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$675,000,000

9⅞% Senior Notes due 2031



EnQuest PLC

EnQuest PLC, incorporated as a public limited liability company under the laws of England and Wales (the "**Company**"), is offering $675 million aggregate principal amount of its 9⅞% Senior Notes due 2031 (the "**Notes**"). We will pay interest on the Notes semi-annually on April 30 and October 30 of each year, commencing October 30, 2026. The Notes will mature on April 30, 2031. The Notes will be issued pursuant to an indenture (the "**Indenture**") dated April 30, 2026 (the "**Issue Date**") by and between, *inter alios*, the Company, the Guarantors (as defined below) and Deutsche Bank Trust Company Americas as trustee (the "**Trustee**").

At any time on or after April 30, 2028 we may redeem all or part of the Notes by paying the redemption prices set forth in these listing particulars (the "**Listing Particulars**"). Prior to April 30, 2028, we will be entitled, at our option, to redeem all or a portion of the Notes by paying 100% of the principal amount of such Notes, plus accrued and unpaid interest, if any, plus a "make-whole" premium. In addition, prior to April 30, 2028, we may redeem, at our option, up to 40% of the Notes with the net proceeds from certain equity offerings. Prior to April 30, 2028, we may redeem during each twelve-month period commencing with the Issue Date up to 10% of the original principal amount of the Notes at a redemption price equal to 103% of the principal amount of the Notes so redeemed, plus accrued and unpaid interest, if any, to the applicable redemption date. If we undergo certain events defined as constituting a change of control, each holder may require us to repurchase all or a portion of its Notes at 101% of their principal amount, plus accrued and paid interest, if any. In the event of certain developments affecting taxation, we may redeem all, but not less than all, of the Notes. On the maturity date, we may redeem all or any remaining part of the Notes not already redeemed at a redemption price equal to 100% of the principal amount of the Notes so redeemed, plus accrued and unpaid interest, if any, to the maturity date.

The Notes will be senior debt of the Company and will rank *pari passu* in right of payment with all the Company's existing and future senior obligations. The Notes initially will be guaranteed on a senior subordinated basis (the "**Note Guarantees**") by certain of our subsidiaries (the "**Guarantors**"). The Notes will be structurally subordinated to all existing and future obligations and other liabilities (including trade payables) of our subsidiaries that are not Guarantors.

These Listing Particulars include information on the terms of the Notes and Note Guarantees, including redemption and repurchase prices, covenants and transfer restrictions.

The Notes are a new issue of securities for which there currently is no market. Application has been made to list the Notes on the Official List of the Luxembourg Stock Exchange (the "**Exchange**") and to be admitted to trading on the Euro MTF Market thereof. These Listing Particulars constitute a prospectus for the purpose of Part IV of the Luxembourg law on prospectuses for securities dated July 16, 2019.

Investing in the Notes involves a high degree of risk. See the "*Risk factors*" section of these Listing Particulars beginning on page 43 for a discussion of certain risks that you should consider in connection with an investment in any of the Notes.

Price: 99.038% (plus accrued interest, if any, from the Issue Date).

We expect that the Notes will be delivered in book entry form through The Depository Trust Company ("**DTC**") on the Issue Date. The Notes will be registered in form and will be initially held in minimum principal amounts of $200,000 and integral multiples of $1,000 in excess thereof and will only be transferrable in minimum principal amounts of $200,000 and integral multiples of $1,000 in excess thereof.

The Notes and the Note Guarantees have not been and will not be registered under the U.S. Securities Act of 1933, as amended (the "U.S. Securities Act"), or the securities laws of any other jurisdiction, and may not be offered or sold within the United States except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the U.S. Securities Act. In the United States, this offering is being made only to "qualified institutional buyers" (as defined in Rule 144A of the U.S. Securities Act) in compliance with Rule 144A under the U.S. Securities Act ("Rule 144A"). You are hereby notified that the Initial Purchasers (as defined herein) of the Notes may be relying on the exemption from the provisions of Section 5 of the U.S. Securities Act provided by Rule 144A. Outside of the United States, this offering is being made in reliance on Regulation S under the U.S. Securities Act. For further details about eligible offerees and resale restrictions, see "*Plan of distribution*" and "*Notice to investors*."

Global Coordinators and Joint Active Bookrunners

Goldman Sachs International *(B&D)* | **DNB Carnegie** | **Deutsche Bank** | **Wells Fargo Securities**

Joint Bookrunners

ING | **Macquarie Capital**

The date of these Listing Particulars is April 30, 2026.

In making your investment decision, you should rely only on the information contained in these Listing Particulars. We and Goldman Sachs International, DNB Carnegie, Inc., Deutsche Bank AG, London Branch, Wells Fargo Securities, LLC, ING Bank N.V., London Branch and Macquarie Capital (USA) Inc. (collectively, the "Initial Purchasers") have not authorized anyone to provide you with any other information. If you receive any other information, you should not rely on it. We and the Initial

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Purchasers are offering to sell the Notes only in places where offers and sales are permitted. You should not assume that the information contained in these Listing Particulars is accurate as of any date other than the date on the front cover of these Listing Particulars. Our business or financial condition and other information in these Listing Particulars may change after that date.

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IMPORTANT INFORMATION ABOUT THESE LISTING PARTICULARS

These Listing Particulars are a document that we are providing only to prospective purchasers of the Notes. You should read these Listing Particulars before making a decision whether to purchase any Notes. You must not:

- use these Listing Particulars for any other purpose;
- make copies of any part of these Listing Particulars or give a copy of it to any other person; or
- disclose any information in these Listing Particulars to any other person, other than a person retained to advise you in connection with the purchase of the Notes.

We have prepared these Listing Particulars based on information we have or have obtained from sources we believe to be reliable. Summaries of documents contained in these Listing Particulars may not be complete. We will make copies of actual documents available to you upon request. Neither we, the Initial Purchasers nor the Trustee, Registrar, Transfer Agent or any Paying Agent is providing you with any legal, investment, business, tax or other advice in these Listing Particulars. You should consult with your own counsel, accountants and other advisors as needed to assist you in making your investment decision and to advise you whether you are legally permitted to purchase the Notes.

These Listing Particulars do not constitute an offer or solicitation by anyone in any jurisdiction in which such offer or solicitation is not authorized or to any person to whom it is unlawful to make such offer or solicitation. No action has been, or will be, taken to permit a public offering in any jurisdiction where action would be required for that purpose. You must comply with all laws applicable in any jurisdiction in which you buy, offer or sell the Notes or possess or distribute these Listing Particulars, and you must obtain all applicable consents and approvals; neither we nor the Initial Purchasers shall have any responsibility for any of the foregoing legal requirements.

We are offering the Notes, and the Guarantors are issuing the Note Guarantees, in reliance on (i) an exemption from registration under the U.S. Securities Act for an offer and sale of securities that does not involve a public offering and (ii) a transaction pursuant to Regulation S that is not subject to the registration requirements of the U.S. Securities Act. If you purchase the Notes, you will be deemed to have made certain acknowledgments, representations and warranties as detailed under "*Notice to investors.*" The Notes are subject to restrictions on transferability and resale and may not be transferred or resold except as permitted under the U.S. Securities Act and applicable securities laws of any other jurisdiction pursuant to registration or exemption therefrom. You may be required to bear the financial risk of an investment in the Notes for an indefinite period. Neither we nor the Initial Purchasers are making an offer to sell the Notes in any jurisdiction where the offer and sale of the Notes is prohibited. Neither we nor the Initial Purchasers are making any representation to you that the Notes are a legal investment for you. In making an investment decision, prospective investors must rely on their own examination of the Company, the Guarantors and the terms of this offering, including the merits and risks involved of an investment in the Notes and the Notes Guarantees.

Each prospective purchaser of the Notes must comply with all applicable laws and rules and regulations in force in any jurisdiction in which it purchases, offers or sells the Notes and must obtain any consent, approval or permission required by it for the purchase, offer or sale by it of the Notes under the laws and regulations in force in any jurisdiction to which it is subject or in which it makes such purchases, offers or sales, and neither we nor the Initial Purchasers shall have any responsibility therefor.

Neither the U.S. Securities and Exchange Commission (the "**SEC**"), any U.S. state securities commission nor any non-U.S. securities authority nor other authority has approved or disapproved of the Notes or determined if these Listing Particulars are truthful or complete. Any representation to the contrary is a criminal offense.

We accept responsibility for the information contained in these Listing Particulars. We have made all reasonable inquiries and confirm to the best of our knowledge, information and belief that the information contained in these Listing Particulars with regard to us and our subsidiaries and affiliates and the Notes is true and accurate in all material respects, that the opinions and intentions expressed in these Listing Particulars are honestly held and that we are not aware of any other facts, the omission of which would make these Listing Particulars or any statement contained herein misleading in any material respect.

Neither the Initial Purchasers nor the Trustee, Registrar, Transfer Agent or any Paying Agent makes any representation or warranty, express or implied, as to, and assumes no responsibility for, the accuracy or completeness of the information contained in these Listing Particulars. Nothing contained in these Listing Particulars is, or shall be relied upon as, a promise or representation by the Initial Purchasers as to the past, the present or the future.

In connection with the offering contemplated by these Listing Particulars, the Initial Purchasers are acting exclusively for the Company and no one else. Accordingly, in connection with the offering contemplated by these Listing Particulars, the Initial Purchasers will not be responsible to anyone other than the Company for providing the protections (regulatory or otherwise) afforded to their clients or for the giving of advice in relation to the offering of the Notes.

We reserve the right to withdraw this offering at any time. We and the Initial Purchasers may reject any offer to purchase the Notes in whole or in part for any reason or no reason, sell less than the entire principal amount of the Notes offered hereby or allocate to any purchaser less than all of the Notes for which it has subscribed. The Initial Purchasers and certain of their respective related entities may acquire, for their own accounts, a portion of the Notes.

The information set out in relation to sections of these Listing Particulars describing clearing and settlement arrangements, including in the "*Description of Notes*" and "*Book-entry, delivery and form,*" is subject to a change in or reinterpretation of the rules, regulations and procedures of DTC currently in effect. While we accept responsibility for accurately summarizing the information concerning DTC, we accept no further responsibility in respect of such information.

We have applied to have the Notes listed on the Official List of the Exchange. Following the listing, the relevant listing particulars will be available at the offices of the Company. Any investor or potential investor should not base any investment decision relating to the Notes on the information contained in these Listing Particulars after publication of the listing particulars and should refer instead to the listing particulars.

IN CONNECTION WITH THIS OFFERING, GOLDMAN SACHS INTERNATIONAL (THE "STABILIZING MANAGER") (OR PERSONS ACTING ON ITS BEHALF) MAY OVER-ALLOT OR EFFECT TRANSACTIONS WITH A VIEW TO SUPPORTING THE MARKET PRICE OF THE NOTES AT A LEVEL OTHER THAN THAT WHICH MIGHT OTHERWISE PREVAIL. HOWEVER, NO ASSURANCE CAN BE GIVEN THAT THE STABILIZING MANAGER (OR PERSONS ACTING ON ITS BEHALF) WILL UNDERTAKE STABILIZATION ACTION. ANY STABILIZATION ACTION MAY BEGIN ON OR AFTER THE DATE ON WHICH ADEQUATE PUBLIC DISCLOSURE OF THE FINAL TERMS OF THIS OFFERING IS MADE AND, IF BEGUN, MAY BE DISCONTINUED AT ANY TIME, BUT IT MUST END NO LATER THAN THE EARLIER OF 30 CALENDAR DAYS AFTER THE ISSUE DATE AND 60 CALENDAR DAYS AFTER THE DATE OF THE ALLOTMENT OF THE NOTES. ANY STABILIZATION ACTION OR OVER-ALLOTMENT MUST BE CONDUCTED BY THE STABILIZING MANAGER (OR PERSONS ACTING ON ITS BEHALF) IN ACCORDANCE WITH ALL APPLICABLE LAWS AND RULES. FOR A DESCRIPTION OF THESE ACTIVITIES, SEE "*PLAN OF DISTRIBUTION*."

NOTICE TO U.S. INVESTORS

This offering is being made in the United States in reliance upon an exemption from registration under the U.S. Securities Act for an offer and sale of the Notes which does not involve a public offering. In making your purchase, you will be deemed to have made certain acknowledgments, representations and agreements. See "*Notice to investors*."

These Listing Particulars are being provided (1) to a limited number of U.S. investors that we reasonably believe to be QIBs under Rule 144A under the U.S. Securities Act for informational use solely in connection with their consideration of the purchase of the Notes and (2) to non-U.S. persons outside the United States pursuant to offshore transactions complying with Rule 903 or Rule 904 of Regulation S under the U.S. Securities Act. The Notes described in these Listing Particulars have not been registered with, recommended by or approved by the SEC, any state securities commission in the United States or any other securities commission or regulatory authority, nor has the SEC, any state securities commission in the United States or any such securities commission or authority passed upon the accuracy or adequacy of these Listing Particulars. Any representation to the contrary is a criminal offense.

NOTICE TO CERTAIN OTHER INVESTORS

EEA

PRIIPs Regulation / Prohibition of sales to EEA retail investors The Notes are not intended to be offered, sold or otherwise made available to and should not be offered, sold or otherwise made available to any retail investor in a member state in the European Economic Area ("**EEA**"). For these purposes, a retail investor means a person who is one (or more) of: (i) a retail client as defined in point (11) of Article 4(1) of Directive (EU) 2014/65 (as amended, "**MiFID II**"); or (ii) a customer within the meaning of Directive (EU) 2016/97 (as amended, the "**Insurance Distribution Directive**"), where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II or (iii) not a qualified investor as defined in Regulation (EU) 2017/1129 (as amended, the "**Prospectus Regulation**").

Consequently no key information document required by Regulation (EU) No 1286/2014 (as amended, the "**PRIIPs Regulation**") for offering, selling or distributing the Notes or otherwise making them available to retail investors in the EEA has been prepared and therefore offering, selling or distributing the Notes or otherwise making them available to any retail investor in the EEA may be unlawful under the PRIIPs Regulation. These Listing Particulars have been prepared on the basis that any offer of Notes in any member state of the EEA will be made pursuant to an exemption under the Prospectus Regulation from the requirement to publish a prospectus for offers of Notes. These Listing Particulars are not a prospectus for the purposes of the Prospectus Regulation.

MIFID II product governance / Professional investors and eligible counterparty only target market Solely for the purposes of each manufacturer's product approval process, the target market assessment in respect of the Notes has led to the conclusion that: (i) the target market for the Notes is eligible counterparties and professional clients only, each as defined in MiFID II; and (ii) all channels for distribution of the Notes to eligible counterparties and professional clients are appropriate. Any person subsequently offering, selling or recommending the Notes (a "**distributor**") should take into consideration the manufacturer's target market assessment; however, a distributor subject to MiFID II is responsible for undertaking its own target market assessment in respect of the Notes (by either adopting or refining the manufacturer's target market assessment) and determining appropriate distribution channels.

Luxembourg

These Listing Particulars should not be considered a public offering of securities in Luxembourg. The Notes may not be offered or sold to the public in Luxembourg, directly or indirectly unless:

(a)

(i) a prospectus has been duly approved by the *Commission de Surveillance du Secteur Financier* (the "**CSSF**") pursuant to part II of the Luxembourg law dated July 16, 2019 on prospectuses for securities, which applies to the Prospectus Regulation (the "**Luxembourg Prospectus Law**"), if Luxembourg is the home Member State as defined under the Prospectus Regulation; or

(ii) if Luxembourg is not the home Member State as defined under the Prospectus Regulation, the CSSF and the European Securities and Markets Authority have been provided by the competent authority in the home Member State with a certificate of approval attesting that a prospectus in relation to the Notes has been duly approved in accordance with the Prospectus Regulation and with a copy of that prospectus; or

(iii) the offer of Notes benefits from an exemption from, or constitutes a transaction not subject to, the requirement to publish a prospectus or similar document under the Luxembourg Prospectus Law; and

(b) the PRIIPs Regulation and the Luxembourg law of April 17, 2018 implementing PRIIPs Regulation in Luxembourg has been complied with.

United Kingdom

U.K. PRIIPs Regulation / Prohibition of sales to U.K. retail investors These Listing Particulars are for distribution only to persons who (i) have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (as amended, the "**Financial Promotion Order**"), (ii) are persons falling within Article 49(2)(a) to (d) ("high net worth companies, unincorporated associations etc.") of the Financial Promotion Order, (iii) are outside the United Kingdom or (iv) are persons to whom an invitation or inducement to engage in investment activity (within the meaning of section 21 of the Financial Services and Markets Act 2000 ("**FSMA**")) in connection with the issue or sale of any Notes may otherwise lawfully be communicated or caused to be communicated (all such persons together being referred to as "**Relevant Persons**"). These Listing Particulars are directed only at Relevant Persons and must not be acted on or relied on by persons who are not Relevant Persons and will be engaged only with Relevant Persons.

The Notes are not intended to be offered, sold or otherwise made available to and should not be offered, sold or otherwise made available to any retail investor in the United Kingdom (the "**U.K.**"). For these purposes, a "retail investor" means a person who is not a professional client, as defined in point (8) of Article 2(1) of Regulation (EU) 600/2014 as it forms part of domestic law by virtue of the European Union (Withdrawal) Act 2018 (as amended, the "**EUWA**"). Consequently, no key information document required by Regulation (EU) No 1286/2014 as it forms part of domestic law by virtue of the EUWA (as amended, the "**U.K. PRIIPs Regulation**") for offering or selling the Notes or otherwise making them available to retail investors in the U.K. has been prepared and, therefore, offering or selling the Notes or otherwise making them available to any retail investor in the U.K. may be unlawful under the U.K. PRIIPs Regulation.

