26 March 2025

ITHACA ENERGY PLC

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

Full Year 2024 Results
Transformational year with continued strategic delivery
Robust 2024 operational and financial performance at the top end of management guidance
Strong Q4 production and EBITDAX, supporting delivery of total 2024 dividend of $500m

Ithaca Energy, a leading UK independent production and growth company, today announces its audited full year results for the year ended 31 December 2024. Actuals to 31 December 2024 reflect the completion of the Group's business combination with substantially all of Eni S.p.A's ("Eni") UK upstream oil and gas assets ("Business Combination") on 3 October 2024 and include approximately three months contribution from Eni UK's assets. Pro forma 2024 reflects a full year of operations for the enlarged Group.

2024 Highlights:

- Material dividend distributions to shareholders with third interim 2024 dividend of $200 million declared today delivering total 2024 dividends declared of $500 million, in line with our 2024 target
- Reaffirming dividend policy for 2025 targeting dividend of 30% post-tax CFFO, with a dividend target of $500 million for FY 2025
- Completion of transformational Business Combination with Eni UK in October 2024
- Entering 2025 as the largest resource holder in UKCS, with estimated 2P Reserves & 2C Resources of 657 mmboe[1] as at 31 December 2024 (2023: 544 mmboe)
- Second largest independent producer in UKCS with pro forma 2024 production of 105.5kboe/d[1]
- Q4 production of 116.0 kboe/d and opex per boe of $14/boe delivering Q4 Adjusted EBITDAX of $646 million, reflects the transformational nature of the Business Combination
- Continued strong production trend into 2025, with average production from November 2024 to February 2025 of >120 kboe/d
- Improved safety record with zero Tier 1 or 2 incidents in the year
- Rosebank project continues to progress in line with multi-year development timeline, following Judicial Review ruling, towards targeted first production in 2026/27
- Successful $2.25 billion refinancing completed in October 2024, providing material financial firepower with over $1 billion of available liquidity as at December 2024
- Eni UK integration activities well-advanced with main IT systems and office relocations completed in January 2025, and reorganisation and streamlining process to be fully complete by 1 July 2025
- Acquisition of JAPEX UK E&P Limited ('JUK') announced 25 March 2025, increasing the Group's stake in the high-quality Seagull field by 15% to 50%, demonstrates continued execution of Ithaca Energy's consolidation strategy in the UKCS

Yaniv Friedman, Executive Chairman, commented: "2024 was a transformational year for Ithaca Energy, having made material progress across our strategic objectives creating value organically and inorganically. We enter our Next Era of growth, with a proven strategy and a range of strategic options for growth. Yesterday's announcement of our acquisition of JAPEX UK, increasing our stake in the high-quality, long-life Seagull field demonstrates continued execution of our inorganic growth strategy, building further scale in our core UKCS market. Our focus in 2025 will continue to be on high-grading investment across our range of growth opportunities, executing in line with our strategy as a value-led investor, to maximise long-term sustainable shareholder value through growth and distributions."

Summary of key financial metrics

	2024	**2023**
Adjusted EBITDAX[2, 3] ($m)	**1,405.0**	1,722.7
Net cash flow from operating activities[3] ($m)	**853.3**	1,290.8
Available liquidity[2, 3] ($m)	**1,015.1**	1,028.2
Profit after tax[3] ($m)	**153.2**	292.6
Basic EPS[3] (Cents)	**13.2**	29.1
Unit operating expenditure[2, 3] ($/boe)	**22.4**	20.5

Other KPIs

Total production (boe/d)[4]	**80,177**	70,239
Tier 1 and Tier 2 process safety events[3]	-	1
Serious injury and fatality frequency[3]	-	-
Scope 1 and 2 emissions (tCO_2e)[4]	**448,190**	435,792
Greenhouse gas intensity ($kgCO_2e$/boe)[4]	**23.9**	25.0

2024 Corporate Highlights

- Material dividend distributions to shareholders with third interim 2024 dividend of $200 million declared today delivering a total 2024 dividend declared of $500 million, in line with our 2024 target
- Completion of transformational Business Combination of Ithaca Energy and Eni UK, creating a dynamic growth player with the largest resource base in the UKCS with 2P Reserves and 2C Resources of 657 mmboe[1] providing significant growth optionality and strong foundations for organic and inorganic long-term growth while supporting sustainable shareholder returns
- Strategy to pursue consolidation in core UKCS basin, reflected in acquisition of JUK post period-end (announced on 25 March 2025), adding 4-4.5 kboe/d to the Group's production base in a well understood, high-quality, long-life asset and taking the Group's working interest in the Seagull field to 50%. Estimated completion date of 30 June 2025.

2024 Operational Highlights

Strong Q4 production performance, with positive production trend continuing into 2025

- 2024 full year production of 80.2 kboe/d[1,4], delivering production at the upper end of guidance of 76–81 kboe/d for the enlarged group
  - Includes six months production from Eni UK assets from 1 July economic effective date (legal completion on 3rd October 2024)
  - Production split approximately 60% liquids and 40% gas

- Pro-forma 2024 production of 105.5 kboe/d[1] placing Ithaca Energy as the second largest independent operator by production in the UKCS (2023: 70.2 kboe/d)
- Strong operational performance in Q4, achieving average production of 116.0 kboe/d[1], reaching peak production rates of 138 kboe/d[1] in the final quarter with continued strong production trend into 2025, with average production from November to February of >120 kboe/d[1]

Unlocking material organic growth opportunities

- Rosebank project progressing in line with multi-year development timeline with estimated first production in 2026/27, including successful completion of major subsea campaign with the installation of all nine subsea structures ahead of schedule, in parallel with ongoing FPSO vessel modification scopes
- Following the outcome of the Rosebank Judicial Review, the Rosebank JV partnership will prepare and submit the downstream end user combustion emissions ('scope 3') assessment after the release of government guidelines, expected in Spring 2025
- Successfully awarded licence extension from 31 March 2024 to 31 March 2026 for Cambo field in Q1 2024. Request for further 18-month extension submitted to the North Sea Transition Authority reflecting the fiscal and regulatory uncertainty faced by the sector and the impact of the ongoing Environmental Impact Assessment review
- First production from Talbot field in November with field delivering in line with expectations and successful exploration well at Jocelyn South in the J-Area in December, which has been tied back during Q1 2025 and is now on production, just three months following the field discovery
- Fotla development concept completed, supporting a Final Investment Decision in 2025, subject to regulatory environment

Safe and responsible operator

- Positive trend in safety performance in 2024, with zero Tier 1 and Tier 2 process safety events recorded in the year and significant reduction in total recordable incident frequency
- Business Combination emissions improvement with reduction in gross operated CO_2e GHG emissions intensity in 2024 to 23.9 $kgCO_2e$/boe (2023: 25.0 $kgCO_2e$/boe)

Sustaining and optimising production to support medium-term production outlook

- Successfully completed the Captain Enhanced Oil Recovery (EOR) Phase II project, executed on plan and within budget, with first Phase II polymer response outperforming expectations
- Continued high levels of activity at Captain, with commencement of a topside drilling campaign in Q3 with the campaign extending over a two-year duration targeting four new production wells, a pilot well and two well workovers
- Completed W1 well workover at Erskine during July, reinstating the fifth production well at the field
- Infill drilling campaigns progressed at Elgin Franklin, Schiehallion and Captain during the year

2024 Financial Highlights

Strong financial performance against guidance for enlarged group, with materially enhanced Q4 2024 results. Key financial highlights in-line with estimated results provided in FY 2024 Trading Update on 20 February 2025:

- Material dividend distributions to shareholders with the announcement of the Group's third interim 2024 dividend declared today of $200 million payable in April 2025, delivering a total 2024 dividend declared of $500 million, in line with our 2024 target
- Adjusted EBITDAX of $1,405 million (2023: $1,723 million) on revenues of $1,982 million (2023: $2,320 million), representing contributions from Eni UK assets from the completion date of 3 October

onwards. Pro forma 2024 Adjusted EBITDAX of $1,985.3 million reflecting a full year contribution of Eni UK assets
- Q4 EBITDAX performance of $646 million, reflects transformational nature of Business Combination
- Net cash flow from operating activities of $853 million representing contributions from Eni UK assets from the completion date of 3 October onwards (2023: $1,291 million)
- Profit after tax for the year of $153.2 million (2023: $292.6 million), inclusive of a post-tax impairment of $103m (2023: $154m)
- Trading performance benefited from the Group's active hedging policy with $135 million of hedge gains in the year due to realised oil prices of $81/bbl before hedging (2023: $85/bbl) and $82/bbl after hedging (2023: $82/bbl) and gas prices of $64/boe before hedging (2023: $76/boe) and $78/boe after hedging (2023: $111/boe)
- 2024 adjusted net operating costs of $649 million, representing a net unit opex cost of $22/boe, below management guidance of $650 million to $730 million for the enlarged Group
    - Includes six months operating costs from Eni UK assets from 1 July economic effective date
- Q4 cost per barrel of $14.0/boe demonstrating the high netback capability of the post deal portfolio
- 2024 net producing asset capital cost of $448 million, at mid-point of management guidance of $410 - $480 million for the enlarged Group
    - Includes six months capital costs from Eni UK assets from 1 July economic effective date
- 2024 net Rosebank capital spend of $198 million, marginally above management guidance of $170 million to $195 million, reflecting material project activity and progress in 2024 supporting a targeted first oil date of 2026/27
- Tax efficient structure, supplemented by the Business Combination, with a material ring fence corporate tax and supplementary charge tax loss position of $5.4 billion and $4.7 billion respectively at year-end 2024
    - Acquisition of JUK includes material tax losses of approximately US$215 million in both Ring Fence Corporation Tax and Supplementary Charge Tax as well as approximately US$105 million Energy Profit Levy losses as at 1 January 2024, reflecting JUK's material investment in the field
- Successful $2.25 billion refinancing completed in Q4, enhancing balance sheet strength and flexibility with available liquidity of over $1 billion
    - New Senior Notes facility of $750 million with 2029 redemption and coupon of 8.125%, lengthening the maturity period and lowering the cost of capital
- Adjusted net debt of $884.9 million (2023: $571.8 million), representing a Group pro forma leverage position of 0.45x (2023: 0.33x)

Guidance and Outlook

2025

Management guidance is inclusive of the acquisition of JUK (announced 25 March), assuming a completion date of the transaction of 30 June 2025.

- We expect full year 2025 production in range of 105-115 kboe/d[1] reflecting a full year of contributions from the Eni UK assets
- FY 2025 net operating cost guidance range of $770–850 million
- FY 2025 net producing asset capital cost guidance range of $560-620 million (excluding pre-FID projects and Rosebank development)
- FY 2025 net Rosebank project capital cost guidance range of $190-230 million
- FY 2025 cash tax guidance of $235-265 million
- Significant gas hedging activity throughout Q1 securing attractive gas hedge positions during a period of escalating prices. Hedged position at 20 March 2025 of 32.1 mmboe (c.71% gas, c.29% oil) from

2025 into 2027 at an average price floor of $75/bbl, and average collar ceiling of $82/bbl, and average wide cost collar ceiling of $91/bbl for oil, and an average price floor of 90p/therm and average collar ceiling of 104p/therm and average wide cost collar ceiling of 133p/therm for gas

- Reaffirming dividend policy for 2025 targeting dividend of 30% post-tax CFFO, at the top end of our capital allocation policy range of 15 - 30% post-tax CFFO, with a target of $500 million for FY 2025

Medium-Term

- Beyond 2025, the Group expects to sustain production above 100 kboe/d in the medium-term reflecting the full benefit of investment in our Captain EOR Phase II project, first production from the Rosebank development and infill drilling programmes at Cygnus, Elgin Franklin and the J Area with material upside from 2C resources
- Enlarged portfolio supports a reduction in opex per barrel with a medium-term forecast to reset towards $20/boe, reflecting increased production volumes from low opex fields and retirement of mature high-opex assets
- Sustaining capex supports medium-term production outlook with continued focus on high grading organic and inorganic investment optionality across our portfolio while prioritising capital allocation to maximise sustainable shareholder returns
- Strong cash flow generation supports the Group's capital allocation policy with a potential for over $9 billion of total pre-tax cash flow from operations from 2P Reserves over the next five years (2025 to 2029) at $80/bbl and 85p/therm

Analyst and Investor Presentation

In addition to a presentation of its Full Year 2024 results, Ithaca Energy will today provide an investor update outlining its strategy to deliver long-term value creation following the recent Business Combination with Eni UK. The presentation will be hosted in person at 09:00 (GMT) today, 26 March 2025**,** and will be available via a live webcast, accessible via our website: **https://investors.ithacaenergy.com/**

A replay will be available on Ithaca Energy's investor relations website following the event.

Notes

1. Given the increase in gas volumes in Ithaca Energy's portfolio following the Eni UK Business Combination, the gas conversion factor metric to boe for reporting purposes has been recalibrated to more accurately reflect energy equivalence on a combined boe basis using an average calorific value of all gas streams. Fuel gas has been included in production rates in line with the Competent Persons Report produced by NSAI
2. Non-GAAP measure (see pages 84 to 87)
3. Contributions from Eni UK assets from the completion date of 3 October 2024
4. Contributions from Eni UK assets from economic effective date of 1 July 2024

FY 2024 performance in review

2024 - A story of transformational growth

2024 has been a transformational year for the Group, having made material progress across our strategic objectives. The Group's Business Combination with substantially all of the upstream assets of Eni SpA in the UK brings together highly complementary portfolios, offering significant scale, balance and optionality, creating a powerful platform to deliver material cash flow generation, organic and inorganic growth and value creation.

The Combination has established Ithaca Energy as a dynamic growth player with the single largest resource base in the UKCS and the underlying un-risked growth potential to become the largest producer in the basin by 2030. Through our Combination and the Group's ongoing investment in key long-life assets, we have materially grown our 2P Reserves and 2C Resources base to 657 mmboe as at 31 December 2024 (2023: 544 mmboe).

A proven strategy and enhanced platform supports 'Next Era' of growth

As we enter our Next Era of growth, we do so with a proven strategy and an enhanced platform for organic and inorganic value creation, drawing on the agility of an independent, the capabilities of a Major and the support of its committed majority shareholders.

Leveraging our enhanced operational and technical capabilities, we aim to be the highest-performing operator in the basin, focused on sustaining production and optimising performance to support our short to medium-term production outlook and investing in our material organic resource base to generate long-term sustainable growth and value creation.

With a proven track record for value-accretive M&A, the Group is well positioned to play a pivotal role in further North Sea consolidation, taking an agile response to continued market dislocation, while expanding its inorganic growth strategy internationally. We remain confident that material opportunity for consolidation exists in the Group's core UKCS market, with the potential for basin exits and portfolio rationalisation as a result of UK fiscal policy. Capitalising on our agility and operational robustness, we are in an ideal position to extract even further value from these opportunities.

By augmenting our proven track record for M&A with our shareholders' global credentials and relationships, Ithaca Energy now has a credible platform to broaden its M&A strategy internationally, establishing an additional option for value creation. The Group will take a disciplined and targeted approach to its international expansion strategy, focusing on investing in regions that offer the potential for scale, further M&A opportunities, and stable fiscal regimes.

With significant organic and inorganic investment optionality, the Group's focus remains on being a disciplined, value-driven investor, targeting growth opportunities that maximise value creation for our shareholders.

Material delivery across all strategic pillars in 2024

During the year, the Group has continued to prioritise targeted investment in high-quality assets across its diverse UK North Sea portfolio.

The Rosebank project, in its first full year of construction activity, continued to make solid progress against its multi-year development timeline towards first production in 2026/27, delivering against the Group's strategy to invest in long-life, low carbon intensity assets supporting long-term production growth. The development achieved a key milestone in July, completing the first major subsea campaign ahead of schedule with installation of all planned structures on the seabed of the field. The Petrojarl Rosebank FPSO engineering and modification scopes continue to progress and remain critical to delivering on the targeted first production date.

The Rosebank JV partnership welcomed the court ruling in relation to the Rosebank Judicial Review in January 2025. The ruling allows the project to continue in its development phase while the partnership gets ready to apply for and obtain the new consent based on the expected new regulatory guidance. We will continue to support Equinor (Operator) as we work closely with the Regulators and Department for Energy Security and Net Zero (DESNZ) to progress the Rosebank project, including submitting a downstream end user combustion emissions (Scope 3) assessment in full compliance with the Government's new environmental guidance, which is targeted to be published in spring 2025.

