2,571.8** |

1 The excess over the nominal value of the shares issued on the completion of the Eni UK business combination on 3 October 2024 of $852.8 million has been reclassified from share premium to merger reserve (see note 2 for further details).

The accompanying notes on pages 26 to 65 are an integral part of the financial statements.

## Consolidated statement of cash flows

**For the year ended 31 December**

| | Note | 2025 $m | 2024 $m |
|---|---|---|---|
| **Cash provided by/(used in):** | | | |
| **Operating activities** | | | |
| Profit before tax | | **840.3** | 334.3 |
| **Adjustments for:** | | | |
| Depletion, depreciation and amortisation | 15 | **840.6** | 600.2 |
| Exploration and evaluation expenses | 14 | **2.1** | 24.6 |
| Impairment charges on oil and gas assets | 19 | **77.5** | 263.0 |
| Fair value remeasurements of contingent consideration | 8 | **22.8** | (27.3) |
| Loan fee amortisation | 9 | **11.1** | 13.2 |
| Fair value gains on derivatives | 30 | **(15.9)** | (0.4) |
| Accretion on deferred consideration and decommissioning liabilities less accretion on decommissioning reimbursements | 9 | **125.5** | 82.9 |
| Finance costs | 9 | **128.0** | 104.5 |
| Finance income | 9 | **(9.8)** | (11.2) |
| Unrealised foreign exchange | | **2.1** | 1.1 |
| Changes in provisions | | **13.6** | – |
| Movements in cash flow hedges not yet settled | | **(27.0)** | – |
| Other non-cash income | | **(9.4)** | – |
| Share-based payment expenses | 33 | **7.4** | 6.1 |
| Decommissioning expenditure | 23 | **(107.2)** | (94.1) |
| Decommissioning reimbursements net of taxation[1] | 11 | **25.3** | 22.5 |
| **Operating cash flows before movements in working capital** | | **1,927.0** | 1,319.4 |
| Decrease/(increase) in inventories | | **29.3** | (84.2) |
| Decrease in trade and other receivables | | **84.5** | 91.5 |
| Decrease in trade and other payables | | **(49.8)** | (131.5) |
| **Operating cash flows** | | **1,991.0** | 1,195.2 |
| Taxation paid | | **(262.9)** | (351.3) |
| Settlement of foreign exchange and commodity derivative financial instruments | | **7.4** | (1.8) |
| Finance income | 9 | **9.8** | 11.2 |
| **Net cash from operating activities** | | **1,745.3** | 853.3 |

1 The comparative amount of $22.5 million was included in the line "decrease in trade and other receivables" in the 2024 Annual Report and Accounts.

**Consolidated statement of cash flows** continued
**For the year ended 31 December**

| | Note | 2025 $m | 2024 $m |
|---|---|---|---|
| **Investing activities** | | | |
| Capital expenditure | | **(884.3)** | (464.1) |
| Business combinations cash acquired | 17 | **16.1** | 107.5 |
| Acquisition of businesses and subsidiary undertakings | 17 | **(309.5)** | – |
| Investment in other financial assets | | **–** | (11.3) |
| Other investments in listed oil and gas shares | | **(38.3)** | – |
| Deferred consideration payments | 26 | **(234.0)** | – |
| Contingent consideration payments | 26 | **(1.6)** | (23.0) |
| **Net cash used in investing activities** | | **(1,451.6)** | (390.9) |
| **Financing activities** | | | |
| Dividends paid | 34 | **(497.7)** | (432.7) |
| Payments for lease liabilities (principal) | 25 | **(46.7)** | (27.9) |
| Drawdown of RBL loan | | **200.0** | 150.0 |
| Repayment of RBL loan | | **(350.0)** | – |
| Fees paid on RBL refinancing | 20 | **–** | (31.6) |
| Proceeds of senior notes due 2029 net of repayment of senior notes due 2026 and fees[1] | 20 | **–** | 86.8 |
| Net proceeds of senior notes due 2031[2] | 20 | **523.9** | – |
| Repayment of bp loan | 20 | **–** | (100.0) |
| Interest and charges paid | | **(121.7)** | (94.7) |
| Interest rate swaps | 30 | **–** | 0.6 |
| **Net cash used in financing activities** | | **(292.2)** | (449.5) |
| Currency translation differences relating to cash | | **3.5** | (1.0) |
| **Increase in cash and cash equivalents** | | **5.0** | 11.9 |
| Cash and cash equivalents at 1 January | | **165.1** | 153.2 |
| **Cash and cash equivalents at 31 December** | | **170.1** | 165.1 |

1 A net receipt of $86.8 million in the year to 31 December 2024 reflects senior notes due 2029 proceeds of $750.0 million less repayment of senior notes due 2026 of $625.0 million less fees and interest of $38.2 million comprising $14.1 million of early repayment charges and $15.1 million interest on the senior notes due 2026 and $9.0 million of fees in relation to the senior notes due 2029.
2 A net receipt of $523.9 million was received in the year to 31 December 2025 reflecting gross proceeds of $529.6 million less direct initial fees of $5.7 million. In addition, $5.3 million of fees were subsequently paid which are included within 'interest and charges paid' above.

The accompanying notes on pages 26 to 65 are an integral part of the financial statements.

## 1. General information

Ithaca Energy plc (the Group or Ithaca Energy), is a public Company limited by shares incorporated and domiciled in the UK and is a Group involved in the development and production of oil and gas in the North Sea. The Group's registered office is 33 Cavendish Square, London, W1G 0PP, United Kingdom.

The financial information for the years ended 31 December 2025 and 2024 contained in this document does not constitute statutory accounts of Ithaca Energy plc (the Company), as defined in section 435 of the Companies Act 2006. The financial information for the years ended 31 December 2025 and 2024 has been extracted from the consolidated financial statements of Ithaca Energy plc and all its subsidiaries (the Group), which were authorised by the Board of Directors on 17 March 2026 and which will be delivered to the Registrar of Companies in due course. The auditor's report on those financial statements was unqualified and did not contain a statement under section 498 of the Companies Act 2006.

## 2. Basis of preparation

The consolidated financial statements are prepared in accordance with United Kingdom adopted International Accounting Standards (IAS) and in conformity with the requirements of the Companies Act 2006.

The consolidated financial statements are presented in US Dollars as this is the functional currency of the business. All values are presented in millions ($m) rounded to one decimal place, except where otherwise indicated.

The principal accounting policies applied in the preparation of the financial statements are set out below. These policies have been consistently applied to all the periods presented.

### Prior period reclassification

The excess of the fair value over the nominal value of the shares issued on the completion of the Eni UK business combination on 3 October 2024 was classified incorrectly to share premium and has been reclassified to merger reserve in order to comply with Section 612 of the Companies Act 2006. Details of amounts as previously stated, prior period reclassifications and amounts as restated were:

| Statement of financial position as at 31 December 2024: | As previously stated | Prior period reclassification | As restated |
|---|---|---|---|
| Share premium ($m) | 1,161.6 | (852.8) | **308.8** |
| Merger reserve ($m) | – | 852.8 | **852.8** |

## 3. Material accounting policies, judgements and estimation uncertainty

### Basis of measurement

The consolidated financial statements have been prepared on a going concern basis using the historical cost convention, except for the revaluation of certain financial assets and financial liabilities, under International Financial Reporting Standards (IFRS), to fair value, including derivative instruments. Historical cost is generally based on the fair value consideration given in exchange for the assets and liabilities.

### Going concern

Management closely monitor the funding position of the Group, including monitoring compliance with covenants and available facilities to ensure sufficient headroom is maintained to fund operations. Management have considered a number of risks applicable to the Group that impact on the Group's ability, and the Parent Company's ability, to continue as a going concern. Short-term and long-term cash forecasts are prepared on a weekly and quarterly basis respectively, along with any related sensitivity analysis. This allows proactive management of any business risk including liquidity risk.

The Directors consider the preparation of the financial statements on a going concern basis to be appropriate. This is due to the following key factors:

- A well-hedged portfolio over the next 12 months;
- Reserves Based Lending (RBL) is undrawn providing liquidity headroom of $1,300 million, plus $214 million of cash at the end of February 2026; and
- Robust operational performance and a well-diversified portfolio.

| Cash flow forecast – base case assumptions: | | 2026 | H1 2027 |
|---|---|---|---|
| Average oil price | $/bbl | 68 | 66 |
| Average gas price | p/th | 83 | 72 |
| Average hedged oil price (including floor price for zero cost collars) | $/bbl | 63 | 66 |
| Average hedged gas price (including floor price for zero cost collars) | p/th | 84 | 76 |

The oil and gas price assumptions used in the going concern and viability assessments represent management's current best estimates of future commodity prices at the date of approval of the Annual Report and Accounts, as supported by data from third-party analysis, whereas the commodity prices used in impairment testing (see note 19) are based on market conditions at 31 December 2025.

Owing to the ongoing fluctuations in commodity demand and price volatility, management prepared sensitivity analyses to the forecasts and applied a number of plausible downside scenarios, including decreases in production of 10%, reduced sales prices of 20% and increases in operating and capital expenditures of 10%. Management aggregated these scenarios to create a reasonable combined worst-case scenario. The sensitivity analysis showed that, without any consideration of the mitigation strategies within management's control, there was no reasonably possible scenario that would result in the business being unable to meet its liabilities as they fell due. In addition, reverse stress tests have been performed reflecting further reductions in commodity prices, prior to any mitigating actions, to determine at what levels prices would have to reach such that there is no liquidity headroom left. The stress tests demonstrated that the likelihood of the fall in prices required to cause a liquidity issue is considered sufficiently remote in the context of the mitigation strategies available to management. The mitigation strategies within the control of management include a reduction in uncommitted capital expenditure and variable opex savings in the low production scenario. The analysis demonstrated that the Group would still continue to comply with financial covenants and have sufficient liquidity throughout the period to 30 June 2027 to continue trading.

Notwithstanding the Group having net current liabilities at 31 December 2025 of $303.9 million (31 December 2024: $456.5 million), there are sufficient undrawn facilities available to enable current liabilities to be settled as they fall due.

**3. Material accounting policies, judgements and estimation uncertainty** continued

Based on their assessment of the Group's financial position in the period to 30 June 2027, the Directors believe that the Group will be able to continue in operational existence for the foreseeable future. Accordingly, they continue to adopt the going concern basis of accounting in preparing the financial statements.

### Basis of consolidation

The consolidated financial statements of the Group includes the financial information of Ithaca Energy plc and all wholly-owned subsidiaries as set out in note 32. All intergroup transactions and balances have been eliminated on consolidation.

Subsidiaries are all entities over which the Group has control. The plc controls an entity when the Group is exposed to or has rights to variable returns from its investments with the entity and has the ability to affect those returns through its power over the investee. Subsidiaries are fully consolidated from the date on which control is transferred to the Group. They are deconsolidated on the date that control ceases.

### Impact of climate change on the financial statements and related notes

#### Judgements in respect of exploration and evaluation assets and estimates made for all other areas in assessing the impact of climate change and the energy transition

Climate change and the transition to a lower-carbon system were considered in preparing the consolidated financial statements. These may have the potential for significant impacts on the carrying values of the Group's assets and liabilities discussed below as well as on assets and liabilities that may be reflected in the future. There is also the potential for significant impact on future cash flows. There is generally a high level of uncertainty about the speed and magnitude of impacts of climate change which, together with limited historical data, provides significant challenges in the preparation of forecasts and financial plans with a wide range of potential future outcomes.

The Group's ambition is to have one of the lowest carbon emission portfolios in the UK North Sea and to achieve Net Zero (whereby the amount of $CO_2$ added by the Group's activities is no greater than the amount taken away), on a net equity basis (by applying the Group's working interest in each respective asset to the total emissions of that asset), and in respect of Scope 1 and 2 emissions, by 2040, ten years ahead of the North Sea Transition Deal commitment. This will be achieved by optimising the Group's current portfolio in the short term and fundamentally transitioning the Group's portfolio over the medium to long term whilst maintaining forecast levels of production. Initiatives include, but are not limited to, operational improvements, offshore electrification, acquisition and investment into lower carbon intensity assets and the eventual cessation of production of mature fields which have higher carbon intensity. In addition, the Eni UK business combination in 2024 and the Seagull and Cygnus acquisitions in 2025 have added relatively low emission assets, thereby reducing the carbon footprint of the Group. Where the Group cannot reduce Scope 1 and Scope 2 emissions, Ithaca Energy will invest in carbon offsets to achieve the Group's goal of Net Zero. All new economic investment decisions include estimated costs of the energy transition based on existing technology and estimated costs of carbon and these opportunities are assessed on their climate impact potential and alignment with Ithaca Energy's Net Zero target, taking into account both greenhouse gas volumes and emissions intensity.

Specific considerations of the potential impacts of climate change on significant judgements and estimates used in the consolidated financial statements are considered below. The items outlined below are likely to manifest themselves over a number of years and are, therefore, not generally considered to represent 'key sources of estimation uncertainty' as required by IAS 1 (being those which could have a material impact on the Group's results in the 12 months following the date of the consolidated statement of financial position) which are separately disclosed later in this note.

#### Impairment of goodwill and property, plant and equipment

The energy transition has the potential to significantly impact future commodity and carbon prices in that as the UK and global energy system decarbonises, reduced demand for oil and gas products in favour of low carbon alternatives could cause oil and gas prices to fall which would, in turn, affect the recoverable amount of goodwill and property, plant and equipment. In the current period management's estimate of the long-term commodity price assumptions are, in nominal terms from 2032, $80/bbl for Brent Crude and 79p/therm for UK NBP gas. Further details of climate change, including a sensitivity in this area are provided in note 19.

Recoverable values used for impairment testing for all cash-generating units (CGUs) include the estimated cost of UK carbon emissions allowances in real terms for $CO_2e$ of £45/tonne, £65/tonne and £80/tonne for 2026, 2027 and 2028 respectively. The recoverable value of CGU's may be impacted by future carbon pricing legislation changes, which could increase operating costs through higher emissions allowances or the introduction of other carbon pricing mechanisms. Electrification of offshore operations for specific assets is planned in line with the Group's 2040 Net Zero ambitions and where feasible based on existing technology and economic value, estimated electrification costs of a market participant are included within the assessment of the recoverable value of the relevant CGU.

#### Property, plant and equipment – depreciation and useful economic lives

The energy transition has the potential to reduce the expected useful economic lives of assets and hence accelerate depreciation charges. Although no changes have been identified or recognised to date, it is anticipated that certain higher emission-intensity assets such as FPF-1 and Alba will cease production in the short to medium term and will be replaced by new lower-emission intensity assets. Management does not currently expect the useful economic lives of the Group's reported property, plant and equipment to significantly change solely as a result of the energy transition. However, significant capital expenditure is still required for ongoing projects and therefore, the useful lives of future capital expenditure may be different.

#### Intangible assets – exploration and evaluation assets

The impacts of climate change and the energy transition may affect the viability of exploration prospects, for example, due to the impact on future commodity and carbon prices (as explained above) or due to the increased risk of regulatory challenge as prospects progress through to development. The recoverability of the existing intangibles was considered during 2025, however, no significant write-offs were identified as a result of climate change considerations. Viability of these assets will continue to be assessed on a regular basis.

#### Decommissioning provisions

Most of the Group's existing decommissioning obligations are estimated to be completed over the course of the next 20 years. The impacts of climate change and the energy transition may bring forward the expected timing of decommissioning activity, increasing the present value of the associated decommissioning provisions. The potential impact of a reasonably possible acceleration of estimated decommissioning dates, which considers the potential impact of the energy transition, is considered to be two years. The impact of such an acceleration of cessation of production across the Group's producing assets with estimated cessation of production dates from 2028 onwards, would result in an increase in the decommissioning provision of approximately $109 million (2024: $93 million). The risk in this area may increase if key assets within the Group's existing exploration, appraisal and development portfolio proceed to the production stage, as this is likely to significantly extend the life of the Group's portfolio, in some cases to 2050 or beyond.

**3. Material accounting policies, judgements and estimation uncertainty** continued

While the pace of the transition to a lower-carbon economy is uncertain, oil and gas demand is expected to remain a key element of the energy mix for many years based on stated policies, commitments and announced pledges to reduce emissions. Therefore, given the estimated useful lives of the Group's oil and gas portfolio, a material adverse change is not anticipated to the carrying value of the Group's assets and liabilities in the short term as a result of climate change and the transition to a lower-carbon economy.

### Business combinations

Business combinations are accounted for using the acquisition method. The cost of a business combination is measured as the fair value of the consideration given for the assets acquired, equity instruments issued and liabilities incurred or assumed at the date of completion of the business combination. Transaction costs incurred are expensed and included in administrative expenses. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the date of the business combination. The excess of the cost of the business combination over the fair value of the Group's share of the identifiable net assets acquired is recorded as goodwill. If the cost of the business combination is less than the Group's share of the net assets acquired, the difference is recognised directly in the consolidated statement of profit or loss as a gain on bargain purchase.

### Goodwill

#### Capitalisation

Goodwill is initially recognised and measured as set out above. Following initial recognition, goodwill is measured at cost less any accumulated impairment losses.

In the event of a business combination or acquisition of an interest in a joint operation in which the activity constitutes a business, as defined in IFRS 3 Business Combinations, the acquisition method of accounting is applied. Goodwill represents the difference between the aggregate of the fair value of purchase consideration transferred at the acquisition date and the fair value of the identifiable assets, liabilities and contingent liabilities acquired, less any non-controlling interest. If, however, the fair value of the purchase consideration transferred is lower than the fair value of the identifiable assets and liabilities acquired, less non-controlling interest, the difference is recognised in the income statement as negative goodwill. The Group's goodwill is related to the requirement to recognise deferred tax for the difference between the assigned fair values and the related tax base (technical goodwill). The fair value of the Group's licences are based on post-tax cash flows or benchmarked multiples. In accordance with IAS 12 paragraphs 15 and 24, a provision is made for deferred tax corresponding to the difference between the acquisition cost and the transferred tax depreciation basis. The offsetting entry to this deferred tax is goodwill. Hence, goodwill arises as a technical effect of deferred tax. Impairments are expected to arise as the deferred tax liability naturally unwinds in the normal course of business. Goodwill is initially measured at cost. Following initial recognition, goodwill is measured at cost less any accumulated impairment. Goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's operating segments. This is subsequently tested for impairment at the Group's operating segment level based on the aggregation of any headroom arising from asset impairment tests.

#### Impairment

Goodwill is tested annually for impairment and also when circumstances indicate that the carrying value may be at risk of being impaired. Impairment is determined for goodwill by assessing the recoverable amount of each CGU or Group of CGUs to which the goodwill relates. If the recoverable amount of a CGU is less than its carrying amount, the impairment loss is allocated first to reduce the carrying amount of goodwill allocated to the unit and then to the other assets of the unit pro-rata based on the carrying amount of each asset in the unit. Any impairment loss is recognised in the consolidated statement of profit or loss. Impairment losses relating to goodwill cannot be reversed in future periods. The CGU for the purposes of the goodwill test is the North Sea, i.e. the entire Group portfolio of oil and gas assets (including E&E assets) which is consistent with the operating segment view of the business.

### Investments

Investments in listed oil and gas shares are initially recorded at cost and are subsequently remeasured on a fair value through other comprehensive income basis due to an irrevocable designation having been made in this respect.

### Interest in joint ventures

Under IFRS 11, joint arrangements are those that convey joint control which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control. Investments in joint arrangements are classified as either joint operations or joint ventures depending on the contractual rights and obligations of each investor.

The Group's interest in joint operations (e.g. exploration and production arrangements) are accounted for by recognising its assets (including its proportionate share of assets held jointly), its liabilities (including its proportionate share of liabilities incurred jointly), its revenue from the sale of its proportionate share of the output arising from the joint operation and its expenses (including its proportionate share of any expenses incurred jointly).

### Revenue

The sale of crude oil, gas or condensate represents a single performance obligation, being the sale of barrels equivalent on collection of a cargo or on delivery of commodity into an infrastructure. Revenue is accordingly recognised for this performance obligation when control over the corresponding commodity is transferred to the customer. Revenue is recognised at a point in time and is measured based on the consideration to which the Group expects to be entitled in a contract with a customer and excludes amounts collected for third parties. Details of hedging gains and losses presented in revenue are discussed in the hedging accounting policy set out below.

Tariff income is recognised as the underlying commodity is shipped through the pipeline network based on established tariff rates.

**3. Material accounting policies, judgements and estimation uncertainty** continued

### Foreign currency translation

Items included in these consolidated financial statements are measured using the currency of the primary economic environment in which the Group and its subsidiaries operate (the functional currency). The consolidated financial statements are presented in US Dollars, which is the Group's presentation currency as well as the functional currency of the Parent Company and each of its subsidiaries. In preparing the financial statements of the Parent and its subsidiaries, transactions in currencies other than the entity's functional currency (foreign currencies) are recognised at the rates of exchange prevailing on the dates of the transactions. At each reporting date, monetary assets and liabilities that are denominated in foreign currencies are retranslated at the rates prevailing at that date. Non-monetary items carried at fair value that are denominated in foreign currencies are translated at the rates prevailing at the date when the fair value was determined. Non-monetary items that are measured in terms of historical cost in a foreign currency are not retranslated.

Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year-end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in the statement of profit or loss.

Exchange differences are recognised in profit or loss in the period in which they arise except for:

- Exchange differences on foreign currency borrowings relating to assets under construction for future productive use, which are included in the cost of those assets when they are regarded as an adjustment to interest costs on those foreign currency borrowings; and
- Exchange differences on transactions entered into to hedge certain foreign currency risks (see below under financial instruments/hedge accounting).

### Dividend distribution

Dividend distribution to the Company's shareholders is recognised as a liability in the Company's financial statements in the period in which the dividends are approved by the Company's shareholders. Details of dividends paid and declared are set out in note 34.

### Financial instruments

All financial instruments are initially recognised at fair value on the statement of financial position. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

The Group derecognises a financial asset only when the contractual rights to the cash flows from the asset expire, or when it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another entity. The difference between the carrying amount of the financial asset derecognised and the consideration received/receivable is recognised in profit or loss.

The Group derecognises financial liabilities when, and only when, the Group's obligations are discharged, cancelled or have expired. The Group considers whether refinancing arrangements represent settlement of the existing debt and issuance of a new debt or an exchange or modification of the previous debt. In making this assessment, the Group considers, amongst other factors, pre-existing early redemption options in the original agreement, the group of lenders to which the new debt is offered and any preferential terms or rights given to the original lenders. Where the new debt is considered to represent an arms-length market offering, the issuance of the new debt is viewed as separate from the extinguishment of the old debt and is treated as the derecognition of the original liability and the recognition of a new liability. The difference between the carrying amount of the financial liability derecognised and the consideration paid/payable (excluding consideration payable for fees incurred on the new liability or accrued interest) is recognised in profit or loss.