These Listing Particulars have been prepared on the basis that any offer of the Notes in the U.K. will be made pursuant to an exemption under the U.K. Prospectus Regulation from the requirement to publish a prospectus for offers of Notes. These Listing Particulars are not a prospectus for the purposes of the U.K. Prospectus Regulation.

U.K. product governance / professional client and eligible counterparty only target market Solely for the purposes of each manufacturer's product approval process, the target market assessment in the United Kingdom in respect of the Notes has led to the conclusion that: (i) the target market for the Notes is professional clients and eligible counterparties, each as defined in the Glossary to the Financial Conduct Authority ("**FCA**") Handbook of Rules and Guidance; and (ii) all channels for distribution of the Notes to eligible counterparties and professional clients are appropriate. Any person subsequently offering, selling or recommending the Notes (a "**distributor**") should take into consideration the manufacturers' target market assessment; however, a distributor subject to the FCA Product Intervention and Product Governance Sourcebook is responsible for undertaking its own target market assessment in respect of the Notes (by either adopting or refining the manufacturers' target market assessment) and determining appropriate distribution channels.

THESE LISTING PARTICULARS CONTAIN IMPORTANT INFORMATION WHICH YOU SHOULD READ BEFORE YOU MAKE ANY DECISION WITH RESPECT TO AN INVESTMENT IN THE NOTES.

FORWARD-LOOKING STATEMENTS

These Listing Particulars include statements that are, or may deemed to be, "forward-looking statements," within the meaning of the securities laws of certain jurisdictions, including statements under the headings "*Presentation of industry and market data*," "*Summary*," "*Risk factors*," "*Management's discussion and analysis of financial condition and results of operations*," "*Our business*" and other sections. These forward-looking statements can be identified by the use of forward-looking terminology, including the terms "anticipate," "expect," "suggests," "plan," "believe," "intend," "estimates," "targets," "projects," "should," "could," "would," "may," "will," "forecast," and other similar expressions or, in each case, their negative or other variations or comparable terminology. These forward-looking statements include all matters that are not historical facts. They appear in a number of places throughout these Listing Particulars and include statements regarding our intentions, beliefs or current expectations concerning, among other things, our results of operations, financial condition, liquidity, prospects, growth, strategies and the industry in which we operate.

We caution you that forward-looking statements are not guarantees of future performance and that our actual results of operations, financial condition and liquidity, and the development of the industry in which we operate may differ materially from those made, described in or suggested by the forward-looking statements contained in these Listing Particulars. In addition, even if our results of operations, financial condition and liquidity, and the development of the industry in which we operate are consistent with the forward-looking statements contained in these Listing Particulars, those results or developments may not be indicative of results or developments in subsequent periods.

Any forward-looking statements that we make in these Listing Particulars speak only as of the date of such statement, and we undertake no obligation and do not intend to update such statements. Comparisons of results for current and any prior periods are not intended to express any future trends or indications of future performance, unless expressed as such, and should only be viewed as historical data.

By their nature, forward-looking statements involve risks and uncertainties because they relate to events and depend on circumstances that may or may not occur in the future and may not be within our control. We believe that these risks and uncertainties include, but are not limited to, those described in the "*Risk factors*" section of these Listing Particulars:

- the volatility in oil and gas prices, including as a result of ongoing conflicts in oil-producing regions;
- climate change legislation, including costs of complying with such legislation;
- the level of our 1P and 2P Reserves and 2C Resources may be lower than expected;
- the inability to replace 2P Reserves that we produce;
- drilling, exploration and production risks and hazards;
- significant uncertainty as to the success of project execution and delivery;
- the competitiveness of our industry;
- the effect of geopolitical conflicts especially regarding the military action of Russia against Ukraine and the resulting sanctions against Russia, Russian companies and individuals, as well as the impact on oil prices;
- the technological developments in the industry;
- the effect of oil prices on our ability to generate future cash to fund capital expenditures, sustain operations and meet liquidity requirements;
- difficulties to repay the Notes or other indebtedness currently scheduled to be repayable;
- the concentration of our production in a relatively small number of fields in the UKCS and South East Asia;
- our reliance on old equipment or assets and infrastructure which is operated by third parties;
- changes in the licensing, regulatory and fiscal regimes in the United Kingdom and South East Asia;
- our acquisition of exploration, development and production properties;
- delays, additional costs and other difficulties relating to our work with commercial partners;

- our customer concentration;
- counterparty credit risk;
- approval of commercial partners regarding exit strategies;
- the failure by us, our contractors and our offtakers and suppliers to obtain access to necessary equipment;
- failure to integrate acquisitions successfully;
- unanticipated increases in decommissioning obligations;
- our hedging activities;
- our dependence on, and our ability to hire and retain, the expertise of certain employees, directors and managers;
- damage to our business reputation;
- inadequate insurance coverage;
- risk of litigation;
- currency exchange and inflation;
- our inability to dispose of assets on attractive terms;
- costs relating to compliance with, or liability under, health, safety and environmental regulations;
- violations of anti-corruption laws;
- disruption to our website and internal systems;
- our lack of ownership of our trademarks and other intellectual property;
- work stoppages and labor disputes;
- changes in our estimated tax liability and changes in tax laws and regulations;
- title to our assets and licenses; and
- compliance with regulatory regimes associated with international operations.

Statements relating to reserves are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

The list above is not exhaustive and there are other factors that may cause our actual results to differ materially from the forward-looking statements contained in these Listing Particulars. Moreover, new risk factors emerge from time to time and it is not possible for us to predict all such risk factors. We cannot assess the impact of all risk factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. Given these risks and uncertainties, you should not place undue reliance on forward-looking statements as a prediction of actual results.

We urge you to read the sections of these Listing Particulars entitled "*Risk factors*," "*Management's discussion and analysis of financial condition and results of operations*," "*Presentation of industry and market data*" and "*Our business*" for a more complete discussion of the factors that could affect our future performance and the markets in which we operate.

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PRESENTATION OF FINANCIAL AND OTHER INFORMATION

Financial information

Our audited group financial statements as at and for the years ended December 31, 2023, 2024 and 2025 (the "**2023 Group Financial Statements**", "**2024 Group Financial Statements**", "**2025 Group Financial Statements**" and together, the "**Group Financial Statements**") included in these Listing Particulars have been prepared in accordance with United Kingdom adopted International Accounting Standards (IFRS), in conformity with the requirements of the Companies Act 2006.

Our Group Financial Statements are presented in U.S. dollars, which is our functional currency.

The Group Financial Statements, including the respective audit reports, contained in the F-Pages to these Listing Particulars should be read in conjunction with the relevant notes thereto.

Prospective investors are advised to consult with their professional advisors for an understanding of: (i) the differences between IFRS and U.S. GAAP and other standards of generally accepted accounting principles and how those differences might affect the financial information included in these Listing Particulars and (ii) the impact that future additions to, or amendments of, IFRS may have on the Company's internal accounting system or calculations of figures of the abovementioned sources.

The financial information included in these Listing Particulars is not intended to comply with the applicable accounting requirements of the U.S. Securities Act and the related rules and regulations of the SEC which would apply if the Notes were being registered with the SEC.

Reportable segments

We report our financial results by segment in accordance with IFRS 8 *Operating Segments.* The regions in which we operate correspond to our operating segments. For the years ended December 31, 2023, 2024 and 2025, our significant reportable segments were the North Sea and Malaysia operations. The Vietnam, Indonesia and Brunei operations, which are new for 2025, are not yet deemed significant in accordance with the quantitative thresholds for separate disclosure under IFRS 8, and so these operations have been aggregated into one reporting group.

Rounding

Certain numerical figures set out in these Listing Particulars, including financial information presented in millions and percentages relating to operational data, have been subject to rounding adjustments and, as a result, the totals of the data in these Listing Particulars may vary slightly from the actual arithmetic totals of such information. Percentages and amounts reflecting changes over time periods relating to financial and other information set forth in "*Management's discussion and analysis of financial condition and results of operations*" are calculated using the unrounded numerical data in the financial statements or the tabular presentation of other information contained in these Listing Particulars, as applicable, and not using the numerical data in the narrative description thereof.

Re-presentations and Restatements

In the 2023 Group Financial Statements, we have corrected certain prior year immaterial errors and re-presented balances within the comparative information for the year ended December 31, 2022 to ensure consistency with the presentation used for the balances as at and for the year ended December 31, 2023. Specifically, certain amounts within the balance sheet and statement of cash flows that have been re-presented relate to (i) U.K. Emission allowances purchased for $1.2 million that are expected to be utilized within twelve months, which have been re-presented from non-current intangible assets to current intangible assets; and (ii) net cash flows (used in)/from financing activities, which have been re-presented to reflect proceeds and repayment of loans and borrowings at their gross amount, which has increased each of proceeds and repayments by $21.7 million.

Following a review of market practice, the unwinding of discount on the Magnus Contingent Consideration was reclassified in the 2024 Group Financial Statements to "other income/expense" from "finance costs" in the income statement to combine it with the other fair value movements. As a result, unless specifically stated otherwise, all amounts shown in these Listing Particulars in respect of "other income/expense" and "finance costs" for the year ended December 31, 2023 refer to such restated information derived from the comparative information found in the 2024 Group Financial Statements. See also "*Management's discussion and analysis of financial condition and results of operations—Significant factors affecting comparability—Magnus oil field acquisition*" and "*—Explanation of income statement items—Net other income and other expense*."

Unamortized fees in relation to the 2021 RBL Facility Agreement for the year ended December 31, 2024 were reclassified from "unamortized fees on loans and borrowings" within "loans and borrowings" to "trade and other receivables" in the 2024 Group Financial Statements to better reflect the variable nature of the 2021 RBL Facility, but have not been restated for prior periods as not material.

Accrued interest on borrowings for the year ended December 31, 2024 was reclassified from "accrued expenses" within "trade and other payables" to "loans and borrowings" in the 2024 Group Financial Statements to better reflect the total borrowings balance, but has not been restated for prior periods, which may impact comparability across the periods presented.

Remeasurements and Exceptional Items

In our 2023 Group Financial Statements, we presented our results in our income statement as "reported in the year/period", using a columnar approach to present this as the sum of our "business performance results" and our "remeasurements and exceptional items" as permitted by IAS 1 (Revised) Presentation of Financial Statements. In 2025, we revisited this presentation and removed this columnar approach in our 2024 and 2025 Group Financial Statements, leading to these financial statements presenting only "reported in the year/period". This change was made to simplify presentation and to align the presentation with industry peers. As a result, unless otherwise indicated, all amounts shown for our financial results of operation for all periods presented in these Listing Particulars reflect the relevant results of operations "reported in the year/period" for the respective period, and are comparable period-over-period.

For further information on remeasurements and exceptional items, see note 4 to our 2023 Group Financial Statements, as well as note 2 to our 2024 Group Financial Statements.

Non-IFRS financial measures and other key performance indicators

These Listing Particulars contain non-IFRS measures and ratios, namely adjusted EBITDA, average adjusted unit operating costs ($/boe), cash capex, cash capital and decommissioning expense, adjusted free cash flow, EnQuest net debt, EnQuest total debt, realized oil prices ($/bbl), adjusted unit production costs ($/boe), adjusted unit tariff and transportation expenses ($/boe) and total cash and available facilities.

These measures are termed "**non-IFRS**" measures because they exclude amounts that are included in, or include amounts that are excluded from, the most directly comparable measure calculated in accordance with IFRS, or are calculated using financial measures that are not calculated in accordance with IFRS. Our management uses these measures when assessing and discussing our financial performance, balance sheet and cash flows.

- "**Adjusted EBITDA**" consists of profit/(loss) for the period attributable to owners of the parent before income tax and finance income/(costs), adjusted by unrealized gains on derivative contracts, net impairment charge/(reversal) to oil and gas assets, change in Magnus Contingent Consideration, insurance income on Kraken and PM8/Seligi, write-off of exploration costs, drilling rig contract regret costs, depletion and depreciation, inventory revaluation, change in decommissioning and other provisions in relation to changes in the Thistle decommissioning provisions, business combination transaction costs, non-cash U.K. emissions allowances gain/(loss) and net foreign exchange (gain)/loss.

- "**Average adjusted unit operating costs ($/boe)**" consists of production and associated tariff and transportation expenses, including the impact of realized gains/losses on derivatives, divided by the barrel of oil equivalent produced.

- "**Cash capex**" represents net cash flows (used in)/from investing activities adjusted to exclude purchase of other intangible assets, payment of contingent considerations, funds loaned under and proceeds from the Bressay-related vendor financing facility, proceeds from farm down activities, acquisition deposits paid and interest received. Group level net cash flows (used in)/from investing activities used to derive cash capex are not directly attributable to the activity at the asset level as they relate to corporate related activities and acquisitions made by the Group.

- "**Cash capital and decommissioning expense**" represents cash capex (as defined above) plus our cash spend on decommissioning activities.

- **"Adjusted Free cash flow**" consists of net cash flow from/used in operating activities adjusted by purchase of property, plant and equipment, purchase of oil and gas and other intangible assets, payment of contingent considerations, estimated cash tax on disposal proceeds, interest received, payment of obligations under

finance leases and interest paid. Adjusted free cash flow does not represent the residual cash flow available for discretionary expenditures.

- "**EnQuest total debt**" represents the sum of outstanding borrowings, bonds and notes, excluding lease liabilities and excluding unamortized fees and accrued interest on loans and borrowings and on bonds.

- "**EnQuest net Debt**" consists of EnQuest total debt (as defined above) less cash and cash equivalents.

- "**Realized oil prices ($/bbl)**" consists of revenue from crude oil sales *plus* realized gains/(losses) on oil derivative contracts, divided by the amount of barrels of crude oil sold.

- "**Adjusted unit tariff and transportation expenses ($/boe)**" consists of tariff and transportation expenses divided by the barrel of oil equivalent produced.

- "**Adjusted unit production costs ($/boe)**" consists of average adjusted unit operating costs (excluding gains/losses on derivatives) less adjusted unit tariff and transportation expenses.

- "**Total cash and available facilities**" (also called liquidity) consists of cash and cash equivalents on the balance sheet plus amounts available for drawing under our facilities.

We present non-IFRS measures and ratios because we believe that they and similar measures are widely used by certain investors, securities analysts and other interested parties as supplemental measures of performance and liquidity. The non-IFRS measures and ratios may not be comparable to other similarly titled measures of other companies and have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our operating results as reported under IFRS. Non-IFRS measures and ratios such as adjusted EBITDA, average adjusted unit operating costs, cash capex, cash capital and decommissioning expense, adjusted free cash flow, EnQuest net debt, EnQuest total debt, realized oil prices ($/bbl), adjusted unit production costs ($/boe), adjusted unit tariff and transportation expenses ($/boe) and total cash and available facilities are not measurements of our performance or liquidity under IFRS and should not be considered as alternatives to operating profit/(loss) or profit/(loss) for the year, capital investment, capital expenditure or any other performance measures derived in accordance with IFRS or any other generally accepted accounting principles or as alternatives to cash flow from operating, investing or financing activities. The financial information contained in these Listing Particulars, including the non-IFRS measures, are not prepared in accordance with the requirements of the U.S. Securities and Exchange Commission (the "**SEC**") or any other generally accepted accounting principles. The non-IFRS measures have limitations as analytical tools. Some of these limitations are:

- they do not reflect our cash expenditures or future requirements for capital commitments;

- they do not reflect changes in, or cash requirements for, our working capital needs;

- they do not reflect the interest expense or cash requirements necessary to service interest or principal payments of our debt;

- they do not reflect any cash income taxes that we may be required to pay;

- they are not adjusted for all non-cash income or expense items that are reflected in our group income statement;

- they do not reflect the impact of earnings resulting from certain matters we consider to not be indicative of our ongoing operations;

- assets are depreciated or amortized over differing estimated useful lives and often have to be replaced in the future, and these measures do not reflect any cash requirements for such replacements; and

- other companies may calculate these measures differently than we do, limiting their usefulness as comparative measures.

Because of these limitations, the non-IFRS measures should not be considered in isolation or as a substitute for performance measures calculated in accordance with IFRS. You should compensate for these limitations by relying primarily on our IFRS results and using these non-IFRS measures only as supplements to evaluate our performance. See "*Summary financial data*," "*Selected financial data*," "*Management's discussion and analysis of financial condition and results of operations*" and our Group Financial Statements and the related notes included elsewhere.

For a definition and description of how our non-IFRS measures are calculated from our Group results of operations and a reconciliation of adjusted EBITDA, adjusted free cash flow and capital expenditure to our IFRS results presented in these Listing Particulars, see "*Summary financial data*."