The Group is progressing its pre-FID projects including Cambo, Fotla, Tornado and K2 by implementing a fast-track approach in project maturation and delivery. Following the Business Combination and the Autumn review of the UK Government's fiscal strategy, we have revitalised the Cambo project, looking to further enhance the technical and operational features of the project, leveraging the experience of our shareholders. In the second half of the year, the Group completed its development concept selection for Fotla, in support of a FID for the tie-back opportunity.

Farm-down processes remain live for Cambo and Fotla with the processes experiencing a temporary pause as the industry awaited the outcome of the new Labour Government's fiscal and regulatory review. The Group has made representations to the North Sea Transition Authority (NSTA) to remove the licence milestone in relation to achieving a farm-down prior to 31 March 2025, to reflect the Group's enhanced strength following the Business Combination with Eni UK, and to grant an extension of the Cambo licence to 30 September 2027 from 31 March 2026. Engagement with the NSTA in relation to this matter remains ongoing.

The successful completion of the EOR Phase II project, on schedule and within budget, at the Group's flagship Captain field, represented a significant milestone in 2024. The multi-year project builds on the success of the platform-based EOR Phase I project, with an expansion to the subsea area of the field. With first polymer injection in the subsea wells achieved in May 2024, the field is already experiencing its first enhanced oil response, which is exceeding expectations with water cuts reducing by over 10% in four producers and increasing oil production by over 2,500 kboe/d, relative to the business plan. The phased response of EOR patterns through 2025 and 2026, together with the 13th drilling campaign, that extends over a two-year duration and targets four new production wells, a pilot well and the workover of two wells, supports Captain's life extension and a strong medium-term production outlook.

In parallel, the Captain asset is focused on delivering stronger levels of uptime performance with a flotel secured for a six-month period in support of optimisation projects and backlog reduction, with an additional 150 Person on Board (POB) capacity reflecting the scale of ongoing activity at the field.

Across the Group's operated portfolio, a successful well workover reinstated the fifth production well at the Erskine field and following scheduled turnaround activity and remediation of compressor issues at the host Lomond field, the field returned to full production in the second half of the year.

The benefits of our Business Combination became immediately evident as the Group's increased non-operated stakes and asset additions in the J Area unlocked near-term value catalysts. In the final quarter, we commenced first production from the Talbot field, adding high-value barrels to the portfolio. In addition, the partnership enjoyed exploration success at Jocelyn South, offering near-term high-value production potential with the field tied back to existing facilities with first production achieved in March 2025, aligning with our strategy to invest in high-return tie-back opportunities close to existing infrastructure to maximise reserve recovery.

Strong operational delivery against 2024 guidance with improved safety record

The Group is proud to report that it continued to deliver a positive trend in its safety performance in 2024, with zero Tier 1 and Tier 2 process safety events recorded in the year (2023: recorded one Tier 1 event, 2022: recorded two Tier 2 events) and a 30% improvement in our Total Recordable Injury Rate, reducing from 3.31 in 2023 to 2.30 per million hours worked in 2024 (2022: 3.38). In recognition of the need for continued improvement across major accident prevention we continue to focus on embedding our process safety fundamentals (supporting greater visibility of our major accident hazard risks), process safety KPIs and the use of our barrier model.

The Group recorded strong operational performance in the final quarter of the year with the enlarged group achieving average production of 116 kboe/d in Q4, reaching peak production rates in the period of 138 kboe/d. A strong final quarter, with all operational issues across our non-operated joint venture (NOJV) portfolio and non-operated infrastructure substantially resolved, supported average 2024 production of 80.2 kboe/d (including six months production from the Eni UK assets reflecting an economic effective date for the combination of 1 July 2024). Improved performance in Q4, allowed the Group to close the year towards the upper end of its revised production guidance range of 76-81 kboe/d for the enlarged Group. Production was split 60% liquids and 40% gas with the Group's operated assets accounting for 43% of total 2024 production. On a full year pro-forma basis, the enlarged portfolio achieved average 2024 production of 105.5 kboe/d (2023: 70.2 kboe/d).

Adjusted net operating costs in 2024 from the effective economic date of 1 July 2024 of $649 million (including six months of ENI UK related operating costs) (2023: $524 million), representing an adjusted net unit opex cost from the effective economic date of 1 July 2024 of $22.1/boe (2023: $20.5/boe), came in marginally below management guidance of $650 million to $730 million for the enlarged Group. Our aim is to maintain opex per boe in the low $20s to deliver high net back production, that remains resilient in all commodity environments.

Total net producing asset capital expenditure (excluding decommissioning) of $448 million (including six months of ENI UK capital costs) (2023: $393 million), came in at the mid-point of the Group's management guidance range of $410 million to $480 million. Net capital expenditure on the progression of the Rosebank development totalled $198 million, compared to management guidance of $170 million to $195 million reflecting the material scopes of project activity completed in the year in line with the multi-year development timeline.

Group cash tax paid in the year of $351 million was below the Group's management guidance range of $390 million to $410 million due primarily to cash tax payments made by the acquired Eni UK business prior to the economic effective date of the Business Combination that will be offset in the final deal working capital settlement. The significant majority of tax payments related to the Energy Profits Levy, including all of the Ithaca Energy legacy business cash tax payments.

Creating an optimised organisation to drive our next phase of growth

In the first half of the year, and in preparation for the Combination, the Group made several changes to its Board of Directors and Executive Management team to enhance its leadership and operational capabilities. These appointments, including a new Executive Chairman, Chief Executive Officer and Chief Operating Officer, reflect the Group's growth ambitions and the operational expertise and rigour required to deliver its next phase of growth. Post completion, the Leadership Team was further augmented by new senior leaders, bringing together a diverse range of experiences and backgrounds, reflecting both our agility and strength.

Having completed the Combination in October 2024, integration activities are now well-advanced, recognising the significant benefits a swift and well-executed integration process provides. The respective workforces of Ithaca Energy and Eni UK have been consolidated into two main offices, primarily at our Aberdeen headquarters, with the migration of all main IT systems completed in early January. The Group has initiated a restructuring process aimed at creating an optimised organisation to support its next phase of growth. The restructuring exercise is expected to impact a small portion of our workforce, with the intention to complete this process by 1 July 2025.

Responsible operator

Our commitment to ESG serves as our licence to operate. We balance the need to supply reliable long-term hydrocarbons, critical to delivering domestic energy security and affordability for the end user, with the necessity to lower our emissions footprint, while doing so safely, creating value for our people, shareholders, partners and communities.

With a clear focus and commitment to value-led decarbonisation, we have embedded a strong ESG mindset across our operations. Our ambitions are supported by a well-defined ESG strategy to acquire assets that benefit the emissions profile of our portfolio, invest in low emission intensity assets that have the ability to materially transition our portfolio in the long-term, and deliver meaningful optimisation activities across our current portfolio in the short term that are economically viable.

Through the addition of Eni UK assets, we have lowered the Greenhouse Gas (GHG) emission intensity of our operated portfolio, bringing our gross operated emissions intensity to 23.9 $kgCO_2e$/boe from 25.0 $kgCO_2e$/boe in 2023 and an exit rate below 20 $kgCO_2e$/boe reflecting the full benefit of the combination to our emissions profile. Whilst our gross operated absolute Scope 1 and 2 emissions have increased to 448,190 tCO_2e in 2024 (2023: 435,792 tCO_2e), reflecting a greater number of contributing assets, the carbon intensity of our operated portfolio has been reduced.

Since 2020, we have held a target of 25% emissions reduction by 2025 from our 2019 levels, on a gross operated basis. This was an industry leading ambition, set before the NSTD was signed, to drive emissions reduction and a GHG conscience in the business. This target has led to a significant reduction from our 2019 baseline and the initiation of several meaningful emission reduction projects, reducing our Scope 1 operated emissions by 23% between 2019 and 2023.

The Group has changed significantly since 2020, including our recent Business Combination with Eni UK in 2024. As a result of portfolio changes, the target no longer has the same impact and benefit as it once did and is not representative of where we are today. The Group now operates the Cygnus field and considerable increased non-operated production, therefore it is more representative for us to track and report on net equity emissions reduction, in alignment with the UK government through the NSTD. As we enter 2025, we have retired our original target and now focus on a net equity absolute emissions target of 25% reduction from 2018 levels by 2027, as set out by the NSTD. In 2024, we re-baselined our Scope 1 absolute emissions and emissions intensity to include the combined business portfolio as it was in 2018. This allows us to track progress towards the targets outlined above. In 2024, our net equity emissions intensity was 20.7 $kgCO_2e$/boe. From 2025, we will report on percentage change from the baseline year, 2018.

Our enlarged portfolio benefits from low intensity assets such as Cygnus and Seagull. As the single largest producing gas field in the UK, Cygnus is a key contributor to UK energy security operating as a low intensity asset, emitting approx. 7 $kgCO_2e$/boe, meaningfully below the current UK average of 24 $kgCO_2e$/boe and significantly below the average emission intensity of importing LNG at 79 $kgCO_2e$/boe.

Across our portfolio, we continued to make material progress with notable emissions reduction projects completed at FPF-1 (single train operation), Alba (gas compressor) and Cygnus (TEG system) and ongoing progress made to deliver flare gas recovery projects at Captain and Cygnus and pump replacement projects and export compressor projects at Captain in the year.

Work on the Captain electrification FEED study was completed in the second half of the year, however continued fiscal and regulatory uncertainty in the year meant that the project did not mature to a final investment decision in 2024. Work continues to be progressed to support the project, however the project risks, increasing abatement costs and continued coupling of the decarbonisation allowance to the Energy Profits Levy regime creates significant economic uncertainty to the project. The Board will determine in 2025 if there is sufficient certainty on the availability of allowances to determine investment viability, with the project also competing for capital across our portfolio.

Enhanced financial firepower supports growth ambitions and material shareholder returns

We remain disciplined in our capital allocation priorities, investing to **sustain** our base production, **protecting** our financial position through maintaining a low leverage position, proactively hedging and optimising our tax positions and delivering material **returns** to shareholders, while retaining the financial flexibility to **evolve** our business through investing in organic and inorganic growth opportunities.

Maintaining a robust Balance Sheet, with significant available liquidity and financial flexibility remains of critical importance to the Group as we continue to pursue our growth aspirations. Our recent Business Combination with Eni UK has strengthened the Group's financial position, with increased scale and diversification and the addition of Eni UK's unlevered asset creating additional debt capacity.

The immediate benefits of the Combination were reflected in the Group's successful $2.25 billion refinancing and credit rating upgrades. The refinancing, including $750 million Senior Notes and $1.5 billion amended and restated floating rate Reserve Based Lending (RBL), including $500 million letters of credit facility, has been further enhanced by a RBL accordion facility of over $700 million and a new $400 million unsecured letter of credit facility secured in November.

The successful refinancing has unlocked significant financial synergies, including lengthening the Group's debt maturity profile, reducing the Group's cost of capital and increasing the Group's liquidity position. With a low pro forma 2024 leverage position of 0.45x (2023: 0.33x) and a robust available liquidity position of over $1 billion at 31 December 2024 (2023: $1 billion), the Group has material financial firepower and flexibility to support further investment in growth.

The Group's net current liability position has increased from $226 million at 31 December 2023 to $467 million at 31 December 2024, largely as a result of the deferred consideration payable on the business combination. The Group expects that the net current liability position will be addressed through a combination of operating cash flows, available liquidity and the realisation of out-of-the-money commodity hedges.

Once again, the importance of our robust hedging policy has been highlighted in the year, recording $135 million of hedging gains. The Group's pro-active approach to hedging recognises the importance of balancing upside exposure to commodity prices while managing downside protection of our cash flows, protecting shareholder returns. The Group has generated over $400 million of hedging gains in respect of financial years 2023 and 2024, the equivalent of our 2023 dividend of $400 million. Following a material build to our hedge book post completion of our Business Combination, the Group ended the year with a hedged position of 21.65 million barrels of oil equivalent (mmboe) (25% oil) from 2025 into 2026 at an average price floor of $77/bbl and average ceiling of $85 for oil and an average price floor of 88p/therm and average collar ceiling of 102p/therm and average wide cost collar ceiling of 132p/therm for gas.

The Group's cash flows continue to be protected by our tax efficient structure, supplemented by the Business Combination, with a material ring fence corporate tax and supplementary charge tax loss position of $5.4

billion and $4.7 billion respectively at year-end. The current tax charge for 2024, representing mainly Energy Profits Levy (EPL) of circa $210 million is payable in October 2025. In addition, following the further amendments to the EPL regime in October 2024, that included a rate increase to 38% and the removal of EPL Investment Allowances, the Group incurred a tax charge of $58 million. Profit after tax for the year of $153.2 million (2023: $292.6 million), was further impacted by a $263.0 million (2023: 557.9 million) pre-tax impairment charge, post-tax $102.7 million (2023: $154.0 million), principally in relation to the Greater Stella Area and Pierce. Profit for the year was lower than 2023 principally due to a higher tax charge in 2024 due to the enactment of the increase in EPL from 35% to 38% and a reduction in Ring Fenced Expenditure Supplement due to some Group tax loss positions reaching their claim limit in 2023.

In 2024, our enlarged portfolio delivered adjusted EBITDAX of $1.4 billion (2023: $1.7 billion), representing contributions from Eni UK assets from the completion date of 3 October onwards. 2024 adjusted EBITDAX was impacted by lower production volumes and realised prices in comparison to 2023.

EBITDAX performance of $646.5 million in the final quarter, reflects the truly transformational nature of our Combination, when compared to the previous quarter EBITDAX of $225.5 million. In fact, Q4 2024 represents the highest quarterly EBITDAX performance since the Group's listing in November 2022, during a significantly more advantageous commodity price environment.

Our robust operating cash flow generation in the year of $0.9 billion (2023: $1.3 billion), supported material shareholder distributions in line with the Group's capital allocation policy, returning a total of $433 million to shareholders during the year, $300 million declared in relation to Financial Year 2024. The Board has today declared an interim dividend of $200 million in respect of the 2024 financial year to be paid in April 2025, bringing our total 2024 dividends declared to $500 million. Since our IPO in November 2022, we have built a strong track record of delivering material returns to shareholders with $900 million of dividends declared and returned to shareholders in respect of 2023 and 2024 calendar years.

Outlook

We enter 2025 in a position of greater strength, strategically, operationally and financially. The transformational Business Combination with Eni UK has solidified Ithaca Energy's position as a leading UKCS operator and highlights our ongoing commitment to value-driven growth.

With a portfolio of scale, balance and optionality and material financial firepower, following the Group's successful refinancing, the Group has an enhanced strategic platform to unlock both organic and inorganic growth through the execution of our strategy. Our focus remains on high-grading investment in our diverse range of growth opportunities to maximise sustainable shareholder value.

Management provides the following guidance for the year, inclusive of the acquisition of Japex UK E&P Limited (announced 25 March), assuming a completion date of the transaction of 30 June 2025, and medium-term outlook:

Our 2025 production guidance of 105-115 kboe/d reflects a full year's contribution from the enlarged portfolio and increasing production from the Captain field as we begin to see the early benefits of our Captain EOR Phase II project.

Beyond 2025, the Group expects to maintain production above 100 kboe/d in the medium-term from its existing producing asset base and the start-up of the Rosebank development.

Our operating cost guidance for 2025 of $770-850 million reflects high netback capability of enlarged portfolio with opex/boe estimated to reduce. We expect to maintain a relatively flat unit operating cost per barrel in the low $20/boe range in the short to medium-term, reflecting our stringent focus on cost control.

Our producing asset capital cost guidance of $560-620 million (excluding capital investment for projects awaiting Final Investment Decision and Rosebank), reflects our continued high levels of activity at Captain, J-Area, Elgin Franklin and Cygnus in support of sustaining our medium-term outlook.

Rosebank development to be in the range of $190-230 million reflecting significant project activity in line with the multi-year development timeline.

Estimated 2025 cash tax payments of $235-265million, primarily EPL related.

The Group continues to proactively hedge in the first quarter of the year, securing attractive gas hedge positions during a period of escalating prices with a hedged position of 32.1 million barrels of oil equivalent (mmboe) (29% oil) from 2025 into 2027 at an average price floor of $75/bbl, and average collar ceiling of $82/bbl, and average wide cost collar ceiling of $91/bbl for oil, and an average price floor of 90p/therm and average collar ceiling of 104p/therm and average wide cost collar ceiling of 133p/therm for gas as at 20 March 2025.