#### IFRS 9 classifications

Cash and cash equivalents are classified at amortised cost which equates to its fair value. Accounts receivable and long-term receivables are classified and carried at amortised cost less expected credit losses. These items have a business model of held to collect and the terms of the financial instrument meet the classification of solely payments of interest on principle outstanding.

Accounts payable, accrued liabilities, certain other long-term liabilities and borrowings are classified as other financial liabilities and carried at amortised cost using the effective interest method. Amortised cost is calculated by taking into account any issue costs, discount or premium. Contingent consideration is measured at fair value though profit or loss. Although the Group does not intend to trade its derivative financial instruments, they are required to be carried at fair value with the treatment of fair value movements explained further below.

#### Transaction costs, presentation and cash flows

Transaction costs that are directly attributable to the acquisition or issue of a financial asset or liability (excluding the costs directly attributable to the new loan commitment facilities) have been included in the carrying value of the related financial asset or liability and are amortised to consolidated net earnings over the life of the financial instrument using the effective interest method.

Directly attributable fees paid on the establishment of new loan commitment facilities are capitalised to the extent that it is probable that some or all of the facility will be drawn down. These costs are recognised on a systematic basis over the period the Group is able to draw down. Fees that are calculated based on the usage of the facility (including letter of credit fees) are expensed as incurred.

Borrowings are presented as non-current when they are not due to be settled within 12 months after the reporting period or where the Group has the right at the end of the reporting period to defer settlement for at least 12 months after the reporting period.

Cash flows relating to refinancing are presented in the statement of cash flows on a net basis where that reflects the actual cash flows received by the Group. The refinancing proceeds in the statement of cash flows are stated after deduction of fees which were deducted from the amount paid to the Group. Other fees paid on refinancing are presented as a separate line item within financing activities or within Interest and charges paid in the statement of cash flows.

## 3. Material accounting policies, judgements and estimation uncertainty continued

### Impairment of financial assets

For trade receivables and accrued income, the Group applies a simplified approach in calculating expected credit losses (ECLs). Therefore, the Group does not track changes in credit risk, but instead recognises any material loss allowance based on lifetime ECLs at each reporting date. For all other financial assets, the Group measures the loss allowance using 12-month expected credit losses unless there was a significant increase in credit risk since initial recognition in which case the loss allowance is measured using lifetime expected credit losses.

In making this assessment whether the credit risk increased significantly since initial recognition, the Group considers both quantitative and qualitative information that is reasonable and supportable, including historical experience and forward-looking information that is available without undue cost or effort. The Group considers that the credit risk increased significantly since initial recognition when the credit rating changes, the debtor has significant financial difficulty or if there was a breach of contract. For balances that are beyond 30 days overdue it is presumed to be an indicator of a significant increase in credit risk.

The Group considers a financial asset in default when contractual payments are 90 days past due. However, in certain cases, the Group may also consider a financial asset to be in default when internal or external information indicates that the Group is unlikely to receive the outstanding contractual amounts in full before taking into account any credit enhancements held by the Group.

A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows. Financial assets written off may still be subject to enforcement activities under the Group's recovery procedures, taking into account legal advice where appropriate. Any recoveries made are recognised in profit or loss.

### Derivative financial instruments

The Group enters into a variety of derivative financial instruments to manage its exposure to commodity risks, interest rate and foreign exchange rate risks. These instruments include: commodity swaps, collars and options; foreign exchange forward contracts and collars; and interest rate swaps. Further details of derivative financial instruments are disclosed in notes 30 and 31.

Derivatives are recognised initially at fair value at the date a derivative contract is entered into and are subsequently remeasured to their fair value at each reporting date. The resulting gain or loss on remeasurement of derivatives is recognised in profit or loss immediately unless the derivative is designated in a hedge relationship and effective as a hedging instrument, in which event the timing of the recognition in profit or loss depends on the nature of the hedge relationship.

A derivative with a positive fair value is recognised as a financial asset whereas a derivative with a negative fair value is recognised as a financial liability. Derivatives are not offset in the financial statements unless the Group has both a legally enforceable right and intention to offset. A derivative is presented as a non-current asset or a non-current liability if the remaining maturity of the instrument is more than 12 months and it is not due to be realised or settled within 12 months. Other derivatives maturing in less than 12 months and expected to be realised or settled in less than 12 months are presented as current assets or current liabilities.

#### Hedge accounting

The Group designates certain derivatives as hedging instruments in respect of commodity risks in cash flow hedges.

At the inception of the hedge relationship, the Group documents the relationship between the hedging instrument and the hedged item, along with its risk management objectives and its strategy for undertaking various hedge transactions. Furthermore, at the inception of the hedge and on an ongoing basis, the Group documents whether the hedging instrument is highly effective in offsetting changes in fair values or cash flows of the hedged item attributable to the hedged risk.

If a hedging relationship ceases to meet the hedge effectiveness requirement relating to the hedge ratio, but the risk management objective for that designated hedging relationship remains the same, the Group adjusts the hedge ratio of the hedging relationship (i.e. rebalances the hedge) so that it meets the qualifying criteria again.

The Group designates only the intrinsic value of option contracts as a hedging instrument, i.e. excluding the time value of the option. The changes in the fair value of the aligned time value of the option are recognised in other comprehensive income and accumulated in the cost of hedging reserve. If the hedged item is transaction-related, the time value is reclassified to profit or loss when the hedged item affects profit or loss. If the hedged item is time period-related, then the amount accumulated in the cost of hedging reserve is reclassified to profit or loss on a rational basis – the Group applies straight-line amortisation. Those reclassified amounts are recognised in profit or loss in the same line as the hedged item. If the Group expects that some or all of the loss accumulated in the cost of hedging reserve will not be recovered in the future, that amount is immediately reclassified to profit or loss.

The effective portion of changes in the fair value of derivatives and other qualifying hedging instruments that are designated and qualify as cash flow hedges is recognised in other comprehensive income and accumulated under the heading of cash flow hedge reserve, limited to the cumulative change in fair value of the hedged item from inception of the hedge. The gain or loss relating to the ineffective portion is recognised immediately in profit or loss, and is included in the 'other gains and losses' line item.

Amounts previously recognised in other comprehensive income and accumulated in equity are reclassified to profit or loss in the periods when the hedged item affects profit or loss, in the same revenue line as the recognised hedged item. However, when the hedged forecast transaction results in the recognition of a non-financial asset or a non-financial liability, the gains and losses previously recognised in other comprehensive income and accumulated in equity are removed from equity and included in the initial measurement of the cost of the non-financial asset or non-financial liability. This transfer does not affect other comprehensive income. Furthermore, if the Group expects that some or all of the loss accumulated in the cash flow hedge reserve will not be recovered in the future, that amount is immediately reclassified to profit or loss.

The Group discontinues hedge accounting only when the hedging relationship (or a part thereof) ceases to meet the qualifying criteria (after rebalancing, if applicable). This includes instances when the hedging instrument expires or is sold, terminated or exercised. The discontinuation is accounted for prospectively. Any gain or loss recognised in other comprehensive income and accumulated in cash flow hedge reserve at that time remains in equity and is reclassified to profit or loss when the forecast transaction occurs. When a forecast transaction is no longer expected to occur, the gain or loss accumulated in the cash flow hedge reserve is reclassified immediately to profit or loss.

**3. Material accounting policies, judgements and estimation uncertainty** continued

If a hedge of a transaction-related item is discontinued part way through the life of the hedge (e.g. due to early termination of the swap, hedging resets), but the hedged item is still expected to occur, the amounts deferred in equity would remain in equity until the earlier of: (i) the hedged transaction occurring; or (ii) expectation that the amount deferred in equity will not be recovered in the future periods.

Notes 30 and 31 set out details of the fair values of the derivative instruments used for hedging purposes, and movements in the cash flow hedge reserve and cost of hedging reserve in equity are detailed in note 30.

### Contingent and deferred consideration

Contingent consideration in relation to a business combination or asset acquisition is accounted for as a financial liability and measured at fair value at the date of acquisition with any subsequent remeasurements recognised in profit or loss in accordance with IFRS 9. These fair values are generally based on risk-adjusted future cash flows discounted using appropriate discount rates. Changes in fair value of the contingent consideration that qualify as measurement period adjustments are adjusted retrospectively, with corresponding adjustments against goodwill. Measurement period adjustments are adjustments that arise from additional information obtained during the 'measurement period' (which cannot exceed one year from the date of the business combination) about facts and circumstances that existed at the date of the business combination.

The subsequent accounting for changes in the fair value of the contingent consideration that do not qualify as measurement period adjustments depends on how the contingent consideration is classified. Contingent consideration that is classified as equity is not remeasured at subsequent reporting dates and its subsequent settlement is accounted for within equity. Other contingent consideration is remeasured to fair value at subsequent reporting dates with changes in fair value recognised in profit or loss.

Deferred consideration is measured at amortised cost because the amount payable in the future is fixed.

Settlement of contingent consideration is recorded as investing outflows in the cash flow statement to the extent that cumulative amounts paid do not exceed the amount recognised at the date of acquisition, with any excess recorded as an operating cash outflow. Settlement of deferred consideration is recorded as either an investing or financing outflow in the cash flow statement, depending on the substance of the arrangement at inception. Key considerations in forming this judgement will include the extent of inferred financing costs included in the overall consideration arrangements at acquisition, the period of time over which the payments are made, the rationale for agreeing to defer elements of the consideration and the general level of funding resources available to the Group at the time of acquisition.

### Cash and cash equivalents

For the purpose of the statement of cash flows, cash and cash equivalents include investments with an original maturity of three months or less. In the statement of financial position, cash and bank balances comprise cash (i.e. cash on hand and demand deposits) and cash equivalents. Cash equivalents are short-term (generally with original maturity of three months or less), highly-liquid investments that are readily convertible to a known amount of cash and which are subject to an insignificant risk of changes in value. Cash equivalents are held for the purpose of meeting short-term cash commitments rather than for investment or other purposes.

### Inventories – hydrocarbon and materials

Inventories of materials are stated at the lower of cost and net realisable value. Cost comprises direct materials and, where applicable, direct labour costs and those overheads that have been incurred in bringing the inventories to their present location and condition. Cost is determined on the first-in, first-out method. Current hydrocarbon inventories are stated at net realisable value, which is based on estimated selling price less any further costs expected to be incurred to completion and disposal/sale. Non-current oil and gas inventories are stated at historic cost. Provision is made for obsolete, slow-moving and defective items where appropriate.

### Lifting or offtake arrangements

Lifting or offtake arrangements for oil and gas produced in certain of the Group's oil and gas properties are such that 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 volume sold is an 'underlift' included within inventories, or an 'overlift' included within trade and other payables in the statement of financial position. Both are stated at net realisable value using an observable year-end oil or gas market price. Movements during an accounting period are adjusted through cost of sales in the consolidated statement of profit or loss.

### Exploration and evaluation assets

**Oil and gas expenditure – exploration and evaluation (E&E) assets**

Geological and geophysical costs and costs incurred pre-licence are expensed as incurred. Costs directly associated with an exploration well are initially capitalised as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, freight costs and payments made to contractors. If potentially commercial quantities of hydrocarbons are not found, the exploration well costs are written off. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an asset. If it is determined that development will not occur, that is, the efforts are not successful, then the costs are expensed.

Costs directly associated with appraisal activity undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalised as an intangible asset. Upon external approval for development and recognition of proved or sanctioned probable reserves, the relevant expenditure is first assessed for impairment and, if required, an impairment loss is recognised. The remaining balance is then transferred to development and production (D&P) assets. If development is not approved and no further activity is expected to occur, then the costs are expensed.

The determination of whether potentially economic oil and natural gas reserves have been discovered by an exploration well is usually made within one year of well completion, but can take longer, depending on the complexity of the geological structure. Exploration wells that discover potentially economic quantities of oil and natural gas in areas where major capital expenditure (e.g. an offshore platform or a pipeline) would be required before production could begin and where the economic viability of that major capital expenditure depends on the successful completion of further exploitation or appraisal work in the area remain capitalised on the balance sheet as long as such work is under way or firmly planned.

## 3. Material accounting policies, judgements and estimation uncertainty continued

### Property, plant and equipment

**Oil and gas expenditure – D&P assets**

#### Capitalisation

Costs of bringing a field into production, including the cost of facilities, wells and subsea equipment, direct costs including staff costs together with E&E assets reclassified in accordance with the above policy, are capitalised as a D&P asset. Normally each individual field development will form an individual D&P asset but there may be cases, such as phased developments, or multiple fields around a single production facility when fields are grouped together to form a single D&P asset.

#### Depreciation

All costs relating to a development are accumulated and not depreciated until the commencement of production. Depreciation is calculated on a unit of production basis based on the proved and probable reserves of the asset generally on a field-by-field basis. Any re-assessment of reserves affects the depreciation rate prospectively. Significant items of plant and equipment will normally be fully depreciated over the life of the field. However, these items are assessed to consider if their useful lives differ from the expected life of the D&P asset.

### Non-oil and natural gas operations

Non-oil and gas assets are initially recorded at cost and depreciated over their estimated useful lives on a straight-line basis as follows: buildings 10 years, computers and office equipment 3 years and furniture and fittings 5 years.

### Impairment

For impairment review purposes the Group's oil and gas assets are aggregated into CGUs typically on a field-by-field basis for development and production assets in accordance with IAS 36, and on a North Sea segment basis for exploration and evaluation assets in accordance with IFRS 6. A review is carried out at each reporting date for any indicators that the carrying value of the Group's assets may be impaired.

Such reviews are carried out on a field-by-field basis for both development and production assets and exploration and evaluation assets. For assets where there are such indicators, an impairment test is carried out on the CGU. The impairment test involves comparing the carrying value with the recoverable value of an asset. The recoverable amount of an asset is determined as the higher of its fair value less costs to sell and value in use. If the recoverable amount of an asset is estimated to be less than its carrying amount, the carrying amount of the asset is reduced to the recoverable amount. The resulting impairment losses are written off to the consolidated statement of profit or loss. Previously impaired assets (excluding goodwill) are reviewed for possible reversal of previous impairment at each reporting date. The maximum possible reversal is capped at the net book value had the asset not been impaired in the past. Where an exploration and evaluation licence is relinquished, amounts capitalised in respect of the licence are written off to profit or loss in the period in which the licence is relinquished.

### Borrowing costs

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets until such time as the assets are substantially ready for their intended use or sale. All other borrowing costs are expensed as incurred. Borrowing costs directly attributable to E&E assets are not capitalised and are expensed directly to profit or loss when incurred.

### Decommissioning liabilities

The Group records the present value of legal obligations associated with the retirement of long-term tangible assets, such as producing well sites and processing plants, in the period in which they are incurred with a corresponding increase in the carrying amount of the related long-term asset. Liabilities for decommissioning are recognised when the Group has an obligation to plug and abandon a well, dismantle and remove a facility or an item of plant and restore the site on which it is located, and when a reliable estimate can be made. Where the obligation exists for a new facility or well, such as oil and gas production or transportation facilities, the obligation generally arises when the asset is installed or the ground/environment is disturbed at the field location. In subsequent periods, the asset is adjusted for any changes in the estimated amount or timing of the settlement of the obligations. The amount recognised is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. Changes in decommissioning cost estimates for assets that have either been fully written off or have ceased production are expensed as impairment charges in the period the change occurs. The carrying amounts of the associated decommissioning assets are depleted using the unit of production method in accordance with the depreciation policy for development and production assets. Actual costs to retire tangible assets are deducted from the liability as incurred. The unwinding of discount in the net present value of the total expected cost is treated as an interest expense. Changes in the estimates are reflected prospectively over the remaining life of the field.

Where some or all of the expenditure required to settle a provision is expected to be reimbursed by another party, a reimbursement asset is recognised when, and only when, it is virtually certain that reimbursement will be received if the entity settles the obligation. The amount recognised for the reimbursement may not exceed the amount of the provision.

### Taxation

**Current tax**

Current income tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amounts are those that are enacted or substantively enacted by the reporting date. Taxable profit differs from net profit, as reported in the consolidated statement of profit or loss, because it excludes items of income or expense that are taxable or deductible in other accounting periods and it further excludes items of income or expenses that are never taxable or deductible.

**3. Material accounting policies, judgements and estimation uncertainty** continued

**Deferred tax**

Deferred tax is recognised using the liability method, providing for temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the financial statements. Deferred tax is measured at the tax rates that are expected to be applied to the temporary differences when they are forecast to reverse, based on the laws that have been enacted or substantively enacted at each balance sheet date. Details of changes in EPL and other tax matters are set out in note 28. Deferred tax liabilities are not recognised if they arise from the initial recognition of goodwill and deferred tax is not accounted for if it arises from initial recognition of an asset or liability in a transaction other than business combination that at the time of the transaction affects neither accounting nor taxable profit or loss. Deferred tax assets are recognised only to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilised. The carrying amount of deferred tax assets is reviewed at each balance sheet date and all available evidence is considered in evaluating the recoverability of these deferred tax assets. Deferred tax assets and liabilities are offset where there is a legally enforceable right to offset current tax assets and liabilities relating to taxes levied by the same taxation authority on either the same taxable entity or different taxable entities where there is an intention to settle the balances on a net basis.

Deferred Petroleum Revenue Tax (PRT) assets are recognised where PRT relief on future decommissioning costs is probable.

### Leases

The Group assesses at contract inception all arrangements to determine whether it is, or contains, a lease. That is, if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. The Group is not a lessor in any transactions, it is only a lessee. The Group recognises a right-of-use asset and a corresponding lease liability with respect to all lease arrangements in which it is the lessee. The Group has elected to apply Paragraph 6 of IFRS 16 to short-term leases (defined as leases with a lease term of 12 months or less) and leases of low-value assets (such as tablets and personal computers, small items of office furniture and telephones). Lease payments associated with these leases are expensed over the relevant lease term.

Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. The cost of right-of-use assets includes the amount of lease liabilities recognised, initial direct costs incurred and lease payments made at or before the commencement date less any lease incentives received. The right-of-use asset is depreciated over the useful life of the asset.

The Group's right-of-use assets are included in property, plant and equipment (note 15).

At the commencement date of the lease, the Group recognises lease liabilities measured at the present value of lease payments to be made over the lease term. In calculating the present value of lease payments, the Group uses its incremental borrowing rate at the lease commencement date because the interest rate implicit in the lease is generally not readily determinable. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the lease payments (e.g. changes to future payments resulting from a change in an index or rate used to determine such lease payments) or a change in the assessment of an option to purchase the underlying asset.

The Group has elected to apply the practical expedient under IFRS 16.15 to account for lease and associated non-lease components as a single lease component on a class-of-asset basis.

### Maintenance expenditure

Expenditure on major maintenance refits or repairs is capitalised where it enhances the life or performance of an asset above its originally assessed standard of performance, replaces an asset or part of an asset which was separately depreciated and which is then written off, or restores the economic benefits of an asset which has been fully depreciated. All other maintenance expenditure is charged to the statement of profit or loss as incurred.

### Share-based payments

The Group issues equity-settled share-based payments to certain employees. Equity-settled share-based payments are measured at fair value at the date of grant. The fair value is expensed over the vesting term either on a straight-line basis or as specified in the vesting terms, based on the Group's estimate of shares that will eventually vest and is adjusted for the effects of non-market-based vesting conditions.

Fair value is measured by using a Black-Scholes or other appropriate valuation model. The expected life used in the model is adjusted based on management's best estimate for the effects of non-transferability, exercise restrictions and behavioural considerations.

### Retirement benefit costs

The Group operates a defined contribution pension scheme and payments into this plan are charged as an expense as they fall due. There is no further obligation to pay contributions into the plan once the contributions specified in the plan rules have been paid.

### Short-term employee benefits

A charge or liability is recognised for benefits accruing to employees in respect of salaries, bonuses, annual leave and sick leave in the period the related service is rendered at the undiscounted amount of the benefits expected to be paid for that service. Charges or liabilities recognised in respect of short-term employee benefits are measured at the undiscounted amount of the benefits expected to be paid in exchange for the related service.

### Segmental reporting

The Group operates a single class of business being oil and gas exploration, development and production and related activities in a single geographical area, presently being the North Sea. The Group's segmental reporting structure remained in place for all periods presented and is consistent with the way in which the Group's activities are reported to the Board and Chief Decision Making Officer. The Group's activities are considered to be an individual operating segment due to the nature of the Group's operations being consistent, and such operations existing in a single geographical region that is covered by the same regulations.

### Changes in accounting pronouncements

The Group has adopted all new and amended IFRS Standards effective in the consolidated financial statements for the period 1 January 2024 to 31 December 2025. There was no material impact from these or from any of the amendments to existing standards and interpretations which were effective from 1 January 2025. The Group has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

## 3. Material accounting policies, judgements and estimation uncertainty continued

### New and revised IFRS Standards in issue but not yet effective

As at 31 December 2025, the Group had not applied the following new Standards or revisions to existing IFRS Standards, that have been issued but were not yet effective at that date.

| | |
|---|---|
| Amendments to the SASB standards | Amendments to the SASB standards to enhance their international applicability |
| Revised IFRS Practice Statement 1 Management Commentary | Revised IFRS Practice Statement 1 Management Commentary |
| Amendments to IFRS 9 and IFRS 7 | Amendments to the classification and measurement of financial instruments |
| Amendments to IFRS 9 and IFRS 7 | Contracts referencing nature-dependent electricity |
| Annual improvements to IFRS | Annual improvements to IFRS Accounting Standards – volume 11 |
| IFRS 18 | Presentation and disclosures in financial statements |
| IFRS 19 | Subsidiaries without public accountability: disclosures |
| Amendments to IFRS 19 | Amendments to IFRS 19 Subsidiaries without public accountability: disclosures |
| Translation to a Hyperinflationary Presentation Currency | Amendments to IAS 21 |

With the exception of IFRS 18, the Group does not expect that the adoption of the new Standards or amendments to existing Standards, listed above, will have a material impact on the consolidated financial statements of the Group in future periods.

IFRS 18 'Presentation and Disclosure in Financial Statements' will supersede IAS 1 'Presentation of Financial Statements' and is effective for annual periods beginning on or after 1 January 2027 subject to endorsement by the UK Endorsement Board.