CERTAIN RESERVES AND PRODUCTION INFORMATION

These Listing Particulars present information concerning our Reserves as of December 31, 2023, 2024 and 2025 which are audited annually by Gaffney, Cline & Associates Ltd. ("**GaffneyCline**"). GaffneyCline is an independent reservoir evaluation company which has prepared its estimates in accordance with resource definitions jointly set out by the Society of Petroleum Engineers ("**SPE**"), the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers ("**SPEE**"), the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists and Engineers in June 2018 in the "Petroleum Resources Management System" ("**PRMS**"). All reserves information in this document is presented on the basis of the PRMS, unless otherwise indicated. Any reference to the 1P or 2P Reserves of our assets in this document is based on the GaffneyCline year end 2023 reserves report dated March 2024 (the "**2023 Reserves Report**"), the GaffneyCline year end 2024 reserves report dated February 2025 (the "**2024 Reserves Report**") and the GaffneyCline year end 2025 reserves report dated February 2026 (the "**2025 Reserves Report**" and together with the 2023 Reserves Report and the 2024 Reserves Report, the "**Annual Reserves Reports**"). Further, any reference to *pro forma* reserves for Block 12W, Vietnam is based on the GaffneyCline report "Block 12W, Offshore Vietnam: Competent Person's Report" dated February 2025, which provided estimates of the entitlement Reserves to Harbour Energy as of December 31, 2024 (the "**Vietnam Report**" and together with the Annual Reserves Reports, the "**Reserves Reports**").

Pursuant to the classifications and definitions provided by the PRMS, 1P Reserves are defined as those quantities of oil which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations ("**Proved Reserves**", or "**1P Reserves**"). If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Pursuant to the classifications and definitions provided by the PRMS, 2P Reserves are defined as the sum of Proved Reserves, plus those additional reserves which analysis of geoscience and engineering data indicate as less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves ("**Probable Reserves**" and together with Proved Reserves, "**2P Reserves**"). It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated 2P Reserves.

Pursuant to the classifications and definitions provided by the PRMS, Contingent Resources are those quantities estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. The 2C Contingent Resources represent the "best estimate" scenario (the "**2C Resources**"); there is a probability of at least 50% that the amount actually recovered will equal or exceed the 2C estimate, in the event that the development project goes ahead.

Unless otherwise indicated, all production figures are presented on a net to our working interest basis. Where gross amounts are indicated, they are presented on a total basis—*i.e.*, the actual interest of the relevant license holder in the relevant fields and license areas without deduction for the economic interest of our commercial partners, taxes or royalty interests or otherwise. Our legal interest and effective working interest in the relevant fields and license areas are separately disclosed. See "*Our business—Production and development*." See also "*Our business—Material agreements relating to our assets*" for a more detailed discussion of the terms of the agreements governing our interests.

See also "*Glossary*" for a description of certain oil and gas metrics and terms.

Hydrocarbon data

The Reserves Reports referenced in these Listing Particulars utilize the following technical estimates:

- oil and natural gas liquids in standard millions of barrels ("**MMbbl**") (a barrel being the equivalent of 42 U.S. gallons); and

- natural gas in billions of cubic feet ("**Bscf**") at standard temperature and pressure bases.

These Listing Particulars present certain production and reserves-related information on an "equivalency" basis. Our conversion of gas from Bscf into millions of barrels of oil equivalent ("**MMboe**") may differ from the conversion used by other companies. We have assumed a conversion rate for natural gas of 5.8 Bscf to 1 MMboe. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value

equivalencies at the wellhead. Although this conversion factor is an industry accepted convention, it is not reflective of price or market value differentials between product types.

The information on reserves in this document is based on economic and other assumptions that may prove to be incorrect. Prospective investors should not place undue reliance on the forward-looking statements in this document or on the ability of the information on reserves in this document to predict actual reserves.

Typical to the industry in which we operate, there are a number of uncertainties inherent in estimating quantities of 1P and 2P Reserves. Our reserve information is based on our assessments of our asset base and our opinion as to the reasonableness of such assessments and represents only estimates. Reserve assessment is a subjective process of estimating underground accumulations of oil and natural gas and cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of a number of variable factors and assumptions, many of which are beyond our control, including the quality of available data and of engineering and geological interpretation and judgment assumptions as to oil price. As a result, estimates of different reserve assessors may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, due to inherent uncertainties and the limited nature of reservoir data and the inherently imprecise nature of reserve estimates, the initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The significance of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Thus investors should not place undue reliance on the accuracy of the reserves information in this document in predicting the actual reserves or on comparisons of similar estimates/information concerning other companies. In addition, except to the extent that we acquire additional properties containing 1P and 2P Reserves or conduct successful exploration and development activities, or both, our 1P and 2P Reserves will decline as reserves are produced. For a discussion of the risks involving the oil and gas industry and reserves specifically, see "*Risk factors—Risks relating to the oil and gas industry*."

Prospective investors should read the whole of this document for more information on our reserves and the reserves definitions we use.

CURRENCY PRESENTATION AND DEFINITIONS

Currency Presentation

In these Listing Particulars, all references to "**U.S. dollars**" and "**$**" are to the lawful currency of the United States of America and all references to "**pound sterling**," "**pence**" and "**£**" are to the lawful currency of the United Kingdom. References to "**euro**" or "**€**" are to the single currency of the participating member states of the Third Stage of European Economic and Monetary Union of the Treaty Establishing the European Community, as amended from time to time.

Definitions

Unless otherwise specified or the context requires otherwise in these Listing Particulars, references to "**EnQuest**," "**Company**," " **Group**", "**we**," "**us**," and "**our**" refer to EnQuest PLC, together with its subsidiaries. When such references refer to actions prior to our founding in March 2010, these references refer to the actions of, as applicable, the previous owners of the relevant interests and assets, Petrofac Energy Developments Limited and Lundin Petroleum AB, as applicable.

The following definitions apply throughout these Listing Particulars, unless the context otherwise requires:

- "**€**" means euro;
- "**£**" means pound sterling;
- "**2021 RBL Facility**" means the facility, which was cancelled on November 20, 2025, made available under the 2021 RBL Facility Agreement;
- "**2021 RBL Facility Agreement**" means the secured revolving borrowing base facility agreement dated as of June 10, 2021, and amended and restated on November 29, 2021 and October 3, 2022, entered into between, among others, the Company, as obligor, and BNP Paribas, as agent and security agent, as amended from time to time;
- "**2027 Notes**" means, collectively, the Company's $305.0 million aggregate principal amount of 11⅝% senior notes due 2027 and the additional $160.0 million aggregate principal amount of the Company's 11⅝% senior notes due 2027 (the "**Tap Notes**"), issued under a New York law governed indenture dated October 25, 2022;
- "**9% Retail Notes**" means the Company's sterling denominated 9.00% fixed rate retail notes due October 27, 2027;
- "**Alba**" means the oil field located in block 16/26a in the UKCS covered by License P.213. See "*Our business—Overview of our UKCS assets—U.K. Upstream—Alba*";
- "**Alma/Galia**" or "**Alma and Galia**" means the oil fields located in blocks 30/24b, 30/24c and 30/25c in the UKCS covered by License P.1825 (for block 30/24b) and License P.1765 (for blocks 30/24c and 30/25c). See "*Our business—Overview of our assets—Overview of our UKCS assets—U.K. Upstream—Alma/Galia*";
- "**Annual Reserves Reports**" means, collectively, the 2023 Reserves Report, the 2024 Reserves Report and the 2025 Reserves Report, each prepared by GaffneyCline;
- "**BEIS**" means the U.K. Department of Business, Energy and Industrial Strategy;
- "**Block 12W**" means the Chim Sáo and Dua production fields where we hold a 53.125% equity interest in following our acquisition of Harbour Energy's business in Vietnam. See "*Our business—Overview of our assets—South East Asia—Vietnam*";
- "**bp**" means BP plc;
- "**Bressay**" means the oil field located in the blocks 3/28a, 3/28b, 3/27b, 9/2a and 9/3a in the UKCS covered by Licenses P234, P493, P920 and P977. See "*Our business—Overview of our assets—U.K. Upstream—Bressay*";
- "**CNOOC**" means CNOOC Petroleum Europe Limited, the operator of the Golden Eagle Area Development;

- "**Conrie**" means the oil field located in block 211/18a in the UKCS covered by License P.236. See "*Our business—Overview of our assets—U.K. Decommissioning—The Dons*";

- "**DESNZ**" means the U.K. Department for Energy Security and Net Zero;

- "**Dons**" or "**the Dons**" means Don Southwest, West Don, Conrie and Ythan. See "*Our business—Overview of our assets—U.K. Decommissioning—The Dons*";

- "**Don Southwest**" means the oil field located in block 211/18c in the UKCS covered by License P.236. See "*Our business—Overview of our assets—U.K. Decommissioning—The Dons*";

- "**DTC**" means The Depository Trust Company;

- "**EQPPM**" means EnQuest Petroleum Production Malaysia Ltd (Registration No. 08497369), a company incorporated in England & Wales and having its registered address at 2nd Floor, Charles House, 5-11 Regent Street, London SW1Y 4LR, United Kingdom;

- "**European Economic Area**" or "**EEA**" means the trading area established by the European Economic Area Agreement of January 1, 1994;

- "**FSMA**" means the Financial Services and Markets Act 2000, as amended;

- "**GaffneyCline**" means Gaffney, Cline & Associates Ltd, or Gaffney, Cline & Associates (Consultants) Pte. Ltd, as the context requires, independent international energy advisory company;

- "**Golden Eagle Area Development**" or "**Golden Eagle Asset**" means the 26.69% non-operated working interest in the area comprising the Golden Eagle, Peregrine and Solitaire fields located in the United Kingdom Petroleum Production License P300 Block 14/26a and the United Kingdom Petroleum Production License P928 Block 20/1a North. See "*Our business—Overview of our UKCS assets—U.K. Upstream—Golden Eagle*";

- "**Greater Kittiwake Area**" or "**GKA**" means the oil fields located in UKCS blocks 21/12a, 21/18a, 21/19a and 21/19b. See "*Our business—Overview of our UKCS assets—U.K. Upstream—Greater Kittiwake Area (GKA)*";

- "**Guarantee Subordination Agreement**" means the subordination agreement originally dated April 9, 2014 between, among others, the Company and BNP Paribas (as facility agent and security trustee) as amended, novated, supplemented, extended and/or restated from time to time to which DNB Bank ASA, London Branch acceded as new senior creditor representative and security trustee, replacing BNP Paribas in such capacities on November 18, 2025;

- "**Guarantors**" means, collectively, EnQuest Heather Limited, EnQuest Britain Limited, EnQuest Heather Leasing Limited, EnQuest Global Limited, EnQuest Petroleum Production Malaysia Ltd and EnQuest Marketing and Trading Limited;

- "**Heather/Broom**" means the oil fields located in blocks 2/5 and 2/4a in the UKCS covered by License P.242 and P.902, respectively: See "*Our business—Overview of our UKCS assets—U.K. Upstream—Heather/Broom*";

- "**HSE&A**" means health, safety, environment and assurance, sometimes referred to herein as health, safety and environment ("**HSE**");

- "**HSEx**" means the U.K. Health and Safety Executive;

- "**Indenture**" has the meaning given to such term in "*Description of Notes*";

- "**International Accounting Standards**" means the International Accounting Standards (IAS), International Financial Reporting Standards (IFRS) and related Interpretations (SIC-IFRIC interpretations), subsequent amendments to those standards and related interpretations, future standards and related interpretations issued or adopted by the International Accounting Standards Board (IASB);

- "**Issue Date**" means the date of issuance of the Notes;
- "**Kinneil Oil Terminal**" means the oil stabilization and gas separation plant which represents the end of the Forties Pipeline System;
- "**Kraken**" means the oil fields located in block 9/2b in the UKCS covered by License P.1077. See "*Our business—Overview of our assets—Overview of our UKCS assets—U.K. Upstream—Kraken*";
- "**KUFPEC**" means Kuwait Foreign Petroleum Exploration Company;
- "**London Stock Exchange**" or "**LSE**" means London Stock Exchange plc;
- "**Magnus**" means the oil fields located 160 kilometers northeast of the Shetland Islands, mainly in block 211/12a and 211/7a covered by license P.193. See "*Our business—Overview of our assets—Overview of our UKCS assets—U.K. Upstream—Magnus*";
- "**Notes**" are to the $675.0 million aggregate principal amount of 9⅞% senior notes due 2031 offered pursuant to these Listing Particulars and to be issued on the Issue Date under the Indenture;
- "**OECD**" means The Organisation for Economic Co-operation and Development;
- "**Offering**" means the issuance of the Notes offered hereby;
- "**OPEC**" means Organization for Petroleum Exporting Countries;
- "**PM8 Extension**" means the PM8 and Seligi fields held pursuant to a production sharing contract with PETRONAS Carigali Sdn. Bhd., E&P Malaysia Venture Sdn. Bhd. (as contractors) and PETRONAS dated December 10, 2014 and "**PM8 Extension PSC**" and "PM8/Seligi" shall be interpreted accordingly;
- "**PSC**" means a production sharing contract, which is a type of host state-investor agreement which entitles the investor (the contractor) to develop a petroleum field for a fixed term;
- "**Reserves Reports**" means, collectively, the Annual Reserves Reports and the Vietnam Report, each prepared by GaffneyCline;
- "**RBL Effective Date**" means November 18, 2025, the date on which all conditions precedent to the first utilization under the RBL Facility were satisfied;
- "**RBL Facility**" means the facilities made available under the RBL Facility Agreement on the RBL Effective Date;
- "**RBL Facility Agreement**" means the secured multicurrency revolving borrowing base facilities agreement dated November 9, 2025, between, among others, the Company, as obligor, and DNB Bank ASA, London Branch, as agent and security agent. See "*Description of certain financing arrangements—RBL Facility*";
- "**Scolty/Crathes**" means the oil fields located in blocks 21/12c, 21/13a and 21/8a in the UKCS covered by License P.1617 (blocks 21/12c and 21/13a) and License P.1107 (block 21/8a). See "*Our business—Overview of our assets—Overview of our UKCS assets—U.K. Upstream—Scolty/Crathes*";
- "**SEC**" means U.S. Securities and Exchange Commission;
- "**Stockholm Stock Exchange**" means NASDAQ OMX Stockholm;
- "**SVT**" means the Sullom Voe Terminal;
- "**SVT Working Capital Facility**" means the revolving loan facility entered into by EnQuest Heather Limited with BNP Paribas in, among others, its capacity as lender for an aggregate amount of £42.0 million dated December 1, 2017, as novated and amended on December 1, 2018 and further amended on November 25, 2020 and January 3, 2022 and further amended pursuant to an amendment and restatement agreement with Deutsche Bank AG, Amsterdam Branch dated April 22, 2024;

- "**Term Loan**" means the facility made available under the Term Loan Facility Agreement, which was repaid in full on September 24, 2024;

- "**Term Loan Facility Agreement**" means the second lien term loan facility agreement dated as of August 25, 2023, entered into between, among others, EnQuest Heather Limited as borrower and certain subsidiaries as guarantors, as amended and/or restated from time to time, which was cancelled on September 24, 2024;

- "**Thistle/Deveron**" means the oil fields located in blocks 211/18a and 211/19a in the UKCS covered by License P.236 and P.475, respectively. See "*Our business—Overview of our UKCS assets—U.K. Upstream—Thistle/Deveron*";

- "**Transactions**" means collectively, the Offering and the redemption of the 2027 Notes using the proceeds of the Offering;

- "**U.K. Corporate Governance Code**" means the U.K. Corporate Governance Code published by the Financial Reporting Council;

- "**U.K. Regulator**" means until March 20, 2022 the Oil and Gas Authority ("**OGA**") and thereafter the North Sea Transition Authority ("**NSTA**"), which is the business name adopted on and from that date by the OGA;

- "**UKCS**" means United Kingdom Continental Shelf;

- "**United Kingdom**" or "**U.K.**" means the United Kingdom of Great Britain and Northern Ireland;

- "**United States**" or "**U.S.**" means United States of America;

- "**U.S. Securities Act**" means the U.S. Securities Act of 1933, as amended, and the rules and regulations promulgated thereunder;

- "**Vendor Loan Facility**" means the deferred payment facility made available under the Vendor Loan Facility Agreement between Baker Hughes UK Funding Limited and EnQuest Heather Limited pursuant to which Baker Hughes agreed to provide EnQuest Heather Limited a deferred payment facility in an amount of up to £23.7 million;

- "**Vietnam Report**" means the GaffneyCline report "Block 12W, Offshore Vietnam: Competent Person's Report" dated February 2025, which provided estimates of the entitlement Reserves to Harbour Energy as of December 31, 2024;

- "**West Don**" means the oil field located in block 211/18b in the UKCS covered by License P.236. See "*Our business—Overview of our assets—Overview of our UKCS assets—U.K. Decommissioning—The Dons*"; and

- "**Ythan**" means the oil field located in blocks 211/18e and 211/19c in the UKCS covered by License P2137. See "*Our business— Overview of our assets—Overview of our UKCS assets—U.K. Decommissioning—The Dons*."

PRESENTATION OF INDUSTRY AND MARKET DATA

In these Listing Particulars, we rely on and refer to information regarding our business and the markets in which we operate and compete. The market data and certain economic and industry data and forecasts used in these Listing Particulars were obtained from governmental and other publicly available information, independent industry publications and reports prepared by industry consultants, including:

- International Commodities Exchange;
- International Monetary Fund ("**IMF**");
- International Energy Agency ("**IEA**");
- Organization of the Petroleum Exporting Countries ("**OPEC**");
- U.S. Energy Information Administration ("**U.S. EIA**");
- International Gas Union ("**IGU**");
- Offshore Energies U.K. ("**OEUK**");
- Energy Institute;
- U.K. Regulator;
- ISI Emerging Markets Group and EMIS;
- U.K. Climate Change Committee;
- U.K. EITI Secretariat; and
- bp.