The Group retains its target for 2025 dividends of $500 million, in line with our capital allocation policy of 15 – 30% post-tax cash flow from operations (CFFO), and our commitment to distributing 30% post-tax CFFO in 2025.

Strong cash flow generation over the next five years (2025 to 2029) with a potential for over $9bn of total pre-tax cash flow from operations from 2P Reserves at $80/bbl and 85p/therm.

Enquiries

Ithaca Energy

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About Ithaca Energy plc

Ithaca Energy is a leading UK independent exploration and production company focused on the UK North Sea 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"), ranking second largest independent by production with the largest resource base.

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-

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 $1,405.0 million (2023: $1,722.7 million), mainly reflecting the lower production in the first half of the year and lower realised gas commodity prices compared with FY23 partly offset by the results of the Business Combination assets being included from 3 October 2024.

Average realised oil prices for 2024 were $81/boe before hedging results and $82/boe after hedging results (2023: $85/boe before hedging results and $82/boe after hedging results). Average realised gas prices for 2024 were $64/boe before hedging results and $78/boe after hedging results (2023: $76/boe before hedging results and $111/boe after hedging results).

Movement on oil and gas inventory was a credit of $84.2 million (2023: $20.6million) representing movements in underlift/overlift entitlements.

During the year, operating costs (excluding over/underlift) including tariff expenses but excluding tanker costs and net of tariff income were $569.6 million (2023: $524.4 million). The increase in unit operating expenditure per boe compared to 2023 reflects the significant fixed cost nature of operating cost spend coupled with lower production in the first half of 2024.

Administrative expenses, excluding Business Combination costs of $16.3 million, were $41.0 million (2023: $34.3 million) with the increase principally due to the ongoing administrative costs of the former Eni UK businesses.

Adjusted EBITDAX analysis

	2024		2023	
Production	**kboe/d**	**mmboe**	**kboe/d**	**mmboe**
Oil	41	15	43	16
Gas	25	9	24	9
Condensate	3	1	3	1
Total production	**69**	**25**	**70**	**26**
Revenues[1]	**$/boe**	**$m**	**$/boe**	**$m**
Oil revenue	81	1,176	85	1,330
Gas revenue	64	599	76	659
Condensate revenue	48	47	44	49
Oil and gas hedging gains	5	135	10	266
Total	**77**	**1,957**	**90**	**2,303**
Movement in oil and gas inventory	3	84	1	20
Tanker costs	(1)	(18)	(1)	(21)
Stella royalties	–	(2)	–	(4)
Total value from production	**79**	**2,021**	**90**	**2,299**
Costs				
Operating costs excluding tanker costs and net of tariff income	(22)	(570)	(20)	(524)
Administrative expenses excluding Business Combination costs	(2)	(41)	(2)	(34)
Foreign exchange losses/materials inventory provision	–	(5)	(1)	(18)
Other operating costs in arriving at adjusted EBITDAX	**(24)**	**(616)**	**(23)**	**(576)**
Adjusted EBITDAX[2]	**55**	**1,405**	**67**	**1,723**

1 Revenues in the above table exclude principally other income and put premiums on oil and gas derivative instruments.
2 Non-GAAP measure.

Adjusted EBITDAX to profit before tax

	2024 $m	2023 $m
Adjusted EBITDAX	1,405.0	1,722.7
Depletion, depreciation and amortisation	(600.2)	(740.3)
Impairment charges on development and production assets	(263.0)	(557.9)
Exploration and evaluation expenses	(24.5)	(13.6)
Net finance costs	(189.4)	(184.0)
Oil and gas put premiums	(4.9)	(15.4)
Change in fair value of contingent consideration	27.3	(8.0)
Remeasurements of decommissioning reimbursement receivables	–	5.6
Revaluation of derivative contracts	0.3	42.8
Business combination costs	(16.3)	–
Historic claim relating to an acquisition	–	50.1
Profit before tax	**334.3**	**302.0**

Depletion, depreciation and amortisation charges were $600.2 million (2023: $740.3 million). The year-on-year reduction was principally due to the lower production in the first half of 2024 and the effect of the write-down of GSA and Alba in FY23 partly offset by the result of the Business Combination. Depletion, depreciation and amortisation per barrel was $24 (2023: $29).

Impairment charges on development and production assets of $263.0 million (2023: $557.9 million) principally reflects a charge of $117 million for the Greater Stella Area due to a downward revision in reserves, lower gas prices than previously forecast and EPL changes together with a charge of $32 million in respect of Pierce due to lower oil prices than previously forecast and EPL changes (see note 19 for further details). Other impairment charges of $112 million were recorded during 2024 principally relating to decommissioning estimate changes on assets that have either been fully written off or have ceased production. The charge in 2023 mainly reflected write-downs of the Greater Stella Area and Alba following changes in commodity prices as well as reductions in planned drilling activities due to EPL.

Exploration and evaluation expenses amounted to $24.5 million (2023: $13.6 million) and principally relate to licence relinquishments during the year.

Net finance costs were $189.4 million (2023: $184.0 million) and include 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. Underlying net finance costs were lower year-on-year as there was less drawn on the RBL facility.

Change in fair value of contingent consideration was a credit of $27.3 million (2023: charge of $8.0 million), mainly due to an updated view from management of the likelihood of certain milestones being achieved.

Revaluation of derivative financial instruments was a credit of $0.3 million (2023: $42.8 million) principally reflecting gains on commodity hedges partly offset by losses on forex forward hedges and interest rate swaps. The credit in 2023 was mainly due to gains on commodity hedges.

Transaction costs of $16.3 million (2023: $nil) reflect principally professional fees and other cost directly related to the Eni UK Business Combination.

The settlement of a historic claim in relation to an acquisition was received in Q1 of 2023.

Financial performance: profit for the year and adjusted net income

	2024 $m	2023 Restated[3] $m
Profit before tax	334.3	302.0
Tax	(181.1)	(9.5)
Profit for the year	**153.2**	**292.5**
Impairment charges[1]	263.0	557.9
Tax credit on impairment charges[1]	(160.3)	(403.9)
Business combination costs	16.3	–
One-off finance charges related to refinancing	22.0	–
Tax credit on business combination costs and one-off finance charges	(28.7)	–
EPL tax impact of rate increase from 35% to 38%	58.1	–
Adjusted net income[2]	**323.6**	**446.5**

1 Post-tax impairment charges of $102.7 million comprise $38.5 million for GSA and Pierce and $64.2 million principally in relation to decommissioning cost estimate changes on assets that have either been fully written off or have ceased production.
2 Non-GAAP measure.
3 See note 2.

Taxation

The tax charge for the year was $181.1 million (2023: $9.5 million) with the increase mainly due to the enactment of the increase in the EPL rate from 35% to 38% and a $88.5 million reduction in Ring Fenced Expenditure Supplement due to some Group tax loss positions reaching their claim limit in FY 2023. The tax charge for the year excludes the impact of the two year extension of EPL to 31 March 2030 which had it been exacted by 31 December 2024 would have increased the tax charge by $318 million. This extension was substantively enacted on 3 March 2025 and will, therefore, be a charge to the consolidated statement of profit or loss in Q1 of 2025.

Earnings per share (EPS)

Statutory EPS was 13.2 cents (2023: 29.1 cents) and adjusted EPS was 27.8 cents (2023: 44.4 cents). Adjusted EPS is a non-GAAP measure which eliminates items which distort period-on-period comparisons such as impairment charges, Business Combination costs, one-off finance charges related to refinancing, the tax effect of such items and tax charges due to changes in EPL.

Shares in issue

On completion of the Business Combination, 639.4 million new ordinary shares of £0.01 each were issued. As a result, at 31 December 2024, there were 1,653.7 million (2023: 1,014.3 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 1,164.3 million (2023: 1,006.7 million).

Dividends

Dividends paid during the year amounted to $432.7 million (2023: $266.0 million), reflecting the third interim dividend for 2023 of $133.6 million and the first and second interim dividends for 2024 of $299.1 million. A further interim dividend for 2024 of $200.0 million will be paid in April 2025.

Financial position: assets/liabilities/equity

	2024 $m	2023 Restated[1] $m
Total assets	8,275.0	6,323.5
Total liabilities	(5,234.6)	(3,802.2)
Net assets and shareholders' equity	**3,040.4**	**2,521.3**

1 See note 2.

Assets

At 31 December 2024, total assets amounted to $8,275.0 million (2023: $6,323.5 million), and comprised current assets of $976.2 million (2023: $845.6 million) and non-currents assets of $7,298.8 million (2023: $5,477.9 million). The increase in total assets was primarily due to the Business Combination (see note 17) partly offset by a reduction in derivative financial assets of $124.3 million due largely to gas collars and swaps with a higher asset valuation at 31 December 2023 which were realised in FY24. In addition, goodwill of $345.6 million arose on the Business Combination.

Liabilities

At 31 December 2024, total liabilities amounted to $5,234.6 million (2023: $3,802.2 million) including decommissioning provisions of $2,655.1 million (2023: $1,859.7 million) and gross borrowings of $1,024.9 million (2023: $748.2 million). The increase in total liabilities during the year was again primarily due to the Business Combination (see note 17) along with an increase of $145 million due to upward revisions to decommissioning cost estimates. In addition, cash payable for the Business Combination amounted to $204.5 million, borrowings increased by $276.7 million principally due to a $150.0 million drawdown on the RBL, the utilisation of the $150 million project capital expenditure facility, a $125 million increase in Senior Notes, offset by the $100 million repayment of the bp loan. In addition, derivative financial liabilities increased by $137.0 million due to gas trades moving out of the money with rising prices. These were all partly offset by a reduction in corporation tax payable of $74.1 million.

Equity and reserves

At 31 December 2024, total equity and reserves amounted to $3,040.4 million (2023: $2,521.3 million). The increase in equity and reserves during the year was primarily due to the fair value of shares issued on the completion of the Business Combination of $861.3 million and the profit for the year of $153.2 million partly offset by dividend payments of $432.7 million and adverse movements on hedging reserves of $68.8 million.

Financial position: cash

	2024 $m	2023 $m
Opening cash	**153.2**	**253.8**
Operating cash flows	853.3	1,290.8
Investing cash flows	(390.9)	(492.4)
Financing cash flows	(449.5)	(900.7)
Foreign exchange	(1.0)	1.7
Net cash flow	11.9	(100.6)
Closing cash	**165.1**	**153.2**
Undrawn borrowing facilities	850.0	725.0
Undrawn project capital expenditure facility	–	150.0
Available liquidity	**1,015.1**	**1,028.2**

Operating cash flows
Net cash from operating activities amounted to $853.3 million (2023: $1,290.8 million), reflecting adverse working capital movements of $101.7 million (2023: $210.8 million) and tax payments of $351.3 million (2023: $176.3 million). The reduction in net cash flow from operating activities was largely driven by lower adjusted EBITAX, higher tax payments and the receipt of the historic claim relating to an acquisition in 2023 partly offet by better working capital management in 2024.

Investing cash flows
Cash flow used in investing activities amounted to $390.9 million (2023: $492.4 million), reflecting capital expenditure of $464.1 million (2023: $478.8 million) driven mainly by Captain EOR Phase II and Rosebank partly set off by cash acquired through the Business Combination amounting to $107.5 million (2023: $nil).

Financing cash flows
Cash outflow from financing activities of $449.5 million (2023: $900.7 million) with interest costs and charges and lease payments of $122.5 million (2023: $141.7 million), a drawdown of principal debt of $150.0 million (2023: repayment of $600.0 million), net proceeds of Senior Notes due 2029 of $86.8 million (2023: $nil), fees paid on RBL refinancing of $31.7 million (2023: $nil) , repayment of the bp unsecured loan of $100.0 million (2023: drawdown of $100.0 million) and dividend payments of $432.7 million (2023: $266.0 million).

Cash balances were $165.1 million (2023: $153.2 million) at 31 December 2024 and available liquidity was $1,015.1 million (2023: $1,028.2 million).

Prior period adjustments
The income tax charge and the profit for the year ended 31 December 2023 have been restated to reduce the former and increase the latter by $76.9 million, in order to correct the deferred EPL tax treatment of impairment charges recorded in Q4 of 2023. Deferred tax assets and retained earnings as at 31 December 2023 have been increased by the same amount. Further details are set out in note 2.

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 2024, the following hedges were in place:

	2025	2026
Oil		
Volume hedged (mmboe)	5.5	–
Weighted average floor hedged price ($/bbl)	77	–
Gas		
Volume hedged (mmboe)	11.4	4.75
Weighted average floor hedged price (p/therm)	89	86

Subsequent events
On 29 January 2025, the Group announced a reorganisation and streamlining of the organisational structure for onshore staff with a targeted completion date of 1 July 2025.

On 30 January 2025, the Court of Session ruled that 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.

On 25 March 2025, the Group announced the signing of a sale and purchase agreement to acquire the entire issued share capital of JAPEX UK E&P Limited for an enterprise value of $193 million, based on an effective date of 1 January 2024. The acquisition, which is subject to certain conditions including regulatory approval, is subject to customary purchase price adjustments, which, assuming an illustrative completion date of 30 June 2025, equates to an estimated payment at completion of approximately $140 million.

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:

- Continuing robust commodity price backdrop and a well-hedged portfolio over the next 12 months;
- Reserves Based Lending (RBL) liquidity headroom of $850 million ($150 million drawn versus $1,000 million available), plus $383 million of cash as at 14 March 2025; and
- Robust operational performance and a well-diversified portfolio.

Cash flow forecast – base case assumptions		2025	H1 2026
Average oil price	$/bbl	71	68
Average gas price	p/therm	107	96
Average hedged oil price (including floor price for zero cost collars)	$/bbl	75	70
Average hedged gas price (including floor price for zero cost collars)	p/therm	91	89

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 2024.

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 2026 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.

Based on their assessment of the Group's financial position over the period to 30 June 2026, 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	2024 $'000	2023 Restated[1] $'000
Revenue	5	**1,981,859**	2,319,811
Cost of sales	6	**(1,139,645)**	(1,317,010)
Gross profit		**842,214**	1,002,801
Impairment charges on development and production assets	19	**(262,984)**	(557,936)
Exploration and evaluation expenses	14	**(24,557)**	(13,634)
Administrative expenses	7	**(57,280)**	(34,259)
Other gains	8	**26,360**	89,091
Profit from operations before tax, finance income and finance costs		**523,753**	486,063
Finance income	9	**11,164**	5,688
Finance costs	9	**(200,578)**	(189,724)
Profit before tax		**334,339**	302,027
Income tax	28	**(181,186)**	(9,473)
Profit for the year		**153,153**	292,554

Earnings per share (EPS)	Note	2024 Cents	2023 Restated[1] Cents
Basic	10	**13.2**	29.1
Diluted	10	**13.0**	28.7

1 The income tax charge, the profit for the year and EPS for the year ended 31 December 2023 have been restated. Further details are set out in note 2.

The results above are entirely derived from continuing operations.

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 27 to 83 are an integral part of the financial statements.

Consolidated statement of comprehensive income
For the year ended 31 December

	Note	2024 $'000	2023 Restated[1] $'000
Profit for the year		**153,153**	292,554
Items that may be reclassified to profit and loss			
Fair value (losses)/gains on cash flow hedges	30	**(213,637)**	92,484
Fair value (losses)/gains on cost of hedging	30	**(50,807)**	3,116
Deferred tax credit/(charge) on cash flow hedges and cost of hedging	28	**195,642**	(71,700)
Other comprehensive (expense)/income		**(68,802)**	23,901
Total comprehensive income for the year		**84,351**	316,455

1 The profit for the year and the total comprehensive income for the year to 31 December 2023 has been restated. Further details are set out in note 2.

The accompanying notes on pages 27 to 83 are an integral part of the financial statements.

Consolidated statement of financial position
As at 31 December

	Note	2024 $'000	2023 Restated[1] $'000
Assets			
Current assets			
Cash and cash equivalents		**165,123**	153,215
Other financial assets		**11,317**	–
Trade and other receivables	11	**417,614**	334,290
Decommissioning reimbursements	11	**23,175**	30,417
Prepayments	12	**42,210**	37,678
Inventories	13	**283,839**	150,496
Derivative financial instruments	31	**32,962**	139,497
		976,240	845,593
Non-current assets			
Decommissioning reimbursements	11	**144,185**	165,064
Exploration and evaluation assets	14	**612,514**	548,354
Property, plant and equipment	15	**4,188,435**	3,258,206
Deferred tax assets	28	**1,224,136**	704,657
Derivative financial instruments	31	**–**	17,810
Goodwill	18	**1,129,476**	783,848
		7,298,746	5,477,939
Total assets		**8,274,986**	6,323,532
Liabilities and equity			
Current liabilities			
Borrowings	20	**(13,025)**	(29,913)
Trade and other payables	22	**(566,471)**	(478,607)
Current tax payable	28	**(247,048)**	(321,116)
Decommissioning liabilities	23	**(152,709)**	(107,026)
Lease liability	25	**(19,447)**	(19,898)
Contingent and deferred consideration	26	**(308,955)**	(101,669)
Derivative financial instruments	31	**(130,476)**	(13,708)
		(1,438,131)	(1,071,937)

1 Deferred tax assets and retained earnings have been restated at 31 December 2023. Further details are set out in note 2.