IFRS 18 (and consequential amendments made to IAS 7 'Statement of Cash Flows', IAS 8 'Accounting Policies: Changes in Accounting Estimates and Errors', IAS 33 'Earnings per share' and IFRS 7 'Financial Instruments: Disclosures') introduces several new requirements that are expected to impact the presentation and disclosure of the Group's consolidated financial statements. These new requirements include:

- Requirements to classify all income and expenses included in the statement of profit or loss into one of five categories and to present two new mandatory subtotals.
- Requirement to use the operating profit subtotal as the starting point for the indirect method of reporting cash flows from operating activities in the statement of cash flows.
- Specific classification requirements for interest paid/received and dividends received in the statement of cash flows such that interest and dividend receipts are included as investing cash flows and interest paid as financing cash flows.
- Required disclosures about certain non-GAAP measures ('management defined performance measures') in a single note to the financial statements.
- Enhanced guidance on the aggregation of information across all the primary financial statements and the notes.

The Group's evaluation of the effect of adopting IFRS 18 is ongoing but it is not currently anticipated that IFRS 18 will have any material quantitative impact but will have a significant impact on the presentation of the Group's financial statements and related disclosures.

### Non-GAAP measures

In measuring the Group's adjusted operating performance, additional financial measures derived from the reported results have been used by management in order to eliminate factors which distort year-on-year comparisons. The Group's adjusted performance is used to explain year-on-year changes when the effect of certain items is significant, including impairment charges on oil and gas asssets, restructuring costs, business combination costs, one-off finance charges related to refinancing, the tax effect of these items where applicable and non-cash deferred tax charges on changes to EPL.

Adjusted EBITDAX, adjusted net income, adjusted EPS, unit operating expenditure, leverage ratio, adjusted net debt and certain other reported metrics are non-GAAP measures that are not specifically defined under IFRS or other generally accepted accounting principles. Further details are set out on pages 66 to 67.

### Critical judgements and key sources of estimation uncertainties

#### Key sources of estimation uncertainty

The key assumptions concerning the future, and other key sources of estimation uncertainty at the reporting period that may have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year, are discussed below.

#### Estimates in oil and gas reserves and contingent resources

The Group's estimates of oil and gas reserves and contingent resources, and the associated production forecasts, are used in the impairment testing of property, plant and equipment and goodwill, in the measurement of depletion and decommissioning provisions, the measurement of certain elements of contingent consideration, the going concern assessment, the viability assessment and in the determination of whether deferred tax assets are recoverable. The business of the Group is to enhance hydrocarbon recovery and extend the useful lives of mature and underdeveloped assets and associated infrastructure in a profitable and responsible manner. Estimates of oil and gas reserves and contingent resources require significant judgement. Factors such as the availability of geological and engineering data, reservoir performance data, drilling of new wells and estimates of future oil and gas prices all impact on the determination of the Group's estimates of its oil and gas reserves, which could result in different future production profiles affecting prospectively the discounted cash flows used in impairment testing.

The Group's estimates of reserves and resource volumes used for accounting purposes are built up from historically-matched models for operated assets and principally from operators' estimates for non-operated assets. A review process is undertaken to compare the results of the Group's internal estimates to those of an independent consultant to understand any differences in underlying assumptions to ensure there are no significant unreconciled differences between the estimates.

**3. Material accounting policies, judgements and estimation uncertainty** continued

For the purposes of depletion and decommissioning estimates, the Group uses proved and probable reserves; and for the purposes of the impairment tests performed and deferred tax asset recoverability, the Group considers the same proved and probable reserves as well as risked resource volumes. These risking adjustments are reflective of management's assessment of technical and commercial factors that reflect the value considerations of a market participant. Changes in estimates of oil and gas reserves and resources resulting in different future production profiles will affect the discounted cash flows used in impairment testing, the anticipated date of decommissioning, the depletion charges in accordance with the unit of production method and the recoverability of deferred tax assets. The sensitivity of the Group's impairment tests and deferred tax recoverability assessments to key sources of estimation uncertainty, including reserves and resources, is discussed below.

#### Estimates in impairment of oil and gas assets and goodwill

Determination of whether the Group's oil and gas assets (note 15) or goodwill (note 18) have suffered any impairment requires an estimation of the recoverable amount of the CGU to which oil and gas assets and goodwill have been allocated. Projected future cash flows are used to determine a fair value less cost to sell to establish the recoverable amount. Key assumptions and estimates in the impairment models relate to: commodity prices that are based on an external view of forward curve prices that are considered to be a best estimate of what a market participant would use; discount rates which reflect management's estimate of a market participant post-tax weighted average cost of capital; and oil and gas reserves and resources on a risked basis as described above. Management's estimates of a market participant's view of pricing and discount rates are supplied by an independent consultant.

The sensitivity of the Group's carrying amounts to these assumptions is illustrated by the impairments and reversals disclosed in note 19, and by the sensitivity disclosures in note 19. Sensitivity disclosures include, in particular, the impact of a 20% reduction in forecast revenues.

#### Contingent consideration

Liabilities for contingent consideration have been recognised on certain business combinations, which are measured at fair value at acquisition and remeasured at fair value through profit and loss at each reporting date. The amounts of contingent consideration ultimately payable depend on several factors, including the progress of certain of the oil and gas properties acquired and the achievement of certain production and commodity price thresholds. Management has estimated the fair value as the aggregate value of each element of the contingent consideration in each case using an appropriate valuation technique, taking into account the likelihood of occurrence of each contingent event and the net present value of the amount potentially payable.

Where applicable, risking assumptions applied in the measurement of contingent consideration were consistent with those applied in the fair valuation of the related oil and gas properties. A 20% decrease in the probability of a trigger event occurring and hence a payment being due, with all other assumptions held constant, would result in a decrease in contingent consideration of $81.8 million (2024: $84.2 million). Whereas a 20% increase in probability of a trigger event occurring, with all other assumptions held constant, would result in an increase in contingent consideration of $64.1 million (2024: $77.1 million).

#### Decommissioning provision estimates

Amounts used in recording a provision for decommissioning are estimates based on current legal and constructive requirements and current technology and price levels for the removal of facilities and plugging and abandoning of wells. Due to changes in relation to these items, the future actual cash outflows in relation to decommissioning are likely to differ in practice. To reflect the effects due to changes in legislation, requirements, technology and price levels, the carrying amounts of decommissioning provisions are reviewed on a regular basis. The effects of changes in estimates do not give rise to prior year adjustments and are dealt with prospectively. For operated assets, cost estimates are based on management's assessment of work programmes (including durations) and supply chain conditions including, amongst other factors, applicable vessel and rig rates and durations. For non-operated assets, cost estimates are arrived at by management's review of the basis of estimates as provided by the respective operators.

While the Group uses its best estimates and judgement, actual results could differ from these estimates. Expected timing of expenditure can also change, for example, in response to changes in laws and regulations or their interpretation, and/or due to changes in commodity prices. The payment dates are uncertain and depend on the production lives of the respective fields. Management does not expect any reasonable change in the expected timing of decommissioning to have a material effect on the decommissioning provisions, assuming cash flows remain unchanged. Decommissioning costs are expected to be incurred over the next 40 years. The Group uses a nominal discount rate of 3.74% for the first five years and 4.75% thereafter (31 December 2024: 4.38% for the first five years and 4.86% thereafter), based on the average risk-free rate over the second half of 2025, to discount the estimated costs. The inflation rate applied to estimated costs is 2.0% (2024: 2.0%). A reduction or an increase in this discount rate of 1% would increase or reduce the decommissioning liabilities by approximately $300 million or $260 million, respectively (2024: $288 million or $247 million, respectively), and is not expected to have a material impact on the corresponding decommissioning reimbursement asset. For further details regarding the estimated value, inputs and assumptions refer to note 23. Given the large number of variables involved, management consider that it is not practical to provide sensitivities for the various other individual assumptions but the aggregated impact of related changes in the next 12 months could be material.

#### Taxation estimates

The Group's operations are subject to a number of specific tax rules which apply to exploration, development and production companies such as the Energy Profits Levy (EPL) at 38%, ring-fenced Corporation Tax at 30%, the Supplementary Charge of 10% and the application of investment allowances. In addition, the tax provision is prepared before the relevant companies have filed their tax returns with the relevant tax authorities and, significantly, before these have been agreed. As a result of these factors, the tax provision process necessarily involves the use of a number of judgements and estimates, including those required in calculating the effective tax rate. The Group recognises deferred tax assets on unused tax losses where it is probable that future taxable profits will be available for utilisation. This requires management to make judgements and assumptions regarding the likelihood of future taxable profits and the amount of deferred tax that can be recognised. Further details regarding the estimated value and related inputs are set out in note 28.

**3. Material accounting policies, judgements and estimation uncertainty** continued

The Group's deferred tax assets are recognised to the extent that taxable profits are expected to arise in the future against which tax losses and allowances in the UK can be utilised, including as a result of Group re-organisations and asset transfers. In accordance with IAS 12 Income Taxes, the Group assesses the recoverability of its deferred tax assets at each period end. Consistent with the impairment sensitivity described above, as at 31 December 2025, a 20% reduction in future revenues, with all other assumptions held constant, would eliminate current headroom and result in a deferred tax asset derecognition of $145 million (2024: $284 million). In such a scenario, the Group would also expect the Energy Security Investment Mechanism to be triggered thereby causing the EPL to be switched off early resulting in a reduction in the associated EPL deferred tax liability. The $145 million (2024: $284 million) derecognition assumes that cash flows are equivalent to taxable profits and that any reorganisation required to utilise certain deferred tax assets does not result in a displacement of other balances. As disclosed in note 28, there are unrecognised allowances of up to circa $64 million (2024: circa $147 million) that have no expiry date and could be recognised in future periods if future revenue from oil and gas activities increases and/or further actions are undertaken.

**Other areas of estimation**

The key assumptions concerning the future, and other sources of estimation uncertainty at the reporting period, that are not expected to cause a material adjustment to the carrying amounts of assets and liabilities within the next financial year, are discussed below:

**Business combinations**

During both 2024 and 2025, the Group has made material business combinations – see note 17 for further details of the provisional purchase price allocations, including the assets and liabilities acquired and the goodwill arising on the transactions. These have been accounted for as business combinations under IFRS 3. The assets and liabilities identified in the purchase price allocations include oil and gas assets, decommissioning liabilities, deferred tax assets and liabilities, and working capital.

The calculations of the fair value of the oil and gas assets acquired requires the Group to estimate the future cash flows expected to arise from the assets of the acquired businesses using discounted cash flow models. Key assumptions and estimates include: commodity prices, discount rates, and oil and gas reserves estimates. See above estimates in the impairment of oil and gas assets and goodwill section and estimates in oil and gas reserves and contingent resources section for further details regarding these assumptions. In addition, the Group has considered the value that a market participant would prescribe to prospective resources in determining the fair value of the oil and gas assets acquired.

The fair value of decommissioning provisions reflects historical events that have occurred up to and including the date of the business combination for which a decommissioning obligation exists and future decommissioning expenditure is expected to be incurred. Where the Group acquires a further interest in a field for which it already holds a working interest, the fair value of the decommissioning liabilities would typically be the existing decommissioning provision for that field proportionately adjusted for the change in working interest.

In determining the values of the deferred tax assets recognised on business combinations, the Group has also made assumptions in respect of the amount of tax losses brought forward, which will be available to offset against future taxable profits of the Group.

**Critical accounting judgements**

The following is the only critical judgement, apart from those involving estimation (which are presented separately above), that the Directors have made in applying the Group's accounting policies and that has the most significant effect on the amounts recognised in the financial statements.

**Rosebank carrying value**

Management has reviewed the pre-tax carrying value of the Rosebank field of $872 million or post-tax $566 million (31 December 2024: pre-tax $617 million or post-tax $304 million). Although the first phase of the Rosebank development had been sanctioned by the NSTA, it was subject to Judicial Review proceedings. On 30 January 2025, the Court of Session ruled that this consent had been unlawfully given in relation to the sanctioning of the Rosebank field development and that a new consent application would be required, which included Scope 3 emissions. It did, however, permit the project to progress as planned whilst this new consent is sought from the Regulators but that no oil could be extracted without this new consent. The revised Environmental Statement has been submitted and we await the next stage of the process. Whilst the outcome of the Judicial Review could be construed as an indicator of impairment, management has no reason to believe that this further consent will not be forthcoming, and further management believe that the most likely outcome will be that the further consent will be granted and that the project will continue progressing as planned with first oil anticipated in the first half of 2027. As a result no impairment charge is required.

## 4. Segmental reporting

The Group operates a single class of business being oil and gas exploration, development and production and related activities in a single geographical area, presently being the North Sea. The Group's segmental reporting structure remained in place for all periods presented and is consistent with the way in which the Group's activities are reported to the Board and Chief Decision Making Officer. The Group's activities are considered to be an individual operating segment due to the nature of the Group's operations being consistent, and such operations existing in a single geographical region that is covered by the same regulations.

## 5. Revenue and other income

The majority of payment terms are on a specified monthly date, as detailed in the initial contract. Otherwise, payment is due within 30 days of the invoice date. No significant judgements have been made in determining the timing of satisfaction of performance obligations, the transaction prices and the amounts allocated to performance obligations. Other income relates to tariff income receivable in the year.

Revenue from two customers exceeded 10% of the Group's consolidated revenue arising from hydrocarbon sales for the year ended 31 December 2025, representing $1,642 million and $1,039 million of revenue, respectively (2024: two customers representing $1,284 million and $420 million of revenue, respectively). It should be noted that the second largest customer in both 2025 and 2024 is a related party and further details of related party transactions are set out in note 32.

Revenue from contracts with customers derives largely from customers within a single geographical region, being the United Kingdom. Revenue from contracts with customers outside of the United Kingdom is immaterial and is, therefore, not disclosed separately.

| | **2025 $m** | 2024 $m |
|---|---|---|
| Oil sales | **1,533.7** | 1,176.3 |
| Gas sales | **1,117.2** | 599.0 |
| Condensate sales | **80.9** | 46.4 |
| Total revenue from contracts with customers | **2,731.8** | 1,821.7 |
| Realised gains on oil derivative contracts | **58.6** | 2.5 |
| Premium payments on oil derivative contracts | – | (1.7) |
| Realised gains on gas derivative contracts | **61.8** | 132.5 |
| Premium payments on gas derivative contracts | **(0.3)** | (3.2) |
| Tariff income | **30.2** | 30.0 |
| Other revenue[1] | **18.1** | – |
| Total revenue from production activities | **2,900.2** | 1,981.8 |
| Other income[2] | **46.3** | – |
| | **2,946.5** | 1,981.8 |

1 Other revenue comprises amounts recovered from partners related to lease obligations.
2 Other income primarily comprises proceeds from insurance claims and claims made for historic R&D expenditure credits.

## 6. Cost of sales

| | **2025 $m** | 2024 $m |
|---|---|---|
| Movement in oil and gas inventory | **11.7** | 84.2 |
| Operating costs of hydrocarbon activities | **(871.6)** | (617.9) |
| Materials inventory provision | **(8.8)** | (3.6) |
| Royalties | **(1.6)** | (2.1) |
| Depreciation on right-of-use assets (note 15) | **(44.9)** | (26.8) |
| Depletion, depreciation and amortisation (note 15) | **(795.7)** | (573.4) |
| | **(1,710.9)** | (1,139.6) |

Royalty costs represent 3.34% of Stella and Harrier field revenue paid to the original licence holders. Ithaca holds a 100% interest in the Stella and Harrier fields.

## 7. Administrative expenses

| | **2025 $m** | 2024 $m |
|---|---|---|
| Administrative expenses, excluding transaction costs | **(47.0)** | (41.0) |
| Transaction costs | **(0.3)** | (16.3) |
| | **(47.3)** | (57.3) |

Transactions costs in 2025 are in relation to the JAPEX UK and Cygnus acquisitions and in 2024 relate to the Eni UK business combination. Further details of these business combinations can be found in note 17.

The total employee benefit expenses which are either capitalised or included in cost of sales, pre-licence exploration and evaluation expenses and administrative expenses are noted below.

| Employee benefit expenses | **2025 $m** | 2024 $m |
|---|---|---|
| Wages and salaries | **(146.5)** | (103.2) |
| Share-based payment charges (note 33) | **(7.4)** | (6.1) |
| Social security costs | **(17.6)** | (11.6) |
| Pension costs | **(18.1)** | (11.9) |
| | **(189.6)** | (132.8) |

Disclosures on Directors' remuneration, share options, long-term incentive schemes and pension entitlements required by the Companies Act 2006 will be contained in the tables and notes within the Remuneration Committee report. Directors' emoluments in aggregate were $6.6 million (2024: $4.4 million).

## 7. Administrative expenses continued

The average number of employees during each year, which included three months of the Eni UK business combination in 2024, was as follows:

| | 2025 Number | 2024 Number |
|---|---|---|
| Onshore and administrative | **462** | 374 |
| Offshore | **336** | 327 |
| | **798** | 701 |

There were no employees associated with the JAPEX UK and Cygnus acquisitions.

| Audit fees | 2025 $m | 2024 $m |
|---|---|---|
| Fees payable to the Company's auditor for audit of the Company's financial statements | **2.3** | 2.5 |
| Audit of the Company's subsidiaries pursuant to legislation | **0.8** | 0.4 |
| Non-audit services provided by the auditors | **0.6** | 0.6 |
| | **3.7** | 3.5 |

Non-audit services provided by the auditors for the year ended 31 December 2025 comprise audit-related assurance services of $355k (2024: $175k), other assurance services of $283k (2024: $462k) relating to the Offering Memorandum for the senior notes due 2031 (2024: the Offering Memorandum in respect of the 2024 refinancing and in relation to certain other refinancing options). As well as the above figures, additional audit fees of $357k (2024: $228k) were charged during the year relating to the finalisation of prior period Group and subsidiary audits.

## 8. Other (losses)/gains

| | 2025 $m | 2024 $m |
|---|---|---|
| Gain on financial instruments (note 30) | **14.5** | 5.2 |
| Fair value remeasurements of contingent consideration (note 26) | **(22.8)** | 27.3 |
| Net foreign exchange | **(5.3)** | (6.1) |
| | **(13.6)** | 26.4 |

## 9. Finance costs and finance income

| | 2025 $m | 2024 $m |
|---|---|---|
| Loan interest and charges | **(54.6)** | (48.1) |
| Senior notes interest | **(68.6)** | (54.9) |
| Loan fee amortisation | **(11.1)** | (13.2) |
| Interest on lease liabilities (note 25) | **(4.8)** | (1.5) |
| Accretion on deferred consideration and decommissioning liabilities less accretion on decommissioning reimbursements | **(125.5)** | (82.9) |
| **Total finance costs** | **(264.6)** | (200.6) |
| | | |
| **Finance income** | **9.8** | 11.2 |

In the year to 31 December 2024, loan interest and charges includes a charge of $14.1 million in respect of the early repayment of the senior notes due 2026 and loan fee amortisation contains a charge of $7.9 million in relation to unamortised fees on the refinancing of the RBL and senior notes. See note 20 for further details.

During the year to 31 December 2025, $13.0 million of interest was capitalised into qualifying assets (2024: $5.8 million) at an interest rate of SOFR (subject to a minimum rate of 5%) plus a commercially-agreed margin on the entirety of the borrowings under the project capital expenditure facility (see note 20 for further details).

## 10. Earnings per share

The calculation of basic earnings per share is based on the profit after tax and the weighted average number of ordinary shares in issue during the year. Basic and diluted earnings per share are calculated as follows:

| | 2025 $m | 2024 $m |
|---|---|---|
| ***Earnings for the year:*** | | |
| Earnings for the purpose of basic and diluted earnings per share | **(84.1)** | 153.1 |
| ***Number of shares (million)*** | | |
| Weighted average number of ordinary shares for the purpose of basic earnings per share | **1,648.8** | 1,164.3 |
| Dilutive potential ordinary shares | **14.4** | 10.5 |
| Weighted average number of ordinary shares for the purpose of diluted earnings per share | **1,663.2** | 1,174.8 |
| ***Earnings per share (cents)*** | | |
| Basic | **(5.1)** | 13.2 |
| Diluted | **(5.1)** | 13.0 |

### 11. Trade and other receivables and decommissioning reimbursements

| Current | 2025 $m | 2024 $m |
|---|---|---|
| Trade receivables | **10.9** | 19.0 |
| Other receivables | **6.3** | 23.0 |
| Joint operations receivables | **111.5** | 106.0 |
| Accrued income | **226.9** | 269.6 |
| | **355.6** | 417.6 |

Materially all trade and other receivables, including receivables from joint operations are not overdue by more than 90 days. The credit risk associated with trade receivables, accrued income and other receivables is considered to be insignificant. No ECL has been recognised in the current or prior year. Accrued income mainly comprises amounts due, but not yet invoiced, for the sale of oil and gas.

| Non-current | 2025 $m | 2024 $m |
|---|---|---|
| Decommissioning reimbursements | **99.7** | 144.2 |

| Current | 2025 $m | 2024 $m |
|---|---|---|
| Decommissioning reimbursements | **64.9** | 23.2 |

| Movements on decommissioning reimbursements were as follows: | 2025 $m | 2024 $m |
|---|---|---|
| At 1 January | **167.4** | 195.5 |
| Accretion net of tax at 30% | **6.2** | 7.4 |
| Reimbursements received | **(25.3)** | (22.5) |
| Change in reimbursement estimates net of tax and adjusted for movements on related contingent consideration | **16.2** | (13.0) |
| **At 31 December** | **164.5** | 167.4 |

### 11. Trade and other receivables and decommissioning reimbursements continued

The decommissioning reimbursements represent the equal and opposite of decommissioning liabilities (note 23), net of tax, associated with the Heather and Strathspey fields and relates to a contractual agreement as part of the CNSL acquisition. As part of the terms of the acquisition of what is now Ithaca Oil and Gas Limited (IOGL), Chevron have the obligation to provide the security and remain financially responsible for the decommissioning obligations of IOGL in relation to these interests. The Group pays the liabilities in respect of Heather and Strathspey and then receives full reimbursement from Chevron.

As these payments are virtually certain, they have been accounted for under IAS 37 as a reimbursement asset.

### 12. Prepayments

| Current | 2025 $m | 2024 $m |
|---|---|---|
| Prepayments | **26.0** | 40.6 |
| Decommissioning securities | **3.4** | 1.6 |
| | **29.4** | 42.2 |

### 13. Inventories

| Current | 2025 $m | 2024 $m |
|---|---|---|
| Hydrocarbon underlift | **125.7** | 171.8 |
| Materials inventories | **206.0** | 175.5 |
| Provision for obsolete materials inventory | **(78.3)** | (63.5) |
| | **253.4** | 283.8 |

During the year to 31 December 2025 a credit of $11.7 million (2024: $84.2 million) of inventory was recognised in the 'movement in oil and gas inventory' line (note 6) and $8.8 million (2024: $3.6 million) of materials inventories were provided for. There were no reversals of materials inventory provisions in either the year ended 31 December 2025 or the year ended 31 December 2024.