Industry publications, surveys and forecasts generally state that the information contained therein has been obtained from sources believed to be reliable, but that there can be no assurance as to the accuracy and completeness of such information. We believe that these industry publications, surveys and forecasts are reliable, but we have not independently verified any of the data from third-party sources. Forecasts and other forward-looking information obtained from these sources are subject to the same qualifications and uncertainties as the other forward-looking statements in these Listing Particulars.

We cannot assure you that any of the assumptions underlying any statements regarding the oil and gas industry are accurate or correctly reflect our position in the industry. Market data and statistics are inherently predictive and speculative and are not necessarily reflective of actual market conditions. Such statistics are based on market research, which itself is based on sampling and subjective judgments by both the researchers and the respondents, including judgments about what types of products and transactions should be included in the relevant market. In addition, the value of comparisons of statistics for different markets is limited by many factors, including that (i) the markets are defined differently, (ii) the underlying information was gathered by different methods and (iii) different assumptions were applied in compiling the data. Accordingly, the market statistics included in these Listing Particulars should be viewed with caution and no representation or warranty is given by any person, including us and the Initial Purchasers, as to their accuracy.

Elsewhere in these Listing Particulars, statements regarding the oil and gas industry are not based on published statistical data or information obtained from independent third parties, but are based solely on our experience, our internal studies and estimates, and our own investigation of market conditions. We cannot assure you that any of these studies or estimates are accurate, and none of our internal surveys or information have been verified by any independent sources. While we are not aware of any misstatements regarding our estimates presented herein, our estimates involve risks, assumptions and uncertainties and are subject to change based on various factors. See "*Risk factors*" and "*Our business*" in these Listing Particulars for further discussion.

SUMMARY

This summary highlights certain information about our business and the Offering described elsewhere in these Listing Particulars. This summary is not complete and does not contain all the information you should consider before investing in the Notes. This summary is qualified in its entirety by, and should be read in conjunction with, the more detailed information included in these Listing Particulars, including our Group Financial Statements, and the related notes thereto.

The reserves and resources data presented in this section have been estimated in accordance with PRMS guidelines and definitions. Estimated reserves and resources presented herein may differ from estimates made in accordance with guidelines and definitions used by other companies in the industry or by the SEC. See "Certain reserves and production information." Unless otherwise indicated, all production figures are presented on a net working interest basis. Where gross amounts are indicated, they are presented on a total basis—i.e., the actual interest of the relevant license holder in the fields and license areas without deduction for the economic interest of other participants, taxes or royalty interests or otherwise. Our legal interest and effective working interest in the relevant fields and license areas are separately disclosed. See "Our business—Production and development." See also "Our business—Material agreements relating to our assets" for a more detailed discussion of the terms of the agreements governing our interests.

You should read carefully the entire Listing Particulars to understand our business, the nature and terms of the Notes and the tax and other considerations which are important to your decision to invest in the Notes, including the risks discussed under the caption "Risk factors" and "Management's discussion and analysis of financial condition and results of operations."

Overview

We are a significant independent energy company in the U.K. North Sea and South East Asia, specializing in the operatorship of mature, underinvested hydrocarbon assets. We are a top quartile operator with a track record of materially extending the economic lives of assets through strong uptime performance, production enhancement, cost discipline and reserve replacement. As of December 31, 2025, we had interests in 18 U.K. production licenses (however, as of February 2026, we relinquished license P2632, reducing our total U.K. production licenses to 17), 14 of which we operate, covering 25 blocks or part blocks in the UKCS. We also have an interest in three licenses in Malaysia, one license in Vietnam, two licenses in Indonesia and one license in Brunei, all but one of which we operate.

While our upstream business remains a core focus given its cash-generating capability, we have also made considerable progress in delivering credible and potentially material new energy and decarbonization opportunities, which are now managed by Veri Energy, a wholly owned subsidiary of the Company. Veri Energy is targeting the creation of a clean energy hub at the EnQuest-operated Sullom Voe Terminal on Shetland, primarily through the repurposing of existing infrastructure, underscoring our commitment to a just and sustainable energy transition. In demonstrating our credible transition plan, we were awarded an A- rating in the 2025 CDP Climate Change Survey, becoming the only oil and gas production company globally to achieve this grade.

We also continue to demonstrate our sector-leading capability in decommissioning, which is becoming an ever more significant component of the competency mix for any North Sea operator.

Since our inception, we have increased our net working interest 1P and net working interest 2P Reserves to 126 MMboe and to 162 MMboe, respectively, as of December 31, 2025 from 36 MMboe and 81 MMboe, respectively, as of January 1, 2010, representing a compound annual growth rate for 2P net working interest Reserves of approximately 4% per annum and representing a 2P net working interest reserves replacement ratio of approximately 1.4x since inception. During the period from January 1, 2010 to December 31, 2025, we added net working interest 2P Reserves of approximately 305 MMboe, of which our production was approximately 223 MMboe. Of our year end 2025 2P net working interest Reserves, approximately 78% represented proved (1P) volumes, with the Group also recognizing 452 MMboe of 2C Resources. As of December 31, 2025, approximately 97% of our 2P net working interest Reserves are located in fields operated by us with approximately 75% of our 2P net working interest Reserves located in fields in the U.K. North Sea.

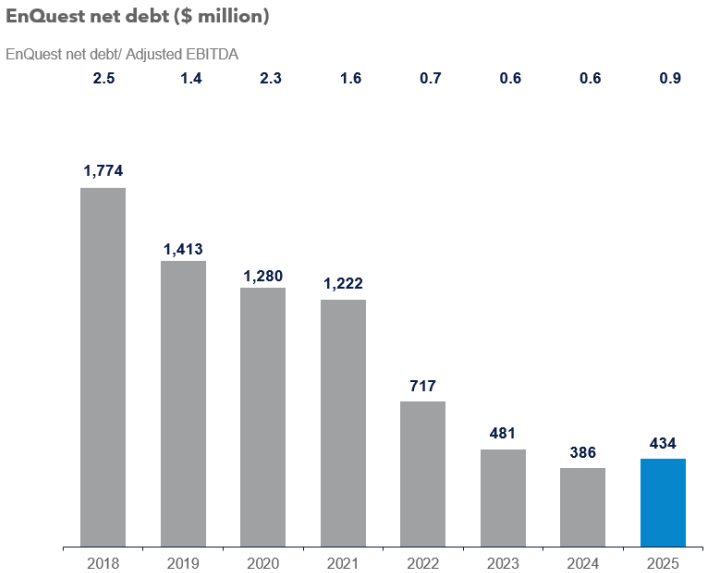
Our producing assets generated revenue and other operating income, gross profit/(loss) and adjusted EBITDA of $1,118.3 million, $280.8 million and $503.8 million, respectively, in the year ended December 31, 2025. In the year ended December 31, 2025, our average adjusted unit operating costs (including hedging) were $25.1/boe.

We were founded in 2010 through a combination of Petrofac Energy Developments Limited ("**PEDL**") and certain assets of Lundin Petroleum AB ("**Lundin**"). We purchased PEDL and the UKCS assets of Lundin in exchange for stock. In 2014, we diversified our geographical footprint by acquiring initial production licenses in Malaysia. Following our initial public offering in April 2010, our shares are listed and trade on the London Stock Exchange. Our shares were also listed on the Stockholm Stock Exchange until December 2023, when the Board decided to delist our shares from the Stockholm Stock Exchange. As of December 31, 2025, our market capitalization was approximately $268.8 million based on the Bloomberg Composite Rate (London) pounds sterling/US dollar exchange rate of $1.3452 per £1.00. In August 2024, our share buy-back program achieved its target of 25 million shares repurchased and held as treasury shares, with all additional shares repurchased immediately cancelled.

We believe that our operational and commercial capabilities, together with experienced technical staff and management, have enabled us to grow production, reserves and resources profitably since 2010. Further, we believe that in the UKCS, South East Asia and potentially other geographic regions, we have, and will continue to have, substantial opportunities for acquisitions and development through low-cost, near-field drilling, well intervention and enhanced oil recovery projects, while maintaining a focus on the health, safety and environmental impacts of our operations. The majority of our existing asset licenses are located in the UKCS in the North Sea. We also have interests in three licenses in Malaysia, one license in Vietnam, two licenses in Indonesia and one license in Brunei. See "*Risk factors—Risks relating to our business—All of our production comes from a small number of offshore assets in the UKCS and South East Asia*, *making us vulnerable to risks associated with having significant production in two regions and only a small number of assets*."

As we navigate the energy transition, one of our top priorities is to achieve and maintain high HSE performance. We believe that we have robust management systems, a culture of positive engagement and a commitment to continuous improvement. We are committed to respecting the people and environments that our business may affect, and we aim to operate our business to achieve safe results, with no harm to people or the environment. To achieve this, we aim to manage our business in compliance with legislation and industry standards, maintain high-quality systems and processes and ensure safe and healthy workplaces. For more information on our health, safety, environment and assurance policies, see "*Our business—Health, safety, environment and assurance*."

As part of our strategy, we aim to maintain a strong balance sheet through consistent deleveraging and prudent capital allocation. In recent years, we have prioritized using free cash flow to reduce our debt. Accordingly, we have significantly reduced our EnQuest net debt from $1.2 billion as of December 31, 2021 to $433.9 million as of December 31, 2025. This represents a reduction of $1.6 billion since peak net debt of $2.0 billion in 2017 and an EnQuest net debt to adjusted EBITDA ratio of 0.9x (compared to 2.5x as of December 31, 2018). The following chart shows the reduction in our EnQuest net debt and EnQuest net debt to adjusted EBITDA ratio for the period indicated:



UKCS

The U.K. North Sea business consists of three directorates:

U.K. Upstream: *Kraken*, *Magnus*, *Golden Eagle, Greater Kittiwake Area*, *Scolty/Crathes*, *Alba*, *Bressay and Bentley*

The U.K. Upstream producing assets are characterized by their high production and operating efficiency. Our strategy is focused on reservoir management and resource development. In the year ended December 31, 2025, daily average net production in the U.K. Upstream directorate was 31,122 boepd, representing 72% of our total daily average net production for that period.

U.K. Midstream: *SVT and pipelines*

Within our Midstream directorate, we operate SVT and approximately 1,000 km of pipelines. Our Midstream business remains focused on the delivery of safe and reliable operations for the processing of East of Shetland and West of Shetland oil and gas, while progressing projects to right-size the terminal to support existing and future upstream operations and significantly lower the terminal's emissions footprint.

In addition, in December 2023, we launched Veri Energy, our wholly owned subsidiary, which is focused on progressing scalable decarbonization and new energy projects. These projects include carbon capture and storage, electrification and e-fuel production by repurposing the existing infrastructure at SVT and connected offshore infrastructure.

U.K. Decommissioning: *Heather/Broom*, *Thistle/Deveron*, *Alma/Galia and the Dons*

The U.K. Decommissioning operations manage end-of-field life decommissioning programs for assets that have already ceased, or are about to cease, production.

South East Asia

Malaysia

We have assets located in Malaysia at PM8/Seligi and DEWA, and we were awarded a PSC partnership for Cendramas in Peninsular Malaysia in February 2026. In the year ended December 31, 2025, daily average net production in Malaysia was 9,201 boepd (including 3,181 boepd associated with Seligi gas in the same period), representing 21% of our total daily average net production for that period.

Vietnam

We also have producing assets located in Vietnam at Chim Sáo and Dua. In the year ended December 31, 2025, daily average net production in Vietnam was 5,283 boepd, with 2,622 attributable to us beginning on July 9, 2025, the completion date of the acquisition of these assets from Harbour Energy.

Indonesia and Brunei

We also have non-producing assets located in Indonesia at Gaea and Gaea II and in Brunei at Block C. See "*Business—Overview of our assets—South East Asia*."

Working interest in producing assets

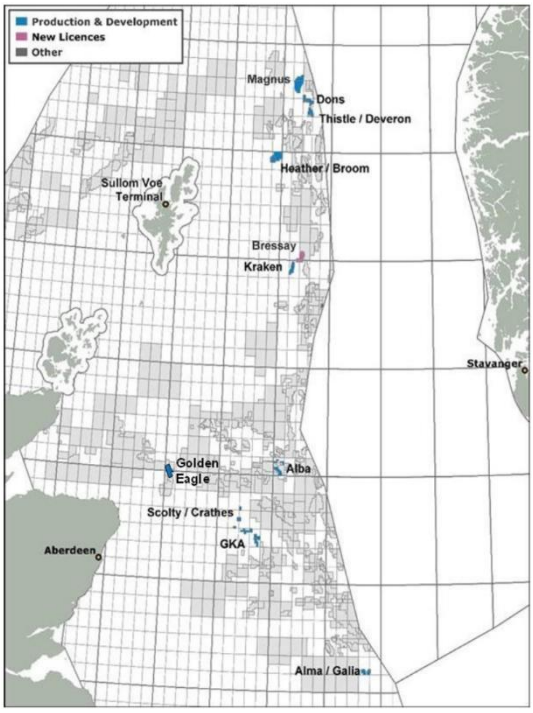
We typically seek to hold a significant working interest in our producing assets and developments, with 100.0% at Magnus, 70.5% at Kraken, 50.0% at GKA, 50.0% at Scolty/Crathes, 85.0% at Bressay, 26.69% at Golden Eagle and 100.0% at Bentley. In Malaysia, we hold a 50.0% working interest in PM8/Seligi, a 42.0% interest in DEWA and from September 2026, a 25.0% participating interest in the Cendramas PSC. In Vietnam, we hold a 53.125% working interest in Chim Sáo and Dua. While we focus on maximizing our operating equity, we have also sought to structure asset acquisitions with significantly lower abandonment equities, in order to minimize our exposure to decommissioning costs.

Through ownership, holding a significant working interest and active participation rights, we are better able to shape the development plan of an asset and influence the timing and method of the extraction of resources than we would be able to if we were passive partners in our fields. As of December 31, 2025, in the U.K., we had ownership interests in 18 producing licenses (however, as of February 2026, we relinquished license P2632,

reducing our total U.K. production licenses to 17), 14 of which were operated and 4 of which were partner-operated. We also have an interest in two producing licenses and one non-producing license in Malaysia, one producing license in Vietnam, two non-producing licenses in Indonesia and one non-producing license in Brunei. For the Group, in the year ended December 31, 2025, 93% of our company production was from operated assets while 7% was from partner-operated assets. We thus have a significant degree of control over the timing and magnitude of operating and capital expenditures for most of our assets. We have the right and obligation under each joint operating agreement to which each asset is a party to take delivery of our share of production from each field for onward sale to third parties of our choice and in the case of Vietnam jointly marketed with our partners. Furthermore, in relation to crude oil, each field temporarily stores production either at the field (such as onboard an FPSO) or at a terminal (such as the SVT). This gives each field owner the ability to accumulate a marketable volume of cargo, which is firstly allocated in full to the field owner with the highest proportionate share of the total stored volume at the time a full cargo accumulates in the first instance. By mutual agreement, field owners may pool their production under a joint operating agreement in order to share in cargoes. With the exception of Vietnam, we have full discretion over the marketing of our attributable volumes across our portfolio and, in relation to assets in which we hold a minority, non-operated stake such as Alba and Golden Eagle, we market our attributable volumes independently of our partners in each field. We market our attributable volumes independently from our field partners to enable us to best leverage our proprietary trading capabilities and substantial industry know-how.

We believe that our existing assets with the highest remaining production potential are Kraken, Magnus and PM8/Seligi. We are also the operator of these assets. There are also material Reserves and Contingent Resources within Kraken, Magnus and PM8/Seligi assets that we believe can be accessed through short-cycle low-cost drilling well intervention and enhanced oil recovery projects. The 2021 acquisitions of approximately 115 MMboe of net 2C Resources associated with our operating interest in Bressay and 131 MMboe of net 2C Resources associated with our operating interest in Bentley provide significant long-term production opportunities that have similarities to our Kraken field. Kraken, Magnus, and the PM8/Seligi fields currently have approximately 33 MMboe, 28 MMboe and 27 MMboe (excluding block PM409, which was relinquished in 2024) of net 2C Resources, respectively. We also have exploration and development potential associated with our interests at DEWA in Malaysia, Gaea and Gaea II in Indonesia and Block C in Brunei.

The following map sets forth the locations of our assets in the UKCS:



The following table sets forth the net daily average production on a working interest basis for each of our producing UKCS operations, our Malaysian operations and our Vietnamese operations for the years ended December 31, 2023, 2024 and 2025:

Region	Working interest	Net daily average production (boepd) For the year ended December 31, 2023	2024	2025
U.K. Upstream		**36,375**	**32,587**	**31,122**
Kraken	70.5	13,580	12,759	10,948
Magnus	100.0	15,933	14,173	15,335
Golden Eagle	26.69	4,199	3,328	2,736
GKA[(1)]	50.0	946	889	816
Scolty/Crathes	50.0	1,466	1,120	1,009
Alba	8.0	251	319	278
Bentley	100.0	—	—	—
Bressay[(2)]	85.0	—	—	—
Malaysia		**7,437**	**8,149**	**9,201**
PM8/Seligi[(3)]	50.0	7,437	8,149	9,201
DEWA[(4)]	42.0	—	—	—
Vietnam		—	—	**2,622**
Block 12W[(5)]	53.125	—	—	2,622
Total		**43,812**	**40,736**	**42,945**

(1) GKA production is split across four fields, Mallard, Grouse, Gadwall and Goosander (all at 50.0% working interest), with Kittiwake being the production facility for the hub.