Consolidated statement of financial position continued
As at 31 December

	Note	2024 $'000	2023 Restated[1] $'000
Non-current liabilities			
Borrowings	20	**(1,011,923)**	(718,238)
Decommissioning liabilities	23	**(2,502,372)**	(1,752,652)
Lease liability	25	**(20,712)**	(660)
Other provisions	24	**(36,190)**	–
Contingent and deferred consideration	26	**(204,294)**	(258,700)
Derivative financial instruments	31	**(20,987)**	–
		(3,796,478)	(2,730,250)
Total liabilities		**(5,234,609)**	(3,802,187)
Net assets		**3,040,377**	2,521,345
Shareholders' equity			
Share capital	27	**20,029**	11,540
Share premium	27	**1,161,615**	308,845
Capital contribution reserve	27	**181,945**	181,945
Own shares	27	**(9,592)**	(12,412)
Share-based payment reserve	27	**18,788**	15,494
Cash flow hedge reserve	30	**(15,784)**	39,818
Cost of hedging reserve	30	**(9,132)**	4,068
Retained earnings		**1,692,508**	1,972,047
Total equity		**3,040,377**	2,521,345

1 Deferred tax assets and retained earnings have been restated at 31 December 2023. Further details are set out in note 2.

The accompanying notes on pages 27 to 83 are an integral part of the financial statements.

Approved on behalf of the Board on 25 March 2025:

Iain C S Lewis
Director

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

	Note	Share capital $'000	Share premium $'000	Capital contribution reserve $'000	Own shares $'000	Share-based payment reserve $'000	Cash flow hedge reserve $'000	Cost of hedging reserve $'000	Retained earnings $'000	Total $'000
Balance at 1 January 2023		11,445	293,712	181,945	–	4,920	16,710	3,275	1,945,465	2,457,472
Dividends paid	34	–	–	–	–	–	–	–	(265,972)	(265,972)
Issuance of shares	27	95	15,133	–	(15,228)	–	–	–	–	–
Share-based payments	27	–	–	–	2,816	10,574	–	–	–	13,390
Comprehensive income for the year:										
Profit for the year as previously stated (note 2)		–	–	–	–	–	–	–	215,635	215,635
Prior period adjustment (note 2)		–	–	–	–	–	–	–	76,919	76,919
Profit for the year as restated (note 2)		–	–	–	–	–	–	–	292,554	292,554
Other comprehensive income		–	–	–	–	–	23,108	793	–	23,901
Total comprehensive income for the year		–	–	–	–	–	23,108	793	292,554	316,455
Balance at 31 December 2023 and 1 January 2024 as restated		11,540	308,845	181,945	(12,412)	15,494	39,818	4,068	1,972,047	2,521,345
Dividends paid	34	–	–	–	–	–	–	–	**(432,692)**	**(432,692)**
Issuance of shares	27	**8,489**	**852,770**	–	–	–	–	–	–	**861,259**
Share-based payments	27	–	–	–	**2,820**	**3,294**	–	–	–	**6,114**
Comprehensive income for the year:										
Profit for the year		–	–	–	–	–	–	–	**153,153**	**153,153**
Other comprehensive expense		–	–	–	–	–	**(55,602)**	**(13,200)**	–	**(68,802)**
Total comprehensive income/(expense) for the year		–	–	–	–	–	**(55,602)**	**(13,200)**	**153,153**	**84,351**
Balance at 31 December 2024		**20,029**	**1,161,615**	**181,945**	**(9,592)**	**18,788**	**(15,784)**	**(9,132)**	**1,692,508**	**3,040,377**

Consolidated statement of cash flows
For the year ended 31 December

	Note	2024 $'000	2023 $'000
Cash provided by/(used in):			
Operating activities			
Profit before tax		**334,339**	302,027
Adjustments for:			
Depletion, depreciation and amortisation	15	**600,216**	740,300
Exploration and evaluation expenses	14	**24,557**	13,634
Impairment charges on development and production assets	19	**262,984**	557,936
(Decrease)/increase in contingent consideration		**(27,317)**	8,008
Loan fee amortisation	9	**13,222**	4,508
Fair value gains on derivatives	30	**(344)**	(43,059)
Accretion on decommissioning liabilities	9	**82,908**	76,162
Other finance costs	9	**104,451**	109,054
Interest income	9	**(11,164)**	(5,688)
Unrealised foreign exchange on cash and cash equivalents		**986**	(1,725)
Share-based payment expenses	33	**6,114**	13,390
Decommissioning expenditure	23	**(94,098)**	(95,552)
Operating cash flows before movements in working capital		**1,296,854**	1,678,995
(Increase)/decrease in inventories		**(84,212)**	26,386
Decrease in trade and other receivables		**113,969**	12,540
Decrease in trade and other payables		**(131,424)**	(249,760)
Operating cash flows		**1,195,187**	1,468,161
Taxation paid		**(351,267)**	(176,305)
Settlement of foreign exchange and commodity derivative financial instruments		**(1,801)**	(6,739)
Interest received	9	**11,164**	5,688
Net cash from operating activities		**853,283**	1,290,805

	Note	2024 $'000	2023 $'000
Investing activities			
Capital expenditure		**(464,078)**	(478,838)
Business combinations cash acquired	17	**107,475**	–
Increase in other financial assets		**(11,317)**	–
Deferred consideration payments	26	–	(6,367)
Contingent consideration payments	26	**(22,994)**	(7,200)
Net cash used in investing activities		**(390,914)**	(492,405)
Financing activities			
Dividends paid	34	**(432,692)**	(265,972)
Payments for lease liabilities (principal)	25	**(27,870)**	(41,902)
Drawdown/(repayment) of RBL loan		**150,000**	(600,000)
Fees paid on RBL refinancing	20	**(31,671)**	–
Proceeds of Senior Notes 2029 net of repayment of Senior Notes 2026 and fees[1]	20	**86,781**	–
(Repayment)/drawdown of bp loan	20	**(100,000)**	100,000
Interest and charges paid		**(94,664)**	(99,825)
Interest rate swaps	30	**638**	6,967
Net cash used in financing activities		**(449,477)**	(900,732)
Currency translation differences relating to cash		**(986)**	1,725
Increase/(decrease) in cash and cash equivalents		**11,908**	(100,607)
Cash and cash equivalents at 1 January		**153,215**	253,822
Cash and cash equivalents at 31 December		**165,123**	153,215

1 A net receipt of $86.8 million reflects 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 $15.1m interest on the Senior Notes due 2026 and $9.0 million of fees in relation to the Senior Notes due 2029.

The accompanying notes on pages 27 to 83 are an integral part of the financial statements.

Notes to the consolidated 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 2024 and 2023 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 2024 and 2023 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 25 March 2025 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 rounded to the nearest thousand ($'000), except when 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 adjustments

During the preparation of the Q1 2024 condensed consolidated financial statements, management identified an incorrect calculation in the 2023 deferred EPL tax charge related to the impairment charge of $229.5 million recorded in Q4 of 2023. As a result of this incorrect calculation, the tax charge and the profit for the year to 31 December 2023 were overstated and understated, respectively by $76.9 million, and the net deferred tax asset and retained earnings were both understated by $76.9 million at 31 December 2023.

Details of amounts as previously stated, prior period adjustments and amounts as restated were:

Statement of financial position as at 31 December 2023:	As previously stated	Prior period adjustment	As restated
Deferred tax assets ($'000)	627,738	76,919	**704,657**
Retained earnings ($'000)	1,895,128	76,919	**1,972,047**
Net assets ($'000)	2,444,426	76,919	**2,521,345**

Statement of profit or loss for the year to 31 December 2023:	As previously stated	Prior period adjustment	As restated
Income tax charge ($'000)	(86,392)	76,919	**(9,473)**
Profit for the year ($'000)	215,635	76,919	**292,554**
Basic EPS (cents)	21.4	7.7	**29.1**
Diluted EPS (cents)	21.2	7.5	**28.7**

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 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.

3. Material accounting policies, judgements and estimation uncertainty continued

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:

- Continuing robust commodity price backdrop and a well-hedged portfolio over the next 12 months;
- Reserves Based Lending (RBL) liquidity headroom of $850 million ($150 million drawn versus $1,000 million available), plus $383 million of cash as at 14 March 2025; and
- Robust operational performance and a well-diversified portfolio.

Cash flow forecast – base case assumptions:		2025	H1 2026
Average oil price	$/bbl	71	68
Average gas price	p/th	107	96
Average hedged oil price (including floor price for zero cost collars)	$/bbl	75	70
Average hedged gas price (including floor price for zero cost collars)	p/th	91	89

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 2024.

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 2026 to continue trading.

Based on their assessment of the Group's financial position in the period to 30 June 2026, 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 listed per 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 and estimates made 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 has given the Group a portfolio with a relatively lower carbon footprint. 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 2031, $83/bbl for Brent Crude and 87p/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 £50/tonne, £70/tonne and £80/tonne for 2025,2026 and 2027 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, 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, as noted in previous years, it is anticipated that certain higher emission-intensity assets such as FPF-1 and Alba will cease production in the 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 2024, 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 entire producing portfolio would result in an increase in the decommissioning provision of approximately $93 million (2023: $69 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.

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.

3. Material accounting policies, judgements and estimation uncertainty continued

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.

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 which is consistent with the operating segment view of the business.

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.

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;
- 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.

3. Material accounting policies, judgements and estimation uncertainty continued

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 preferencial 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 twelve 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 twelve 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 dedution 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.

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.

3. Material accounting policies, judgements and estimation uncertainty continued

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.

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.

Note 30 and note 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.

3. Material accounting policies, judgements and estimation uncertainty continued

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.

3. Material accounting policies, judgements and estimation uncertainty continued

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.

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
Computer and office equipment	3 years
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.

3. Material accounting policies, judgements and estimation uncertainty continued

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.

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.

3. Material accounting policies, judgements and estimation uncertainty continued

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.

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 or reversals, 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 the increase in rate of 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 84 to 87.

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 2023 to 31 December 2024. There was no material impact from these or from any of the amendments to existing standards and interpretations which were effective from 1 January 2024. 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 2024 , the Group had not applied the following new Standards or revisions to existing IFRS Standards, that have been issued but are not yet effective.

IFRS S1	*General requirements for disclosure of sustainability related financial information*
IFRS S2	*Climate related disclosures*
Amendments to SASB standards	*Amendments to the SASB standards to enhance their international applicability*
Amendments to IAS 21	*Lack of exchangeability*
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*

With the exception of IFRS S1, IFRS S2 and 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. The Group is currently assessing the impact of the sustainability and climate Standards which will apply from 1 January 2026 and the Group is also considering the impact of the adoption of IFRS 18 which will apply from 1 January 2027 onwards.

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.

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.

3. Material accounting policies, judgements and estimation uncertainty continued

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 occuring and hence a payment being due, with all other assumptions held constant, would result in a decrease in contingent consideration of $84.2 million (2023: $97.1 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 $80.4 million (2023: $84.1 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. Whereas previously the Group used a uniform nominal discount rate over all future years, it has now revised its methodology to use a short-to-medium-term nominal discount rate and a long-term nominal discount rate. The Group uses a nominal discount rate of 4.38% for the first five years and 4.86% thereafter (31 December 2023: 4.60% for all years), based on the average risk-free rate over the second half of 2024, to discount the estimated costs. The inflation rate applied to estimated costs is 2.0% (2023: 2.0%). Given the long-term nature of the Group's decommissioning liabilities and the historic compounded inflation rates in the industry, management do not believe that the current short-term inflationary pressures will have a material impact on the decommissioning liabilities of the Group. A reduction or an increase in this discount rate of 1% would increase or reduce the decommissioning liabilities by approximately $288 million or $247 million, respectively (2023: $223 million or $188 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.

3. Material accounting policies, judgements and estimation uncertainty continued

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 at 35% to 31 October 2024 and 38% thereafter, 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.

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 2024, 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 $284 million (2023: $304 million). It should be noted that mitigating actions are considered to be available to materially offset this impact. The $284 million (2023: $304 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 $150 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

In 2024, the Group has made a material business combination – see note 17 for further details of the provisional purchase price allocation, including the assets and liabilities acquired and the goodwill arising on the transaction. This has been accounted for as a business combination under IFRS 3. The assets and liabilities identified in the purchase price allocation include oil and gas assets, decommissioning liabilities, deferred tax assets and liabilities, and working capital.

The total consideration payable includes both the market value of new ordinary shares issued at the date of completion and a monetary settlement based on working capital movements, and certain other transactions such as dividend payments, between the economic effective date of 1 July 2024 and date of completion. The amount payable under this monetary settlement is discussed further in note 17.

The calculation 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 business 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.

In determining the value of the deferred tax asset recognised on the Business Combination, 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.

3. Material accounting policies, judgements and estimation uncertainty continued

Critical accounting judgements

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

Cambo and Rosebank carrying values

Management has reviewed the pre-tax carrying value of the Cambo field of $391 million or post tax $234 million (2023: pre-tax $391 million or post-tax $234 million) and has concluded that due to the licence extension to 31 March 2026 and the detailed plans in place for final investment decision (FID), there are currently no indicators of impairment. The Group is actively engaging with potential farm-in partners to secure an aligned joint venture partnership that would help progress the project towards FID and assist in obtaining additional funding for the project. Management has submitted a request for a further 18 month extension of the licence to 30 September 2027 and to remove a milestone commitment that would otherwise require a joint venture partner to be secured by 31 March 2025, with the latter no longer considered by management as a commercial pre-requisite for the project to proceed to development following completion of the Eni UK Business Combination and the consequential increase in the scale and funding capability of the Group. A decision in respect of this request is expected by the North Sea Transition Authority (NSTA) by the end of the second quarter of 2025. Details of contingent consideration in respect of Cambo are set out in note 26.

Similarly, management has reviewed the pre-tax carrying value of the Rosebank field of $617 million or post-tax $304 million (31 December 2023: pre-tax $413 million or post-tax $237 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. 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 2026/27. 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

	2024 $'000	2023 $'000
Oil sales	**1,176,274**	1,329,751
Gas sales	**598,962**	658,659
Condensate sales	**46,437**	48,789
Other income	**30,000**	32,341
Realised gains/(losses) on oil derivative contracts	**2,572**	(31,676)
Put premiums on oil derivative instruments	**(1,696)**	(11,850)
Realised gains on gas derivative contracts	**132,550**	297,387
Put premiums on gas derivative instruments	**(3,240)**	(3,590)
	1,981,859	2,319,811

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 2024, representing $1,284 million and $420 million of revenue, respectively (2023: two customers representing $1,296 million and $436 million of revenue, respectively). It should be noted that the second largest customer in both 2024 and 2023 is now 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.

6. Cost of sales

	2024 $'000	2023 $'000
Movement in oil and gas inventory	**84,193**	20,582
Operating costs of hydrocarbon activities	**(617,919)**	(576,660)
Materials inventory provision	**(3,568)**	(16,268)
Royalties	**(2,135)**	(4,364)
Depreciation on right-of-use assets (note 15)	**(26,819)**	(42,648)
Depletion, depreciation and amortisation (note 15)	**(573,397)**	(697,652)
	(1,139,645)	(1,317,010)

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

	2024 $'000	2023 $'000
Administrative expenses, excluding transaction costs	**(40,977)**	(34,259)
Transaction costs	**(16,303)**	–
	(57,280)	(34,259)

Transactions costs in 2024 relate to the Eni UK Business Combination. Further details of the Business Combination 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	2024 $'000	2023 Restated $'000
Wages and salaries	**(103,156)**	(93,009)
Share-based payment charges (note 33)	**(6,114)**	(16,369)
Social security costs	**(11,561)**	(10,770)
Pension costs	**(11,936)**	(9,997)
	(132,767)	(130,145)

Wages and salaries costs of $104.0 million and social security costs of $12.3 million disclosed in the 2023 Annual Report and Accounts incorrectly included one-off transactions in respect of the MEP (see note 33) and certain other Executive share options, which had already been included in the share-based payments charge line. Comparatives for 2023 have been restated to exclude these.