## 14. Exploration and evaluation assets

| | $m |
|---|---|
| At 1 January 2024 | 548.4 |
| Additions | 36.3 |
| Change in decommissioning estimates (note 23) | 4.4 |
| Business combinations (note 17) | 48.0 |
| Write-offs/relinquishments | (24.6) |
| At 31 December 2024 and 1 January 2025 | 612.5 |
| Additions | **45.9** |
| Change in decommissioning estimates (note 23) | **(2.2)** |
| Revisions to 2024 business combinations (note 17) | **(23.9)** |
| Transfers to development and production assets (note 15) | **(24.2)** |
| Write-offs/relinquishments | **(2.1)** |
| **At 31 December 2025** | **606.0** |

Following completion of geotechnical evaluation activity, certain North Sea licences were declared unsuccessful and certain prospects were declared non-commercial. This resulted in the carrying value of these licences being fully written-off to $nil with $2.1 million being expensed in the year to 31 December 2025 (2024: $24.6 million).

The transfers from exploration and evaluation assets to right-of-use assets and development and production assets in 2025 relates to the Jocelyn South well. The principal component of exploration and evaluation assets at 31 December 2025 is the Cambo field with a pre-tax carrying value of $415 million (2024: $391 million).

## 15. Property, plant and equipment

Additions to right-of-use assets in the year to 31 December 2025 and the year to 31 December 2024 principally relate to modifications to the Rosebank FPSO and will begin to be depreciated on commencement of production. The related lease will commence on delivery of the FPSO to the joint venture partners at first oil, which is currently anticipated to be in the first half of 2027. Additions to right-of-use assets in the year to 31 Decemeber 2025 also include a drilling rig for Cygnus, a decommissioning vessel for Alba and a two-year extension to the Skandi Gamma supply vessel which was originally included in right-of-use asset additions in the year to 31 December 2024.

Other fixed assets include buildings, computer equipment, office equipment and furniture and fittings.

| | Right-of-use operating assets $m | Development and production assets $m | Other fixed assets $m | Total $m |
|---|---|---|---|---|
| **Cost** | | | | |
| At 1 January 2024 | 156.2 | 7,976.8 | 47.6 | 8,180.6 |
| Additions | 136.2 | 483.5 | 0.5 | 620.2 |
| Business combinations (note 17) | 18.7 | 997.9 | – | 1,016.6 |
| Change in decommissioning estimates (note 23) | – | 54.6 | – | 54.6 |
| At 31 December 2024 and 1 January 2025 | 311.1 | 9,512.8 | 48.1 | 9,872.0 |
| Additions | **244.0** | **723.2** | **8.2** | **975.4** |
| Business combinations (note 17) | – | **249.4** | – | **249.4** |
| Transfers from exploration and evaluation assets (note 14) | – | **24.2** | – | **24.2** |
| Change in decommissioning estimates (note 23) | – | **160.5** | – | **160.5** |
| **At 31 December 2025** | **555.1** | **10,670.1** | **56.3** | **11,281.5** |
| **Depletion, depreciation, amortisation and impairment** | | | | |
| 1 January 2024 | (85.5) | (4,808.7) | (28.1) | (4,922.3) |
| Depletion, depreciation and amortisation charge for the year | (26.8) | (568.1) | (5.3) | (600.2) |
| Impairment charge (note 19) | – | (161.1) | – | (161.1) |
| At 31 December 2024 and 1 January 2025 | (112.3) | (5,537.9) | (33.4) | (5,683.6) |
| Depletion, depreciation and amortisation charge for the year | **(44.9)** | **(788.2)** | **(7.5)** | **(840.6)** |
| Impairment charge (note 19) | **(3.6)** | **(8.2)** | – | **(11.8)** |
| **At 31 December 2025** | **(160.8)** | **(6,334.3)** | **(40.9)** | **(6,536.0)** |
| Net book value at 31 December 2024 | 198.8 | 3,974.9 | 14.7 | 4,188.4 |
| **Net book value at 31 December 2025** | **394.3** | **4,335.8** | **15.4** | **4,745.5** |

The transfers from exploration and evaluation assets to right-of-use operating assets and development and production assets in 2025 relates to the Jocelyn South well following successful commencement of production. At the point of transfer, the Jocelyn South assets were tested for impairment and the recoverable amount exceeded the carrying value of the well.

## 16. Interests in joint operations

The contractual agreement for the licence interests in which the Group has an investment do not typically convey control of the underlying joint arrangement to any one party, even where one party has a greater than 50% equity ownership of the area of interest.

The Group's material joint operations as at 31 December are as follows:

| | | | | Group net % interest | |
|---|---|---|---|---|---|
| Block | Licence | Field/discovery name | Operator | **2025** | 2024 |
| 9/11c | P.979 | Mariner | Adura Operations Limited | **8.89%** | 8.89% |
| 9/11b | P.726 | Mariner | Adura Operations Limited | **8.89%** | 8.89% |
| 30/2c | P.672 | Jade | Chrysaor Petroleum Company U.K. Limited | **32.50%** | 32.50% |
| 22/30c and 29/5c | P.666 | Elgin-Franklin | TotalEnergies E&P UK Limited | **27.95%** | 27.95% |
| 15/29b | P.590 | Callanish | Chrysaor Production (U.K.) Limited | **20.00%** | 20.00% |
| 204/25a | P.559 | Schiehallion | BP Exploration Operating Company Limited | **35.30%** | 35.30% |
| 204/19b and 204/20b | P.556 | Suilven | Ithaca SP E&P Limited | **50.00%** | 50.00% |
| 29/5b | P.362 | Elgin-Franklin | TotalEnergies E&P UK Limited | **27.95%** | 27.95% |
| 21/4a | P.347 | Callanish | Chrysaor Production (U.K.) Limited | **13.70%** | 13.70% |
| 16/27b | P.345 | Britannia | Ithaca MA Limited | **35.75%** | 35.75% |
| 9/11a | P.335 | Mariner | Adura Operations Limited | **8.89%** | 8.89% |
| 13/22a | P.324 | Captain | Ithaca SP E&P Limited | **85.00%** | 85.00% |
| 22/18a | P.292 | Arbroath, Arkwright, Carnoustie, Wood | Neo Energy Resources UK Limited | **41.03%** | 41.03% |
| 22/17s, 22/22a and 22/23a | P.291 | Arbroath, Arkwright, Brechin, Carnoustie, Cayley, Shaw | Neo Energy Resources UK Limited | **41.03%** | 41.03% |
| 23/26b | P.264 | Erskine | Ithaca Energy (UK) Limited | **50.00%** | 50.00% |
| 9/11d and 9/12b | P.2508 | Mariner | Adura Operations Limited | **8.89%** | 8.89% |
| 9/11g | P.2151 | Mariner | Adura Operations Limited | **8.89%** | 8.89% |
| 16/26a A-ALB | P.213 | Alba | Ithaca Oil and Gas Limited | **36.67%** | 36.67% |
| 16/26a B-BRI | P.213 | Britannia | Ithaca MA Limited | **33.17%** | 33.17% |
| 16/26a | P.213 | N/A | Ithaca Oil and Gas Limited | **34.50%** | 34.50% |
| 3/7a | P.203 | Columba E | CNR International (U.K.) Limited | **20.00%** | 20.00% |
| 3/8a and 3/8a | P.199 | Columba B/D | CNR International (U.K.) Limited | **5.60%** | 5.60% |
| 22/30b | P.188 | Elgin-Franklin | TotalEnergies E&P UK Limited | **27.95%** | 27.95% |
| 21/20a | P.185 | Cook | Ithaca SP E&P Limited | **61.35%** | 61.35% |
| 8/15a | P.1758 | Mariner | Equinor UK Limited | **8.89%** | 8.89% |
| 30/7b | P.1589 | Jade | Chrysaor Petroleum U.K. Limited | **32.50%** | 32.50% |
| 30/1f | P.1588 | Vorlich[1] | Ithaca MA Limited | **100.00%** | 100.00% |

## 16. Interests in joint operations continued

| Block | Licence | Field/discovery name | Operator | Group net % interest 2025 | 2024 |
|---|---|---|---|---|---|
| 30/1c | P.363 | Vorlich | Ithaca MA Limited | **34.00%** | 34.00% |
| 205/2a | P.1272 | Rosebank | Adura Operations Limited | **20.00%** | 20.00% |
| 205/1a | P.1191 | Rosebank | Adura Operations Limited | **20.00%** | 20.00% |
| 15/29a | P.119 | Alder | Ithaca Energy (UK) Limited | **73.68%** | 73.68% |
| 15/29a | P.119 | Britannia | Ithaca MA Limited | **75.00%** | 75.00% |
| 21/3a | P.118 | Brodgar | Chrysaor Production (U.K.) Limited | **25.00%** | 25.00% |
| 23/22a | P.111 | Pierce | Enterprise Oil Limited | **34.01%** | 34.01% |
| 15/30a | P.103 | Britannia | Chrysaor Production (U.K.) Limited | **33.03%** | 33.03% |
| 21/5a | P.103 | Enochdhu | Chrysaor Production (U.K.) Limited | **50.00%** | 50.00% |
| 213/26b and 213/27a | P.1026 | Rosebank | Equinor UK Limited | **20.00%** | 20.00% |
| 23/26a | P.057 | Erskine | Ithaca Energy (UK) Limited | **50.00%** | 50.00% |
| 22/18n | P.020 | Montrose | Neo Energy Resources UK Limited | **41.03%** | 41.03% |
| 22/17n, 22/17s, 22/22a and 22/23a | P.019 | Godwin, Montrose | Neo Energy Resources UK Limited | **41.03%** | 41.03% |
| 30/11a and 30/12d | P.1820 | Isabella | Total Energies E&P North Sea UK Limited | **72.50%** | 72.50% |
| 204/8, 204/9c, 204/10c, 204/13, 204/14d and 204/15 | P.2403 | Tornado | Ithaca SP E&P Limited | **50.00%** | 50.00% |
| 30/7a and 30/12a | P.032 | Judy/Joanne | Chrysaor Petroleum Company U.K. Limited | **33.00%** | 33.00% |
| 30/7c | P.2221 | Judy | Chrysaor Petroleum Company U.K. Limited | **33.00%** | 33.00% |
| 30/13d A | P.079 | Judy | Chrysaor Petroleum Company U.K. Limited | **15.00%** | 15.00% |
| 30/6a | P.11 | Jasmine | Chrysaor Petroleum Company U.K. Limited | **33.00%** | 33.00% |
| 29/4d | P.752 | Glenelg | TotalEnergies E&P UK Limited | **8.00%** | 8.00% |
| 22/29b | P.2613 | Glenelg Protection | TotalEnergies E&P UK Limited | **32.14%** | 32.14% |
| 30/20a | P.2220 | Tommeliten | ConocoPhillips (U.K.) Holdings Limited | **0.07%** | 0.07% |
| 30/13e | P.2456 | Talbot | Harbour Energy Limited | **33.00%** | 33.00% |

## 16. Interests in joint operations continued

| Block | Licence | Field/discovery name | Operator | Group net % interest 2025 | 2024 |
|---|---|---|---|---|---|
| 30/7d and 30/8a | P.2399 | Judy East | Chrysaor Petroleum Company U.K. Limited | **33.00%** | 33.00% |
| N/A | Pipeline | GAEL | INEOS FPS Limited | **10.23%** | 10.23% |
| N/A | Pipeline | SEAL | TotalEnergies E&P UK Limited | **21.87%** | 21.87% |
| 44/11a and 44/12a | P.1055 | Cygnus | Ithaca (NE) E&P Limited | **85.00%** | 38.75% |
| 22/29c | P.1622 | Seagull | BP Exploration Operating Company Limited | **50.00%** | 35.00% |
| 47/14b | P.614 | Juliet | Ithaca (NE) E&P Limited | **81.00%** | 81.00% |
| 44/24a | P.611 | Minke | Ithaca (NE) E&P Limited | **15.56%** | 15.56% |
| 44/29b | P.454/P.611 | Orca UK | Ithaca (NE) E&P Limited | **15.56%** | 15.56% |
| 44/19b | P.1139 | Cameron | Tullow Limited | **27.50%** | 27.50% |
| N/A | Pipeline | ETS | Kellas North Sea 2 Limited | **25.00%** | 25.00% |
| 36/30a, 42/3a, 42/4 and 42/5a | P.2133 | Ossian | Spirit Energy Limited | **30.00%** | 30.00% |
| 42/2b, 42/3b, 42/7a, 42/8b and 42/9b | P.2126 | Aurora | Spirit Energy Limited | **30.00%** | 30.00% |
| 44/11b | P.1731 | Cepheus | Ithaca (NE) E&P Limited | **34.48%** | 34.48% |

1 Vorlich is a joint operation through a UUOA between Ithaca MA Limited and bp, which extends across both Vorlich licences. Under the terms of the UUOA, key decisions effectively require unanimous approval by both parties.

In addition, the Group has the following wholly-owned licences and fields or discoveries which, although not currently joint operations, are presented for completeness:

| Block | Licence | Field/discovery name | Operator | Group net % interest 2025 | 2024 |
|---|---|---|---|---|---|
| 22/1b | P.2373 | F Block (Fotla and Fortriu) | Ithaca Oil and Gas Limited | **100.00%** | 100.00% |
| 29/10b | P.1665 | Abigail | Ithaca SP E&P Limited | **100.00%** | 100.00% |
| 204/4a and 204/5a | P.1189 | Cambo | Ithaca SP E&P Limited | **100.00%** | 100.00% |
| 204/9a and 204/10a | P.1028 | Cambo | Ithaca SP E&P Limited | **100.00%** | 100.00% |
| 30/6a and 29/10a | P.011 | Stella/Harrier | Ithaca Energy (UK) Limited | **100.00%** | 100.00% |
| 29/15, 30/11c, 30/16i and 30/6d | P.2622 | J-Area West | N/A | **100.00%** | 100.00% |
| 16/22b | P.2638 | Quad 16 | N/A | **100.00%** | 100.00% |

### 17. Business combinations

The provisional fair values of the identifiable assets and liabilities of the 2025 acquisitions, and the final fair values of the 2024 business combination were:

| | JAPEX UK $m | Cygnus $m | Total 2025 $m | Total 2024 $m |
|---|---|---|---|---|
| Property, plant and equipment (note 15) | 57.6 | 191.8 | 249.4 | 1,016.6 |
| Exploration and evaluation assets (note 14) | – | – | – | 24.1 |
| Cash | 16.1 | – | 16.1 | 107.5 |
| Inventory | 3.5 | 3.5 | 7.0 | 62.3 |
| Trade and other receivables | 11.6 | 1.7 | 13.3 | 178.0 |
| **Total assets excluding deferred tax** | **88.8** | **197.0** | **285.8** | **1,388.5** |
| Trade and other payables | (12.6) | (21.2) | (33.8) | (221.4) |
| Current tax payable | – | – | – | (50.0) |
| Decommissioning provisions (note 23) | (12.4) | (113.0) | (125.4) | (668.2) |
| Other provisions (note 24) | – | – | – | (38.8) |
| Lease liabilities (note 25) | – | – | – | (22.0) |
| **Total liabilities excluding deferred tax** | **(25.0)** | **(134.2)** | **(159.2)** | **(1,000.4)** |
| Deferred tax assets (note 28) | 91.8 | 45.2 | 137.0 | 820.7 |
| Deferred tax liabilities (note 28) | (3.2) | (92.6) | (95.8) | (545.8) |
| **Total identifiable net assets at fair value** | **152.4** | **15.4** | **167.8** | **663.0** |
| Consideration satisfied by the issue of new shares | – | – | – | 861.3 |
| Cash consideration | 156.4 | 153.1 | 309.5 | – |
| Deferred consideration (note 26) | – | 10.5 | 10.5 | 204.4 |
| **Total consideration** | **156.4** | **163.6** | **320.0** | **1,065.7** |
| **Goodwill arising (note 18)** | **4.0** | **148.2** | **152.2** | **402.7** |
| **Net cash flows**[1] | **(140.3)** | **(153.1)** | **(293.4)** | **107.5** |

1 Acquisition payments net of cash acquired.

### 17. Business combinations continued

The fair value (FV) of assets and liabilities relating to the 2024 business combination have been reassessed in the measurement period to 2 October 2025 as follows:

| | Final FV $m | Provisional FV $m | Adjustment to goodwill $m |
|---|---|---|---|
| Exploration and evaluation assets (note 14) | 24.1 | 48.0 | 23.9 |
| Trade and other payables | (221.4) | (212.5) | 8.9 |
| Current tax payable | (50.0) | (69.2) | (19.2) |
| Decommissioning provisions (note 23) | (668.2) | (651.0) | 17.2 |
| Other provisions (note 24) | (38.8) | (34.9) | 3.9 |
| Deferred tax assets (note 28) | 820.7 | 846.4 | 25.7 |
| Deferred tax liabilities (note 28) | (545.8) | (549.1) | (3.3) |
| **Total adjustments to goodwill (note 18)** | | | **57.1** |
| **Provisional goodwill (note 18)** | | | **345.6** |
| **Final goodwill** | | | **402.7** |

The reduction in FV of exploration and evaluation assets relates to the Constellation South and Peach prospects. The increase in the FV of trade and other payables relates to an increase in Non-Operated Joint Venture payables. The reduction in current tax payable is principally due to a reclassification of a deferred tax asset to a current tax asset. The increase in decommissioning provisions is in relation to cost estimate changes for decommissioning work required at the date of acquisition and the increase in other provisions relates to a mismeasurement that existed at the acquisition date. The reductions in deferred tax liabilities and deferred tax assets reflects both the reclassification to current tax described above as well as the reassessment of the tax attributes of the business combination.

The acquisition of 100% of JAPEX UK completed on 7 July 2025 for a total consideration of $156.4 million thereby increasing the Group's interest in the Seagull asset from 35.0% to 50.0% and the acquisition of 46.25% of Spirit Energy's interest in the Cygnus field completed on 1 October 2025 for a total consideration of $163.6 million thereby increasing the Group's working interest in the Cygnus field from 38.75% to 85.0%. The business combination in 2024 comprised 100% of each of Eni Elgin/Franklin Limited, Eni UKCS Limited, Eni Energy E&P Limited and Eni Energy E&P UKCS Limited.

From the date of acquisition, JAPEX UK contributed $44.5 million of revenue and $27.7 million of profit before tax and the additional Cygnus interest contributed $57.4 million of revenue and $26.5 million of profit before tax. Had these acquisitions completed 1 January 2025, the JAPEX UK acquisition would have contributed $86.7 million of revenue and $45.6 million of profit before tax and the Cygnus acquisition would have contributed $282.7 million of revenue and $173.4 million of profit before tax for the 2025 financial year.

In the year to 31 December 2024, from the date of the business combination, the Eni UK businesses contributed $290.1 million of revenue and $195.0 million of profit before tax. Had this business combination completed on 1 January 2024, the Eni UK businesses would have contributed $1,014.0 million of revenue and $598.4 million of profit before tax for the 2024 financial year.

**17. Business combinations** continued

Business combination-related costs of $0.3 million (2024: $16.3 million), comprising professional fees and other direct costs, were incurred in the year to 31 December 2025 and are included within 'administrative expenses' in note 7.

The fair values of the oil and gas assets and the intangible assets of the business combinations have been determined using valuation techniques based on discounted cash flows using forward curve commodity prices and estimates of long-term commodity prices reflective of market conditions at the completion dates, a discount rate based on observable market data and cost and production profiles generally consistent with the proved and probable reserves acquired with each asset. The decommissioning liabilities recognised have been estimated based on internal engineering estimates for operated assets and operator cost estimates for non-operated assets, with reference to observable market data.

The goodwill of $152.2 million in the year to 31 December 2025 (2024: $402.7 million) arises principally from the requirement to recognise deferred tax assets and liabilities for the difference between the assigned fair values and the tax bases of the acquired assets and liabilities assumed in a business combination including, where applicable, capital allowance recognition between the effective date and the completion date under the terms of the SPA. The assessment of fair values of oil and gas assets acquired is based on cash flows after tax. Nevertheless, in accordance with IAS 12 Income Taxes, paragraphs 15 and 19, a provision is made for deferred tax corresponding to the tax rate multiplied by the difference between the acquisition cost and the tax base. The offsetting entry to this deferred tax is goodwill. Hence, goodwill arises as a technical effect of deferred tax (technical goodwill). There are no specific IFRS guidelines pertaining to the allocation of technical goodwill and management has therefore applied the general guidelines for allocating goodwill. Technical goodwill is allocated by segment, in line with where it arises, and none is expected to be deductible for income tax purposes.

**18. Goodwill**

| | **2025 $m** | 2024 $m |
|---|---|---|
| Balance at 1 January | **1,129.5** | 783.9 |
| Additions (note 17) | **152.2** | 345.6 |
| Revisions to 2024 business combinations (note 17) | **57.1** | – |
| **Balance at 31 December** | **1,338.8** | 1,129.5 |

The goodwill of $784 million at 1 January 2024 relates to historic business combinations comprising principally Chevron in 2019 and Summit in 2022.

The goodwill on business combinations in 2025 relates to JAPEX UK and Cygnus and in 2024 it relates to the Eni UK businesses, as detailed in note 17.

The goodwill is not tax deductible on either the JAPEX UK, Cygnus or the Eni UK business combinations.

**18. Goodwill** continued

Goodwill is monitored, and tested for impairment, at the operating segment level, being the North Sea (the entire Group portfolio of oil and gas assets). This is consistent with the operating segment view of the business, which is presented to the Board and the Chief Decision Making Officer. The Group's activities are considered to be an individual operating segment due to the uniform nature of the Group's operations within a single geographical area, overseen by the same management and subject to the same regulations. The fair value estimate is categorised as level 3 in the fair value hierarchy.

Annual impairment tests were performed at both 31 December 2025 and 31 December 2024. These reviews were carried out on a fair value less cost of disposal basis using risk-adjusted post-tax cash flow projections from the approved business plans, including the same commodity prices, life of field cost profiles and production volumes used for impairment of oil and gas assets (see note 19), discounted at a post-tax discount rate of 9.7% (2024: 10.0%). Assumptions and estimates in the Group impairment models are detailed in note 3. The recoverable amount of the North Sea CGU at 31 December 2025 was $125 million (2024: $419 million) higher than its carrying amount, including goodwill, and hence no impairment was recorded (2024: $nil). An increase of 1% in the discount rate would result in an impairment of $108 million (2024: $nil) to goodwill. Details of further sensitivities are provided in note 19.