(2) In 2023, we sold 15.0% of the working interest in the Bressay license to RockRose UKCS 10 Ltd, a subsidiary of Viaro Energy.

(3) For the years ended December 31, 2023, 2024 and 2025, respectively, the net daily average production reflects 604 boepd, 1,978 boepd and 3,181 boepd associated with Seligi gas.

(4) DEWA fields acquired with a completion date of October 21, 2024 and are not yet producing.

(5) Production volumes have been calculated from July 9, 2025, the completion date of the acquisition of Block 12W from Harbour Energy. For the year ended December 31, 2025, total net daily average production was 5,283 boepd.

Our production on a working interest basis increased by 5.4% to 42,945 boepd for the year ended December 31, 2025.

Reserves & Contingent Resources

The following table sets forth the 1P Reserves, 2P Reserves and 2C Resources as of the years ended December 31, 2023, 2024 and 2025. Reserves are presented as EnQuest net entitlement Reserves volumes according to the PRMS and separately as EnQuest working interest Reserves volumes for comparative purposes. Contingent Resources are presented as EnQuest working interest volumes only.

	EnQuest net working interest Reserves[(1)]			EnQuest net entitlement Reserves[(3)]		
	2023	2024	2025	2023	2024	2025
1P Reserves						
Oil (MMbbl)	123	110	105	117	106	102
Gas (Bscf)[(4)]	60	109	120	53	91	104
Total 1P Reserves (MMboe)	**133**	**129**	**126**	**126**	**121**	**120**
Pro forma Adjustments[(2)]						
Vietnam Oil (MMbbl)	—	3	—	—	3	—
Vietnam Gas (Bscf)	—	2	—	—	2	—
Total Vietnam 1P Reserves (MMboe)	—	3	—	—	3	—
***Pro forma* Total 1P Reserves (MMboe)**	**n.a.**	**132**	**n.a.**	**n.a.**	**124**	**n.a.**
2P Reserves						
Oil (MMbbl)	161	143	133	153	137	128
Gas (Bscf)[(5)]	82	147	171	71	118	142
Total 2P Reserves (MMboe)	**175**	**169**	**163**	**165**	**157**	**152**
Pro forma Adjustments						
Vietnam Oil (MMbbl)	—	5	—	—	5	—
Vietnam Gas (Bscf)	—	10	—	—	10	—
Total Vietnam 2P Reserves (MMboe)	—	7	—	—	7	—
***Pro forma* Total 2P Reserves (MMboe)**	**n.a.**	**176**	**n.a.**	**n.a.**	**164**	**n.a.**

2C Resources						
Oil (MMbbl)	336	323	344	n.a.	n.a.	n.a.
Gas (Bscf)	314	178	582	n.a.	n.a.	n.a.
Total 2C Resources (MMboe)	**389**	**354**	**452**	**n.a.**	**n.a.**	**n.a.**
Pro forma Adjustments						
Vietnam Oil (MMbbl)	—	2	—	n.a.	n.a.	n.a.
Vietnam Gas (Bscf)	—	16	—	n.a.	n.a.	n.a.
Total Vietnam 2C Resources (MMboe)	—	5	—	n.a.	n.a.	n.a.
***Pro forma* Total 2C Resources (MMboe)**	**n.a.**	**359**	**n.a.**	**n.a.**	**n.a.**	**n.a.**

(1) EnQuest net working interest Reserves and Contingent Resources are EnQuest's working interest fraction of the gross field reserves and contingent resources.

(2) GaffneyCline's report assessing reserves and resources for Block 12W in Vietnam as of December 31, 2024 was prepared when entitlements of those reserves and resources were attributable to Harbour Energy, up until July 9, 2025, at which time EnQuest completed the transaction that entitled EnQuest to the reserves and resources. Hence the reported year end 2024 Vietnam Reserves do not represent EnQuest Reserves as at December 31, 2024 but are included in table above as "*Pro forma Adjustments*."

(3) For assets governed by Production Sharing Contracts ("**PSC**") (PM8/Seligi in Malaysia and Block 12W in Vietnam), EnQuest Net Entitlement Reserves are EnQuest's net economic entitlement according to the PSC terms, *i.e.*, EnQuest's share of cost and profit oil and gas.

(4) For the years ended December 31, 2023, 2024 and 2025, 1P gas reserves included 40.8 Bscf used for fuel and 19.4 Bscf (working interest) or 12.5 Bscf (net entitlement) used for sales, 36.7 Bscf used for fuel and 72.0 Bscf (working interest) or 54.0 Bscf (net entitlement) used for sales and 38.4 Bscf used for fuel and 81.5 Bscf (working interest) or 65.2 Bscf (net entitlement) used for sales, respectively. *Pro forma* adjustments reflect 1P Vietnam reserves as of December 31, 2024 and included 0 Bscf used for fuel and 2.3 Bscf (working interest) or 2.2 Bscf (net entitlement) used for sales.

(5) For the years ended December 31, 2023, 2024 and 2025, 2P gas reserves included 46.6 Bscf used for fuel and 35.8 Bscf (working interest) or 24.3 Bscf (net entitlement) used for sales, 42.5 Bscf used for fuel and 104.4 Bscf (working interest) or 76.0 Bscf (net entitlement) used for sales and 46.8 Bscf used for fuel and 124.2 Bscf (working interest) or 94.8 Bscf (net entitlement) used for sales, respectively. *Pro forma* adjustments reflect 2P Vietnam reserves as of December 31, 2024 and included 0 Bscf used for fuel and 10.3 Bscf (working interest) or 9.5 Bscf (net entitlement) used for sales.

Strengths

We believe that the combination of our high-quality asset portfolio, operational expertise, financial strength and differentiated tax position will position us to deliver on our strategy and take advantage of organic and inorganic production and development opportunities in the U.K. North Sea, South East Asia and beyond.

Track record of value creation with a demonstrated ability to execute value-accretive transactions across commodity price volatility

We have an attractive portfolio of operated producing and non-producing assets located in the U.K. North Sea and across South East Asia. We employ a rigorous framework for all M&A that we believe delivers value accretive acquisitions, including the Magnus and Golden Eagle asset acquisitions, which re-weighted our portfolio toward mid-life assets. Our acquisitions in prior years have typically achieved payback within 12 to 18 months, and we take an entrepreneurial, innovative approach to structuring deals, with limited upfront consideration and a focus on value. As part of our strategy to diversify and grow our asset base, we have expanded our operational footprint beyond our core regions in the U.K. North Sea and Malaysia. In July 2025, we completed the acquisition of Harbour Energy's business in Vietnam (the "**Vietnam Acquisition**"), securing a 53.125% equity interest and operatorship in the Chim Sáo and Dua production fields ("**Block 12W**"). The Vietnam Acquisition was largely self funded by interim free cash flow, highlighting the deal's strong economics and rapid payback. In the year ended December 31, 2025, Block 12W produced 5,283 boepd, 2,622 of which was attributable to us following the completion of the acquisition on July 9, 2025. Block 12W had EnQuest working interest 2P Reserves of 7.4 MMboe and 2C Resources of 5.3 MMboe as of December 31, 2025, adding significant resources to our existing reserves.

In addition, we have entered into new production sharing contracts ("**PSCs**") for appraisal and development in Indonesia, Malaysia and Brunei, including the Seligi 1B gas project in Malaysia, where approximately 6 kboepd of gas production was brought onstream approximately nine months ahead of schedule, with gas production beginning in December 2025. Optimized gas production has enabled us to satisfy higher demand, which has exceeded the base delivery requirement by up to 40% since the start of the conflict in the

Middle East. In July 2025, we were awarded the Block C PSC in Brunei, which hosts condensate-rich gas discoveries with a pathway to development and supply to both domestic and international LNG markets. In August 2025, we signed PSCs for the Gaea and Gaea II exploration blocks in Papua Barat, Indonesia, marking our entry into a region with significant multi-Tscf unrisked resource potential near bp-operated LNG infrastructure. These new country entries reflect our disciplined approach to value-accretive growth, enhance our geographic and commodity diversification and position us to leverage our technical and operational expertise in emerging South East Asian markets, where there is strong demand for energy.

These transactions have resulted in Group-wide growth, with our liquidity (being total cash and available facilities) increasing by over $200 million, from $474 million in 2024 to $679 million in 2025. This increase in liquidity was due in large part to the refinancing of our 2021 RBL Facility, which was completed in November 2025. The refinanced RBL Facility comprises a $400 million secured multicurrency revolving loan facility and a $400 million secured multicurrency revolving letter of credit facility, with an accordion option of up to $800 million (consisting of an accordion option of up to $400 million in respect of each of the revolving loan facility and the revolving letter of credit facility) to support, among other things, larger M&A transactions. See "*—Recent Developments—RBL Facility Agreement*" and "*Risk Factors—Risks relating to our business— Our strategy of delivering sustainable and transformative growth through transformative consolidation transactions may increase our debt and the complexity of our operations*." Our production also increased by more than 5%, from 40,736 boepd for the year ended December 31, 2024 to 42,945 boepd for the year ended December 31, 2025, despite natural field declines in the U.K. North Sea and third-party equipment outages. We also successfully navigated a weaker U.S. dollar environment and lower oil prices in 2025, reducing unit operating costs (including hedging) to $25.1/bbl from $25.6/bbl in 2024.

On February 26, 2026, we signed an agreement to settle the Magnus Contingent Consideration for $60 million, representing the final settlement of the profit share liability related to Magnus, thereby securing 100% of future Magnus cash flows and removing the associated $433 million liability that was on our balance sheet as of June 30, 2025. There is no resulting change to the decommissioning arrangements, which require us to pay an effective 9% of decommissioning obligations. This settlement not only simplifies our balance sheet and enhances our credit profile by removing a significant liability but is also expected to unlock $777 million of incremental undiscounted life-of-field free cash flow over the remaining life of Magnus.

Strong, resilient free cash flow generation that facilitates both reinvestment and deleveraging, aided by an advantageous tax position

We generated adjusted EBITDA of $503.8 million during the year ended December 31, 2025. Our cash generated from operations for the years ended December 31, 2023, 2024 and 2025 was $854.7 million, $685.9 million and $497.8 million, respectively. We also generated adjusted free cash flow for the year ended December 31, 2025 of $8.7 million, contributing to $1.3 billion of total free cash flow generated since the start of 2021. Our strong cash flow performance during the periods under review enabled us to refinance and repay certain components of our indebtedness. This led to a simplified capital structure with a lower-than-expected utilization and enabled the full repayment of the 2021 RBL Facility in early 2024 and its cancellation on November 20, 2025. As of December 31, 2025 we had total cash and available facilities of $678.6 million. Facility B (as defined herein) under the RBL Facility Agreement had $381.5 million letter of credit utilization, with $18.5 million residual availability thereunder. Facility A (as defined herein) remained undrawn. See "*Description of certain financing arrangements—RBL Facility*".

We also reduced our costs significantly in the year ended December 31, 2025, including the previously negotiated 70% reduction in the Kraken FPSO lease cost as of April 1, 2025, equivalent to approximately $80 million in savings per year.

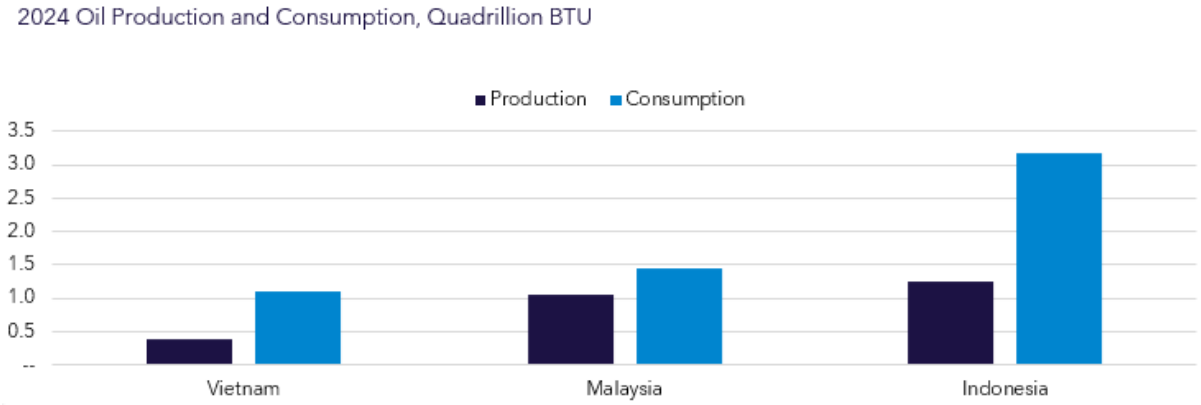
In the U.K., we have a $3 billion tax loss position equating to $1.2 billion in tax shield value built up through material U.K. investment. This tax loss position comprises readily accessible recognized tax assets of $1,851.3 million as of December 31, 2025 and a further $1,118 million not yet recognized. These tax assets shelter EnQuest's U.K. operations from corporation tax (30%) and supplementary charge (10%), with the Group only paying the EPL (38%). This results in a differentiated post-tax cash flow of approximately 62% for EnQuest, more than 2.8x higher than the differentiated post-tax cash flow for full U.K. tax payers paying headline rates. In addition, we have unused U.K. mainstream corporation tax losses of $578.4 million as of December 31, 2025 (December 31, 2024: $496.1 million). We believe that our capital structure, strong liquidity and our tax assets will provide us with the financial flexibility to implement our strategy and, in turn, deliver increased cash flows.

Well-positioned to capitalize on the strategic importance of hydrocarbons and the positive commercial landscapes in the U.K. and South East Asia

Throughout 2025, the U.K. Government clarified the fiscal and regulatory regime for oil and gas activity, creating a more supportive economic environment. In June 2025, the U.K. Government published their Scope 3 guidance, providing emissions framework clarity and removing the risk of retrospective compliance obligations. In November 2025, the U.K. Government announced the Oil and Gas Price Mechanism ("**OGPM**") as the successor to the EPL, representing a more pragmatic and predictable windfall tax mechanism. In addition, the NSTA approved further developments in the North Sea, including granting a license extension for the Cambo field and approving the Tornado and Fotla development concepts (all operated by Ithaca Energy), while the Rosebank field (operated by Equinor) continues to progress in line with its timeline, targeting first oil by 2026–2027, together providing a clear pathway to future production. We believe that our continued focus on established jurisdictions with developed petroleum markets, including the United Kingdom, provides us with an attractive operating environment underpinned by a stable and consistent regulatory regime and fiscal environment.

As oil prices surged following events in the Middle East in the first quarter of 2026, the U.K. Government accelerated the momentum toward greater affordability and security of supply. Concerns regarding future supply and domestic energy prices led the government to make announcements favoring domestic production. Europe's energy dependency, already sharply exposed by the ongoing Russia-Ukraine conflict, is further compounded as Middle East instability threatens a second major supply axis. As a result, North Sea oil and gas output has been recognized as a strategic national asset with cross-party support, reinforcing the investment case for new developments and life extension projects in the North Sea.

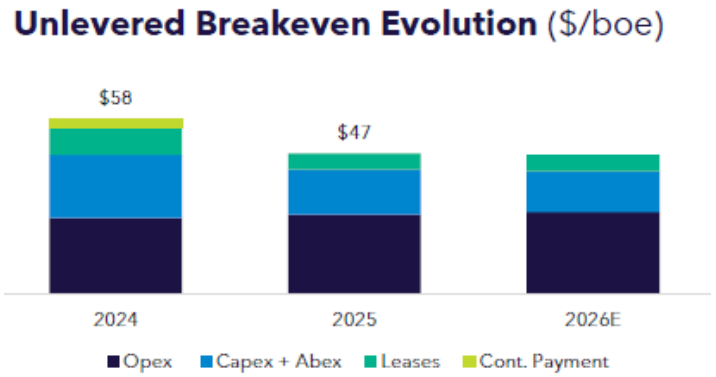
In South East Asia, structural tailwinds favor domestic upstream production. Vietnam, Malaysia and Indonesia all have growing economies, based on increased gross domestic product per capita from 2021 to 2024, but are simultaneously structurally short energy, with total gas demand historically above gas supply. With our presence in four South East Asian countries, we are well-positioned to capitalize on this structural imbalance.



Source: EIA, World Bank

Robust free cash flow potential as a result of enhanced margins, material tax losses and oil price leverage

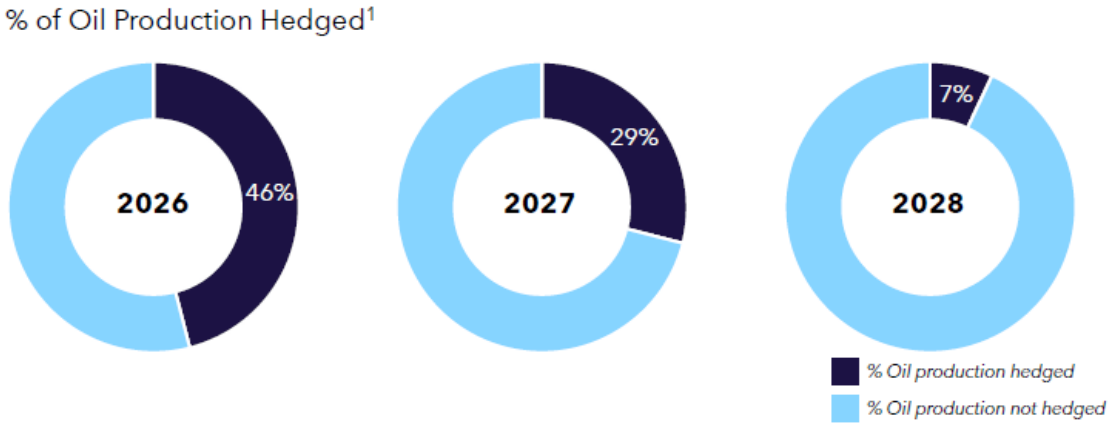
In the year ended December 31, 2025, we generated adjusted free cash flow of $8.7 million, contributing to $1.3 billion of total free cash flow generated since the start of 2021. This strong performance has been in part due to reducing asset break-even levels and substantial U.K. tax loss assets, which together provide leverage to current oil price strength. Our overall pre-tax unlevered breakeven costs have decreased from $58.3/boe in the year ended December 31, 2024 to $46.8/boe in the year ended December 31, 2025.