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 $4.4 million (2023: $13.4million).

The average number of employees during each year was as follows:

	2024	2023
Onshore and administrative	**374**	316
Offshore	**327**	283
	701	599

7. Administrative expenses continued

Audit fees	2024 $'000	2023 $'000
Fees payable to the Company's auditor for audit of the Company's financial statements	**2,564**	1,286
Audit of the Company's subsidiaries pursuant to legislation	**407**	326
Non-audit services provided by the auditors	**637**	205
	3,508	1,817

Non-audit services provided by the auditors for the year ended 31 December 2024 comprise audit-related assurance services of $175k (2023: $205k), other assurance services of $462k (2023: $nil) relating to work on the Offering Memorandum in respect of the refinancing and in relation to certain other refinancing options. In addition to the above figures, additional audit fees of $228k were charged during 2024 relating to the finalisation of prior period group and subsidiary audits.

8. Other gains and losses

	2024 $'000	2023 $'000
Gain on financial instruments (note 30)	**5,167**	43,059
Fair value gains/(losses) on contingent consideration and accretion on deferred consideration (note 26)	**27,317**	(8,008)
Remeasurements of decommissioning reimbursement receivables	**–**	5,645
Net foreign exchange	**(6,124)**	(1,673)
Settlement of historic claim relating to an acquisition	**–**	50,068
	26,360	89,091

On 12 February 2023, the Group reached agreement on the settlement of a historic claim relating to an acquisition. Under the terms of the agreement the Group received $50.1 million.

9. Finance costs and finance income

	2024 $'000	2023 $'000
Loan interest and charges	**(48,036)**	(47,494)
Senior notes interest	**(54,904)**	(58,377)
Loan fee amortisation	**(13,222)**	(4,508)
Interest on lease liabilities (note 25)	**(1,508)**	(3,183)
Accretion on decommissioning liabilities less accretion on decommissioning reimbursements	**(82,908)**	(76,162)
Total finance costs	**(200,578)**	(189,724)
Finance income	**11,164**	5,688

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 2024, $5.8 million of interest was capitalised into qualifying assets (2023: $nil) at an interest rate of SOFR (subject to a minimum rateof 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:

	2024 $'000	2023 Restated[1] $'000
Earnings for the year:		
Earnings for the purpose of basic and diluted earnings per share	**153,153**	292,554
Number of shares (million)		
Weighted average number of ordinary shares for the purpose of basic earnings per share	**1,164.3**	1,006.7
Dilutive potential ordinary shares	**10.5**	12.7
Weighted average number of ordinary shares for the purpose of diluted earnings per share	**1,174.8**	1,019.4
Earnings per share (cents)		
Basic	**13.2**	29.1
Diluted	**13.0**	28.7

1 See note 2.

11. Trade and other receivables and decommissioning reimbursements

Current	2024 $'000	2023 $'000
Trade receivables	**18,962**	19,968
Other receivables	**23,042**	24,369
Joint operations receivables	**105,999**	91,960
Accrued income	**269,611**	197,993
	417,614	334,290

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.

11. Trade and other receivables and decommissioning reimbursements continued

Non-current	2024 $'000	2023 $'000
Decommissioning reimbursements	**144,185**	165,064

Current	2024 $'000	2023 $'000
Decommissioning reimbursements	**23,175**	30,417

Movements on decommissioning reimbursements were as follows:

	2024 $'000	2023 $'000
At 1 January	**195,481**	200,825
Accretion net of tax at 30%	**7,370**	7,536
Reimbursements received	**(22,450)**	(22,101)
Change in reimbursement estimates	**(13,041)**	9,221
At 31 December	**167,360**	195,481

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	2024 $'000	2023 $'000
Prepayments	**40,572**	34,355
Decommissioning securities	**1,638**	3,323
	42,210	37,678

13. Inventories

Current	2024 $'000	2023 $'000
Hydrocarbon underlift	**171,795**	60,427
Materials inventories	**175,514**	125,674
Provision for obsolete materials inventory	**(63,470)**	(35,605)
	283,839	150,496

14. Exploration and evaluation assets

	$'000
At 1 January 2023	775,773
Additions	165,516
Transfers to right-of-use operating assets and development and production assets (note 15)	(379,301)
Write-offs/relinquishments	(13,634)
At 31 December 2023 and 1 January 2024	548,354
Additions	**36,327**
Change in decommissioning estimates (note 23)	**4,390**
Business combinations (note 17)	**48,000**
Write-offs/relinquishments	**(24,557)**
At 31 December 2024	**612,514**

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 $24.6 million being expensed in the year to 31 December 2024 (2023: $13.6 million).

The transfers from exploration and evaluation assets to right-of-use assets and development and production assets in 2023 relates to the Rosebank field.

The principal component of exploration and evaluation assets at 31 December 2024 is the Cambo field with a pre-tax carrying value of $391 million (2023: $391 million).

15. Property, plant and equipment

	Right-of-use operating assets $'000	Development and production assets $'000	Other fixed assets $'000	Total $'000
Cost				
At 1 January 2023	98,927	7,112,652	45,912	7,257,491
Additions	26,468	358,361	1,728	386,557
Transfers from exploration and evaluation assets (note 14)	30,774	348,527	–	379,301
Change in decommissioning estimates (note 23)	–	157,224	–	157,224
At 31 December 2023 and 1 January 2024	156,169	7,976,764	47,640	8,180,573
Additions	**136,264**	**483,511**	**545**	**620,320**
Business combinations (note 17)	**18,673**	**997,937**	–	**1,016,610**
Change in decommissioning estimates (note 23)	–	**54,581**	–	**54,581**
At 31 December 2024	**311,106**	**9,512,793**	**48,185**	**9,872,084**
Depletion, depreciation, amortisation and impairment				
At 1 January 2023	(42,867)	(3,555,656)	(24,072)	(3,622,595)
Depletion, depreciation and amortisation charge for the year	(42,648)	(693,573)	(4,079)	(740,300)
Impairment charge (note 19)	–	(559,472)	–	(559,472)
At 31 December 2023 and 1 January 2024	(85,515)	(4,808,701)	(28,151)	(4,922,367)
Depletion, depreciation and amortisation charge for the year	**(26,819)**	**(568,139)**	**(5,258)**	**(600,216)**
Impairment charge (note 19)	–	**(161,066)**	–	**(161,066)**
At 31 December 2024	**(112,334)**	**(5,537,906)**	**(33,409)**	**(5,683,649)**
Net book value at 31 December 2023	70,654	3,168,063	19,489	3,258,206
Net book value at 31 December 2024	**198,772**	**3,974,887**	**14,776**	**4,188,435**

The transfers from exploration and evaluation assets to right-of-use operating assets and development and production assets in 2023 relates to the Rosebank development following consent being granted for the development by the North Sea Transition Authority (NSTA) on 27 September 2023. Subsequently, this decision was the subject of a Judicial Review and on 30 January 2025, the Court of Session ruled that 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 approval is sought (see note 3 for further details). At the point of transfer in 2023, the Rosebank assets were tested for impairment and the recoverable amount exceeded the carrying value of the field.

Additions to right-of-use assets in the year to 31 December 2024 and the year to 31 December 2023 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 2026/27.

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

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	**2024**	2023
9/11c	P.979	Mariner	Equinor UK Limited	**8.89%**	8.89%
9/11b	P.726	Mariner	Equinor UK Limited	**8.89%**	8.89%
30/2c	P.672	Jade	Chrysaor Petroleum Company U.K. Limited	**32.50%**	25.50%
22/30c and 29/5c	P.666	Elgin-Franklin	TotalEnergies E&P UK Limited	**27.95%**	6.09%
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%**	6.09%
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	Equinor UK 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	Repsol Resources UK Limited	**41.03%**	41.03%
22/17s, 22/22a and 22/23a	P.291	Arbroath, Arkwright, Brechin, Carnoustie, Cayley, Shaw	Repsol 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	Equinor UK Limited	**8.89%**	8.89%
9/11g	P.2151	Mariner	Equinor UK 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%**	6.09%

16. Interests in joint operations continued

Block	Licence	Field/discovery name	Operator	Group net % interest 2024	Group net % interest 2023
15/18b	P.2158	Marigold[1]	Ithaca Oil and Gas Limited	**100.00%**	100.00%
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%**	25.50%
30/1f	P.1588	Vorlich[2]	Ithaca MA Limited	**100.00%**	100.00%
30/1c	P.363	Vorlich	Ithaca MA Limited	**34.00%**	34.00%
205/2a	P.1272	Rosebank	Equinor UK Limited	**20.00%**	20.00%
205/1a	P.1191	Rosebank	Equinor UK 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	Repsol Resources UK Limited	**41.03%**	41.03%
22/17n, 22/17s, 22/22a and 22/23a	P.019	Godwin, Montrose	Repsol 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%**	10.00%
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%**	–
30/7c	P.2221	Judy	Chrysaor Petroleum Company U.K. Limited	**33.00%**	–
30/13d A	P.079	Judy	Chrysaor Petroleum Company U.K. Limited	**15.00%**	–
30/6a	P.11	Jasmine	Chrysaor Petroleum Company U.K. Limited	**33.00%**	–
29/4d	P.752	Glenelg	TotalEnergies E&P UK Limited	**8.00%**	–
22/29b	P.2613	Glenelg Protection	TotalEnergies E&P UK Limited	**32.14%**	–
30/20a	P.2220	Tommeliten	ConocoPhillips (U.K.) Holdings Limited	**0.07%**	–
30/13e	P.2456	Talbot	Harbour Energy Limited	**33.00%**	–

16. Interests in joint operations continued

Block	Licence	Field/discovery name	Operator	Group net % interest 2024	2023
30/7d and 30/8a	P.2399	Judy East	Chrysaor Petroleum Company U.K. Limited	**33.00%**	–
N/A	Pipeline	GAEL	INEOS FPS Limited	**10.23%**	–
N/A	Pipeline	SEAL	TotalEnergies E&P UK Limited	**21.87%**	–
44/11a and 44/12a	P.1055	Cygnus	Ithaca (NE) E&P Limited	**38.75%**	–
22/29c	P.1622	Seagull	BP Exploration Operating Company Limited	**35.00%**	–
47/14b	P.614	Juliet	Ithaca (NE) E&P Limited	**81.00%**	–
44/24a	P.611	Minke	Ithaca (NE) E&P Limited	**15.56%**	–
44/29b	P.454/P.611	Orca UK	Ithaca (NE) E&P Limited	**15.56%**	–
44/19b	P.1139	Cameron	Tullow Limited	**27.50%**	–
N/A	Pipeline	ETS	Kellas North Sea 2 Limited	**25.00%**	–
36/30a, 42/3a, 42/4 and 42/5a	P.2133	Ossian	Spirit Energy Limited	**30.00%**	–
42/2b, 42/3b, 42/7a, 42/8b and 42/9b	P.2126	Aurora	Spirit Energy Limited	**30.00%**	–
44/11b	P.1731	Cepheus	Ithaca (NE) E&P Limited	**34.48%**	–
43/14a	P.2430	Cavendish North	Spirit Energy Limited	**40.00%**	–
43/15a, 44/11d and 44/12e	P.2429	Bennett	Ithaca (NE) E&P Limited	**40.00%**	–

1 Marigold is a joint operation through a Unitisation and Unit Operating Agreement (UUOA) between Ithaca Oil and Gas Limited which owns licence P.2158, and Anasuria Hibiscus UK Limited and Caldera Petroleum (UK) Limited, which jointly own a licence for an adjacent block. Under the terms of the UUOA, key decisions over the operations require the unanimous consent of Ithaca and certain other parties, such that joint control is present.

2 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 2024	2023
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	Chrysaor Petroleum Company U.K. Limited	**100.00%**	–
16/22b	P.2638	Quad 16	N/A	**100.00%**	–

17. Business combinations

The Business Combination comprising 100% of each of Eni Elgin/Franklin Limited, Eni UKCS Limited, Eni Energy E&P Limited and Eni Energy E&P UKCS Limited, which established the Group with the largest resource base in the UKCS, completed on 3 October 2024 with the Group issuing 639,360,174 new ordinary shares of £0.01 each, representing at that time 38.7% of the enlarged Group. On that date, the opening market share price was £1.0146 per share and the US Dollar exchange rate was $1.32768:£1.00. The resulting share issuance consideration of $861 million will be augmented by a transaction cash amount primarily reflecting settlement for working capital balances, including cash, at the date of completion together with certain other transactions between the economic effective date of 1 July 2024 and completion on 3 October 2024. The acquisition date of 3 October 2024 is the date the group obtained control for accounting purposes. The amount payable under this mechanism has been agreed at $215.0 million of which $164.0 million is payable within 12 months and $51.0 million is payable in more than 12 months. These amounts have been discounted at 4.33%. The discounted amount payable is $204.5 million (see note 26) and this is the amount of the cash consideration below.

The provisional fair values of the identifiable assets and liabilities as at the date of completion of the Business Combination were:

	Total 2024 $'000
Property, plant and equipment (note 15)	1,016,610
Exploration and evaluation assets (note 14)	48,000
Cash	107,475
Inventory	62,221
Trade and other receivables	178,037
Total assets excluding deferred tax	**1,412,343**
Trade and other payables	(281,680)
Decommissioning provisions (note 23)	(650,999)
Other provisions (note 24)	(34,865)
Lease liabilities (note 25)	(22,049)
Total liabilities excluding deferred tax	**(989,593)**
Deferred tax asset (note 28)	846,408
Deferred tax liability (note 28)	(549,062)
Total identifiable net assets at fair value	**720,096**
Consideration satisfied by the issue of new shares	861,259
Deferred consideration (note 26)	204,465
Total consideration	**1,065,724**
Goodwill arising on the Business Combination (note 18)	**345,628**
Net cash flows relating to the Business Combination during 2024, being cash acquired	**107,475**

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 in the year to 31 December 2024. Had the 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 $16.3 million (2023: $nil), comprising principally professional fees and other direct costs, were incurred in the year to 31 December 2024 and are included within 'administrative expenses' in note 7.

The fair values of the oil and gas assets and the intangible assets of the Eni UK businesses 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 date, 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 generated on the Business Combination is largely the result of the IFRS requirement to recognise a deferred tax liability of $549.1 million on the fair value of the property, plant and equipment and exploration and evaluation assets acquired through the Business Combination, despite these assets being recognised on a post tax basis.

18. Goodwill

	2024 $'000	2023 $'000
Balance at 1 January	**783,848**	783,848
Additions (note 17)	**345,628**	–
Balance at 31 December	**1,129,476**	783,848

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

The goodwill on business combinations in the year to 31 December 2024 relates to the Eni UK businesses, as detailed in note 17.

The goodwill is not tax deductible on the Eni UK Business Combination.

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 Maker. 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 2024 and 31 December 2023. These reviews were carried out on a fair value less cost of disposal basis using risk-adjusted 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 10.0% (2023: 10.3%). Assumptions and estimates in the Group impairment models are detailed in note 3. The recoverable amount of the North Sea CGU at 31 December 2024 was $418.8 million higher than its carrying amount, including goodwill, and hence no impairment was recorded (2023 : $nil). An increase of 1% in the discount rate assumption would not result in a post-tax impairment of goodwill. Details of further sensitivities are provided in note 19.

19. Impairment charges on oil and gas assets

	2024 $'000	2023 $'000
D&P assets (note 15)	**(148,815)**	(559,472)
Decommissioning cost estimate changes on assets which have either been fully written off or have ceased production (note 23)	**(99,672)**	–
Fixed asset additions on assets that have been fully written off (note 15)	**(12,251)**	–
Other movements	**(2,246)**	1,536
Total impairment charges on D&P assets	**(262,984)**	(557,936)

The impairment charge on D&P assets of $148.8 million (2023: $559.5million) principally reflects a charge for the Greater Stella Area (GSA) of $117 million due to a downward revision of reserves, lower gas prices than previously forecast and EPL changes together with a charge of $32 million in respect of Pierce due to lower oil prices than previously forecast and EPL changes. The charge in 2023 primarily related to Alba of $141 million and GSA of $373 million. In addition, decommissioning cost estimate changes on fields which have been fully written off or have ceased production amounted to $99.7 million and fixed asset additions on fields which have been fully written off amounted to $12.3 million.