**19. Impairment charges on oil and gas assets**

| | **2025 $m** | 2024 $m |
|---|---|---|
| D&P assets (note 15) | **(8.2)** | (148.8) |
| Decommissioning cost estimate changes on assets which have either been fully written off or have ceased production (note 23) | **(64.4)** | (99.7) |
| Fixed asset additions on assets that have been fully written off (note 15) | **(4.5)** | (12.3) |
| Other movements | **(0.4)** | (2.2) |
| **Total impairment charges on D&P assets** | **(77.5)** | (263.0) |

The impairment charge on D&P assets of $8.2 million (2024: $148.8 million) relates to an impairment on Alder which ceased production during the year. In the year to 31 December 2024, the $148.8 million impairment comprised a charge for the Greater Stella Area (GSA) of $116.4 million due to a downward revision of reserves, lower gas prices than previously forecast and EPL changes together with a charge of $32.4 million in respect of Pierce due to lower oil prices than previously forecast and EPL changes.

Estimated production volumes, supported by third-party analysis, and cash flows used in impairment reviews are considered up to the date of cessation of production on a field-by-field basis, including operating and capital expenditure and are derived from management approved business plans.

An impairment review was carried out at the end of 2025 on the Group's producing assets with the main triggers being lower oil and gas prices. The review was carried out on a fair value less cost of disposal basis using post-tax risk adjusted cash flow projections discounted at a post-tax discount rate of 9.7%, and represents level 3 in the fair value hierarchy. The post-tax recoverable amount for Alder was $nil.

**19. Impairment charges on oil and gas assets** continued

The following assumptions were used at Q4 2025 in developing the cash flow model and applied over the expected life of the respective fields:

| | Price assumptions (nominal) | |
|---|---|---|
| | **Oil** | **Gas** |
| Post-tax discount rate assumption | **9.7%** | **9.7%** |
| 2026 | **$62/bbl** | **82p/therm** |
| 2027 | **$65/bbl** | **75p/therm** |
| 2028 | **$70/bbl** | **77p/therm** |
| 2029 | **$74/bbl** | **75p/therm** |
| 2030 | **$77/bbl** | **76p/therm** |
| 2031 | **$79/bbl** | **77p/therm** |
| 2032[1] | **$80/bbl** | **79p/therm** |

1 Post-2032, an annual 2% increase is applied to the price assumptions.

With all other assumptions held constant, including the cessation of EPL in March 2030, a 20% decrease in the forecast revenues, illustrating a 20% decrease in commodity prices, would result in an additional post-tax impairment to development and production assets of $434 million (2024: $303 million) and a post-tax impairment to exploration and evaluation assets of $nil million (2024: $nil) at 31 December 2025. In addition, under this scenario, goodwill would be impaired in its entirety (2024: goodwill impairment of $929 million).

A 20% increase in forecast revenues would not result in any change to the impairment charge in the year ended 31 December 2025 (2024: $24 million post-tax reduction in the impairment charge). An increase or decrease of 1% in the discount rate assumption would not result in a material additional post-tax impairment or reversal of impairment of PP&E.

Due to declines in future commodity prices, goodwill headroom reduced to $125 million (2024: $419 million). Commodity prices would have to be 2% lower than the base case scenario for there to be no goodwill headroom left.

The Group has also conducted a sensitivity scenario on the climate-related risk of a reduction in demand for oil and gas commodity prices due to changing consumer preferences and/or government regulations. Utilising the Climate Scenario average oil price while maintaining all other parameters in line with the base case, would result in an additional post-tax impairment of PP&E of $nil (2024: $63 million). To calculate the Climate Scenario average oil and gas prices, the Group used data from the International Energy Agency (IEA) climate scenarios (NZ, STEPS, CPS) price assumptions.

**19. Impairment charges on oil and gas assets** continued

An impairment review was carried out at the end of 2024 on the Group's producing assets with the main triggers being lower forward oil and gas prices and changes in EPL legislation. The review was carried out on a fair value less cost of disposal basis using risk adjusted cash flow projections discounted at a post-tax discount rate of 10.0%, and represents level 3 in the fair value hierarchy. The post-tax recoverable amounts for GSA and Pierce were $2 million and $25 million, respectively.

The following assumptions were used at Q4 2024 in developing the cash flow model and applied over the expected life of the respective fields:

| | Price assumptions (nominal) | |
|---|---|---|
| | Oil | Gas |
| Post-tax discount rate assumption | 10.0% | 10.0% |
| 2025 | $75/bbl | 98p/therm |
| 2026 | $74/bbl | 84p/therm |
| 2027 | $77/bbl | 81p/therm |
| 2028 | $79/bbl | 82p/therm |
| 2029 | $80/bbl | 83p/therm |
| 2030 | $82/bbl | 85p/therm |
| 2031[1] | $83/bbl | 87p/therm |

1 Post 2031, an annual 2% is applied to the price assumptions.

## 20. Borrowings

| | 2025 $m | 2024 $m |
|---|---|---|
| ***Current*** | | |
| Accrued interest costs on borrowings | **(26.9)** | (23.2) |
| Unamortised short-term bank fees | **7.3** | 6.6 |
| Unamortised short-term senior notes fees | **5.5** | 3.6 |
| Total current borrowings | **(14.1)** | (13.0) |
| ***Non-current*** | | |
| Accrued interest costs on borrowings | **(18.8)** | – |
| RBL facility | – | (150.0) |
| Senior unsecured notes 2029 | **(750.0)** | (750.0) |
| Senior unsecured notes 2031 | **(528.3)** | – |
| Project capital expenditure facility | **(150.0)** | (150.0) |
| Unamortised long-term bank fees | **20.6** | 24.6 |
| Unamortised long-term senior notes fees | **18.8** | 13.5 |
| Total non-current borrowings | **(1,407.7)** | (1,011.9) |

### Reserves Based Lending (RBL) facility

During 2024, the Group completed a refinancing of the RBL facility. The RBL facility amount at 31 December 2025 was $1.8 billion (2024: $1.5 billion), consisting of a loan facility of $1,300 million (2024: $1,000 million) and a letter of credit facility of $500 million (2024: $500 million), with a maturity to 2029, and subject to interest at a reference rate of SOFR plus 4.0% in years one to four and SOFR plus 4.25% thereafter. At 31 December 2025, the total loan availability was $1,300 million (2024: $1,000 million), of which $nil (2024: $150 million) was drawn, leaving the full $1,300 million (2024: $850 million) being available for drawdown. In addition, under the RBL facility, there is an accordion facility of up to $1,000 million, of which $565 million was committed at 31 December 2025 (2024: $265 million).

Loan fees of $32.4 million relating to the refinancing of the RBL facility were capitalised in the year to 31 December 2024 and are being amortised over the term of the loan. As at 31 December 2025, $27.9 million (2024: $31.2 million) remains to be amortised.

The obligations of the borrower under the RBL facility are secured by the assets of the guarantor members of the Group, such as security including share pledges, floating charges and/or debentures. Total assets pledged as security at 31 December 2025 was $8,447 million (2024: $8,275 million).

Covenants under the RBL are detailed below.

## 20. Borrowings continued

### Senior notes due 2029

In 2024, the Group completed the refinancing of its senior unsecured notes with the issuance of $750 million 8.125% senior unsecured notes due October 2029 and repayment in full of the $625 million 9.0% 2026 notes issued during 2021. Loan fees of $17.8 million relating to the senior notes 2029 were capitalised in the year to 31 December 2024 and are being amortised over the life of the loan. Of this amount, $13.8 million (2024: $17.1 million) remains to be amortised as at 31 December 2025.

In the year to 31 December 2024, the Group received a net cash inflow of $86.8 million from the refinancing of the senior notes 2029, reflecting senior notes 2029 proceeds of $750.0 million less repayment of senior notes 2026 of $625.0 million less fees and interest of $38.2 million comprising $14.1 million of early repayment charges and $15.1 million interest on the senior notes due 2026 and $9.0 million of fees in relation to the senior notes due 2029. Fees of $7.8 million in relation to the new senior notes were paid separately and $1.0 million was accrued at 31 December 2024.

### Senior notes due 2031

In 2025, the Group issued €450 million of 5.50% senior unsecured notes due September 2031. These senior unsecured notes were swapped to US Dollars at an all-in effective interest rate of approximately 6.7%. Loan fees of $11.0 million relating to the senior notes 2031 were capitalised and are being amortised over the life of the loan. Of this amount, $10.5 million (2024: $nil) remains to be amortised as at 31 December 2025.

### Project capital expenditure facility

The project capital expenditure facility of up to $150 million relates to a field development. The full amount of this facility was drawn at 31 December 2025 (2024: $150 million) and it is repayable by instalment expected to be from 2027. Under the terms of the arrangement, interest is payable at a rate of SOFR (subject to a minimum of 5%) plus a commercially agreed margin.

### Covenants

The Group is subject to covenants related to the RBL facility. Failure to meet the terms of one or more of these covenants may constitute an event of default as defined in the facility agreements, potentially resulting in accelerated repayment of the debt obligations. The Group was in compliance with all its relevant quarterly financial and operating covenants during all periods shown for the RBL facility. There are no ongoing maintenance or financial covenant tests associated with either the 2029 or 2031 senior unsecured notes.

In addition to the below financial covenants, the Group is subject to restrictive covenants under the RBL facility and the 2029 and 2031 notes. These restrictive covenants include restrictions on: making certain payments (including, subject to certain exceptions, dividends and other distributions); certain activities with respect to outstanding share capital; repaying or redeeming subordinated debt or share capital; creating or incurring certain liens; making certain acquisitions and investments or loans; selling, leasing or transferring certain assets including shares of any of the Group's restricted subsidiaries; incurring expenditure on exploration and appraisal activities in excess of approved levels; guaranteeing certain types of the Group's other indebtedness; expanding into unrelated businesses; merging or consolidating with other entities; or entering into certain transactions with affiliates.

**20. Borrowings** continued

The key financial covenant and other conditions in the RBL which, if not met, could trigger repayment within 12 months of the reporting date include:

- As at the end of each 12 month period ending 30 June and 31 December, the ratio of adjusted net debt to adjusted EBITDAX shall be less than 3.5:1. 'Adjusted net debt' referred to is not an IFRS measure. The Group uses adjusted net debt as a measure to assess its financial position. Adjusted net debt comprises amounts outstanding under the Group's RBL facility, project capital expenditure facility and senior notes, less cash and cash equivalents;
- On submission of Corporate Cashflow Projections, total projected sources of funds must exceed the total projected uses of funds for the following 12-month period, or if tested prior to first oil from Rosebank, a period of up to 24 months. Corporate Cashflow Projections must be submitted in June and December each year and on the occurrence of certain events (including on refinancing, when an interest in a petroleum asset is acquired or when certain distributions are made);
- The ratio of the net present value of cash flows secured under the RBL for the economic life of the fields to the amount drawn under the facility must not fall below 1.15:1; and
- The ratio of the net present value of cash flows secured under the RBL for the life of the debt facility to the amount drawn under the facility must not fall below 1.05:1.

## 21. Changes in liabilities arising from financing activities

| | 1 January 2025 $m | Financing cash flows(i) $m | Non-cash changes: Additions(iii) $m | Non-cash changes: Business combinations $m | Non-cash changes: Amortisation $m | Non-cash changes: Other movements(ii) $m | 31 December 2025 $m |
|---|---|---|---|---|---|---|---|
| Borrowings (note 20) | 1,024.9 | **252.2** | – | – | **11.1** | **133.6** | **1,421.8** |
| Lease liabilities | 40.1 | **(46.7)** | **117.4** | – | – | **1.4** | **112.2** |
| Total liabilities from financing activities | 1,065.0 | **205.5** | **117.4** | – | **11.1** | **135.0** | **1,534.0** |

| | 1 January 2024 $m | Financing cash flows(i) $m | Non-cash changes: Additions(iii) $m | Non-cash changes: Business combinations $m | Non-cash changes: Amortisation $m | Non-cash changes: Other movements(ii) $m | 31 December 2024 $m |
|---|---|---|---|---|---|---|---|
| Borrowings (note 20) | 748.1 | 12.0 | 150.0 | – | 13.2 | 101.6 | 1,024.9 |
| Lease liabilities | 20.6 | (29.4) | 25.4 | 22.0 | – | 1.5 | 40.1 |
| Interest rate derivatives (note 30) | (0.6) | 0.6 | – | – | – | – | – |
| Total liabilities from financing activities | 768.1 | (16.8) | 175.4 | 22.0 | 13.2 | 103.1 | 1,065.0 |

(i) The cash flows from borrowings, lease liabilities and interest rate derivatives make up the net amount of proceeds from borrowings and repayments of borrowings in the cash flow statement.
(ii) Other movements include interest accruals and new liabilities in the year.
(iii) Additions to borrowings in 2024 reflects the project capital expenditure facility (see note 20 for further details).

## 22. Trade and other payables

| | 2025 $m | 2024 $m |
|---|---|---|
| Trade payables | **(54.3)** | (21.9) |
| Hydrocarbon amounts owed to joint operations/overlift | **(55.2)** | (102.1) |
| Other payables | **(24.8)** | (38.1) |
| Accruals | **(432.9)** | (394.6) |
| Deferred income | **(43.1)** | (9.8) |
| | **(610.3)** | (566.5) |

The Directors consider the carrying values of trade and other payables to approximate the fair value. Other payables mainly comprise amounts owed due to production adjustments and amounts owed to joint operations partners. Deferred income represents receipts in advance of deliveries to customers.

## 23. Decommissioning liabilities

| | 2025 $m | 2024 $m |
|---|---|---|
| Balance at 1 January | **(2,655.1)** | (1,859.7) |
| 2024 business combinations and revisions (note 17) | **(17.2)** | (651.0) |
| Business combination additions in 2025 (note 17) | **(125.4)** | – |
| Accretion | **(124.9)** | (93.4) |
| Additions and revisions to estimates | **(266.5)** | (145.1) |
| Decommissioning provision utilised | **107.2** | 94.1 |
| Balance at 31 December | **(3,081.9)** | (2,655.1) |
| ***Current*** | | |
| Balance at 1 January | **(152.7)** | (107.0) |
| Balance at 31 December | **(328.0)** | (152.7) |
| ***Non-current*** | | |
| Balance at 1 January | **(2,502.4)** | (1,752.7) |
| Balance at 31 December | **(2,753.9)** | (2,502.4) |

The total future decommissioning liability represents the estimated cost to decommission, in situ or by removal, the Group's net ownership interest in all wells, infrastructure and facilities, based upon forecast timing in future periods. The Group uses a nominal discount rate of 3.74% for the first five years and 4.75% thereafter (31 December 2024: 4.38% for the first five years and 4.86% thereafter) and an inflation rate of 2.0% (31 December 2024: 2.0%) over the varying lives of the assets to calculate the present value of the decommissioning liabilities. The impact of a change in discount rate is considered in note 3. Revisions to estimates in the years ended 31 December 2025 comprised principally Elgin Franklin, Captain, Heather and Strathspey, J-block and Cygnus. In both 2025 and 2024 revisions to estimates were due to changes in both cost estimates and discount rate assumptions.

## 23. Decommissioning liabilities continued

Additions and revisions to estimates comprise:

| | 2025 $m | 2024 $m |
|---|---|---|
| Development and production assets (note 15) | **(160.5)** | (54.6) |
| Exploration and evaluation assets (note 14) | **2.2** | (4.4) |
| Assets which have either been fully written-off or have ceased production | **(70.5)** | (99.7) |
| Assets which are subject to decommissioning reimbursements (note 11) | **(36.8)** | 13.6 |
| Other movements | **(0.9)** | – |
| | **(266.5)** | (145.1) |

The estimated 2026 decommissioning spend of $328 million (2024: estimated 2025 decommissioning spend of $153 million) which includes $93 million (2024: $33 million) for assets that are subject to reimbursement, has been treated as a current liability as at 31 December 2025. Although the Group currently expects to incur decommissioning costs over the next 40 years, it is estimated that approximately 36% (2024: 40%) of the decommissioning liability relates to assets which are expected to cease production in the next five years and includes spend for assets that will be reimbursed (see note 11 for further details).

The principal assets where decommissioning activity was ongoing at 31 December 2025 were Alba, Anglia, CMS 111, Elgin Franklin, Greater Stella Area, Heather and Stathspey.

## 24. Other provisions

| | 2025 $m | 2024 $m |
|---|---|---|
| At 1 January | **(36.2)** | – |
| Business combination additions (note 17) | – | (34.9) |
| Revisions to 2024 business combinations (note 17) | **(3.9)** | – |
| Amounts utilised | **30.5** | – |
| Other movements | **(1.6)** | (1.3) |
| **At 31 December** | **(11.2)** | (36.2) |
| ***Current*** | | |
| Balance at 1 January | – | – |
| Balance at 31 December | **(7.6)** | – |
| ***Non-current*** | | |
| Balance at 1 January | **(36.2)** | – |
| Balance at 31 December | **(3.6)** | (36.2) |

At 31 December 2025, other provisions comprise a provision for office dilapidations, an office onerous contract provision, a commodity mismeasurement provision and the residual balance of the gas sales agreement liabilities described below. Amounts utilised in the year to 31 December 2025 reflect principally credit notes issued for these gas sales agreements.

**24 Other provisions** continued

At 31 December 2024, other provisions reflected principally estimated liabilities taken on through the Eni UK business combination in respect of certain historic gas sales agreements along with the ongoing cost of such gas sales agreements. It was not anticipated at that time that any part of the liability would be settled within 12 months of the balance sheet date and, therefore, it was classified in its entirety as a non-current liability.

The Group expects to settle these liabilities in up to five years.

## 25. Lease liabilities

| Current | 2025 $m | 2024 $m |
|---|---|---|
| Lease liabilities | (59.1) | (19.4) |

| Non-current | 2025 $m | 2024 $m |
|---|---|---|
| Lease liabilities | (53.1) | (20.7) |

The following table sets out a maturity analysis of lease payments, showing the undiscounted lease payments to be paid after the reporting date. All lease liabilities are fully payable within five years from 31 December 2025.

| | 2025 $m | 2024 $m |
|---|---|---|
| Less than one year | (65.6) | (21.0) |
| One to five years | (59.1) | (21.9) |
| Total undiscounted lease payments | (124.7) | (42.9) |
| Future finance charges | 12.5 | 2.8 |
| Lease liabilities in the financial statements | (112.2) | (40.1) |

| | 2025 $m | 2024 $m |
|---|---|---|
| At 1 January | (40.1) | (20.6) |
| Additions | (117.4) | (25.4) |
| Business combination additions (note 17) | – | (22.0) |
| Interest | (4.8) | (1.5) |
| Foreign exchange movements | (1.3) | – |
| Payments | 51.4 | 29.4 |
| At 31 December | (112.2) | (40.1) |
| Current | (59.1) | (19.4) |
| Non-current | (53.1) | (20.7) |
| | (112.2) | (40.1) |

**25. Lease liabilities** continued

The additions in the year to 31 December 2025 relate principally to a drilling rig at Cygnus, a decommissioning vessel for Alba and a two-year extension to the lease on the Skandi Gamma supply vessel.

The additions in the year to 31 December 2024 relate to the Skandi Gamma supply vessel.

The leased assets added through the business combination in 2024 comprised principally office accommodation, an ERRV lease and a helicopter lease for Cygnus.

Amounts recognised in profit and loss related to leases are detailed in notes 6 and 9.

## 26. Contingent and deferred consideration

| Current | 2025 $m | 2024 $m |
|---|---|---|
| Contingent consideration | (68.0) | (75.0) |
| Deferred consideration payable to related-party for business combination (note 17) | (43.1) | (160.2) |
| Marubeni deferred consideration | – | (68.3) |
| | (111.1) | (303.5) |

| Non-current | 2025 $m | 2024 $m |
|---|---|---|
| Contingent consideration | (184.3) | (165.5) |
| Deferred consideration payable to related-party for business combination (note 17) | (15.6) | (44.2) |
| | (199.9) | (209.7) |

| | 2025 $m | 2024 $m |
|---|---|---|
| Cash flows relating to contingent and deferred considerations | (235.6) | (23.0) |

Movement in contingent consideration is as follows:

| | 2025 $m | 2024 $m |
|---|---|---|
| At 1 January | (240.5) | (296.4) |
| Payments made | 1.6 | 23.0 |
| Changes in fair value | (13.4) | 32.9 |
| **At 31 December** | **(252.3)** | (240.5) |

**26. Contingent and deferred consideration** continued

Movement in deferred consideration is as follows:

| | **2025 $m** | 2024 $m |
|---|---|---|
| At 1 January | **(272.7)** | (64.0) |
| Additions from business combinations (note 17) | **(10.5)** | (204.4) |
| Payments made | **234.0** | – |
| Accretion | **(9.5)** | (4.3) |
| **At 31 December** | **(58.7)** | (272.7) |

Cash outflows in the year ended 31 December 2025 of $235.6 million (2024: $23.0 million) are principally in relation to the consideration payable on the Eni UK business combination and the Marubeni deferred consideration.

### Eni UK Business Combination

The deferred consideration at 31 December 2025 was $48.2 million (2024: $204.4 million) discounted at 4.33% (2024: 4.33%).

### Cygnus acquisition

The deferred consideration at 31 December 2025 was $10.5 million (2024: $nil). As this payment is expected to be made early in 2026, this amount has not been discounted.

### Marubeni

The contingent consideration arrangement relating to the Marubeni acquisition depends on whether various milestones in the Sale and Purchase Agreement (SPA) are met as follows: set gross export production volume from Montrose Infill Project Phase 1, set cumulative gross export production volume following Arbroath well reinstatements, set gross export production volume from next new well in the Shaw Field and, an amount payable during the Value Sharing Period (1 January 2022 to 31 December 2024) in relation to sales in excess of a set oil trigger price. The amount payable in relation to sales in excess of a set oil trigger price is capped under the terms of the SPA.

The carrying amount at 31 December 2025, discounted at 6.53%, was $84 million (2024: $78 million using a discount rate of 6.33%). The total undiscounted potential consideration as at 31 December 2025 was $225 million (2024: $228 million).

### Siccar

The Siccar acquisition included elements of consideration that are payable depending on whether various milestones of the SPA are met as follows: Final Investment Decision and the associated reserves in respect of the Cambo and Rosebank fields and, an amount paid in relation to sales in excess of a set floor oil price between 1 January 2023 and 31 December 2025. The amount payable in relation to sales in excess of a set oil trigger price is capped under the terms of the SPA. The carrying amount at 31 December 2025, discounted at 6.53% was $130 million (2024: $118 million using a discount rate of 6.33%). The total undiscounted potential consideration as at 31 December 2025 was $285 million (2024: $343 million).

**26. Contingent and deferred consideration** continued

### Others

During the year ended 31 December 2023, the Group acquired a further 30% equity in the Cambo field from Shell. The acquisition included elements of consideration that are payable upon certain events occurring and contingent consideration has been recognised to reflect this. The consideration value equates to $1.50 per barrel of oil equivalent of the P50 resource volumes of the field, and is payable on the earlier of receipt of proceeds of any subsequent sale of a working interest in Cambo by the Group, or first oil. The carrying amount at 31 December 2025, discounted at 6.53%, was $13.8 million (2024: $11.7 million discounted at 6.33%).