Note: 2026E column based on 45 kboepd of targeted production and assumes 2026 lease costs in line with 2025 lease costs.

Additionally, average oil prices are expected to increase in 2026, due in part to the conflict in the Middle East, with Bloomberg's consensus forecast, as of March 2026, projecting an average oil price of approximately $90/bbl for 2026, compared to less than $70/bbl in 2025. We estimate that if oil prices had been $10/bbl higher in the year ended December 31, 2025, this would have resulted in approximately $100 million of additional adjusted free cash flow during that year, based on our 2025 production and unit operating costs (including adjustments for hedging to, and excluding tax impacts on, the additional revenue), with further upside in the event of additional oil price increases. As we aim to increase our production and decrease our costs in 2026, increased oil prices would allow us to target an increase in profitability.

Our active hedging strategy also enables resilient cash flows, even at lower oil prices. We are well-hedged, while maintaining upside price exposure. We typically maintain unhedged exposure in near months, complemented by a rolling hedge portfolio across outer periods in order to opportunistically lock in volumes for near-term price lifts during periods of price strength. In 2024, we refreshed our hedging strategy, with a focus on underpinning our budget for the following 24 months and on maximizing RBL Facility capacity. As of April 15, 2026, we have approximately 3.8 MMbbls of production hedged through 2026, utilizing swaps at an average price of $73.2/bbl, and we have approximately 3.5 MMbbls of production hedged for 2027, utilizing swaps at an average price of $64.4/bbl. Finally, we have approximately 0.9 MMbbls of production hedged for 2028, utilizing swaps at an average price of $64.6/bbl. The figure below shows our hedging as a percentage of production.



Note: 2026 includes approximately 1.1MMbbls of hedges from the first quarter of 2026.
(1) At illustrative 2026 mid-point oil production.

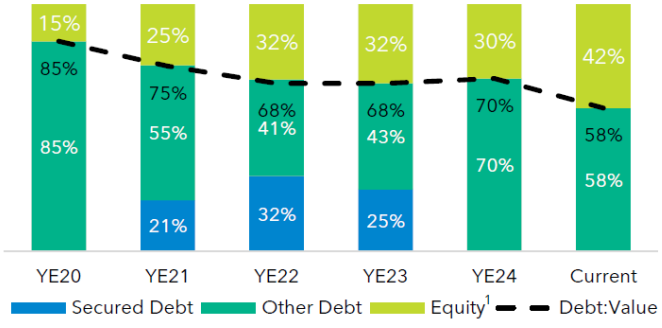
Flexible and simplified capital structure designed for disciplined capital decisions

In the year ended December 31, 2025, we simplified our capital structure, through a combination of our existing 2027 Notes ($465 million as of December 31, 2025), our existing 9% Retail Notes ($179 million as of December 31, 2025) and the refinancing of our 2021 RBL Facility in November 2025. The refinanced RBL Facility provides $800 million of financing capacity, comprising a $400 million secured multicurrency revolving loan tranche, which remained undrawn as of December 31, 2025, and a $400 million secured multicurrency letter of credit facility that simplifies the provision of decommissioning security. In addition, the RBL Facility includes an accordion option of up to $800 million (consisting of an accordion option of up to $400 million in respect of

each of the revolving loan facility and the revolving letter of credit facility), to support, among other things, larger M&A transactions. With a strong cash balance and funds remaining available to draw down under the RBL Facility, our total cash and available facilities totaled $679 million at December 31, 2025 (including $269 million in cash), an increase from $474 million as of December 31, 2024 and from $284 million as of December 31, 2020, supporting disciplined capital allocation and providing significant flexibility to pursue value-accretive opportunities.

Balance sheet strength, active management of capital structure and financial discipline remain key priorities. Through our entry into multiple countries in South East Asia, we have been growing through diversification and internationalization, allowing us to strategically focus on investments with fast payback times and attractive risk-adjusted returns. Within this framework of capital discipline, we seek to deploy capital selectively and prioritize opportunities that enhance resilience and reduce concentration risk. As a result, we were able to issue our first shareholder dividend of $15.3 million in 2025. Further to this, we announced our intention to pay an increased dividend of $20 million in 2026, subject to shareholder approval at our annual general meeting on May 22, 2026.

We have significantly strengthened our capital structure since December 31, 2020, primarily through a reduction in net debt and growth in equity value. Between December 31, 2020, and December 31, 2025, net debt decreased by 66%, supported by a 21% increase in cash (including restricted cash) and a 139% increase in liquidity, improving financial flexibility and reducing leverage. In the period from December 31, 2020 to March 31, 2026, our market capitalization increased by 92%, further contributing to a stronger equity base. As a result, the equity share of our enterprise value increased from 17% to 54%, a 37% increase. The graph below shows the increasing equity component of our capital structure from 2020 to 2025.



	YE2020	Current	Change
Net Debt	1,280	434	- 66%
Cash[2]	223	269	+ 21%
Liquidity	284	679	+ 139%
Equity (Market Cap.)	262	504[3]	+ 92%
Equity % of Enterprise Value	17%	54%	+ 37%[4]

(1) Market value of equity.
(2) Includes restricted cash
(3) Market capitalization as of March 31, 2026 (21p/share x 1.85bn s/o, GBPUSD 1.29).
(4) Stated on an absolute basis.

Strategy

We aim to remain one of the U.K.'s leading independent energy companies, utilizing our top quartile operating performance and differentiated U.K. tax position to rescale the business through transformative M&A. We are focused on growing scale through diversification and internationalization across our U.K. North Sea and South East Asian operations, delivering value and reducing emissions, while maintaining balance sheet discipline. We intend to deliver sustainable and transformative growth by targeting the acquisition of flowing barrels, with robust production profiles and low capital requirements, while continuing to exploit our existing reserves, commercializing and developing discoveries and converting our significant Contingent Resources into reserves. In addition, we will continue to assess renewable energy and decarbonization opportunities, prioritizing those that leverage existing infrastructure. We are developing cost-effective and efficient plans to transform SVT and prepare and repurpose the site to progress decarbonization opportunities at scale, focused on carbon capture and storage, electrification through onshore wind, and the production of e-fuels.

Continued operational excellence with a focus on ESG and sustainability

We have a strong track record of conducting our operations in a safe and environmentally responsible manner and seek to maintain the highest safety standards. As an energy company, safely improving the operating, financial and environmental performance of mature and late-life assets remains a key focus. Our highly skilled and integrated teams strive to enhance hydrocarbon recovery through focused improvement programs, prioritizing employee safety and mitigating the effects of climate change. We recognize that industry, along with other key stakeholders such as governments and regulators, must contribute to reducing the impact of carbon-related emissions on climate change. We are committed to playing our part in achieving national emission reduction targets and the drive to net-zero, with our wholly owned subsidiary, Veri Energy, having overall responsibility for delivering our emission reduction objectives. Through our environmental management system ("**EMS**"), we strive to ensure that our operations are undertaken in a manner that manages and mitigates our impact on the environment. The EMS is aligned with the requirements of the International Organization for Standardization's environmental management system—ISO 14001—and is independently verified every two years, the last time being in September 2025. In the United Kingdom, we will continue to publish our annual Environmental Statement, and in Malaysia, environmental management and reporting are undertaken through PETRONAS Malaysia Petroleum Management. Additionally, we intend to produce environmental reports that include our Vietnam, Indonesia and Brunei assets going forward.

Our in-house technical and operations teams underpin our development and operations-focused strategies. We believe that we are differentiated from our peers by the breadth and depth of these teams, their knowledge and experience in engineering, subsurface, execution and operations and our leadership in innovative integrated developments, such as Magnus. We have a spectrum of integrated technical capabilities, combining subsurface, production operations, facilities, management, project management, planning and drilling, providing us with the right mix of capabilities to deliver new oil field developments and optimize production from producing assets in maturing basins by leveraging our differentiated operating capabilities. Our oil and gas reserves and resources increased by approximately 18% for the year ended December 31, 2025, compared to 2024, reflecting the impact of our focused development and portfolio strategy. We are a top-quartile operator, increasing our production by approximately 5.4% over the same period and achieving underlying asset uptime of approximately 89% (92% excluding the impact of the third-party outage at Magnus in the first half of 2025). We have delivered these results while reducing Scope 1 and Scope 2 CO_2 equivalent emissions and operating costs, extending field life and demonstrating sector-leading decommissioning performance.

Our operational expertise also enabled us to deliver three years and over six million man-hours of lost time incident frequency ("**LTI**")-free performance in Malaysia, and we received the 'HSE Excellence Award' at the PETRONAS Emerald Awards in May 2025. We continue to prioritize focus across the organization on driving personal responsibility for safety, increasing hazard awareness and providing excellent supervision at the worksites. Our operating capabilities have been recognized through prestigious industry awards. At the PETRONAS Emerald Awards in June 2025, we were named "Operator of the Year" for the second consecutive year, underscoring our commitment to operational excellence in the region. In addition, we received recognition for "Abandonment Excellence," reflecting our sector-leading performance in well P&A activities. These accolades from PETRONAS serve as strong validation of our expertise, dedication to safety and ability to deliver complex projects efficiently and responsibly in one of South East Asia's key energy markets.

The Board added its support to our sustainability plan during 2023 by approving a commitment to reach net zero Scope 1 and Scope 2 emissions by 2040 and will work closely with management to ensure that appropriate and credible milestones are set for the journey to net zero. As part of this journey, we have set annual interim targets to reduce Group-wide Scope 1 and Scope 2 emissions by 10% across a rolling three-year period. These targets, which started in 2020, are linked to compensation across the Group. In the United Kingdom, by December 31, 2025, we had reduced our Scope 1 and Scope 2 emissions by approximately 46% compared to 2018. In addition, we were awarded a sector-leading A- rating for our 2025 CDP Climate Change submission ("**CDP**"), an improvement from our B rating in 2024, which we believe validates our continued focus on the impact of our business on climate change. CDP represents the pre-eminent ESG rating used by investors and financial institutions, and the overall improvement in our scoring in recent years has been driven by recognition of our credible transition plan and defined actions to pursue progress towards net zero.

As the energy transition progresses and other industry operators continue to shift their focus from mature basins within various geographies, it is expected that there will be further opportunities for us to access additional oil and gas reserves and resources. We are focused on expanding our footprint in South East Asia, delivering

geographic diversification as well as increasing the gas component of our portfolio commodity mix. However, we will aim to ensure we identify the right opportunities where we can deliver incremental emission reductions relative to the carbon footprint of the seller. In addition, we will continue to assess renewable energy and decarbonization opportunities that would leverage existing infrastructure.

We are developing cost-effective and efficient plans to transform SVT, right-sizing and repurposing the site to progress decarbonization opportunities at scale. These plans are centered on carbon capture and storage, electrification via onshore wind, and the production of e-fuels. The availability of the deep-water port and jetties and a pipeline network linked to several well-understood offshore reservoirs presents the opportunity to repurpose infrastructure to import and permanently store material quantities of CO_2 from isolated emitters in the U.K., Europe or further afield. Veri Energy holds two U.K. carbon storage licenses, awarded by the U.K. Regulator, covering locations which are accessible from our existing infrastructure. Initial study work suggests a project with the potential for up to 10 million tonnes per annum of storage and in excess of 200 million tonnes of total capacity at our two licensed storage sites, ramping up from as early as 2028. We also remain focused on right-sizing SVT for future operations and are progressing two major projects; the construction of new stabilization facilities ("**NSF**"), and a strategic project to connect the terminal to the U.K.'s electricity grid. It is expected that the NSF will right-size the terminal's oil stabilizing (removing gas from the oil so that it is safe for onwards transportation) and processing capacity to meet the future production profile associated with the East of Shetland offshore fields.

The safety of our people and operations is and will continue to be integral to our values. We have a group-wide health, safety, environment and assurance policy. We undertake ongoing improvement activities in support of the 'SAFE' behaviors: (i) standards (following rules and procedures), (ii) awareness (understanding the hazards and controls), (iii) fairness (adopting the correct behaviors) and (iv) engagement (communicating effectively).

Maintain a disciplined approach to financial management and a strong balance sheet that provide optionality around organic and inorganic opportunities

We aim to have a conservative financial profile and strong balance sheet with ample liquidity. Debt reduction and active management of our debt maturities will remain a priority. We have reduced our EnQuest net debt to $433.9 million as of December 31, 2025, significantly lower than $1.2 billion as of December 31, 2021, which resulted in a corresponding reduction of leverage to 0.9x, calculated using EnQuest net debt as of December 31, 2025 over adjusted EBITDA for the year ended December 31, 2025. This is down from a peak of 6.6x at December 31, 2017. Our consistent deleveraging is driven by total free cash flow of $1.3 billion generated since the start of 2021, and our prudent approach to capital allocation. While we intend to use debt financing and access to capital markets when appropriate, we will seek to manage the business with leverage levels that are reflective of the financial capacity of our assets.

With a strong cash balance and funds remaining available to draw down on the RBL Facility, our total cash and available facilities totaled $679 million at December 31, 2025, an increase from $474 million at December 31, 2024.

We will continue to focus our capital allocation strategy on identifying investments that prioritize positive cash flow generation. With a focus on short-cycle projects, we can adjust our capital allocation decisions to match the prevailing oil demand and price environment and are actively and continuously assessing program optimization in light of the Energy Profits Levy ("**EPL**") and the subsequent OGPM in the United Kingdom. In the year ended December 31, 2025, our cash outflow on capital expenditure ("cash capex") was $179.2 million, excluding acquisitions. In the year ended December 31, 2024, our cash outflow on capital expenditure ("cash capex") was $252.9 million, excluding acquisitions, as compared to $152.2 million in the year ended December 31, 2023.

As part of our prudent risk management program, we actively hedge our exposure to oil prices on a graduated rolling basis to provide strong price protection throughout the economic cycle. Liquidity risk will continue to be monitored closely through cash flow forecasts and sensitivity analysis. We will also continue to manage credit risk by assessing the creditworthiness of potential counterparties before entering into transactions with them and by continuing to evaluate their creditworthiness after transactions have been initiated.

We will continue to drive organic growth by prioritizing fast payback infill drilling across our core portfolio. In addition, we are focused on unlocking upside on our existing assets, for instance via the Kraken EOR project and the Seligi 1B gas project, where approximately 6 kboepd of gas production was brought onstream

approximately nine months ahead of schedule. We are working to convert our significant Contingent Resources into reserves, notably at Bressay & Bentley, DEWA and Block C.

We continue to evaluate potentially transformative inorganic acquisition opportunities in the U.K. and South East Asia. Our focus is to identify assets that fit our business model, including those that can best utilize our U.K. tax losses and create synergies for our tax credits under the EPL. With a total of over $3 billion in tax assets in the United Kingdom as of December 31, 2025, we have set the conditions to deliver value-accretive and transformative inorganic growth and, even in a fiscally volatile environment, our growth strategy remains robust. We will also continue to evaluate and pursue cost optimization initiatives, including through selective acquisitions with vendor loan structures, partnership opportunities and business combinations, in each case which may be material, in order to secure an adequate supply of resources, rigs or other infrastructure used or useful in the business when we believe to do so will be value-accretive and enhance our long-term growth and strategic objectives. See "*—Track record of value creation with a demonstrated ability to execute value-accretive transactions across commodity price volatility*" and "*Risk Factors—Risks relating to our business—Our strategy of delivering sustainable and transformative growth through transformative consolidation transactions may increase our debt and the complexity of our operations.*"

Maximize the performance of our existing asset portfolio and deliver innovative value-add initiatives

We aim to employ a cost-conscious approach to our operations and implement innovative initiatives to enhance their value. Since 2015, we have significantly reduced our capital expenditure. We have also reduced our unit operating costs (including hedging) from $25.6/bbl in the year ended December 31, 2024 to $25.1/bbl in the year ended December 31, 2025, and continue to target cost-reduction strategies. We also strive to utilize innovative transaction structures to facilitate the transfer of the right assets into the right hands.

We believe we are strongly positioned to be an energy transition leader by responsibly optimizing production at our existing assets, leveraging existing infrastructure, delivering strong decommissioning performance and exploring new energy and further decarbonization opportunities. In December 2023, we launched Veri Energy, which builds on work undertaken by our infrastructure and new energy business, and is focused on progressing scalable decarbonization and new energy projects. These projects include carbon capture and storage, electrification via onshore wind, and the production of e-fuels and are focused on repurposing the existing infrastructure at SVT and connected offshore infrastructure. We bring the infrastructure, key relationships and project delivery expertise and will look to engage strategic and financial partners to progress these projects, enabling us to employ a capital-light approach.