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 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 amount for GSA and Pierce was $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:

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

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

With all other assumptions held constant, a 20% decrease in the forecast revenues, illustrating a 20% decrease in commodity prices, would result in an additional post-tax impairment of PP&E of $303 million (2023: $22 million) at 31 December 2024. In addition, under this scenario there would be a goodwill impairment of $1,174 million. This sensitivity is considered to be consistent with those applied to the going concern and viability assessments in that it assumes that the 10% reduction in production and the 10% increases in operating and capital expenditures are offset by the mitigation strategies within the control of management as described in note 3.

A 20% increase in forecast revenues would reduce the reported post-tax impairment by $24 million (2023: $26 million). 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.

19. Impairment charge on oil and gas assets continued

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 $63 million (2023: nil). To calculate the Climate Scenario average oil and gas prices, the Group used data from the International Energy Agency (IEA) climate scenarios (NZ, STEPS, APS) price assumptions.

An impairment review was carried out at the end of 2023 on the Group's producing assets with the main triggers being a reduction in future reserves on Alba, a decrease in short-term forward oil prices against all oil producing CGUs and a decrease in short-term gas prices for GSA and other predominantly gas-producing CGUs with relatively short remaining useful economic lives. 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 10.3%, and represents level 3 in the fair value hierarchy. The recoverable amount (post tax) for Alba and GSA was $nil and $29.7 million, respectively.

The following assumptions were used at Q4 2023 in developing the cash flow model and applied over the expected life of the respective fields:

	Post-tax discount rate assumption	Price assumptions (nominal)						
		2024	2025	2026	2027	2028	2029	2030[1]
Oil	10.3%	$85/bbl	$83/bbl	$87/bbl	$90/bbl	$93/bbl	$96/bbl	$99/bbl
Gas	10.3%	101p/therm	96p/therm	83p/therm	85p/therm	87p/therm	89p/therm	90p/therm

1 Post 2030, an annual 2% is applied to the price assumptions.

20. Borrowings

	2024 $'000	2023 $'000
Current		
Accrued interest costs on borrowings	**(23,196)**	(34,420)
Unamortised short-term bank fees	**6,603**	3,036
Unamortised short-term senior notes fees	**3,568**	1,471
Total current borrowings	**(13,025)**	(29,913)
Non-current		
RBL facility	**(150,000)**	–
Senior unsecured notes	**(750,000)**	(625,000)
bp unsecured loan	–	(100,000)
Project capital expenditure facility	**(150,000)**	–
Unamortised long-term bank fees	**24,546**	4,555
Unamortised long-term senior notes fees	**13,531**	2,207
Total non-current borrowings	**(1,011,923)**	(718,238)

Adjusted net debt, which does not include accrued interest on borrowings, lease liabilities or unamortised fees, is set out in non-GAAP measures on pages 84 to 87.

Reserves Based Lending (RBL) facility

During 2024, the Group completed a refinancing of the RBL facility. The refinancing represented an early exit from and extinguishment of the original RBL facility and replacement with a new RBL facility based on market terms at the date of the refinancing. There was no net cash receipt or payment for the $150m principal amount of the RBL on refinancing as the drawdown was re-distributed between syndicate banks to the RBL by the facility agent. The new RBL facility amount at 31 December 2024 was $1.5 billion, consisting of a loan facility of $1,000 million and a letter of credit facility of $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 2024, the total loan availability was $1,000 million (2023: $725 million), of which $150 million (2023: none) was drawn down, leaving an amount of $850 million (2023: $725 million) being available for drawdown. In addition, under the new RBL facility, there is an accordion facility of up to $1,000 million, of which $265 million was committed at 31 December 2024.

Loan fees of $32.4 million relating to the refinancing of the RBL facility were capitalised and are being amortised over the term of the loan. Of this amount, $31.7 million (2023: $nil) was paid in the year to 31 December 2024 and $0.7 million (2023: $nil) was accrued at 31 December 2024. As at 31 December 2024, $31.1 million (2023: $6.0 million) remains to be amortised. Unamortised fees of $5.3 million were written off to finance costs on the refinancing which extinguished the previous RBL facility.

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 2024 was $8,275million (2023: $6,324 million).

Covenants under the RBL are detailed below.

20. Borrowings continued

Senior notes

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. The refinancing of the senior notes represented an early exit from and extinguishment of the original 2026 senior notes and replacement with new senior notes based on market terms at the date of the refinancing. Loan fees of $17.8 million relating to the new senior notes were capitalised and are being amortised over the life of the loan, $17.1 million (2023: $3.7 million) remains to be amortised as at 31 December 2024.Unamortised fees of $2.6 million relating to the 2026 notes, together with an associated $14.1 million early repayment fee, were written off to finance costs on the refinancing.

The Group received a net cash inflow of $86.8m from the refinancing of the Senior Notes, 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 $15.1m interest on the Senior Notes due 2026 and $9.0 million of fees in relation to the Senior Notes due 2029. Fees of $7.8m in relation to the new senior notes were paid separately and $1.0 million was accrued at 31 December 2024.

bp facility

The $100 million facility with bp was repaid in full as part of the refinancing in October 2024.

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 2024 (2023: $nil) 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 the $750 million unsecured notes.

In addition to the below financial covenants, the Group is subject to restrictive covenants under the RBL facility and 2029 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.

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; and
- 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 occurence 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 2024 $'000	Financing cash flows[i] $'000	Non-cash changes: Additions[iii] $'000	Non-cash changes: Business combinations $'000	Non-cash changes: Fair value movements $'000	Non-cash changes: Amortisation $'000	Non-cash changes: Other movements[ii] $'000	31 December 2024 $'000
Borrowings (note 20)	748,150	11,955	150,000	–	–	13,226	101,617	**1,024,948**
Lease liabilities	20,559	(29,378)	25,422	22,049	–	–	1,507	**40,159**
Interest rate derivatives (note 30)	(637)	637	–	–	–	–	–	–
Total liabilities from financing activities	**768,072**	**(16,786)**	**175,422**	**22,049**	–	**13,226**	**103,124**	**1,065,107**

	1 January 2023 $'000	Financing cash flows[i] $'000	Non-cash changes: Additions $'000	Non-cash changes: Business combinations $'000	Non-cash changes: Fair value movements $'000	Non-cash changes: Amortisation $'000	Non-cash changes: Other movements[ii] $'000	31 December 2023 $'000
Borrowings (note 20)	1,213,731	(596,642)	–	–	–	4,507	126,554	**748,150**
Lease liabilities	58,858	(45,085)	3,603	–	–	–	3,183	**20,559**
Interest rate derivatives (note 30)	(7,125)	6,967	–	–	(479)	–	–	**(637)**
Total liabilities from financing activities	**1,265,464**	**(634,760)**	**3,603**	–	**(479)**	**4,507**	**129,737**	**768,072**

(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

	2024 $'000	2023 $'000
Trade payables	**(21,910)**	(34,559)
Hydrocarbon amounts owed to joint operations/overlift	**(102,061)**	(72,486)
Other payables	**(38,069)**	(68,034)
Accruals	**(394,602)**	(254,781)
Deferred income	**(9,829)**	(48,747)
	(566,471)	(478,607)

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. The prior year deferred income was recognised in revenue in the current year.

23. Decommissioning liabilities

	2024 $'000	2023 $'000
Balance at 1 January	**(1,859,678)**	(1,720,540)
Business combination additions (note 17)	**(650,999)**	–
Accretion	**(93,436)**	(74,621)
Additions and revisions to estimates	**(145,066)**	(160,069)
Decommissioning provision utilised	**94,098**	95,552
Balance at 31 December	**(2,655,081)**	(1,859,678)
Current		
Balance at 1 January	**(107,026)**	(146,829)
Balance at 31 December	**(152,709)**	(107,026)
Non-current		
Balance at 1 January	**(1,752,652)**	(1,573,711)
Balance at 31 December	**(2,502,372)**	(1,752,652)

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. Whereas previously the Group used a uniform nominal discount rate over all future years, it has now revised its methodology to use a short-to-medium-term nominal discount rate and a long-term nominal discount rate. The Group uses a nominal discount rate of 4.38% for the first five years and 4.86% thereafter (31 December 2023: 4.60% for all years) and an inflation rate of 2.0% (31 December 2023: 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 2024 and 2023 were due to changes in both cost estimates and discount rate assumptions.

The estimated 2025 decommissioning spend of $153 million (2023: estimated 2024 decommissioning spend of $107 million) has been treated as a current liability as at 31 December 2024. Although the Group currently expects to incur decommissioning costs over the next 40 years, it is estimated that approximately 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 2024 were Alba, Anglia, Causeway, CMS 111, Elgin Franklin, Heather, Hunter, Juliet, Stathspey and Topaz.

24. Other provisions

	2024 $'000	2023 $'000
At 1 January	–	–
Business combination additions (note 17)	**(34,865)**	–
Cost of gas sales during the year	**(1,325)**	–
At 31 December	**(36,190)**	–

Other provisions reflect principally estimated liabilities taken on through the Business Combination in respect of certain historic gas sales agreements along with the ongoing cost of such gas sales agreements. It is not anticipated that any part of this liability will be settled within 12 months of the balance sheet date and, therefore, it has been classified in its entirety as a non-current liability. The Group expects to start settling these liabilities between one and five years.

25. Lease liabilities

Current	2024 $'000	2023 $'000
Lease liabilities	**(19,447)**	(19,898)

Non-current	2024 $'000	2023 $'000
Lease liabilities	**(20,712)**	(660)

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 2024.

	2024 $'000	2023 $'000
Less than one year	**(21,046)**	(20,152)
One to five years	**(21,876)**	(669)
Total undiscounted lease payments	**(42,922)**	(20,821)
Future finance charges	**2,763**	263
Lease liabilities in the financial statements	**(40,159)**	(20,558)

	2024 $'000	2023 $'000
At 1 January	**(20,558)**	(58,858)
Additions	**(25,422)**	(3,603)
Business combination additions (note 17)	**(22,049)**	–
Interest	**(1,508)**	(3,183)
Payments	**29,378**	45,086
At 31 December	**(40,159)**	(20,558)
Current	**(19,447)**	(19,898)
Non-current	**(20,712)**	(660)
	(40,159)	(20,558)

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

The additions in the year to 31 December 2023 relate to modifications of the Captain Emergency Response and Rescue Vessel (ERRV) lease.

The leased assets added through the Business Combination 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	2024 $'000	2023 $'000
Contingent consideration	**(74,990)**	(101,669)
Deferred consideration payable to related party for business combination (note 17)	**(165,672)**	–
Marubeni deferred consideration	**(68,293)**	–
	(308,955)	(101,669)

Non-current	2024 $'000	2023 $'000
Contingent consideration	**(165,501)**	(194,721)
Deferred consideration payable to related party for business combination (note 17)	**(38,793)**	–
Marubeni deferred consideration	**–**	(63,979)
	(204,294)	(258,700)

	2024 $'000	2023 $'000
Cash flows relating to contingent and deferred considerations	**(22,994)**	(13,567)

Movement in contingent consideration is as follows:

	2024 $'000	2023 $'000
At 1 January	**(296,390)**	(258,896)
Additions	**–**	(26,872)
Payments made	**22,994**	7,200
Changes in fair value	**32,905**	(17,822)
At 31 December	**(240,491)**	(296,390)

Movement in deferred consideration is as follows:

	2024 $'000	2023 $'000
At 1 January	**(63,979)**	(67,904)
Additions	**(204,465)**	–
Payments made	**–**	6,367
Accretion	**(4,314)**	(2,442)
At 31 December	**(272,758)**	(63,979)

26. Contingent and deferred consideration continued

Cash outflows in the year ended 31 December 2024 of $23.0 million (2023: $13.6 million) are in relation to the consideration payable on the MOGL, Siccar oil price triggers and an interim payment on Rosebank in the year to 31 December 2024.

Marubeni

The contingent consideration arrangement relating to the 2022 acquisition of MOGL 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 2024, discounted at 6.33%, was $78 million (2023: $111 million using a discount rate of 4.6%). The total undiscounted potential consideration as at 31 December 2024 is $228 million (2023: $230 million).

The Marubeni deferred consideration of $68.3 million is payable 1 July 2025.

Siccar

During the year ended 31 December 2022, the Group acquired Siccar Point Energy, which 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. 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 2024, discounted at 6.33% was $118 million (2023: $130 million using a discount rate of 4.6%). The total undiscounted potential consideration as at 31 December 2024 is $343 million (2023: $362 million).

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 2024, discounted at 6.33%, was $11.7 million (2023: $12.7 million undiscounted).

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 2024, discounted at 6.33%, was $9.0 million (2023: $14.2 million undiscounted).

A further $nil (2023: $3.0 million) relates to Yeoman/Marigold which has been fully risked. The unrisked amount is $11.0 million (2023: $11.0 million) which is contingent on achieving Field Development Plan along with a further $6.0 million (2023: $6.0 million) unrisked on certain production criteria being met.

During the year ended 31 December 2024, the contingent consideration liability in relation to Strathspey, in accordance with the Sale and Purchase Agreement with Chevron, has reduced by $1.9 million to $23.7 million as a result of changes in variables in the calculation of the liability.

Revaluation of contingent consideration in the year to 31 December 2024 resulted in a decrease of $32.9 million (2023: increase of $17.8 million).

27. Share capital and reserves

(a) Issued share capital

The issued share capital is as follows:

	Number of common shares	Amount $'000
At 31 December 2023	1,014,372,281	11,540
Shares issued during the year	639,360,174	8,489
At 31 December 2024	1,653,732,455	20,029

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 (see note 17 for further details).

On 5 October 2023, 7,807,305 ordinary shares of £0.01 each were issued to the Ithaca Energy plc Employee Benefit Trust (EBT) to satisfy the exercise of share options during the year and in future years.

(b) Share premium

	2024 $'000	2023 $'000
At 1 January	**308,845**	293,712
Additions	**852,770**	15,133
At 31 December	**1,161,615**	308,845

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.

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.

Additions during 2023 represent the difference between the nominal value per share of £0.01 and the closing share price on the day before the shares were issued to the EBT multiplied by the number of shares issued.

(c) Capital contribution reserve

	2024 $'000	2023 $'000
At 1 January and 31 December	**181,945**	181,945

(d) Own shares

	2024 $'000	2023 $'000
At 31 December	**(9,592)**	(12,412)

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 2024, 1,860,112 (2023: 1,443,561) ordinary shares were used to satisfy the exercise of share options. At 31 December 2024, the EBT held 6,325,918 (2023: 8,186,030) ordinary shares of £0.01 each.

(e) Share-based payment reserve (note 33)

	2024 $'000	2023 $'000
At 31 December	**18,788**	15,494

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

	2024 $'000	2023 Restated[1] $'000
Current tax		
Current corporation tax charge	**(17,746)**	(39,308)
Current EPL tax charge	**(221,420)**	(333,425)
True-up in respect of prior years	**30,573**	(17,426)
Total current tax charge	**(208,593)**	(390,159)
Deferred tax		
True-up in respect of prior years	**(21,068)**	6,370
Group tax (charge)/credit in consolidated statement of profit or loss	**(1,905)**	304,279
Group tax credit/(charge) in consolidated statement of other comprehensive income	**195,642**	(71,700)
Total deferred tax credit	**172,669**	238,949
Deferred Petroleum Revenue Tax		
Deferred PRT credit in statement of profit or loss	**50,381**	70,037
Total tax charge through consolidated statement of profit or loss	**(181,186)**	(9,473)

1 See note 2.

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:

	2024 $'000	2023 Restated[1] $'000
Accounting profit before tax	**334,339**	302,027
At tax rate of 40% (2023: 40%)	**(133,735)**	(120,811)
Non-deductible expense	**8,700**	(34,578)
Financing costs not allowed for SCT	**(13,581)**	(704)
Ring Fence Expenditure Supplement	**14,340**	102,866
Deferred tax effect of investment allowance	**33,219**	56,930
True-up in respect of prior years	**9,504**	(11,673)
Deferred PRT net of corporation tax	**30,229**	42,022
Deferred tax on EPL	**119,102**	292,829
Current tax on EPL	**(221,420)**	(333,425)
Income taxed at different rates	**(27,956)**	–
Share-based payments	**412**	1,945
Unrecognised tax losses	**–**	(4,874)
Total tax charge recorded in the consolidated statement of profit or loss	**(181,186)**	(9,473)

1 See note 2.

The Company is UK tax resident. The effective rate of tax applicable for UK ring fence oil and gas activities in both 2024 and 2023 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 was enacted on 14 July 2022 with further changes announced on 17 November 2022 such that the Levy was increased to 35% from 1 January 2023 until 31 March 2028 increasing the effective UK ring fence oil and gas tax rate to 75%. On 6 March 2024, it was announced that EPL will 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 was a charge to the consolidated statement of profit or loss of $58.1 million (2023: $nil) in the year to 31 December 2024. The extensions to 31 March 2029 and 31 March 2030 had not been substantively enacted at 31 December 2024 and are, therefore, not reflected in the results for the year ended 31 December 2024.