During the year ended 31 December 2023, the Group acquired 40% equity in the Fotla field from Spirit. The acquisition included elements of consideration that are payable upon certain events occurring and contingent consideration has been recognised to reflect this. The consideration comprises two capped amounts with approximately two-thirds payable on final investment decision and one-third on first production. The carrying amount at 31 December 2025, discounted at 6.53%, was $10.2 million (2024: $9.0 million discounted at 6.33%).

During the year ended 31 December 2025, the contingent consideration liability in relation to Strathspey, in accordance with the Sale and Purchase Agreement with Chevron, has reduced by $8.9 million to $14.8 million as a result of changes in variables in the calculation of the liability.

The total undiscounted potential consideration of other liabilities as at 31 December 2025 was $80 million (2024: $98 million).

Revaluation of contingent consideration in the year to 31 December 2025 resulted in a increase of $13.4 million (2024: decrease of $32.9 million).

Details of the valuation of contingent consideration and sensitivities are set out in notes 3 and 30.

## 27. Share capital and reserves

### (a) Issued share capital

The issued share capital is as follows:

| | Number of common shares | Amount $m |
|---|---|---|
| **At 31 December 2024 and 31 December 2025** | **1,653,732,455** | **20.0** |

On 3 October 2024, 639,360,174 ordinary shares of £0.01 each were issued to Eni UK Limited, an indirect wholly-owned subsidiary of Eni S.p.A., as consideration for the Eni UK business combination.

## 27. Share capital and reserves continued

### (b) Share premium

| | 2025 $m | 2024 Restated[1] $m |
|---|---|---|
| **At 1 January and 31 December** | **308.8** | 308.8 |

1 See note 2.

The share premium account represents the cumulative difference between the market share price and the nominal share value on the issuance of new ordinary shares multiplied by the number of shares issued.

### (c) Merger reserve

| | 2025 $m | 2024 Restated[1] $m |
|---|---|---|
| **At 31 December** | **852.8** | 852.8 |

1 See note 2.

The merger reserve represents the cumulative difference between the market share price and the nominal share value on the issuance of new ordinary shares used to fund acquisitions multiplied by the number of shares issued.

Additions during 2024 represent the difference between the nominal value per share of £0.01 and the opening share price on the day of the completion of the Eni business combination multiplied by the number of shares issued.

### (d) Capital contribution reserve

| | 2025 $m | 2024 $m |
|---|---|---|
| **At 1 January and 31 December** | **181.9** | 181.9 |

### (e) Own shares

| | 2025 $m | 2024 $m |
|---|---|---|
| **At 31 December** | **(4.7)** | (9.6) |

Own shares comprise shares held in the Ithaca Energy plc EBT, which are being used to satisfy the exercise of employee share options. During the year to 31 December 2025, 3,193,406 (2024: 1,860,112) ordinary shares were used to satisfy the exercise of share options. At 31 December 2025, the EBT held 3,132,512 (2024: 6,325,918) ordinary shares of £0.01 each.

### (f) Share-based payment reserve (note 33)

| | 2025 $m | 2024 $m |
|---|---|---|
| **At 31 December** | **21.3** | 18.8 |

The share-based payment reserve represents the cumulative charge for share options, as described in note 33, less the cumulative cost of share option exercises.

## 28. Taxation

| | 2025 $m | 2024 $m |
|---|---|---|
| *Current tax* | | |
| Current corporation tax charge | **(29.3)** | (17.8) |
| Current EPL tax charge | **(375.7)** | (221.4) |
| True-up in respect of prior years | **41.6** | 30.6 |
| **Total current tax charge** | **(363.4)** | (208.6) |
| *Deferred tax* | | |
| True-up in respect of prior years | **4.6** | (21.1) |
| Group tax charge in consolidated statement of profit or loss | **(563.2)** | (1.9) |
| Group tax (charge)/credit in consolidated statement of other comprehensive income | **(336.9)** | 195.6 |
| **Total deferred tax (charge)/credit** | **(895.5)** | 172.6 |
| *Deferred Petroleum Revenue Tax* | | |
| True-up in respect of prior years | **(14.9)** | – |
| Deferred PRT credit for the year | **12.5** | 50.4 |
| Deferred PRT (charge)/credit in consolidated statement of profit or loss | **(2.4)** | 50.4 |
| **Total tax charge through consolidated statement of profit or loss** | **(924.4)** | (181.2) |

The Company is UK tax resident. The effective rate of tax applicable for UK ring fence oil and gas activities in both 2025 and 2024 was 40% (excluding the Energy Profits Levy), consisting of a Ring Fence Corporation Tax rate of 30% and the supplementary charge of 10%. Items affecting the tax charge include interest income taxed at non-oil and gas tax rate of 25%, true-ups in respect of prior years resulting from filing of prior year tax returns, a 10% uplift on ring fence losses, Ring Fence Expenditure Supplement increasing the losses available to offset future profits subject to Ring Fence Corporation Tax and Supplementary Charge. In addition, investment allowance, a 62.5% uplift on capital expenditure, is available reducing the profits subject to the supplementary charge only. Petroleum Revenue Tax (PRT) is applied at 0% on certain oil and gas fields in the UK, however, adjustments to recognised deferred PRT assets are made to reflect updated expectations of reversal against profits subject to the 0% PRT rate. The Energy Profits Levy of 35% originally applied up to 31 March 2028. On 6 March 2024, it was announced that EPL would be extended by one year to 31 March 2029 and on 29 July 2024, it was announced that there would be a further extension to March 2030 and that the rate would increase from 35% to 38% from 1 November 2024. The impact of this rate increase was a charge to the consolidated statement of profit or loss of $58.1 million in the year to 31 December 2024. The extension to 31 March 2030 was substantively enacted on 3 March 2025 and resulted in a deferred tax charge of $327.6 million in the year to 31 December 2025. As part of the Autumn 2025 Budget, it was announced that the EPL would be replaced by a permanent revenue-based oil and gas price mechanism (OGPM). The OGPM will only apply during periods of high prices and the amount that will be chargeable to the OGPM will be the part of the realised revenue that exceeds the respective oil and gas thresholds (announced as $90 per barrel for oil and 90p per therm for gas, which are to be adjusted annually in line with CPI inflation). The mechanism will be implemented in a future Finance Bill and will come into force on 1 April 2030 or earlier if the energy security investment mechanism is triggered. If the OGPM had been substantively enacted by the balance sheet date, there would have been no material impact on the financial statements of the Group.

## 28. Taxation continued

The tax on the Group's profit before tax differs from the theoretical amount that would arise using the 40% statutory rate of tax applicable for UK ring fence oil and gas activities as follows:

| | 2025 $m | 2024 $m |
|---|---|---|
| Accounting profit before tax | **840.3** | 334.3 |
| At tax rate of 40% (2024: 40%) | **(336.1)** | (133.7) |
| Non-deductible (expense)/income | **(11.1)** | 8.7 |
| Financing costs not allowed for SCT | **(12.7)** | (13.6) |
| Ring Fence Expenditure Supplement | **14.6** | 14.3 |
| Deferred tax effect of investment allowance | **52.7** | 33.2 |
| True-up in respect of prior years | **31.3** | 9.5 |
| Deferred PRT net of corporation tax | **20.1** | 30.2 |
| Deferred tax on EPL | **(295.5)** | 119.1 |
| Current tax on EPL | **(375.7)** | (221.4) |
| Income taxed at different rates | **(13.0)** | (27.9) |
| Share-based payments | **1.5** | 0.4 |
| Foreign exchange movements on current taxation | **(0.5)** | – |
| **Total tax charge recorded in the consolidated statement of profit or loss** | **(924.4)** | (181.2) |

Deferred tax at 31 December relates to the following:

| | 2025 $m | 2024 $m |
|---|---|---|
| Deferred corporation tax liability | **(2,953.0)** | (2,197.5) |
| Deferred corporation tax asset | **3,175.3** | 3,279.6 |
| Deferred PRT asset | **139.7** | 142.1 |
| **Net deferred tax asset** | **362.0** | 1,224.2 |

Deferred tax assets primarily relate to decommissioning liabilities, brought forward tax losses and accumulated losses and profits related to derivative contracts. Deferred tax liabilities primarily relate to accelerated capital allowances on property, plant and equipment and accumulated losses and profits related to derivative contracts. Deferred tax balances are presented net as they arise in the same jurisdiction and the Group has a legally-enforceable right to offset as well as an intention to settle on a net basis. There are unrecognised deferred tax assets in relation to allowances of up to circa $64 million (2024: circa $147 million) that have no expiry date and could be recognised in future periods if future revenue from oil and gas activities increases and/or further actions are undertaken. A deferred tax asset of $72 million (2024: $63 million) associated with non-oil and gas losses, of which there is no expiry date, has not been recognised for deferred tax purposes as it is not sufficiently certain that there will be future non-oil and gas profits to offset these losses.

**28. Taxation** continued

The net movement on deferred tax in the statement of financial position, including deferred PRT, is as follows:

| | 2025 $m | 2024 $m |
|---|---|---|
| At 1 January | **1,224.2** | 704.7 |
| Consolidated statement of profit or loss (charge)/credit | **(561.0)** | 27.4 |
| Other comprehensive income (charge)/credit | **(336.9)** | 195.7 |
| Deferred tax on decommissioning reimbursements (note 11) | **16.9** | (0.9) |
| Business combinations[1] (note 17) | **18.8** | 297.3 |
| **At 31 December** | **362.0** | 1,224.2 |

The net movement on deferred tax through the consolidated statement of profit or loss and consolidated statement of comprehensive income, excluding PRT, relates to the following:

| | 2025 $m | 2024 $m |
|---|---|---|
| Accelerated capital allowances | **(447.4)** | 101.0 |
| Tax losses | **(236.2)** | (203.3) |
| Decommissioning provision | **97.1** | 61.7 |
| Deferred PRT | **0.9** | (20.2) |
| Hedging[2] | **(348.3)** | 201.5 |
| Share schemes | **0.8** | 0.9 |
| Foreign exchange movements | **(3.8)** | – |
| Investment allowances | **41.4** | 31.0 |
| | **(895.5)** | 172.6 |

1 2025 business combination additions of $41.2 million (deferred tax assets of $137.0 million less deferred tax liabilities of $95.8 million) less a reassessment of $22.4 million (reduction in deferred tax assets of $25.7 million less a reduction in deferred tax liabilities of $3.3 million) on 2024 business combinations as set out in note 17.

2 Hedging relates to deferred tax on derivatives designated in cash flow hedges and used for economic hedges.

**28. Taxation** continued

| Gross deferred corporation tax liabilities | Hedges $m | Other timing differences $m | Deferred corporation tax on deferred PRT $m | Accelerated tax depreciation $m | Total $m |
|---|---|---|---|---|---|
| **At 1 January 2024** | (107.7) | – | (36.7) | (1,723.6) | (1,868.0) |
| Business combinations (note 17) | – | – | – | (549.1) | (549.1) |
| True-up in respect of prior years | – | – | – | (16.0) | (16.0) |
| Origination and reversal of temporary differences | 201.5 | – | (20.1) | 148.0 | 329.4 |
| Reclassification to deferred corporation tax assets | (93.8) | – | – | – | (93.8) |
| **At 31 December 2024 and 1 January 2025** | – | – | (56.8) | (2,140.7) | (2,197.5) |
| Business combinations (note 17) | **–** | **–** | **–** | **(92.5)** | **(92.5)** |
| True-up in respect of prior years | **–** | **(3.8)** | **6.0** | **(9.1)** | **(6.9)** |
| Origination and reversal of temporary differences | **(348.3)** | **–** | **(5.0)** | **(396.6)** | **(749.9)** |
| Reclassification from deferred corporation tax assets | **93.8** | **–** | **–** | **–** | **93.8** |
| **At 31 December 2025** | **(254.5)** | **(3.8)** | **(55.8)** | **(2,638.9)** | **(2,953.0)** |

| Gross deferred corporation tax assets | Share schemes $m | Decommissioning provision $m | Other provisions $m | Tax losses $m | Hedges $m | Total $m |
|---|---|---|---|---|---|---|
| **At 1 January 2024** | 4.0 | 721.7 | – | 1,755.2 | – | 2,480.9 |
| Business combinations (note 17) | – | 257.4 | 21.4 | 567.6 | – | 846.4 |
| True-up in respect of prior years | – | – | – | (5.0) | – | (5.0) |
| Origination and reversal of temporary differences | 0.9 | 60.8 | – | (198.2) | – | (136.5) |
| Reclassification to deferred corporation tax liabilities | – | – | – | – | 93.8 | 93.8 |
| **At 31 December 2024 and 1 January 2025** | 4.9 | 1,039.9 | 21.4 | 2,119.6 | 93.8 | 3,279.6 |
| Business combinations (note 17) | **–** | **57.0** | **(21.4)** | **75.7** | **–** | **111.3** |
| True-up in respect of prior years | **–** | **–** | **–** | **14.5** | **–** | **14.5** |
| Origination and reversal of temporary differences | **0.8** | **113.8** | **–** | **(250.7)** | **–** | **(136.3)** |
| Reclassification from deferred corporation tax liabilities | **–** | **–** | **–** | **–** | **(93.8)** | **(93.8)** |
| **At 31 December 2025** | **5.7** | **1,210.7** | **–** | **1,958.9** | **–** | **3,175.3** |

## 28. Taxation continued

| *Deferred PRT asset* | Total $m |
|---|---|
| At 1 January 2024 | 91.7 |
| Origination and reversal of temporary differences | 50.4 |
| **At 31 December 2024 and 1 January 2025** | 142.1 |
| True-up in respect of prior years | **(14.8)** |
| Origination and reversal of temporary differences | **12.4** |
| **At 31 December 2025** | **139.7** |

The carrying value of the net deferred tax asset (DTA) and the deferred PRT asset at 31 December 2025 of $222 million and $140 million, respectively (2024: $1,082 million and $142 million, respectively), are supported by estimates of the Group's future taxable income, based on the same price and cost assumptions as used for impairment testing. The Group has undertaken and will undertake further restructuring exercises to move certain assets between Group entities. Existing restructuring exercises have now been substantially completed. The recoverability of the deferred corporation tax asset is supported by this restructuring. The DTA relating to losses within the Group are expected to unwind against taxable profits before the end of 2031.

On 20 June 2023, Finance (No. 2) Act 2023 was substantially enacted in the UK, introducing a global minimum effective tax rate of 15%. The legislation implements a domestic top-up tax and a multinational top-up tax, effective for all accounting periods starting on or after 31 December 2023. The adoption of this has not had a material impact as the prevailing rate of tax in the United Kingdom is in excess of the 15% minimum rate. The Group has applied the exemption under IAS 12 to recognising and disclosing information about deferred tax assets and liabilities related to top-up income taxes and, therefore, there is no impact on the tax values reported.

## 29. Commitments and contingencies

| | **2025 $m** | 2024 $m |
|---|---|---|
| **Capital commitments** | | |
| Capital commitments incurred jointly with other venturers (Group's share) | **308.9** | 399.6 |

The Group's capital expenditure is driven largely by full-phase expenditure on existing producing fields, new development projects and appraisal and development activities. As of 31 December 2025, the Group had commitments for future capital expenditure amounting to $309 million (2024: $400 million). The key component of this relates to the Rosebank development at both dates. There are also commitments in relation to AFEs (authorisations for expenditure) signed for activities on Captain enhanced oil extraction at both dates and commitments for Cygnus drilling activities at 31 December 2025.

### Contingencies

The Group enters into letters of credit and surety bonds to provide security for the Group's obligations under certain field and bi-lateral decommissioning security agreements, or equivalent, Sullom Voe Terminal Tariff Agreements and deferred payment obligations. The instruments are either held by the Law Debenture Trust Corporation P.L.C. under a trust deed or EnQuest Heather Limited, as SVT Terminal Operator. At 31 December 2025, the Group had $963 million (31 December 2024: $822 million) in letters of credit and surety bonds outstanding relating to security obligations under certain decommissioning and security agreements.

## 30. Financial instruments

To estimate the fair value of financial instruments, the Group uses quoted market prices when available, or industry accepted third-party models and valuation methodologies that utilise observable market data. In addition to market information, the Group incorporates transaction specific details that market participants would utilise in a fair value measurement, including the impact of non-performance risk. The Group characterises inputs used in determining fair value using a hierarchy that prioritises inputs depending on the degree to which they are observable. However, these fair value estimates may not necessarily be indicative of the amounts that could be realised or settled in a current market transaction. The three levels of the fair value hierarchy are as follows:

- Level 1 – inputs represent quoted prices in active markets for identical assets or liabilities (for example, exchange-traded commodity derivatives). Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – inputs other than quoted prices included within Level 1 that are observable, either directly or indirectly, as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, market interest rates and volatility factors, which can be observed or corroborated in the marketplace. The Group obtains information from sources such as the New York Mercantile Exchange and independent price publications.
- Level 3 – inputs that are less observable, unavailable or where the observable data does not support the majority of the instrument's fair value.

In forming estimates, the Group utilises the most observable inputs available for valuation purposes. If a fair value measurement reflects inputs of different levels within the hierarchy, the measurement is categorised based upon the lowest level of input that is significant to the fair value measurement. The valuation of over-the-counter financial swaps and collars is based on similar transactions observable in active markets or industry standard models that primarily rely on market observable inputs. Substantially all of the assumptions for industry standard models are observable in active markets throughout the full term of the instrument. These are categorised as Level 2.

Gains or losses on financial instruments, that are not hedge accounted for, are recorded through the 'other gains' line in the consolidated statement of profit or loss. Credit valuation adjustments (CVA) and debit valuation adjustments (DVA) are calculated for each trade using two key inputs, being future exposures and credit spreads (incorporating both probability of default and loss given default). Future exposures have been estimated using an expected exposure-based approach over the lifetime of the trades. For the risk associated with counterparties, the credit spread is calculated using market observable credit default spreads. For the own credit risk, the credit spread is calculated using reference to a senior unsecured quoted publicly traded bond of the Group using appropriate tenor adjustments, except for out-of-the-money derivatives with counterparties which are in the Group's RBL. These derivatives rank higher than those with other counterparties as they are fully secured as part of the RBL agreement. Therefore, for the own risk credit risk adjustment (DVA) it has been estimated that the loss given default is zero and hence there is no DVA recognised for those derivatives which are with counterparties of the RBL.

All of the Group's assets are pledged as security against borrowings.

## 30. Financial instruments continued

The accounting classification of each category of financial instruments and their carrying amounts as at 31 December 2025 are set out below:

| | Measured at amortised cost $m | Mandatorily measured at fair value through profit or loss $m | Derivatives designated in hedge relationships $m | Measured at fair value through other comprehensive income $m | Total carrying amount $m |
|---|---|---|---|---|---|
| **Financial assets** | | | | | |
| Cash and cash equivalents | **170.1** | – | – | – | **170.1** |
| Other financial assets | **11.3** | – | – | – | **11.3** |
| Trade and other receivables[1] | **355.6** | – | – | – | **355.6** |
| Investments | – | – | – | **49.0** | **49.0** |
| Derivative financial instruments | – | **8.4** | **352.9** | – | **361.3** |
| **Financial liabilities** | | | | | |
| Borrowings | **(1,421.7)** | – | – | – | **(1,421.7)** |
| Trade and other payables[2] | **(503.8)** | – | – | – | **(503.8)** |
| Lease liabilities | **(112.2)** | – | – | – | **(112.2)** |
| Contingent and deferred consideration | **(58.7)** | **(252.3)** | – | – | **(311.0)** |
| Derivative financial instruments | – | – | **(9.9)** | – | **(9.9)** |
| | | | | | **(1,411.3)** |

1 Excluding VAT receivable.
2 Excluding deferred income, inventory overlift and bonus/holiday pay accruals.

**30. Financial instruments** continued

The accounting classification of each category of financial instruments and their carrying amounts as at 31 December 2024 are set out below:

| | Measured at amortised cost $m | Mandatorily measured at fair value through profit or loss $m | Derivatives designated in hedge relationships $m | Total carrying amount $m |
|---|---|---|---|---|
| **Financial assets** | | | | |
| Cash and cash equivalents | 165.1 | – | – | 165.1 |
| Other financial assets | 11.3 | – | – | 11.3 |
| Trade and other receivables[1] | 411.1 | – | – | 411.1 |
| Derivative financial instruments | – | – | 33.0 | 33.0 |
| **Financial liabilities** | | | | |
| Borrowings | (1,024.9) | – | – | (1,024.9) |
| Trade and other payables[2] | (439.7) | – | – | (439.7) |
| Lease liabilities | (40.2) | – | – | (40.2) |
| Contingent and deferred consideration | (272.7) | (240.5) | – | (513.2) |
| Derivative financial instruments | – | (7.5) | (144.0) | (151.5) |
| | | | | (1,549.0) |

1 Excluding VAT receivable.
2 Excluding deferred income, inventory overlift and bonus/holiday pay accruals.

The following table presents the Group's material financial instruments measured at fair value for each hierarchy level as at 31 December 2025:

| | **Level 1 $m** | **Level 2 $m** | **Level 3 $m** | **Total Fair Value $m** |
|---|---|---|---|---|
| Investments | **49.0** | – | – | **49.0** |
| Contingent consideration (note 26) | – | – | **(252.3)** | **(252.3)** |
| Derivative financial instrument asset | – | **361.3** | – | **361.3** |
| Derivative financial instrument liability | – | **(9.9)** | – | **(9.9)** |

**30. Financial instruments** continued

Movements in level 3 contingent consideration in the 12 months to 31 December 2025 were as follows:

| | **$m** |
|---|---|
| At 1 January 2025 | (239.3) |
| Changes in fair value | **(13.0)** |
| **At 31 December 2025** | **(252.3)** |

Movements in level 1 investments in the 12 months to 31 December 2025 were as follows:

| | **$m** |
|---|---|
| At 1 January 2025 | – |
| Additions | **38.3** |
| Fair value remeasurements | **10.7** |
| **At 31 December 2025** | **49.0** |

The following table presents the Group's material financial instruments measured at fair value for each hierarchy level as at 31 December 2024:

| | Level 1 $m | Level 2 $m | Level 3 $m | Total fair value $m |
|---|---|---|---|---|
| Contingent consideration (note 26) | – | (1.2) | (239.3) | (240.5) |
| Derivative financial instrument asset | – | 33.0 | – | 33.0 |
| Derivative financial instrument liability | – | (151.5) | – | (151.5) |

Movements in level 3 financial instruments in the 12 months to 31 December 2024 were as follows:

| | $m |
|---|---|
| At 1 January 2024 | (272.3) |
| Cash settlements | 15.0 |
| Changes in fair value | 18.0 |
| **At 31 December 2024** | (239.3) |

Level 3 contingent consideration is valued on a discounted cash flow basis with the key inputs being commodity prices, the probability of certain future events occurring ('trigger events') and the discount rate.