Leverage integrated technical capabilities

We believe we have the right mix of integrated technical capabilities to select appropriate development and production options, deliver high levels of underlying asset uptime and control costs to realize value from maturing and underdeveloped assets. We aim to leverage our differentiated operational capabilities to responsibly optimize production across our portfolio to achieve asset life extension and maximize economic recovery from those assets to enable future growth. Similarly, we are using our skills to assess repurposing opportunities of existing infrastructure and progress scalable new energy and decarbonization opportunities.

Use of Proceeds

We intend to use the gross proceeds from the issue of the Notes (i) to redeem the outstanding 2027 Notes in full, (ii) for payment of fees, costs, discounts and expenses in connection with the Transactions and (iii) to replenish cash on the balance sheet.

Recent developments

RBL Facility Agreement

On November 9, 2025, we entered into a secured multicurrency revolving borrowing base facilities agreement, between, among others, the Company, as obligor, and DNB Bank ASA, London Branch, as agent and security agent (the "**RBL Facility Agreement**"). The RBL Facility Agreement provides for commitments split as to $400.0 million in respect of a secured multicurrency revolving loan facility ("**Facility A**") and $400.0 million in respect of a secured multicurrency revolving letter of credit facility ("**Facility B**").

On November 20, 2025, (i) all loan drawings under the 2021 RBL Facility Agreement were repaid with cash from balance sheet and (ii) the letters of credit outstanding under the 2021 RBL Facility Agreement and the existing surety bonds and cash which support our decommissioning obligations were cancelled and returned and replaced by new letters of credit issued under Facility B. The 2021 RBL Facility was then cancelled. As of December 31, 2025, Facility B under the RBL Facility Agreement had $381.5 million utilized, with $18.5 million residual availability thereunder. Facility A remained undrawn. The amount of letters of credit outstanding corresponds to the security in place supporting our decommissioning obligations outstanding as of December 31, 2025. On January 1, 2026, certain letters of credit under Facility B were replaced by surety bonds resulting in our decommissioning security agreement obligations being covered by £225.7 million utilization of Facility B and £90.0 million of surety bonds.

For a summary of the terms of the RBL Facility Agreement, see "*Description of certain financing arrangements—RBL Facility*".

Block 12W Production Sharing Contract Extension

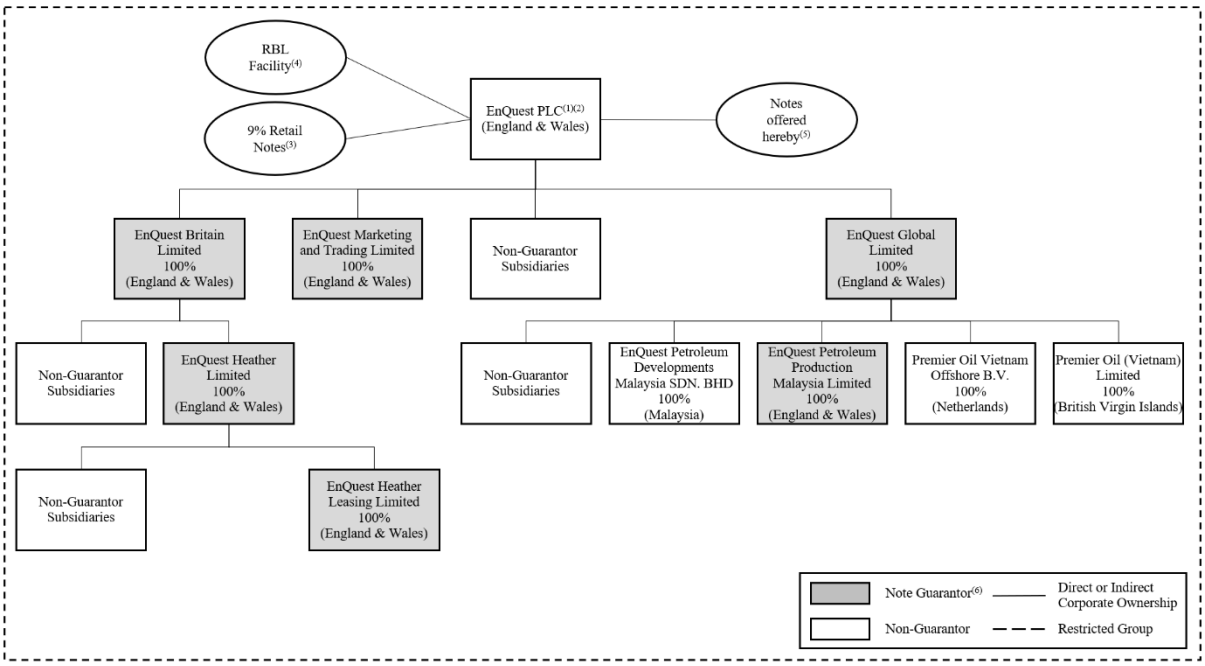
On February 9, 2026, we were awarded a four-year extension to the Block 12W Production Sharing Contract ("**PSC**") by PetroVietnam. Granted on the PSC's existing terms, this extension runs to July 2034 and provides us the opportunity to access upside across Block 12W, with prospectivity spread across three gas discoveries and several additional targets, and progress discovered resources into reserves.

Cendramas PSC Partnership

On February 11, 2026, we received a Letter of Award ("**LOA**") as a partner in the Cendramas PSC in peninsular Malaysia, in partnership with Medco Asia Pacific Limited and DIALOG Resources Sdn Bhd by Petroliam Nasional Berhad (PETRONAS) through Malaysia Petroleum Management. The terms of the LOA, subject to the finalization and signing of the Joint Operating Agreement and the Cendramas PSC, will be effective from September 23, 2026.

CORPORATE STRUCTURE AND CERTAIN FINANCING ARRANGEMENTS

The following chart shows a simplified summary of our corporate and financing structure after giving effect to the Transactions. For further information, see "*Use of proceeds*". The chart does not include all of our subsidiaries or all of the debt obligations thereof. Unless otherwise indicated, the subsidiaries included in the simplified structure below are directly or indirectly wholly owned by EnQuest PLC. Our legal interests in our assets vary based on our contractual arrangements with our commercial partners and the relevant licenses and related agreements. For a description of our interests in certain assets, see "*Our business—Overview of our assets*." For a summary of the debt obligations identified in this diagram, see "*Description of Notes*," "*Description of certain financing arrangements*" and "*Capitalization*."



(1) As of December 31, 2025, EnQuest had an issued share capital of 1,885,029,503 allotted and fully paid ordinary shares of 5 pence each, of which 20,000,000 ordinary shares were held in Treasury. As of December 31, 2025, we had a market capitalization of $268.8 million based on the Bloomberg Composite Rate (London) pounds sterling/U.S. dollar exchange rate of $1.3452 per £1.00.

(2) The issuer of the Notes will be EnQuest PLC, a public limited company incorporated under the laws of England and Wales.

(3) As of December 31, 2025, the Company had outstanding $179.4 million (equivalent) aggregate principal amount of the 9% Retail Notes. The 9% Retail Notes mature on October 27, 2027. The 9% Retail Notes accrue interest at a fixed coupon of 9.0% payable semi-annually in arrears. The 9% Retail Notes are senior obligations of the Company ranking *pari passu* in right of payment with all existing and future obligations of the Company that are not expressly subordinated in right of payment to the Notes, including obligations under the RBL Facility Agreement. See "*Capitalization*" and "*Description of certain financing arrangements*."

(4) On November 9, 2025, the Company entered into the RBL Facility Agreement on the terms described therein which are summarized in these Listing Particulars. The RBL Facility will mature on the earliest of (i) the reserve tail date (as set out in the RBL Facility Agreement), (ii) December 31, 2031, (iii) if the 2027 Notes have not been repaid in full by the date falling six months before its maturity date, six months before such maturity date or (iv) if an obligor has incurred capital market indebtedness with a maturity (or scheduled principal repayment) on or before December 31, 2031 (including the indebtedness under the Notes but excluding indebtedness under the 9% Retail Notes), six months before the earliest maturity date (or scheduled principal repayment). The RBL Facility is guaranteed by each of the RBL Guarantors (as defined herein) and certain other subsidiaries of the Company and secured on the shares and certain assets of the RBL Guarantors (as defined herein) and such other companies. The RBL Facility Agreement provides for commitments split as to $400.0 million in respect of a secured multicurrency revolving loan facility ("**Facility A**") and $400.0 million in respect of a secured multicurrency revolving letter of credit facility ("**Facility B**"). As of December 31, 2025, the RBL Facility had a letter of credit utilization under Facility B of $381.5 million, with $18.5 million residual availability thereunder. Facility A was undrawn as of December 31, 2025. See "*Description of certain financing arrangements—RBL Facility"* and *"—Financing—Letters of credit, surety bonds and restricted cash*."

(5) The Notes offered hereby will be senior obligations of the Company ranking *pari passu* in right of payment with all existing and future obligations of the Company that are not expressly contractually subordinated in right of payment to the Notes, including obligations under the 9% Retail Notes and the RBL Facility. The Notes will be senior in right of payment to all future obligations of the Company that are subordinated in right of payment to the Notes. The Notes will be effectively subordinated to all existing and future secured obligations of the Company, including obligations under the 9% Retail Notes and the RBL Facility to the extent of the value of the property and assets securing such obligations. The Notes will be structurally subordinated to all existing and future obligations of the Company's subsidiaries that do not guarantee the Notes, including any trade payables and letters of credit issued by or on behalf of such subsidiaries. The Notes will be guaranteed on a senior subordinated basis by the Guarantors, subject to limitations under applicable law as set forth below under the caption "*The Offering—Guarantors*." See "*Description of Notes*" and "*Capitalization*."

(6) The Notes will be guaranteed on a senior subordinated basis (the "**Note Guarantees**") by EnQuest Heather Limited, EnQuest Britain Limited, EnQuest Heather Leasing Limited, EnQuest Global Limited, EnQuest Petroleum Production Malaysia Ltd and EnQuest Marketing and Trading Limited (collectively, the "**Guarantors**") on the Issue Date. Certain of the Guarantors, as well as certain other subsidiaries that will not guarantee the Notes, are also guarantors in respect of the RBL Facility. From time to time, we may conduct internal reorganizations, which may include the merger or liquidation of Group entities, which may include Guarantors. See "*Description of Notes—Certain Definitions—"Permitted Reorganization"*."

THE OFFERING

The following is a brief summary of certain terms of this offering. It is not intended to be complete and it is subject to important limitations and exceptions. Accordingly, it may not contain all the information that is important to you. For additional information regarding the Notes and the Note Guarantees, see "*Description of Notes*."

Issuer..... EnQuest PLC, incorporated as a public limited company under the laws of England and Wales (the "**Company**").

Notes offered ..... $675.0 million aggregate principal amount of 9⅞% Senior Notes due 2031 (the "**Notes**").

Issue date ..... April 30, 2026.

Issue price..... 99.038% (plus accrued interest, if any, from the Issue Date).

Maturity date ..... April 30, 2031.

Interest rate..... 9⅞% per annum.

Interest payment dates ..... We will pay interest on the Notes semi-annually in arrears on April 30 and October 30, beginning on October 30, 2026. Interest will accrue from the Issue Date.

Form and denomination..... The Company will issue the Notes on the Issue Date in global registered form in minimum denominations of $200,000 and integral multiples of $1,000 in excess thereof maintained in book-entry form. Notes in denominations of less than $200,000 will not be available.

Ranking of the Notes ..... The Notes will be:

- senior obligations of the Company;
- *pari passu* in right of payment with all existing and future obligations of the Company that are not expressly contractually subordinated in right of payment to the Notes, including obligations under the 9% Retail Notes and the RBL Facility Agreement;
- senior in right of payment to all future obligations of the Company that are subordinated in right of payment to the Notes;
- effectively subordinated to all existing and future secured obligations of the Company, including obligations under the 9% Retail Notes and the RBL Facility Agreement, to the extent of the value of the property and assets securing such obligations, unless such assets also secure the Notes on an equal and ratable or senior basis;
- structurally subordinated to all existing and future obligations of the Company's subsidiaries that do not guarantee the Notes, including any non-Guarantor subsidiaries of the Company that guarantee the 9% Retail Notes and the RBL Facility; and
- guaranteed on a senior subordinated basis by the Guarantors, subject to limitations under applicable law as set forth below under the caption "—*Guarantors*."

Guarantors..... The Notes will be guaranteed on a senior subordinated basis (the "**Note Guarantees**") by EnQuest Heather Limited, EnQuest Britain Limited,

EnQuest Heather Leasing Limited, EnQuest Global Limited, EnQuest Petroleum Production Malaysia Ltd and EnQuest Marketing and Trading Limited (collectively, the "**Guarantors**") on the Issue Date.

As of December 31, 2025, after giving *pro forma* effect to the Transactions:

- the Company and its consolidated subsidiaries had $912.8 million of indebtedness, of which $912.8 million is represented by the Notes, the 9% Retail Notes, the SVT Working Capital Facility and the Vendor Loan Facility; and

- the non-Guarantor subsidiaries of the Company did not have any financial indebtedness (excluding intercompany indebtedness), but were in some cases guarantors under the RBL Facility.

As of and for the year ended December 31, 2025, the Company and the Guarantors represented 95% of the Company's revenue and other operating income and 84% of the Company's total assets.

Although the Indenture governing the Notes contains limitations on the amount of additional indebtedness the Company and its restricted subsidiaries are allowed to incur, these limitations are subject to a number of significant qualifications and exceptions, and, under certain circumstances, the amount of additional indebtedness could be substantial.

The obligations of each Guarantor under its Note Guarantee will be limited to an amount that can be guaranteed under applicable laws, and will not apply to the extent a Note Guarantee would be illegal or unenforceable under applicable local and bankruptcy laws. See "*Risk factors—Risks relating to the Notes and our structure—Each Note Guarantee will be subject to certain limitations on enforcement and may be limited by applicable laws or subject to certain defenses that may limit its validity and enforceability*" and "*Certain insolvency law considerations*."

Ranking of the Note Guarantees ..... Each Note Guarantee will be:

- a senior subordinated obligation of the respective Guarantor;

- contractually subordinated in right of payment to all existing and future senior obligations of that Guarantor, including such Guarantor's obligations under the RBL Facility;

- *pari passu* in right of payment with all existing and future senior subordinated obligations of that Guarantor;

- senior in right of payment to all future obligations of that Guarantor that are expressly contractually subordinated to that Guarantor's Note Guarantee;

- structurally subordinated to all existing and future obligations of such Guarantor's subsidiaries that do not guarantee the Notes; and

- effectively subordinated to all existing and future secured obligations of that Guarantor (including under the RBL Facility), to the extent of the value of the property and assets

securing such obligations, unless such assets also secure the Note Guarantees on an equal and ratable or senior basis.

The Note Guarantees will be subject to certain contractual and legal limitations as described under "*Risk factors—Each Note Guarantee will be subject to certain limitations on enforcement and may be limited by applicable laws or subject to certain defenses that may limit its validity and enforceability*" and may be released under certain circumstances. See "*Description of Notes—Note Guarantees release*."

Use of proceeds..... We intend to use the gross proceeds from the issue of the Notes (i) to redeem the outstanding 2027 Notes in full, (ii) for payment of fees, costs, discounts and expenses in connection with the Transactions and (iii) to replenish cash on the balance sheet. See "*Use of proceeds*."

Original Issue Discount..... The Notes may be issued with original issue discount ("**OID**") for U.S. federal income tax purposes. If the Notes are issued with original issue discount, in addition to the stated cash interest on such series of Notes, U.S. holders (as defined under "*Taxation—Certain United States federal income tax considerations to U.S. holders*") will generally be required to include the amounts representing the original issue discount in gross income on a constant yield basis in advance of receipt of the cash payments to which such income is attributable. See "*Taxation—Certain United States federal income tax considerations to U.S. holders—Original issue discount*."

Additional amounts ..... All payments made by us under or with respect to the Notes or by any of the Guarantors with respect to any Note Guarantee will be made without withholding or deduction for taxes unless required by law. If the Company or any Guarantor is required by law to withhold or deduct for taxes imposed by any relevant taxing jurisdiction with respect to a payment to the holders of Notes, the Company or such Guarantor, as applicable, will pay the additional amounts necessary so that the net amount received by the holders of Notes after such withholding or deduction is equal to the amount that they would have received in the absence of such withholding or deduction, subject to certain exceptions. See "*Description of Notes—Additional amounts*."

Optional redemption for tax reasons . In the event of certain developments affecting taxation of the Notes the Company may redeem the Notes in whole, but not in part, at any time upon giving prior notice, at a redemption price of 100% of the principal amount, plus accrued and unpaid interest, if any, and additional amounts, if any, to the date of redemption. See "*Description of Notes—Redemption for changes in taxes*."

Optional redemption ..... Prior to April 30, 2028 the Company may redeem all or part of the Notes at a redemption price equal to 100% of the principal amount of such Notes redeemed, plus accrued and unpaid interest, if any, to the redemption date, plus a "make-whole" premium, as described under "*Description of Notes—Optional redemption*."