28. Taxation continued

Deferred tax at 31 December relates to the following:

	2024 $'000	2023 Restated[1] $'000
Deferred corporation tax liability	**(2,197,590)**	(1,868,022)
Deferred corporation tax asset	**3,279,585**	2,480,921
Deferred PRT asset	**142,141**	91,758
Net deferred tax asset	**1,224,136**	704,657

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 allowances of up to circa $150 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.Non-oil and gas losses of $217 million (2023: $251 million), of which there is no expiry date, have 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.

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

	2024 $'000	2023 Restated[1] $'000
At 1 January	**704,657**	392,457
Profit or loss credit	**27,408**	380,686
Other comprehensive income credit/(charge)	**195,643**	(71,700)
Deferred tax on decommissioning reimbursements (note 11)	**(916)**	3,214
Business combinations (note 17)	**297,344**	–
At 31 December	**1,224,136**	704,657

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:

	2024 $'000	2023 Restated[1] $'000
Accelerated capital allowances	**100,974**	515,277
Tax losses	**(203,307)**	(216,937)
Decommissioning provision	**61,685**	52,440
Deferred PRT	**(20,153)**	(28,015)
Hedging[2]	**201,534**	(101,744)
Share schemes	**963**	3,978
Investment allowances	**30,973**	13,950
	172,669	238,949

1 See note 2.
1 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 $'000	Deferred corporation tax on deferred PRT $'000	Accelerated tax depreciation $'000	Total $'000
At 1 January 2023	–	(8,688)	(2,250,125)	(2,258,813)
Reclassification from deferred corporation tax assets	(8,678)	–	–	(8,678)
True-up in respect of prior years	2,721	–	8,307	11,028
Origination and reversal of temporary differences	(101,744)	(28,015)	441,281	311,522
At 31 December 2023 as previously stated	(107,701)	(36,703)	(1,800,537)	(1,944,941)
Prior period adjustment (note 2)	–	–	76,919	76,919
At 31 December 2023 and 1 January 2024 as restated	(107,701)	(36,703)	(1,723,618)	(1,868,022)
Business combinations (note 17)	**–**	**–**	**(549,062)**	**(549,062)**
True-up in respect of prior years	**–**	**–**	**(16,027)**	**(16,027)**
Origination and reversal of temporary differences	**201,534**	**(20,153)**	**147,973**	**329,354**
Reclassification to deferred corporation tax assets	**(93,833)**	**–**	**–**	**(93,833)**
At 31 December 2024	**–**	**(56,856)**	**(2,140,734)**	**(2,197,590)**

Gross deferred corporation tax assets	Share schemes $'000	Decommissioning provision $'000	Other provisions $'000	Tax losses $'000	Hedges $'000	Total $'000
At 1 January 2023	–	666,052	–	1,972,174	(8,678)	2,629,548
True-up in respect of prior years	177	–	–	(4,989)	–	(4,812)
Reclassification to deferred corporation tax liabilities	–	–	–	–	8,678	8,678
Origination and reversal of temporary differences	3,802	55,654	–	(211,949)	–	(152,493)
At 31 December 2023 and 1 January 2024	3,979	721,706	–	1,755,236	–	2,480,921
Business combinations (note 17)	–	**257,392**	**21,350**	**567,666**	–	**846,408**
True-up in respect of prior years	–	**(8)**	–	**(5,033)**	–	**(5,041)**
Origination and reversal of temporary differences	**962**	**60,776**	–	**(198,274)**	–	**(136,536)**
Reclassification from deferred corporation tax liabilities	**–**	**–**	**–**	**–**	**93,833**	**93,833**
At 31 December 2024	**4,941**	**1,039,866**	**21,350**	**2,119,595**	**93,833**	**3,279,585**

28. Taxation continued

Deferred PRT asset	Total $'000
At 1 January 2023	21,721
Origination and reversal of temporary differences	70,037
At 31 December 2023 and 1 January 2024	91,758
Origination and reversal of temporary differences	**50,381**
At 31 December 2024	**142,141**

The carrying value of the net deferred tax asset (DTA) and the deferred PRT asset at 31 December 2024 of $1,082 million and $142 million, respectively (2023: $613 million and $92 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 2029.

An EPL (or 'Levy') was enacted on 14 July 2022, applying a Levy of 25% to the profits of oil and gas companies until 31 December 2025 or earlier if prices return to normalised levels. On 17 November 2022, the Levy was increased to 35% and extended to 31 March 2028 regardless of oil and gas prices. The Levy is charged on oil and gas profits calculated on the same basis as Ring Fence Corporation Tax (RFCT), however, excludes relief for decommissioning and finance costs. RFCT losses and investment allowance are not available to offset the EPL. On 9 June 2023 an Energy Security Investment Mechanism price floor was announced which would remove the EPL if both average oil and gas prices fall to, or below, $71.40 per barrel for oil and £0.54 per therm for gas, for two consecutive quarters. It is not currently forecast that this price floor will be met for both oil and gas prices and, therefore, there is currently no impact from this on tax carrying values. On 6 March 2024, an extension of the Levy until 31 March 2029 was announced 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, of which only the rate increase had been enacted at 31 December 2024. Had the two-year extension to 31 March 2030 been enacted at 31 December 2024, this would have reduced the net deferred tax asset by $318 million. This extension was substantively enacted on 3 March 2025 and will, therefore, be a charge to the consolidated statement of profit or loss in Q1 of 2025.

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

	2024 $'000	2023 $'000
Capital commitments		
Capital commitments incurred jointly with other venturers (Group's share)	**399,613**	506,959

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 2024, the Group had commitments for future capital expenditure amounting to $400 million (2023: $507 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.

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 2024, the Group had $822 million (31 December 2023: $450 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.

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 $'000	Mandatorily measured at fair value through profit or loss $'000	Derivatives designated in hedge relationships $'000	Total carrying amount $'000
Financial assets				
Cash and cash equivalents	**165,123**	–	–	**165,123**
Other financial assets	**11,317**	–	–	**11,317**
Trade and other receivables - excluding VAT receivable	**411,056**	–	–	**411,056**
Derivative financial instruments	–	–	**32,962**	**32,962**
Financial liabilities				
Borrowings	**(1,024,948)**	–	–	**(1,024,948)**
Trade and other payables - excluding deferred income, inventory overlift and bonus/holiday pay accruals	**(439,674)**	–	–	**(439,674)**
Lease liability	**(40,159)**	–	–	**(40,159)**
Contingent and deferred consideration	**(272,758)**	**(240,491)**	–	**(513,249)**
Derivative financial instruments	–	**(7,484)**	**(143,979)**	**(151,463)**
				(1,549,035)

30. Financial instruments continued

The accounting classification of each category of financial instruments and their carrying amounts as at 31 December 2023 are set out below:

	Measured at amortised cost $'000	Mandatorily measured at fair value through profit or loss $'000	Derivatives designated in hedge relationships $'000	Total carrying amount $'000
Financial assets				
Cash and cash equivalents	153,215	–	–	153,215
Trade and other receivables - excluding VAT receivable	330,351	–	–	330,351
Derivative financial instruments	–	2,782	154,525	157,307
Financial liabilities				
Borrowings	(748,151)	–	–	(748,151)
Trade and other payables - excluding deferred income, inventory overlift and bonus/holiday pay accruals	(343,279)	–	–	(343,279)
Lease liability	(20,559)	–	–	(20,559)
Contingent and deferred consideration	(63,979)	(296,390)	–	(360,369)
Derivative financial instruments		(10,373)	(3,335)	(13,708)
				(845,193)

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 $'000	**Level 2 $'000**	**Level 3 $'000**	**Total Fair Value $'000**
Contingent consideration (note 26)	–	**(1,165)**	**(239,326)**	**(240,491)**
Derivative financial instrument asset	–	**32,962**	–	**32,962**
Derivative financial instrument liability	–	**(151,463)**	–	**(151,463)**

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

	$'000
At 1 January 2024	**(272,351)**
Cash settlements	**14,995**
Changes in fair value	**18,030**
At 31 December 2024	**(239,326)**

30. Financial instruments continued

The following table presents the Group's material financial instruments measured at fair value for each hierarchy level as at 31 December 2023:

	Level 1 $'000	Level 2 $'000	Level 3 $'000	Total Fair Value $'000
Contingent consideration (note 26)	–	(24,039)	(272,351)	(296,390)
Derivative financial instrument asset	–	157,307	–	157,307
Derivative financial instrument liability	–	(13,708)	–	(13,708)

Movements in level 3 financial instruments in the 12 months to 31 December 2023 were as follows:

	$'000
At 1 January 2023	(223,246)
Additions	(26,872)
Accretion	(8,799)
Changes in fair value	(13,434)
At 31 December 2023	(272,351)

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 6.33% (31 December 2023: 4.6%).

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 million (31 December 2023: $23.3 million) 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 $21.7 million (31 December 2023: $41.0 million).

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	**2024 $'000**	2023 $'000
20% decrease in probability	**84,245**	97,119
20% increase in probability	**(77,051)**	(84,086)

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	**2024 $'000**	2023 $'000
1% decrease in discount rate	**(5,707)**	(5,284)

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.

30. Financial instruments continued

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 2024 and 31 December 2023, 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 $1,024.9 million (2023: $748.2 million) and the equivalent fair value is $1,025.5 million (2023: $781.4 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 table below presents the gain on financial instruments that has been recognised in the consolidated statement of profit or loss as disclosed in note 8.

	2024 $'000	2023 $'000
Revaluation of forex forward contracts	**(1,310)**	7,313
Revaluation of interest rate swaps	**(637)**	(6,488)
Revaluation of commodity hedges	**2,291**	42,006
Total revaluation gain on financial instruments	**344**	42,831
Realised gains/(losses) on forex forward contracts	**5,760**	(6,282)
Realised gains on interest rate swaps	**638**	6,967
Realised losses on commodity hedges	**(1,575)**	(457)
Total gain on financial instruments (note 8)	**5,167**	43,059

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	**2024 $'000**	2023 $'000
At 1 January	**39,818**	16,710
Change in fair value of derivative instruments	**(68,492)**	358,141
Amounts recycled to revenue	**(135,122)**	(265,711)
Amounts recycled to operating costs	**(8,738)**	–
Amounts recycled to dividends	**(1,285)**	–
Amount per consolidated statement of comprehensive income	**(213,637)**	92,430
Deferred tax on movement in year	**158,035**	(69,322)
Cash flow hedge reserve at 31 December	**(15,784)**	39,818

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	2024 $'000	2023 $'000
At 1 January	**4,068**	3,275
Change in fair value of the intrinsic value of derivative instruments	**(55,744)**	(12,269)
Amounts recycled to revenue – oil put premiums	**1,697**	11,850
Amounts recycled to revenue – gas put premiums	**3,240**	3,590
Amount per consolidated statement of comprehensive income	**(50,807)**	3,170
Deferred tax on movement in year	**37,607**	(2,378)
Cost of hedging reserve at 31 December	**(9,132)**	4,068

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;
- 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 and 30% for year four, and 0% thereafter.

30. Financial instruments continued

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 table below represents total commodity hedges in place at the 2023 year-end:

Derivative	**Term**	**Volume**		**Average price**
Oil swaps	Jan 24 – Dec 24	1,931,500	bbls	$82/bbl
Oil collars	Jan 24 – Dec 24	2,744,000	bbls	$75/bbl floor – $87/bbl ceiling
Gas swaps	Jan 24 – Dec 24	53,175,000	therms	140p/therm
Gas swaps	Jan 25 – Sep 25	18,225,000	therms	120p/therm
Gas collars	Jan 24 – Dec 24	123,350,000	therms	135p/therm floor – 210p/therm ceiling
Gas collars	Jan 25 – Mar 25	9,000,000	therms	130/therm floor – 185p/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 carrying value of commodity derivatives at the reporting date. The impact on equity is the same as the impact on profit before tax.

Change in realised commodity price	**2024 $'000**	2023 $'000
20% decrease in realised oil price	**(235,713)**	(177,151)
20% decrease in realised gas price	**(119,799)**	(146,794)

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.

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 2024 or 31 December 2023.

30. Financial instruments continued

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	**2024 $'000**	2023 $'000
Increase of 250 basis points	**(8,369)**	(22,370)

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 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.

As at 31 December 2023, the Group had an average of £10.2 million per quarter hedged at an average forward rate of $1.219:£1 for the period January to December 2024. As at 31 December 2023, the Group had an average of £30.3 million per quarter hedged at an average collar floor of $1.200:£1 and average collar ceiling of $1.230:£1 for the period January to December 2024.

The following table summarises the sensitivity to a reasonably possible change in the US Dollar to 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 Sterling foreign exchange rate	**2024 $'000**	2023 $'000
10% weakening of Sterling against the US Dollar (2023 revised as explained below)	**(6,895)**	(6,855)

In the 2023 Annual Report and Accounts, the Group incorrectly included non-monetary items denominated in Sterling to calculate the above sensitivity analysis. The correct impact on profit before tax was a loss of $7 million and not a loss of $123 million as disclosed previously.

A 10% strengthening of 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 Sterling denominated monetary net assets at 31 December 2024 were £55 million (2023: £53.8 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 2024, 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 2024 (31 December 2023: $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 2024, the Group's exposure is $nil (31 December 2023: $nil).

30. Financial instruments continued

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.

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 2023 and 2024, substantially all accounts payable are current. As borrowings are linked to SOFR, a spot rate at 31 December 2024 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 2024:

	Weighted average effective interest rate	Within 1 year $'000	Within 2 to 5 years $'000	More than 5 years $'000	Total $'000	Carrying amount $'000
Trade and other payables	-	**(439,674)**	-	-	**(439,674)**	**(439,674)**
Contingent and deferred consideration	-	**(310,132)**	**(212,908)**	**(44,536)**	**(567,576)**	**(513,249)**
Lease liabilities	**5.69%**	**(21,046)**	**(21,876)**	-	**(42,922)**	**(40,159)**
Borrowings	**8.14%**	**(85,462)**	**(1,356,881)**	-	**(1,442,343)**	**(1,024,948)**
		(856,314)	**(1,591,665)**	**(44,536)**	**(2,492,515)**	**(2,018,030)**

The following table shows the timing of cash outflows, including future interest, relating to financial liabilities, excluding derivatives, at 31 December 2023:

	Weighted average effective interest rate	Within 1 year $'000	Within 2 to 5 years $'000	More than 5 years $'000	Total $'000	Carrying amount $'000
Trade and other payables	–	(343,279)	–	–	(343,279)	(343,279)
Contingent and deferred consideration	–	(101,669)	(248,388)	(44,508)	(394,565)	(360,369)
Lease liabilities	6.07%	(20,152)	(669)	–	(20,821)	(20,559)
Borrowings	8.85%	(64,190)	(840,085)	–	(904,275)	(748,151)
		(529,290)	(1,089,142)	(44,508)	(1,662,940)	(1,472,358)

30. Financial instruments continued

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.

At 31 December 2024	Within 1 year $'000	Within 2 to 5 years $'000	Total $'000
Net-settled (derivative liabilities):			
Commodity options	**(74,252)**	**(10,293)**	**(84,545)**
Gross-settled:			
Foreign exchange forwards – gross outflows	**(191,464)**	–	**(191,464)**
Foreign exchange collars – gross outflows	**(191,074)**	–	**(191,074)**
	(456,790)	**(10,293)**	**(467,083)**

At 31 December 2023	Within 1 year $'000	Within 2 to 5 years $'000	Total $'000
Net-settled (derivative liabilities):			
Commodity options	(2,290)	–	(2,290)
Gross-settled:			
Foreign exchange forwards – gross outflows	(113,342)	–	(113,342)
Foreign exchange collars – gross outflows	(155,071)	–	(155,071)
	(270,703)	–	(270,703)

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:

	2024 $'000	2023 $'000
Oil swaps – cash flow hedge	**19,836**	9,913
Oil collars – cash flow hedge	**6,536**	7,434
Gas swaps – cash flow hedge	**(49,522)**	47,232
Gas swaps – non-cash flow hedge	–	(2,290)
Gas collars – cash flow hedge	**(81,185)**	89,944
Interest rate swaps – non-cash flow hedge	–	637
FX forwards – cash flow hedge	**214**	(3,961)
FX forwards – non-cash flow hedge	**(7,484)**	–
FX collars – cash flow hedge	**(6,896)**	(3,335)
FX collars – non-cash flow hedge	–	(1,975)
	(118,501)	143,599

Maturity analysis of derivative financial instruments	2024 $'000	2023 $'000
Non-current assets	–	17,810
Current assets	**32,962**	139,497
Non-current liabilities	**(20,987)**	–
Current liabilities	**(130,476)**	(13,708)
	(118,501)	143,599

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 $260 million (2023: $113 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 2024 of $113 million (2023: $88 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 2024 and 2023.