The forecast cash flows are discounted at a rate of 6.53% (31 December 2024: 6.33%).

Management has considered alternative scenarios to assess the valuation of the contingent consideration including, but not limited to, the key accounting estimate relating to the oil price. A reduction or increase in the price assumptions of 20% are considered to be reasonably possible changes. A 20% reduction in the oil price would result in a decrease in contingent consideration of $nil (31 December 2024: $nil) as the forecast price is already at a level which is lower than the trigger price. A 20% increase in the oil price would lead to an increase in contingent consideration of $nil (31 December 2024: $21.7 million).

## 30. Financial instruments continued

The following table summarises the sensitivity of the Group's profit before tax due to changes in the carrying value of level 3 financial instruments at the reporting date resulting from a 20% change in the probability of a trigger event occurring, risking of project and conditions being met for payment of contingent consideration, with all other variables held constant. The impact on equity is the same as the impact on profit before tax.

| Change in probability | **2025 $m** | 2024 $m |
|---|---|---|
| 20% decrease in probability | **81.8** | 84.2 |
| 20% increase in probability | **(64.1)** | (77.1) |

The following table summarises the sensitivity of the Group's profit before tax due to changes in the carrying value of level 3 financial instruments at the reporting date resulting from a 1% decrease in discount rate, with all other variables held constant. The impact on equity is the same as the impact on profit before tax.

| Change in discount rate | **2025 $m** | 2024 $m |
|---|---|---|
| 1% decrease in discount rate | **(5.8)** | (5.7) |

A 1% increase in discount rate would have the equal but opposite effect to the amounts shown above, on the basis that all other variables remain constant.

Financial instruments of the Group consist mainly of cash and cash equivalents, receivables, payables, loans and financial derivative contracts, all of which are included in the financial statements. At 31 December 2025 and 31 December 2024, financial instruments and the carrying amounts reported on the balance sheet approximates the fair values with the exception of borrowings. The carrying amount of borrowing is at amortised cost of $1,421.8 million (2024: $1,024.9 million) and the equivalent fair value is $1,438.3 million (2024: $1,025.5 million) that was categorised as level 3 in the fair value hierarchy level. Equivalent fair value was calculated using discounted cash flow method. The unobservable input is adjustment due to credit risk to risk free rates.

The following table presents the gain on financial instruments that has been recognised in the consolidated statement of profit or loss as disclosed in note 8.

## 30. Financial instruments continued

| | **2025 $m** | 2024 $m |
|---|---|---|
| Revaluation of forex forward contracts | **7.5** | (1.3) |
| Revaluation of interest rate swaps | – | (0.6) |
| Revaluation of forex collar contracts | **8.4** | – |
| Revaluation of commodity hedges | – | 2.3 |
| **Total revaluation gain on financial instruments** | **15.9** | 0.4 |
| Realised (losses)/gains on forex forward contracts | **(1.4)** | 5.8 |
| Realised gains on interest rate swaps | – | 0.6 |
| Realised losses on commodity hedges | – | (1.6) |
| **Total gain on financial instruments (note 8)** | **14.5** | 5.2 |

### Cash flow hedge reserve

The table below presents the movement in financial instruments that has been recognised through the statement of comprehensive income relating to the cash flow hedge reserve:

| Cash flow hedge reserve | **2025 $m** | 2024 $m |
|---|---|---|
| At 1 January | **(15.7)** | 39.9 |
| Change in fair value of derivative instruments | **500.1** | (68.5) |
| Amounts recycled to revenue | **(120.0)** | (135.1) |
| Amounts recycled to operating costs | **(10.4)** | (8.7) |
| Amounts recycled to dividends | **(5.1)** | (1.3) |
| Amounts recycled to foreign exchange gains and losses | **1.3** | – |
| Amounts recycled to purchase of subsidiary undertakings | **1.7** | – |
| Amounts recycled to taxation | **(3.7)** | – |
| Amount per consolidated statement of comprehensive income | **363.9** | (213.6) |
| Deferred tax on movement in year | **(283.9)** | 158.0 |
| **Cash flow hedge reserve at 31 December** | **64.3** | (15.7) |

## 30. Financial instruments continued

### Cost of hedging reserve

The table below presents the movement in financial instruments that has been disclosed through the statement of comprehensive income relating to the cost of hedging reserve:

| Cost of hedging reserve | 2025 $m | 2024 $m |
|---|---|---|
| At 1 January | **(9.1)** | 4.1 |
| Change in time value of derivative instruments | **67.8** | (55.7) |
| Amounts recycled to revenue – premium payments on oil derivative contracts | – | 1.7 |
| Amounts recycled to revenue – premium payments on gas derivative contracts | **0.3** | 3.2 |
| Amount per consolidated statement of comprehensive income | **68.1** | (50.8) |
| Deferred tax on movement in year | **(53.0)** | 37.6 |
| **Cost of hedging reserve at 31 December** | **6.0** | (9.1) |

The Group has identified that it is exposed principally to these areas of market risk.

### i) Commodity risk

Commodity price risk related to crude oil prices is the Group's most significant market risk exposure. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals. The Group is also exposed to natural gas price movements on uncontracted gas sales. Natural gas prices, in addition to the worldwide factors noted above, can also be influenced by local market conditions. The Group's expenditures are subject to the effects of inflation and prices received for the product sold are not readily adjustable to cover any increase in expenses from inflation. The Group may periodically use different types of derivative instruments to manage its exposure to price volatility, thus mitigating fluctuations in commodity-related cash flows.

In all periods presented, the Group has designated certain commodity options as a cash flow hedge of highly probable sales. Because the critical terms (i.e. the quantity, maturity and underlying price) of the commodity option and their corresponding hedged items are the same, the Group performs a qualitative assessment of effectiveness and it is expected that the intrinsic value of the commodity option and the value of the corresponding hedged items will systematically change in opposite direction in response to movements in the price of underlying commodity if the price of the commodity increases above the strike price of the derivative. The main source of hedge ineffectiveness in these hedge relationships is the effect of the counterparty and the Group's own credit risk on the fair value of the option contracts, which is not reflected in the fair value of the hedged item and if the forecast transaction will happen earlier or later than originally expected. There was no hedge ineffectiveness in the current or prior year.

The Group's target is to hedge oil and gas prices up to a maximum of 75% of the next 12 months' production on a rolling annual basis, up to 50% in the following 12-month period and 25% in the subsequent 12-month period. On a rolling basis, the Group has minimum and maximum hedging requirements under the RBL. The minimum requirements depend on levels of utilisation with reference to the latest borrowing base amount, as follows:

- If drawn amounts under the loan tranche of the RBL are below 10%, no hedging is required;

## 30. Financial instruments continued

- If drawn amounts are above 10% but below 50%, the Group is required to hedge no less than 35% for the first 12 months and no less than 20% for the following 12 month period; and
- If drawn amounts are equal to or greater than 50%, the Group is required to hedge no less than 50% for the first 12 months and no less than 30% for the following 12 month period.

Maximum hedging volumes are set, on a rolling basis, at 85% for year one, 65% for year two, 50% for year three, 30% for year four and 0% thereafter.

The table below represents total commodity hedges in place at the 2025 year-end:

| Derivative | Term | Volume | | Average price |
|---|---|---|---|---|
| Oil swaps | **Jan 26 – Dec 27** | **10,029,000** | **bbls** | **$67/bbl** |
| Oil collars | **Jan 26 – Dec 27** | **9,735,000** | **bbls** | **$60/bbl floor – $69/bbl ceiling** |
| Gas swaps | **Jan 26 – Mar 27** | **219,020,000** | **therms** | **97p/therm** |
| Gas collars | **Jan 26 – Mar 27** | **530,190,000** | **therms** | **81p/therm floor – 112p/therm ceiling** |

The table below represents total commodity hedges in place at the 2024 year-end:

| Derivative | Term | Volume | | Average price |
|---|---|---|---|---|
| Oil swaps | Jan 25 – Dec 25 | 3,505,500 | bbls | $78/bbl |
| Oil collars | Jan 25 – Dec 25 | 1,969,500 | bbls | $74/bbl floor – $85/bbl ceiling |
| Gas swaps | Jan 25 – Dec 26 | 296,750,000 | therms | 98p/therm |
| Gas puts | Jan 25 – Dec 26 | 217,725,000 | therms | 81p/therm |
| Gas collars | Jan 25 – Dec 26 | 348,555,000 | therms | 83p/therm floor – 102p/therm ceiling |

The following table summarises the sensitivity of a 20% decrease in realised commodity prices, with all other variables held constant, of the Group's profit before tax due to changes in the realised price of reported revenues in the year. The impact on equity is the same as the impact on profit before tax.

| Change in realised commodity price | 2025 $m | 2024 $m |
|---|---|---|
| 20% decrease in realised oil price | **(306.7)** | (235.7) |
| 20% decrease in realised gas price | **(223.4)** | (119.8) |

A 20% increase in realised commodity prices would have the equal but opposite effect to the amounts shown above, on the basis that all other variables remain constant.

## 30. Financial instruments continued

### ii) Interest risk

The calculation of interest payments for the RBL facility and the optional project capital expenditure facility incorporate SOFR. The Group is, therefore, exposed to interest rate risk to the extent that SOFR may fluctuate. The Group mitigates the risk of SOFR fluctuations by entering into interest rate swaps on floating rates.

There were no interest rate financial instruments in place at either 31 December 2025 or 31 December 2024.

The following table summarises the sensitivity of an increase of 250 basis points in SOFR, with all other variables held constant, of the Group's profit before tax due to changes in the carrying value of monetary liabilities at the reporting date.

| Change in interest rate | **2025 $m** | 2024 $m |
|---|---|---|
| Increase of 250 basis points | **(8.4)** | (8.4) |

A decrease in 250 basis points in interest rates would have the equal but opposite effect to the amounts shown above, on the basis that all other variables remain constant.

### iii) Foreign exchange rate risk

The Group is exposed to foreign exchange risks to the extent it transacts in various currencies, while measuring and reporting its results in US Dollars. Since time passes between the recording of a receivable or payable transaction and its collection or payment, the Group is exposed to gains or losses on non-US Dollar amounts and on balance sheet translation of monetary accounts denominated in non-US Dollar amounts due to spot rate fluctuations from year-to-year.

As at 31 December 2025, the Group had an average of £25.0 million per quarter hedged at an average forward rate of $1.238:£1 for the period January to December 2026. As at 31 December 2025, the Group had an average of £70.1 million per quarter hedged at an average collar floor of $1.221:£1 and average collar ceiling of $1.267:£1 for the period January 2026 to December 2027.

As at 31 December 2024, the Group had an average of £21.3 million per quarter hedged at an average forward rate of $1.273:£1 for the period January to December 2025. As at 31 December 2024, the Group had an average of £49.5 million per quarter hedged at an average collar floor of $1.268:£1 and average collar ceiling of $1.298:£1 for the period January to December 2025.

The following table summarises the sensitivity to a reasonably possible change in the US Dollar to Pound Sterling foreign exchange rate, with all other variables held constant, of the Group's profit before tax due to changes in the carrying value of monetary assets and liabilities at the reporting date. The impact on equity is the same as the impact on profit before tax. The Group's exposure to foreign currency changes for all other currencies is less significant.

| Change in Pounds Sterling foreign exchange rate | **2025 $m** | 2024 $m |
|---|---|---|
| 10% weakening of Pounds Sterling against the US Dollar | **(14.1)** | (6.9) |

## 30. Financial instruments continued

A 10% strengthening of Pounds Sterling against the US Dollar would have had the equal but opposite effect to the amounts shown above, on the basis that all other variables remain constant.

The Group's Pound-Sterling denominated monetary net liabilitiess at 31 December 2025 were £107 million (2024: £55 million).

### iv) Credit risk

The majority of the Group's trade and other receivables are with customers in the oil and gas industry and are subject to normal industry credit risks and are unsecured. Customers of the Group are mainly oil and gas majors with good credit ratings and low credit risk, including bp, Eni and Shell.

The Group assesses partners' creditworthiness before entering into farm-in or joint venture agreements. In the past, the Group has not experienced credit loss in the collection of accounts receivable. As the Group's exploration, drilling and development activities expand with existing and new joint venture partners, the Group will assess and continuously update its management of associated credit risk and related procedures.

The Group regularly monitors all customer receivable balances outstanding in excess of 90 days for ECLs. As at 31 December 2025, substantially all accounts receivables are current, being defined as less than 90 days. The Group has no allowance for doubtful accounts as at 31 December 2025 (31 December 2024: $nil).

The Group may be exposed to certain losses in the event that counterparties to derivative financial instruments are unable to meet the terms of the contracts. The Group's exposure is limited to those counterparties holding derivative contracts with positive fair values at the reporting date and these counterparties represent a very low risk of default. As at 31 December 2025, the Group's exposure is $nil (31 December 2024: $nil).

Credit valuation adjustments (CVA) and debit valuation adjustments (DVA) are calculated for each trade using two key inputs, being future exposures and credit spreads (incorporating both probability of default and loss-given default).

Future exposures have been estimated using an expected exposure-based approach over the lifetime of the trades. For the risk associated with counterparties, the credit spread is calculated using market observable credit default spreads. For the own credit risk, the credit spread is calculated using reference to a senior unsecured quoted publicly traded bond of the Group using appropriate tenor adjustments, except for out-of-the-money derivatives with counterparties which are in the Group's RBL. These derivatives rank higher than those with other counterparties as they are fully secured as part of the RBL agreement. Therefore for the own risk credit risk adjustment (DVA) it has been estimated that the loss given default is zero and hence there is no DVA recognised for those derivatives which are with counterparties of the RBL. The Group also has credit risk arising from cash and cash equivalents held with banks and financial institutions. The maximum credit exposure associated with financial assets is the carrying values.

## 30. Financial instruments continued

### v) Liquidity risk

Liquidity risk includes the risk that as a result of its operational liquidity requirements, the Group will not have sufficient funds to settle a transaction on the due date. The Group manages liquidity risk by maintaining adequate cash reserves, banking facilities, and by considering medium and future requirements by continuously monitoring forecast and actual cash flows. The Group considers the maturity profiles of its financial assets and liabilities. As at 31 December 2024 and 2025, substantially all accounts payable are current. As borrowings are linked to SOFR, a spot rate at 31 December 2025 was used to calculate future borrowings cash flows.

The following table shows the timing of cash outflows, including future interest, relating to financial liabilities, excluding derivatives, at 31 December 2025:

| | Weighted average effective interest rate | Within 1 year $m | Within 2 to 5 years $m | More than 5 years $m | Total $m | Carrying amount $m |
|---|---|---|---|---|---|---|
| Trade and other payables | – | **(503.8)** | – | – | **(503.8)** | **(503.8)** |
| Contingent and deferred consideration | – | **(112.5)** | **(219.8)** | **(27.0)** | **(359.3)** | **(311.0)** |
| Lease liabilities | **7.86%** | **(65.6)** | **(59.1)** | – | **(124.7)** | **(112.2)** |
| Borrowings | **7.59%** | **(109.8)** | **(1,275.4)** | **(554.9)** | **(1,940.1)** | **(1,421.7)** |
| | | **(791.7)** | **(1,554.3)** | **(581.9)** | **(2,927.9)** | **(2,348.7)** |

The following table shows the timing of cash outflows, including future interest, relating to financial liabilities, excluding derivatives, at 31 December 2024:

| | Weighted average effective interest rate | Within 1 year $m | Within 2 to 5 years $m | More than 5 years $m | Total $m | Carrying amount $m |
|---|---|---|---|---|---|---|
| Trade and other payables | – | (439.7) | – | – | (439.7) | (439.7) |
| Contingent and deferred consideration | – | (310.1) | (212.9) | (44.5) | (567.5) | (513.2) |
| Lease liabilities | 5.69% | (21.0) | (21.9) | – | (42.9) | (40.2) |
| Borrowings | 8.14% | (85.5) | (1,356.9) | – | (1,442.4) | (1,024.9) |
| | | (856.3) | (1,591.7) | (44.5) | (2,492.5) | (2,018.0) |

The following tables set out the details of the Group's liquidity analysis for its derivative financial instruments based on contractual maturities. The tables have been drawn up based on the undiscounted net cash inflows and outflows on derivative instruments that settle on a net basis, and the undiscounted gross inflows and outflows on those derivatives that require gross settlement. When the amount payable or receivable is not fixed, the amount disclosed has been determined by reference to the projected interest rates as illustrated by the yield curves existing at the reporting date.

## 30. Financial instruments continued

| At 31 December 2025 | Within 1 year $m | Within 2 to 5 years $m | Total $m |
|---|---|---|---|
| Net-settled (derivative liabilities): | | | |
| Commodity options | **(0.2)** | **(0.6)** | **(0.8)** |
| Gross-settled: | | | |
| Foreign exchange forwards – gross outflows | **(123.6)** | – | **(123.6)** |
| Foreign exchange collars – gross outflows | **(312.7)** | **(397.3)** | **(710.0)** |
| | **(436.5)** | **(397.9)** | **(834.4)** |

| At 31 December 2024 | Within 1 year $m | Within 2 to 5 years $m | Total $m |
|---|---|---|---|
| Net-settled (derivative liabilities): | | | |
| Commodity options | (74.2) | (10.3) | (84.5) |
| Gross-settled: | | | |
| Foreign exchange forwards – gross outflows | (191.5) | – | (191.5) |
| Foreign exchange collars – gross outflows | (191.1) | – | (191.1) |
| | (456.8) | (10.3) | (467.1) |

### vi) Capital management

The Group's objectives when managing capital are to safeguard the Group's ability to continue as a going concern in order to provide returns to shareholders and benefits for other stakeholders and to maintain an optimal capital structure to reduce the cost of capital. The Group regularly monitors the capital requirements of the business over the short, medium and long term, in order to enable it to foresee when additional capital will be required.

The Group has approval from management to hedge external risks, commodity prices, interest rates and foreign exchange risk. This is designed to reduce the risk of adverse movements in market prices, interest rates and exchange rates eroding the Group's financial results.

## 31. Derivative financial instruments

The net carrying amount of each category of derivative is set out below:

| | 2025 $m | 2024 $m |
|---|---|---|
| Oil swaps – cash flow hedge | **65.3** | 19.9 |
| Oil collars – cash flow hedge | **26.1** | 6.5 |
| Gas swaps – cash flow hedge | **95.2** | (49.5) |
| Gas collars – cash flow hedge | **113.7** | (81.2) |
| FX forwards – cash flow hedge | **10.5** | 0.2 |
| FX forwards – non-cash flow hedge | – | (7.5) |
| FX collars – cash flow hedge | **41.3** | (6.9) |
| FX collars – non-cash flow hedge | **8.4** | – |
| Cross-currency interest rate swaps | **(9.1)** | – |
| | **351.4** | (118.5) |

| Maturity analysis of derivative financial instruments | 2025 $m | 2024 $m |
|---|---|---|
| Non-current assets | **93.5** | – |
| Current assets | **267.8** | 33.0 |
| Non-current liabilities | **(0.6)** | (21.0) |
| Current liabilities | **(9.3)** | (130.5) |
| | **351.4** | (118.5) |

The fair value of commodity derivatives is estimated using a net present value model (commodity swaps) or an appropriate option valuation model (options and collars). These contracts are valued using observable market pricing data including volatilities. A 20% reduction in future commodity prices, with all other assumptions held constant, would result in a decrease in the fair value of derivatives of $353 million (2024: $260 million). A 20% increase in future commodity prices, with all other assumptions held constant, would result in an increase in the intrinsic value of option derivative instruments at 31 December 2025 of $124 million (2024: $113 million).

Derivative financial instruments that are with counterparties included within the RBL are subject to Master Netting Agreements, this includes the majority of the Group's derivative financial instruments as at 31 December 2025 and 2024.

The terms of the Master Netting Arrangements create a legally enforceable right of offset that comes into effect only on the occurrence of a specified event of default or termination event or other events not expected to happen in the normal course of business. Although the Group has the ability to net settle certain transactions with certain counterparties where an election has been made, this is not considered to be significant at either 31 December 2025 or 31 December 2024. Accordingly, the Group has not offset any derivatives balances in the statement of financial position in any of the periods presented.

## 31. Derivative financial statements continued

Financial instruments subject to enforceable master netting agreements and similar agreements at 31 December 2025 are detailed below:

| | Amount recognised in the statement of financial position $m | Related amounts not set off in the statement of financial position $m | Net amount $m |
|---|---|---|---|
| Derivative assets | **361.3** | **(8.4)** | **352.9** |
| Derivative liabilities | **(9.9)** | **8.4** | **(1.5)** |

Financial instruments subject to enforceable master netting agreements and similar agreements at 31 December 2024 are detailed below:

| | Amount recognised in the statement of financial position $m | Related amounts not set off in the statement of financial position $m | Net amount $m |
|---|---|---|---|
| Derivative assets | 33.0 | (23.0) | 10.0 |
| Derivative liabilities | (151.5) | 23.0 | (128.5) |

## 32. Related-party transactions

The immediate Parent undertaking is DKL Energy Limited (incorporated in Jersey) which owns 50.5% (2024: 52.2%) of the issued share capital of Ithaca Energy plc. The registered office address of DKL Energy Limited is 47 Esplanade, St Helier, JE1 0BD, Jersey.

Eni UK Limited, an indirect wholly owned subsidiary of Eni S.p.A., owns 35.9% (2024: 37.2%) of the issued share capital of Ithaca Energy plc.Related-party transactions with Eni S.p.A. group from 3 October 2024 were as follows:

| | Sales to related parties $m | Purchases from related parties $m | Amounts owed by related parties at 31 December $m | Amounts owed to related parties at 31 December[1] $m |
|---|---|---|---|---|
| 2024 | 305.6 | 2.0 | 111.6 | 210.9 |
| 2025 | **1,039.0** | **15.9** | **130.1** | **100.6** |

1 Includes $48.2 million (2024: $204.4 million) of deferred consideration in respect of the Eni UK business combination (see nots 17 and 26).

Amounts owed by and to related parties are unsecured. Amounts owed by related parties comprise principally of hydrocarbon sales and amounts owed to related parties comprise primarily deferred consideration and amounts due under technical service agreements.

The ultimate Parent of the Group is Delek Group Limited (incorporated in Israel), an independent E&P Company listed on the Tel Aviv Stock Exchange. There were no related-party transactions with Delek Group Limited in either the year ended 31 December 2025 or the year ended 31 December 2024.