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 31 December 2024. Accordingly, the Group has not offset any derivatives balances in the statement of financial position in any of the periods presented.

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 $000	Related amounts not set off in the statement of financial position $000	Net amount $000
Derivative assets	**32,962**	**(22,962)**	**10,000**
Derivative liabilities	**(151,463)**	**22,962**	**(128,501)**

Financial instruments subject to enforceable master netting agreements and similar agreements at 31 December 2023 are detailed below:

	Amount recognised in the statement of financial position $000	Related amounts not set off in the statenment of finacial position $000	Net amount $000
Derivative assets	157,306	(4,436)	152,870
Derivative liabilities	(13,708)	4,436	(9,272)

32. Related-party transactions

The immediate parent undertaking is DKL Energy Limited (incorporated in Jersey) which owns 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.

Following the Business Combination, as set out in note 17, Eni UK Limited, an indirect wholly owned subsidiary of Eni S.p.A., owns 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 $000	Purchases from related parties $000	Amounts owed by related parties at 31 December 2024 $000	Amounts owed to related parties at 31 December 2024[1] $000
2024	305,634	2,037	111,639	210,910

1. Includes $204.5 million of deferred consideration in respect of the Business Combination (see note 17 and note 26).

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. The Group and Delek's ultimate controlling party is Mr Itshak Sharon Tshuva.

There were no related party transactions with Delek Group Limited or Mr Tshuva in either the year ended 31 December 2024 or the year ended 31 December 2023.

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	Country of incorporation	% equity interest at 31 December 2024	2023
Ithaca Energy (E&P) Limited	1	Jersey	100%	100%
Ithaca Energy (UK) Limited	2	Scotland	100%	100%
Ithaca Minerals (North Sea) Limited	2	Scotland	100%	100%
Ithaca Energy (Holdings) Limited	3	Bermuda	100%	100%
Ithaca Energy Holdings (UK) Limited	2	Scotland	100%	100%
Ithaca Energy (North Sea) PLC	2	Scotland	100%	100%
Ithaca Oil and Gas Limited	4	England and Wales	100%	100%
Ithaca Petroleum Ltd	4	England and Wales	100%	100%
Ithaca Causeway Limited	4	England and Wales	100%	100%
Ithaca Gamma Limited	4	England and Wales	100%	100%
Ithaca Alpha (NI) Limited	5	Northern Ireland	100%	100%
Ithaca Epsilon Limited	4	England and Wales	100%	100%
Ithaca Exploration Limited	4	England and Wales	100%	100%
Ithaca Petroleum EHF	6	Iceland	100%	100%
Ithaca Dorset Limited	4	England and Wales	100%	100%
Ithaca SP UK Limited	4	England and Wales	100%	100%
Ithaca GSA Holdings Limited	1	Jersey	100%	100%
Ithaca GSA Limited	1	Jersey	100%	100%
Ithaca Energy Developments UK Limited	4	England and Wales	100%	100%
FPF-1 Limited	7	Jersey	100%	100%
Ithaca MA Limited	4	England and Wales	100%	100%
Ithaca SP Bonds PLC	4	England and Wales	100%	100%
Ithaca SP Finance Limited	4	England and Wales	100%	100%
Ithaca SP (Holdings) Limited	4	England and Wales	100%	100%
Ithaca SP E&P Limited	4	England and Wales	100%	100%
Ithaca SP O&G Limited	4	England and Wales	100%	100%
Ithaca SPE Limited	4	England and Wales	100%	100%
Ithaca Zeta Limited	4	England and Wales	100%	100%
Ithaca EF Limited (formerly Eni Elgin/Franklin Limited)	4	England and Wales	100%	–
Ithaca UKCS (formerly Eni UKCS Limited)	4	England and Wales	100%	–
Ithaca (NE) E&P Limited (formerly Eni Energy E&P UK Limited)	4	England and Wales	100%	–
Ithaca (NE) UKCS Limited (formerly Eni Energy E&P UKCS Limited)	4	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 Borgartúni 26, 105 Reykjavík, Iceland
7 26 New Street, St Helier, Jersey, JE2 3RA
8 All of the above shares represent an ordinary class of shares.

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 periods ended 31 December 2024 and 2023:

Key management personnel	2024 $'000	2023 $'000
Salaries and short-term employee benefits	**5,910**	5,741
Payments made in lieu of pension contributions	**288**	249
Company pension contributions	**148**	106
Compensation for loss of office	**153**	–
Share-based payment	**1,575**	5,863
	8,074	11,959

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

On 5 January 2024 Alan Bruce stepped down from his role as Chief Executive Officer and on 28 May 2024 Gilad Myerson stepped down from his role as Executive Chairman. Full details of the section 430 (2B) of the Companies Act 2006 disclosures in respect of Mr Myerson will be included in the Remuneration Committee report and full details in respect of Mr Bruce were included in the Directors' remuneration report in the 2023 Annual Report and Accounts.

33. Share-based payments

The charge for share-based payment transactions in the year to 31 December 2024 was $6.1 million (2023: $16.4 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 and DBS were as follows:

	Heritage awards	At-IPO awards	2022 LTIP awards	2024 LTIP awards	2024 RSU awards	2024 DBS awards	Total
Balance at 1 January 2023	1,687,296	4,908,903	2,836,660	–	–	–	9,432,859
Awarded during the year in lieu of dividend payments	191,401	190,426	–	–	–	–	381,827
Forfeited during the year	(127,880)	(296,966)	(276,123)	–	–	–	(700,969)
Exercised during the year	(921,882)	(521,679)	–	–	–	–	(1,443,561)
Balance at 31 December 2023	**828,935**	**4,280,684**	**2,560,537**	–	–	–	**7,670,156**
Granted during the year	–	–	–	**3,589,590**	**303,103**	**239,291**	**4,131,984**
Awarded during the year in lieu of dividend payments	**76,000**	**1,454,497**	–	**532,474**	**51,211**	**40,430**	**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	**18,976**	**4,467,161**	**2,310,618**	**4,122,064**	**354,314**	**279,721**	**11,552,854**
Exercisable at 31 December 2024	**18,976**	**2,478,094**	–	–	–	–	**2,497,070**
Share option exercise price	**£nil**	**£nil**	**£nil**	**£nil**	**£nil**	**£nil**	**N/A**
Weighted average share price on date of exercise	**£1.20**	**£1.15**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
Weighted average remaining life	**N/A**	**0.9 years**	**1.3 years**	**2.6 years**	**2.5 years**	**2.5 years**	**N/A**

All LTIP, DBS and RSU awards are nil-cost options. There are no performance conditions attaching to the Heritage, At-IPO, 2024 DBS or 2024 RSU awards. Details of the performance conditions of the 2022 LTIP and the 2024 LTIP are set out in the Remuneration Committee report. The fair values of all the LTIP 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 vest 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 and the 2024 RSU awards vest in three equal tranches over the period to 4 July 2027. 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 2024 was $6.1 million (2023: $12.9 million).

IPO-related share options

Under the terms of their termination agreements, both Mr Myerson and Mr Bruce retained an entitlement to $2.0 million worth of share options each. The IPO-related share options were fully expensed in the period up to 31 December 2023 and the charge for the year to 31 December 2024 was $nil (2023: $0.5 million).

33. Share-based payments continued

Management Equity Plan (MEP)

During the year to 31 December 2023, Mr Myerson elected to receive the Aggregate Guaranteed Payment (AGP) and $8.0 million (AGP of $10.0 million less special bonuses of $2.0 million) was paid to him on 1 December 2023. As a result, the MEP share options, which would otherwise have vested over the period to 30 September 2026, were transferred back to the Company for nil payment.

There were no performance conditions attaching to either the MEP share options or the AGP.

The total share-based payment charge for MEP arrangements in the year to 31 December 2024 was $nil (2023: $3.0million).

The share-based payment reserve of $18.8 million (2023: $15.5 million) reflects the opening balance of $15.5 million (2023: $4.9 million) plus the charge of $6.1 million (2023: $12.9 million) for LTIPs and DBSs plus the charge of $nil (2023: $0.5 million) for IPO-related share options less the cost of satisfying exercises during the year of $2.8 million (2023: $2.8 million).

34. Dividends

	2024 $m	2023 $m
First 2024 interim dividend of $0.0986 (2023: $0.132) per ordinary share announced 22 August 2024 and paid 27 September 2024	**99.4**	133.0
Second 2024 dividend of $0.1209 (2023: $0.132) per ordinary share announced 21 November 2024 and paid 20 December 2024	**199.7**	133.0
Total dividends paid relating to the year ended 31 December[1]	**299.1**	266.0
Third 2024 interim dividend of $0.[XXXX] (2023: $0.132) per ordinary share announced [XX] March 2025 and payable [XX] April 2025 (not accrued in the 2024 results)[1]	**200.0**	133.6
Total dividends paid or payable relating to year ended 31 December	**499.1**	399.6

1. The third 2023 interim dividend of $133.6 million was paid on 17 April 2024. Total cash payments in the year to 31 December 2024 were $432.7 million.

35. Subsequent events

On 29 January 2025, the Group announced a reorganisation and streamlining of the organisational structure for onshore staff with a targeted completion of 1 July 2025. It is not anticipated that the cost of this reorganisation will be material.

On 30 January 2025, the Court of Session ruled that 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 but that no oil could be extracted until consent has been given. Further details are set out in note 3.

On 25 March 2025, the Group announced the signing of a sale and purchase agreement to acquire the entire issued share capital of JAPEX UK E&P Limited for an enterprise value of $193 million, based on an effective date of 1 January 2024. The acquisition, which is subject to certain conditions including regulatory approval, and is subject to customary purchase price adjustments, which, assuming an illustrative completion date of 30 June 2025, equates to an estimated payment at completion of approximately $140 million.

Alternative Performance Measures

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, tax, put premiums on oil and gas derivative instruments, revaluation of derivative contracts, depletion depreciation and amortisation, impairment charges, exploration and evaluation expenditure, remeasurements of decommissioning reimbursement receivables, fair value gains or losses on contingent consideration, business combination costs and historic claims relating to acquisitions. 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 profit after tax as follows:

	2024 $m	2023 $m
Profit after tax	**153.2**	292.5
Taxation charge[1] (note 28)	**181.1**	9.5
Depletion, depreciation and amortisation (note 15)	**600.2**	740.3
Impairment charges on development and production assets (note 19)	**263.0**	557.9
Finance income (note 9)	**(11.2)**	(5.7)
Finance costs (note 9)	**200.6**	189.7
Oil and gas put premiums (note 5)	**4.9**	15.4
Revaluation of derivative contracts (note 30)	**(0.3)**	(42.8)
Business combination costs (note 7)	**16.3**	–
Exploration and evaluation expenses (note 14)	**24.5**	13.6
Historic claim relating to an acquisition (note 8)	–	(50.1)
Remeasurements of decommissioning reimbursement receivables (note 8)	–	(5.6)
Fair value (gains)/losses on contingent consideration (note 8)	**(27.3)**	8.0
Adjusted EBITDAX	**1,405.0**	1,722.7

1 The tax charge for the year rounds to $181.2 million, however. profit after tax plus the tax charge rounds to $334.3 million, so the tax charge has been rounded down in the above table to accurately reflect the profit before tax.

Adjusted net income: profit after tax excluding impairment charges or reversals, 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 profit after tax as follows:

	2024 $m	2023 $m
Profit after tax	**153.2**	292.5
Impairment charges[1]	**263.0**	557.9
Tax credit on impairment charges[1]	**(160.3)**	(403.9)
Business combination costs	**16.3**	–
One-off finance charges related to refinancing	**22.0**	–
Tax credit on business combination costs and one-off finance charges	**(28.7)**	–
EPL tax impact of increase in rate from 35% to 38%	**58.1**	–
Adjusted net income	**323.6**	446.5

1. Post-tax impairment charges of $102.7 million comprise of $38.5 million in relation to the Greater Stella Area and Pierce and $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 1,164.3 million (2023: 1,006.7 million)

	2024	2023
Adjusted EPS (cents)	**27.8**	44.4

Adjusted net debt: consists of amounts outstanding under RBL facility, senior unsecured loan notes, bp unsecured loan 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:

	2024 $m	2023 $m
RBL drawn facility	**(150.0)**	–
Senior unsecured notes	**(750.0)**	(625.0)
bp unsecured loan	**–**	(100.0)
Project capital expenditure facility	**(150.0)**	–
Cash and cash equivalents	**165.1**	153.2
Adjusted net debt	**(884.9)**	(571.8)

Alternative Performance Measures continued

Pro forma leverage ratio: adjusted net debt at the end of the year divided by adjusted EBITDAX for the year then ended, including $580.3 million of adjusted EBITDAX generated by the Eni UK businesses from 1 January 2024 to 2 October 2024. The 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:

	2024	2023
Adjusted net debt ($m)	**884.9**	571.8
Pro forma adjusted EBITDAX ($m)	**1,985.3**	1,722.7
Pro forma leverage ratio	**0.45x**	0.33x

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:

	2024 $m	2023 $m
Cash and cash equivalents	**165.1**	153.2
Undrawn borrowing facilities	**850.0**	725.0
Undrawn project capital expenditure facility	–	150.0
Available liquidity	**1,015.1**	1,028.2

Group free cash flow: net cash flow from operating activities less cash used in investing activities, adjusting for 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:

	2024 $m	2023 $m
Net cash flow from operating activities	**853.3**	1,290.8
Net cash used in investing activities, including cash acquired through business combinations	**(390.9)**	(492.4)
Cash acquired through business combination	**(107.5)**	–
Bank interest and charges	**(109.6)**	(99.8)
Interest rate swaps	**0.6**	7.0
Group free cash flow	**245.9**	705.6

Unit operating expenditure: operating costs (excluding over/underlift) including tariff expense but excluding 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:

	2024	2023
Operating costs of hydrocarbon activities per note 6 ($m)	**617.9**	576.7
Less tanker costs included within operating costs of hydrocarbon activities in note 6 ($m)	**(18.3)**	(20.7)
Less tariff income included within other income in note 5 ($m)	**(30.0)**	(31.6)
Operating costs used to calculate unit operating expenditure ($m)	**569.6**	524.4
Production (mmboe)	**25.42**	25.64
Unit operating expenditure ($/boe)	**22.4**	20.5

Alternative Performance Measures continued

Adjusted operating costs and adjusted unit operating expenditure: operating costs less tanker costs, net of tariff income including those related to the Eni UK businesses from the effective economic date of the business combination of 1 July 2024 and adjusted unit operating expendidure being adjusted operating costs divided by total production from the effective economic date of 1 July 2024.

	2024	2023
Operating costs less tanker costs, net of tariff income as set out above ($m)	**569.6**	N/A
Eni UK businesses' operating costs less tanker costs, net of tariff income from 1 July 2024 to 2 October 2024 ($m)	**79.4**	N/A
Adjusted operating costs used to calculate unit operating expenditure ($m)	**649.0**	N/A
Production (mmboe)	**29.34**	N/A
Adjusted unit operating expenditure ($/boe)	**22.1**	N/A

Other key performance indicators

DD&A rate per barrel: depletion, depreciation and amortisation charge for the year divided by net production for the year. D,D&A per barrel was:

	2024	2023
Depletion, depreciation and amortisation per note 15 ($m)	**600.2**	740.3
Production (mmboe)	**25.42**	25.64
DD&A ($/boe)	**23.6**	28.8

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 2024 was 80,177 boe/d (2023: 70,239 boe/d). This includes 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 above, with the exception of the adjusted rate per barrel, include volumes from the Eni UK businesses from the date of completion of 3 October 2024 as the associated costs have been recorded from that date.

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 2024 (2023: 1).

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 2024 (2023: 0).