**32. Related-party transactions** continued

The consolidated financial statements include the financial information of the Group, which comprises the Company and the subsidiaries listed in the following table:

| | Registered office | Registered number | Country of incorporation | % equity interest at 31 December | |
|---|---|---|---|---|---|
| | | | | **2025** | 2024 |
| Ithaca Energy (E&P) Limited | 1 | 126983 | Jersey | **100%** | 100% |
| Ithaca Energy (UK) Limited | 2 | SC272009 | Scotland | **100%** | 100% |
| Ithaca Minerals (North Sea) Limited[8] | 2 | SC274666 | Scotland | **100%** | 100% |
| Ithaca Energy (Holdings) Limited | 3 | 46504 | Bermuda | **100%** | 100% |
| Ithaca Energy Holdings (UK) Limited[8] | 2 | SC437615 | Scotland | **100%** | 100% |
| Ithaca Energy (North Sea) PLC | 2 | SC595124 | Scotland | **100%** | 100% |
| Ithaca Oil and Gas Limited | 4 | 01546623 | England and Wales | **100%** | 100% |
| Ithaca Petroleum Limited[8] | 4 | 05223667 | England and Wales | **100%** | 100% |
| Ithaca Causeway Limited | 4 | 06167799 | England and Wales | **100%** | 100% |
| Ithaca Gamma Limited[8] | 4 | 05929104 | England and Wales | **100%** | 100% |
| Ithaca Alpha (NI) Limited[8] | 5 | NI073431 | Northern Ireland | **100%** | 100% |
| Ithaca Epsilon Limited[8] | 4 | 05979869 | England and Wales | **100%** | 100% |
| Ithaca Exploration Limited[8] | 4 | 05914627 | England and Wales | **100%** | 100% |
| Ithaca Dorset Limited | 4 | 01135213 | England and Wales | **100%** | 100% |
| Ithaca SP UK Limited | 4 | 02586927 | England and Wales | **100%** | 100% |
| Ithaca GSA Holdings Limited | 1 | 111751 | Jersey | **100%** | 100% |
| Ithaca GSA Limited | 1 | 109212 | Jersey | **100%** | 100% |
| Ithaca Energy Developments UK Limited[8] | 4 | 07105041 | England and Wales | **100%** | 100% |
| FPF-1 Limited | 6 | 103593 | Jersey | **100%** | 100% |
| Ithaca MA Limited | 4 | 03947050 | England and Wales | **100%** | 100% |
| Ithaca SP Bonds PLC[8] | 4 | 11029537 | England and Wales | **100%** | 100% |
| Ithaca SP Finance Limited | 4 | 09102885 | England and Wales | **100%** | 100% |
| Ithaca SP (Holdings) Limited | 4 | 09102478 | England and Wales | **100%** | 100% |
| Ithaca SP E&P Limited | 4 | 01504603 | England and Wales | **100%** | 100% |
| Ithaca SP O&G Limited | 4 | 09858988 | England and Wales | **100%** | 100% |
| Ithaca SPE Limited | 4 | 09103084 | England and Wales | **100%** | 100% |
| Ithaca Zeta Limited | 4 | 08860426 | England and Wales | **100%** | 100% |
| Ithaca EF Limited | 4 | 03772746 | England and Wales | **100%** | 100% |
| Ithaca UKCS Limited | 4 | 01019748 | England and Wales | **100%** | 100% |
| Ithaca (NE) E&P Limited | 4 | 01483021 | England and Wales | **100%** | 100% |
| Ithaca (NE) UKCS Limited | 4 | 03386464 | England and Wales | **100%** | 100% |
| Ithaca J E&P Limited (formerly JAPEX UK E&P LIMITED) | 4 | 08946587 | England and Wales | **100%** | – |

## 32. Related party transactions continued

Transactions between subsidiaries are eliminated on consolidation.

Foot notes relating to table on preceding page:

1 47 Esplanade, St Helier, Jersey, JE1 0BD
2 13 Queen's Road, Aberdeen, Scotland AB15 4YL
3 Canon's Court, 22 Victoria Street, Hamilton HM 12, Bermuda
4 Pinsent Masons LLP, 1 Park Row, Leeds, England, LS1 5AB
5 Pinsent Masons LLP, The Soloist, 1 Lanyon Place, Belfast, BT1 3LP
6 26 New Street, St Helier, Jersey, JE2 3RA
7 All of the above shares represent an ordinary class of shares.
8 Under section 479A of the Companies Act 2006, this 100% owned subsidiary will take advantage of the audit exemption for the year ended 31 December 2025. In accordance with section 479C of the Companies Act 2006, Ithaca Energy plc will guarantee the debts and liabilities of this UK subsidiary undertaking.

### Key management personnel

The following table provides remuneration to key management personnel, being the Executive Directors and members of the Executive Leadership Team, for the years ended 31 December 2025 and 2024:

| Key management personnel | **2025 $m** | 2024 $m |
|---|---|---|
| Salaries and short-term employee benefits | **6.3** | 5.9 |
| Payments made in lieu of pension contributions | **0.3** | 0.3 |
| Company pension contributions | **0.2** | 0.1 |
| Compensation for loss of office | – | 0.2 |
| Share-based payment | **2.3** | 1.6 |
| | **9.1** | 8.1 |

Further details regarding share-based payments received by key management personnel are set out below.

## 33. Share-based payments

The charge for share-based payment transactions in the year to 31 December 2025 was $7.4 million (2024: $6.1 million). Like other elements of compensation, this charge is processed through the time-writing system which allocates costs, based on time spent by individuals, to various activities within the Ithaca Energy plc Group. Part of this cost is, therefore, capitalised as directly attributable to capital projects and part is charged to the statement of profit or loss as operating costs of hydrocarbon activities, pre-licence exploration costs or administrative expenses.

## 33. Share-based payments continued

### Long-Term Incentive Plans (LTIPs), Restricted Stock Units (RSUs) and Deferred Bonus Shares (DBSs)

Outstanding share options under LTIPs, RSUs and DBSs were as follows:

| | Heritage awards | At-IPO awards | 2022 LTIP awards | 2024 LTIP awards | RSU and DBS awards | 2025 LTIP awards | Total |
|---|---|---|---|---|---|---|---|
| Balance at 1 January 2024 | 828,935 | 4,280,684 | 2,560,537 | – | – | – | 7,670,156 |
| Granted during the year | – | – | – | 3,589,590 | 542,394 | – | 4,131,984 |
| Awarded during the year in lieu of dividend payments | 76,000 | 1,454,497 | – | 532,474 | 91,641 | – | 2,154,612 |
| Forfeited during the year | – | (293,867) | (249,919) | – | – | – | (543,786) |
| Exercised during the year | (885,959) | (974,153) | – | – | – | – | (1,860,112) |
| Balance at 31 December 2024 and I January 2025 | 18,976 | 4,467,161 | 2,310,618 | 4,122,064 | 634,035 | – | 11,552,854 |
| Granted during the year | – | – | – | – | **391,963** | **2,276,380** | **2,668,343** |
| Awarded during the year in lieu of dividend payments | – | **318,694** | – | **(532,474)** | **79,398** | – | **(134,382)** |
| Forfeited during the year | – | **(106,279)** | **(368,941)** | **(149,531)** | – | – | **(624,751)** |
| Exercised during the year | **(18,976)** | **(3,048,094)** | – | – | **(126,336)** | – | **(3,193,406)** |
| Balance at 31 December 2025 | – | **1,631,482** | **1,941,677** | **3,440,059** | **979,060** | **2,276,380** | **10,268,658** |
| Exercisable at 31 December 2025 | – | **1,631,482** | – | – | – | – | **1,631,482** |
| Share option exercise price | **£nil** | **£nil** | **£nil** | **£nil** | **£nil** | **£nil** | **N/A** |
| Weighted average share price on date of exercise | **£1.23** | **£1.87** | **N/A** | **N/A** | **£2.28** | **N/A** | **N/A** |
| Weighted average remaining life | **N/A** | **N/A** | **0.3 years** | **1.6 years** | **1.8 years** | **2.3 years** | **N/A** |

**33. Share-based payments** continued

All LTIP, DBS and RSU awards are nil-cost options. There are no performance conditions attaching to the Heritage, At-IPO, DBS or RSU awards. Details of the performance conditions of the 2022 LTIP, the 2024 LTIP and the 2025 LTIP are set out in the Remuneration Committee report. The fair values of all awards were determined based on the share price on date of award. The Heritage awards vested over the period to 14 November 2023, the At-IPO awards vested in three equal tranches over the period to 14 November 2025, the 2022 LTIP awards vest over the period to 1 April 2026, the 2024 LTIP awards vest over the periods to 4 July 2027 and 11 October 2027, the 2024 DBS awards vest over the period to 5 July 2027, the 2024 RSU awards vest in three equal tranches over the period to 4 July 2027, the 2025 DBS awards vest over the period to 16 April 2028 and the 2025 LTIP awards vest over the period to 31 March 2028. It is anticipated that future exercises of LTIP, DBS and RSU awards will be settled by equity.

The total charge for LTIP share options, DBS awards and RSU awards in the year to 31 December 2025 was $7.4 million (2024: $6.1 million).

The share-based payment reserve of $21.3 million (2024: $18.8 million) reflects the opening balance of $18.8 million (2024: $15.5 million) plus the charge of $7.4 million (2024: $6.1 million) for LTIPs, DBSs and RSUs less the cost of satisfying exercises during the year of $4.9 million (2024: $2.8 million).

**34. Dividends**

| | **2025 $m** | 2024 $m |
|---|---|---|
| First 2025 interim dividend of $0.1010 (2024: $0.0986) per ordinary share announced 20 August 2025 and paid 11 September 2025 | **166.4** | 99.4 |
| Second 2025 dividend of $0.0804 (2024: $0.1209) per ordinary share announced 19 November 2025 and paid 18 December 2025 | **132.0** | 199.7 |
| **Total dividends paid relating to the year ended 31 December[1]** | **298.4** | 299.1 |
| Third 2025 interim dividend of $0.1209 (2024: $0.1209) per ordinary share announced 18 March 2026 and payable on 16 April 2026 (not accrued in the 2025 results)[1] | **200.0** | 199.3 |
| **Total dividends paid or payable relating to year ended 31 December** | **498.4** | 498.4 |

1 The third 2024 interim dividend of $199.3 million was paid on 25 April 2025. Total cash payments in the year to 31 December 2025 were $497.7 million (2024: $432.7 million).

## Non-GAAP measures

The Group uses certain performance metrics that are not specifically defined under United Kingdom adopted International Financial Reporting Standards or other generally accepted accounting principles. These measures are considered to be important as they track both operational and financial performance and are used to manage the business and to provide an objective comparison to Ithaca Energy's peer group. These non-GAAP measures which are presented in the Annual Report and Accounts are defined below.

**Adjusted EBITDAX:** earnings before finance income, finance costs, taxation charges, premium payments on oil and gas derivative contracts, revaluation gains or losses on financial instruments, depletion depreciation and amortisation, impairment charges on oil and gas assets, exploration and evaluation expenditure, fair value remeasurements of contingent consideration, restructuring costs and business combination costs. The Group believes that adjusted EBITDAX is a useful measure for stakeholders because it is a measure closely tracked by management to evaluate the Group's operating performance and to make financial, strategic and operating decisions and because it may help stakeholders to better understand and evaluate, in the same manner as management, the underlying trends in the Group's operational performance on a comparable basis, period-on-period. Adjusted EBITDAX is reconciled to (loss)/profit after tax as follows:

| | 2025 $m | 2024 $m |
|---|---|---|
| **(Loss)/profit after tax** | **(84.1)** | 153.1 |
| Taxation charge (note 28) | **924.4** | 181.2 |
| Depletion, depreciation and amortisation (note 15) | **840.6** | 600.2 |
| Impairment charges on oil and gas assets (note 19) | **77.5** | 263.0 |
| Finance income (note 9) | **(9.8)** | (11.2) |
| Finance costs (note 9) | **264.6** | 200.6 |
| Premium payments on oil and gas derivative contracts (note 5) | **0.3** | 4.9 |
| Revaluation gains on financial instruments (note 30) | **(15.9)** | (0.4) |
| Restructuring costs | **8.0** | – |
| Business combination costs (note 7) | **0.3** | 16.3 |
| Exploration and evaluation expenses (note 14) | **2.1** | 24.6 |
| Fair value remeasurements of contingent consideration (note 8) | **22.8** | (27.3) |
| **Adjusted EBITDAX** | **2,030.8** | 1,405.0 |

**Adjusted net income:** (loss)/profit after tax excluding impairment charges on oil and gas assets, restructuring costs, business combination costs, one-off finance charges related to refinancing and the tax effects of these items where applicable and non-cash deferred tax charges on changes in EPL. Adjusted net income, which is presented as it eliminates items which distort year-on-year comparisons, is reconciled to (loss)/profit after tax as follows:

| | 2025 $m | 2024 $m |
|---|---|---|
| **(Loss)/profit after tax** | **(84.1)** | 153.1 |
| Impairment charges on oil and gas assets[1] | **77.5** | 263.0 |
| Tax credit on impairment charges on oil and gas assets[1] | **(33.6)** | (160.3) |
| Restructuring costs | **8.0** | – |
| Business combination costs | **0.3** | 16.3 |
| One-off finance charges related to refinancing | – | 22.0 |
| Tax credit on restructuring costs, business combination costs and one-off finance charges | **(6.5)** | (28.6) |
| Deferred tax impact of EPL changes substantively enacted during the year | **327.6** | 58.1 |
| **Adjusted net income** | **289.2** | 323.6 |

1. Post-tax impairment charges of $43.9 million (2024: $102.7 million) comprising $1.8 million related to Alder (2024: $38.5 million in relation to the Greater Stella Area and Pierce) and $42.1 million (2024: $64.2 million) principally in relation to decommissioning cost estimate changes on fields that have either been fully written off or have ceased production.

**Adjusted earnings per share (EPS):** Adjusted net income divided by average shares for the year of 1,648.8 million (2024: 1,164.3 million):

| | 2025 | 2024 |
|---|---|---|
| **Adjusted EPS (cents)** | **17.5** | 27.8 |

**Adjusted net debt:** consists of amounts outstanding under RBL facility, senior unsecured loan notes and project capital expenditure facility less cash and cash equivalents and excludes intragroup debt arrangements or liabilities represented by letters of credit and surety bonds. Adjusted net debt, which excludes accrued interest on borrowings, lease liabilities and unamortised fees, comprises:

| | 2025 $m | 2024 $m |
|---|---|---|
| RBL drawn facility | – | (150.0) |
| Senior unsecured notes 2029 | **(750.0)** | (750.0) |
| Senior unsecured notes 2031 | **(528.3)** | – |
| Project capital expenditure facility | **(150.0)** | (150.0) |
| Cash and cash equivalents | **170.1** | 165.1 |
| **Adjusted net debt** | **(1,258.2)** | (884.9) |

**Pro forma leverage ratio:** adjusted net debt at the end of the year divided by adjusted EBITDAX for the year then ended, including $34.7 million and $185.7 million of pre-acquisition adjusted EBITDAX from JAPEX UK and Cygnus, respectively (2024: $580.3 million of adjusted EBITDAX generated by the Eni UK businesses from 1 January 2024 to 2 October 2024). The pro forma leverage ratio is considered to be an important measure as it is indicative of the borrowing potential of the Group. The calculations are as follows:

| | 2025 | 2024 |
|---|---|---|
| Adjusted net debt ($m) | 1,258.2 | 884.9 |
| Pro forma adjusted EBITDAX ($m) | 2,251.2 | 1,985.3 |
| **Pro forma leverage ratio** | **0.56x** | 0.45x |

**Available liquidity:** the sum of cash and cash equivalents on the balance sheet and the undrawn amounts available to the Group using existing approved third-party facilities, excluding letters of credit. Available liquidity is regarded as a key measure as it is indicative of the financial capacity of the Group. Available liquidity comprises:

| | 2025 $m | 2024 $m |
|---|---|---|
| Cash and cash equivalents | 170.1 | 165.1 |
| Undrawn borrowing facilities | 1,300.0 | 850.0 |
| **Available liquidity** | **1,470.1** | 1,015.1 |

**Group free cash flow:** net cash flow from operating activities less cash used in investing activities, adjusting for acquisition payments, deferred consideration payments and cash acquired through business combinations, less bank interest and charges and interest rate swaps. This measure is considered a useful indicator of the Group's ability to make strategic investments, repay the Group's debt and meet other payment obligations. Group free cash flow reconciles to net cash flow from operating activities as follows:

| | 2025 $m | 2024 $m |
|---|---|---|
| **Net cash flow from operating activities** | 1,745.3 | 853.3 |
| Net cash used in investing activities, excluding the cost of acquisitions, deferred consideration payments and cash acquired through business combinations | (924.2) | (390.9) |
| Cash acquired through business combinations | (16.1) | (107.5) |
| Bank interest and charges | (121.7) | (94.7) |
| Interest rate swaps | – | 0.6 |
| **Group free cash flow** | **683.3** | 260.8 |

**Unit operating expenditure:** operating costs (excluding over/underlift) including tariff expense but excluding restructuring costs, tanker costs and net of tariff income, divided by net production for the year. This measure is considered a useful indicator of ongoing operating costs and is also used to compare performance between assets. Operating costs for this calculation reconcile to note 6 as follows:

| | 2025 | 2024 |
|---|---|---|
| Operating costs of hydrocarbon activities per note 6 ($m) | 871.6 | 617.9 |
| Less restructuring costs ($m) | (4.5) | – |
| Less tanker costs included within operating costs of hydrocarbon activities in note 6 ($m) | (19.6) | (18.3) |
| Less tariff income per note 5 ($m) | (30.2) | (30.0) |
| **Operating costs used to calculate unit operating expenditure ($m)** | **817.3** | 569.6 |
| Production (mmboe) | 43.26 | 25.42 |
| **Unit operating expenditure ($/boe)** | **18.9** | 22.4 |

## Other key performance indicators

**DDA rate per barrel:** depletion, depreciation and amortisation charge for the year divided by net production for the year. DDA per barrel was:

| | 2025 | 2024 |
|---|---|---|
| Depletion, depreciation and amortisation per note 15 ($m) | 840.6 | 600.2 |
| Production (mmboe) | 43.26 | 25.42 |
| **DDA ($/boe)** | **19.4** | 23.6 |

**Production:** total hydrocarbons produced related to Ithaca Energy's equity in operated and non-operated fields divided by the number of days in the year. Production in 2025 was 119 kboe/d (2024: 80 kboe/d). In 2024, this included the volumes from the Eni UK businesses from the effective economic date of 1 July 2024. It should be noted that the volumes used in the per barrel calculations for 2024 above include volumes from the Eni UK businesses from the date of completion of 3 October 2024 as the associated costs were recorded from that date.

Pro forma production for 2025 of 131 kboe/d is based on total production of 47.68 mmboe including pre-acquisition volumes of 0.86 mmboe and 3.56 mmboe for Seagull and Cygnus respectively. Pro forma volumes for 2025, being our incremental working interests for the whole year, for Seagull and Cygnus were 1.55 mmboe and 4.76 mmboe respectively, equating to 17 kboe/d.

**Tier 1 and 2 process safety events:** process safety incidents as defined by API 465 Process Safety-Recommended Practice On Key Performance Indicators. There were no Tier 1 or 2 process safety events recorded in 2025 (2024: 0).

**Serious injury and fatality frequency:** the number of serious injuries resulting in permanent impairment, as defined by IOGP, per million hours worked. There were no such incidents in 2025 (2024: 0).

## Five years at a glance

| Statement of profit or loss | **2025** | 2024 | 2023 | 2022 | 2021 |
|---|---|---|---|---|---|
| Revenue ($m) | **2,946.5** | 1,981.8 | 2,319.8 | 2,598.5 | 1,428.2 |
| Adjusted EBITDAX ($m) | **2,030.8** | 1,405.0 | 1,722.7 | 1,916.2 | 1,035.4 |
| Adjusted earnings ($m) | **289.2** | 323.6 | 446.5 | 462.8 | 415.5 |
| Unit operating expenditure ($/boe) | **18.9** | 22.4 | 20.5 | 19.0 | 18.0 |
| Basic EPS (Cents) | **(5.1)** | 13.2 | 29.1 | 102.6 | 42.4 |
| Adjusted EPS (Cents) | **17.5** | 27.8 | 44.4 | 46.0 | 41.3 |

| Statement of financial position | | | | | |
|---|---|---|---|---|---|
| Total assets ($m) | **8,447.0** | 8,275.0 | 6,323.5 | 6,759.6 | 4,731.8 |
| Total liabilities ($m) | **(5,875.2)** | (5,234.6) | (3,802.2) | (4,302.1) | (4,055.3) |
| Shareholders' equity ($m) | **2,571.8** | 3,040.4 | 2,521.3 | 2,457.5 | 676.5 |
| Shares in issue at year end (m) | **1,653.7** | 1,653.7 | 1,014.4 | 1,006.6 | N/A |
| Market capitalisation at year end ($m) | **3,689.5** | 2,294.2 | 1,714.6 | 2,050.7 | N/A |

| Cash flow | | | | | |
|---|---|---|---|---|---|
| Net cash flow from operating activities ($m) | **1,745.3** | 853.3 | 1,290.8 | 1,723.3 | 912.7 |
| Investing activities ($m) | **(1,451.6)** | (390.9) | (492.4) | (1,404.2) | (220.2) |
| Financing activities ($m) | **(292.2)** | (449.5) | (900.7) | (107.4) | (650.7) |
| Foreign exchange ($m) | **3.5** | (1.0) | 1.7 | (2.7) | 1.8 |
| Increase/(decrease) in cash ($m) | **5.0** | 11.9 | (100.6) | 209.0 | 43.6 |

| Other financial measures | | | | | |
|---|---|---|---|---|---|
| Adjusted net debt ($m) | **(1,258.2)** | (884.9) | (571.8) | (971.2) | (930.2) |
| Available liquidity ($m) | **1,470.1** | 1,015.1 | 1,028.2 | 578.8 | 619.8 |
| Pro forma leverage ratio | **0.56x** | 0.45x | 0.33x | 0.51x | 0.90x |

| Operational/strategic measures | | | | | |
|---|---|---|---|---|---|
| Average daily production (kboe/d) | **119** | 80 | 70 | 71 | 56 |
| Reserves and resources (mmboe) | **658** | 657 | 544 | 512 | 291 |
| Tier 1 and tier 2 process safety events | **0** | 0 | 1 | 2 | 2 |
| Serious injury and fatality frequency | **0** | 0 | 0 | 0 | 0 |
| Scope 1 and Scope 2 emissions (kt$CO_2$e) | **437.5** | 448.2 | 435.8 | 483.3 | 497.9 |
| GHG intensity (kg$CO_2$e/boe) | **17.2** | 23.9 | 25.0 | 23.8 | 24.6 |