In addition, on or prior to April 30, 2028 the Company may redeem up to 40% of the aggregate principal amount of each of the Notes with the net cash proceeds from specified equity offerings at a redemption price equal to 109.875% of the principal amount thereof plus accrued and unpaid interest, if any, to the redemption date, provided that at least 50% of the aggregate principal amount of the Notes remain outstanding after the redemption. See "*Description of Notes—Optional redemption*."

Prior to April 30, 2028, the Company may redeem during each twelve-month period commencing with the Issue Date up to 10% of the original principal amount of the Notes at its option, at a redemption price equal to 103% of the principal amount of the Notes so redeemed, plus accrued and unpaid interest, if any, to the applicable redemption date. See "*Description of Notes—Optional redemption*."

The Company may redeem the Notes on or after April 30, 2028 in whole or in part, at its option at the redemption prices as described under "*Description of Notes—Optional redemption*."

Change of control..... Upon the occurrence of certain change of control events, the Company will be required to offer to repurchase the Notes at a purchase price equal to 101% of their aggregate principal amount, plus accrued and unpaid interest, if any, to the date of the purchase. See "*Description of Notes—Repurchase at the option of holders—Change of control*."

Certain covenants..... The Indenture limits, among other things, the ability of the Company and its restricted subsidiaries to:

- incur additional debt and issue guarantees and preferred stock;
- make certain payments, including dividends and other distributions, with respect to outstanding share capital;
- repay or redeem subordinated debt or share capital;
- create or incur certain liens;
- impose restrictions on the ability of the Company's restricted subsidiaries to pay dividends or other payments to the Company or any of its other restricted subsidiaries;
- make certain investments or loans;
- sell, lease or transfer certain assets, including shares of any restricted subsidiary of the Company;
- guarantee certain types of other indebtedness of the Company or its restricted subsidiaries without also guaranteeing the Notes;
- expand into unrelated businesses;
- merge or consolidate with other entities; and
- enter into certain transactions with affiliates.

Each of the covenants is subject to a number of important exceptions and qualifications. See "*Description of Notes—Certain covenants*."

Transfer restrictions..... The Notes and the Note Guarantees have not been, and will not be, registered under U.S. federal or state or any foreign securities laws. The Notes are subject to restrictions on transfer and may not be offered or sold except pursuant to an exception from, or in a transaction not subject to, the registration requirements of the U.S. Securities Act. See "*Notice to investors*."

No prior market..... The Notes will be new securities for which there is no market. Although the Initial Purchasers have informed the Company that they intend to

	make a market in the Notes, they are not obligated to do so and they may discontinue market-making at any time without notice. Accordingly, the Company cannot assure you that an active trading market for the Notes will develop or be maintained.
Listing	Application has been made to list the Notes on the Official List of the Luxembourg Stock Exchange and to trade the Notes on the Euro MTF Market thereof. There can be no assurance that the listing will be maintained.
Governing law	The Notes, the Note Guarantees and the Indenture will be governed by New York law.
Trustee	Deutsche Bank Trust Company Americas.
Registrar, Transfer Agent and Principal Paying Agent	Deutsche Bank Trust Company Americas.
Risk factors	Investing in the Notes involves substantial risks. You should consider carefully all the information in these Listing Particulars and, in particular, you should evaluate the specific risk factors set forth under "*Risk factors*" before making a decision whether to invest in the Notes.

SUMMARY FINANCIAL DATA

The following tables present our summary historical consolidated financial information as of and for the years ended December 31, 2023, 2024 and 2025, which has been derived from our Group Financial Statements and notes thereto as of and for the years ended December 31, 2023, 2024 and 2025. Our Group Financial Statements as of and for the years ended December 31, 2023, 2024 and 2025 should be read in conjunction with the relevant reports of our independent auditor for such periods.

Our Group Financial Statements as at and for the year ended December 31, 2023, 2024 and 2025 included in these Listing Particulars have been prepared in accordance with United Kingdom adopted International Accounting Standards in conformity with the requirements of the Companies Act 2006. The financial statement data set forth in the following tables should be read in conjunction with "*Presentation of financial and other information*," "*Capitalization*," "*Use of proceeds*," "*Management's discussion and analysis of financial condition and results of operations*," "*Selected financial data*," our annual financial statements and related notes.

In our 2024 Group Financial Statements, we removed the separate disclosure of remeasurements and exceptional items from the presentation of our income statement to simplify their presentation and to align the presentation with industry peers. As a result, unless otherwise indicated, all amounts shown for our financial results of operation for the financial year ended December 31, 2023 presented herein reflect the relevant results of operations "reported in the year/period" for the relevant period. See "*Presentation of financial and other information*."

Historical results may not necessarily be indicative of results that may be expected for any future period.

Summary historical group income statement data

	For the year ended December 31,		
	2023	**2024**	**2025**
		(in millions of $)	
Revenue and other operating income	1,487.4	1,180.7	1,118.3
Cost of sales	(946.8)	(787.4)	(837.5)
Gross profit/(loss)	**540.7**	**393.3**	**280.8**
Net impairment reversal/(charge) on oil and gas assets	(117.4)	(71.4)	5.8
General and administrative expenses	(6.3)	(5.7)	(7.5)
Other income/(expenses)[1][2]	(19.6)	(4.7)	369.7
Profit/(loss) from operations before tax and finance income/(costs)	**397.4**	**311.5**	**648.8**
Finance costs[2]	(172.1)	(159.4)	(164.6)
Finance income	6.5	14.5	9.2
Profit/(loss) before tax	**231.8**	**166.6**	**493.4**
Income tax	(262.6)	(72.8)	(491.9)
Profit/(loss) for the period attributable to owners of the parent	**(30.8)**	**93.8**	**1.6**

(1) "Other income/(expenses)" is shown as the net amount of "other income" and "other expenses" in our 2023 Group Financial Statements.

(2) In respect of the year ended December 31, 2023, the unwinding of discount on the Magnus Contingent Consideration was reclassified in the 2024 Group Financial Statements to "other income/expense" from "finance costs" in the income statement to combine it with the other fair value movements. Therefore, these amounts are derived from the unaudited comparative column of the 2024 Group Financial Statements. See also "*Management's discussion and analysis of financial condition and results of operations—Significant factors affecting comparability—Magnus oil field* acquisition" and "*—Explanation of income statement items—Net other income and other expense*."

Summary historical balance sheet data

	As of December 31,		
	2023	**2024**	**2025**
		(in millions of $)	
Non-current assets	3,025.9	3,000.0[1]	2,984.6
Current assets	739.9	562.6	609.7
Total assets	**3,765.8**	**3,562.6**	**3,594.3**

	As of December 31,		
	2023	2024	2025
Total equity	**456.7**	**542.5**	**528.1**
Non-current liabilities	2,462.4	2,316.4[(1)]	2,214.7
Current liabilities	846.7	703.8[(2)]	851.6
Total liabilities	**3,309.1**	**3,020.1**	**3,066.3**
Total equity and liabilities	**3,765.8**	**3,562.6**	**3,594.3**

(1) In respect of the year ended December 31, 2024, unamortized fees in relation to the 2021 RBL Facility Agreement for the year ended December 31, 2024 were reclassified from "unamortized fees on loans and borrowings" within "loans and borrowings" to "trade and other receivables" in the 2024 Group Financial Statements (resulting in an increase of non-current assets in an amount of $2.1 million and an increase in current assets in an amount of $1.4 million) but have not been restated for prior periods as not material.

(2) Accrued interest on borrowings for the year ended December 31, 2024 was reclassified from "accrued expenses" within "trade and other payables" to "loans and borrowings" to better reflect the total borrowings balance, but has not been restated for prior periods.

Summary historical cash flow statement data

	For the year ended December 31,		
	2023	2024	2025
	(in millions of $)		
Net cash flows from operating activities	754.2	507.6[(1)]	362.7
Net cash flows used in investing activities	(262.7)	(182.4)[(1)]	(194.2)
Net cash flows used in financing activities	(478.6)	(352.9)	(193.0)

(1) In respect of the year ended December 31, 2024, "purchases of intangible assets" of $1.1 million in investing activities was reclassified to operating activities as "cash paid for purchase of other intangible assets" in the 2025 Group Financial Statements (resulting in a decrease of net cash flows from operating activities in an amount of $1.1 million and a decrease of net cash flows used in investing activities in an amount of $1.1 million), but has not been restated for prior periods as not material.

Other financial data and key ratios

	As of and for the year ended December 31,		
	2023	2024	2025
	(in millions of $, except ratios and per share information)		
Adjusted EBITDA[(1)]	824.7	673.9	503.8
Cash capital and decommissioning expense[(2)]	(211.1)	(313.4)	(236.1)
Adjusted free cash flow[(3)]	300.0	53.2	8.7
Finance costs[(4)]	172.1	159.4	164.6
EnQuest total debt[(5)]	794.5	666.1	702.8
EnQuest net debt[(5)]	480.9	385.8	433.9
Adjusted EBITDA/Finance costs[(6)]	3.6	4.2	3.1
EnQuest net debt/adjusted EBITDA[(7)]	0.6	0.6	0.9
As adjusted EnQuest net debt[(8)]			450.7
As adjusted finance costs[(9)]			87.0
Adjusted EBITDA/as adjusted finance costs[(1)(9)]			5.8x
As adjusted EnQuest net debt/adjusted EBITDA[(1)(9)]			0.9x

(1) Adjusted EBITDA consists of profit/(loss) for the period attributable to owners of the parent before income tax and finance income/(costs), adjusted by unrealized gains on derivative contracts, net impairment charge/(reversal) to oil and gas assets, change in Magnus Contingent Consideration, insurance income on Kraken and PM8/Seligi, write-off of exploration costs, drilling rig contract regret costs, depletion and depreciation, inventory revaluation, change in decommissioning and other provisions in relation to changes in the Thistle decommissioning provisions, business combination transaction costs, non-cash U.K. emissions allowances gain/(loss) and net foreign exchange (gain)/loss. Adjusted EBITDA is not a measurement of performance under IFRS or U.S. GAAP and you should not consider adjusted EBITDA as an alternative to (i) operating profit or profit from continuing activities (as determined in accordance with IFRS) as a measure of our operating performance, (ii) cash flows from operating investing and financing activities as a measure of our ability to meet our cash needs or (iii) any other measures of performance under IFRS or other generally accepted accounting principles.

We believe that adjusted EBITDA is a useful indicator of our ability to incur and service our indebtedness and can assist securities analysts, investors and other parties to evaluate us. Adjusted EBITDA and similar measures are used by different companies for differing purposes and are often calculated in ways that reflect the circumstances of those companies. You should exercise caution in comparing adjusted EBITDA as reported by us to adjusted EBITDA of other companies. See the below table for a reconciliation of profit for the period from continuing operations to adjusted EBITDA.

	For the year ended December 31,		
	2023	2024	2025
	(in millions of $)		
Profit/(loss) for the period attributable to owners of the parent	(30.8)	93.8	1.6
Income tax	262.6	72.8	491.9
Profit/(loss) before tax	**231.8**	**166.6**	**493.4**
Finance income	(6.5)	(14.5)	(9.2)
Finance costs	172.1	159.4	164.6
Profit/(loss) from operations before tax and finance income/(costs)	**397.4**	**311.5**	**648.8**
Unrealized gains on derivative contracts[(a)]	(24.6)	(0.3)	(77.5)
Net impairment charge/(reversal) to oil and gas assets[(b)]	117.4	71.4	(5.8)
Change in Contingent Consideration	(10.8)	15.9	(387.1)
Insurance income on Kraken and PM8/Seligi riser incident	(4.1)	(1.7)	0.1
Write-off of exploration costs[(c)]	5.6	0.2	0.2
Drilling rig contract regret costs[(d)]	—	14.6	—
Depletion and depreciation[(e)]	298.3	269.3	272.4
Inventory revaluation[(f)]	(0.6)	(5.5)	2.8
Change in decommissioning and other provisions[(g)]	34.5	7.1	9.8
Business combination transaction costs[(h)]	—	—	0.4
Other non-cash U.K. emissions allowances (gains)/losses[(i)]	—	1.3	11.5
Net foreign exchange (gain)/loss[(j)]	11.7	(10.0)	28.3
Adjusted EBITDA	**824.7**	**673.9**	**503.8**

(a) For the year ended December 31, 2025, reflects (i) $45.2 million unrealized gains on oil and derivative contracts, comprised of gains from commodity options of $7.8 million, gains from commodity swaps of $37.2 million and gains from commodity futures of $0.2 million. For the year ended December 31, 2024 reflects (i) $3.1 million unrealized gains on oil and derivative contracts, comprised of gains from commodity options of $10.6 million, losses from commodity swaps of $7.3 million and losses from commodity futures of $0.2 million and (ii) $2.8 million losses on derivative contracts related to operating costs, comprised of losses from foreign exchange contracts of $2.4 million and losses from UKA contracts of $0.5 million. For the year ended December 31, 2023 reflects (i) $28.5 million unrealized gains on oil and derivative contracts, comprised of gains from commodity options of $19.1 million and gains from commodity swaps of $9.3 million and (ii) $3.8 million losses from UKA contracts related to operating costs.

(b) In the year ended December 31, 2025 the net impairment reversal of $5.8 million was split between impairment charges of $23.0 million in respect of oil and gas assets and reversals of $28.8 million in respect of right-of-use assets within the North Sea segment primarily due to a combination of lower discount rate, changes in production and cost profiles, including the impact of weaker U.S. dollar and lower near-term oil price assumptions. In the year ended December 31, 2024, the net impairment charge of $71.4 million was split between impairment charges of $75.4 million recognized in respect of oil and gas assets and a reversal of $4.0 million, in respect of right-of-use assets, respectively, within the North Sea segment primarily due to energy profits levy ("**EPL**") revisions, lower near-term oil price assumptions profiles, partially offset by a lower discount rate and changes in production. In the year ended December 31, 2023, the net impairment charge of $117.4 million was split between impairment charges of $123.5 million recognized in respect of oil and gas assets and a reversal of $6.0 million in respect of right-of-use assets, respectively, within the North Sea segment primarily due to production and cost profile updates on non-operated assets, partially offset by higher forecast oil prices.

(c) Reflects, for the years ended December 31, 2023, 2024 and 2025, write-off of unsuccessful exploration costs in Malaysia.

(d) Reflects costs associated with a drilling rig contract at Kraken terminated due to a deferral of infill drilling.

(e) For the year ended December 31, 2025 represents depletion of oil and gas assets of $267.3 million and depreciation of $5.1 million. For the year ended December 31, 2024 represents depletion of oil and gas assets of $263.3 million and depreciation of $6.0 million. For the year ended December 31, 2023 represents depletion of oil and gas assets of $292.2 million and depreciation of $6.1 million.

(f) For the year ended December 31, 2025, a net charge was recognized in the income statement of $2.8 million. For the year ended December 31, 2024, a net credit was recognized in the income statement of $5.5 million. For the year ended December 31, 2023, a net credit was recognized in the income statement of $0.6 million.

(g) For the year ended December 31, 2025, represents other expenses of $9.8 million relating to a change in decommissioning provisions and $4.8 million relating to a change in Thistle decommissioning provisions, partially offset by other provision changes of $4.7 million. For the year ended December 31, 2024 represents other expenses of $6.7 million relating to a change in decommissioning provisions and $0.4 million relating to a change in Thistle decommissioning provisions. For the year ended December 31, 2023 represents other expenses of $31.2 million relating to a change in decommissioning provisions and $1.6 million relating to a change in Thistle decommissioning provisions.

(h) For the year ended December 31, 2025, relates to the acquisition of Harbour Energy's business in Vietnam.

(i) U.K. emissions allowances ("UKAs") purchased to settle the Group's liability related to emissions are recognized on the balance sheet as an intangible asset at cost. The UKAs will be derecognized upon settling the liability with the respective regulator.

(j) For the year ended December 31, 2025 represents other expense of $28.3 million relating to net foreign exchange losses. For the year ended December 31, 2024 represents other income of $10.0 million relating to net foreign exchange gains. For the year ended December 31, 2023 represents other expense of $11.7 million relating to net foreign exchange losses.

(2) Cash capital and decommissioning expense represents investing activities on a cash basis (cash capex) plus our cash spend on decommissioning activities. See "*Management's discussion and analysis of financial condition and results of operations—Capital investment*."

	For the year ended December 31,		
	2023	**2024**	**2025**
		(in millions of $)	
Reported Net cash flows used in investing activities	(262.7)	(182.4)	(194.2)
Adjustments			
Purchase of other intangible assets	0.9	—	—
Payment of Magnus Contingent Consideration – Profit share	65.5	48.5	—
Payment of Golden Eagle contingent consideration – Acquisition costs	50.0	—	—
Bressay-related vendor financing facility loaned/(received)	—	(107.5)	—
Proceeds from farm down activities	—	(1.3)	—
Acquisition	—	—	20.3
Interest received	(5.9)	(10.1)	(5.3)
Cash capex	**(152.2)**	**(252.9)**	**(179.2)**
Decommissioning spend	(58.9)	(60.5)	(56.8)
Cash capital and decommissioning expense	**(211.1)**	**(313.4)**	**(236.1)**

(3) The table below sets forth our reconciliation of our net cash flow adjusted for net repayment/proceed of loans and borrowings, net of share issues and cost of acquisitions.

	For the year ended December 31,		
	2023	**2024**	**2025**
		(in millions of $)	
Net cash flows from operating activities	754.2	507.6	362.7
Adjustments			
Purchase of property, plant and equipment	(141.7)	(249.2)	(175.0)
Purchase of oil and gas and other intangible assets	(11.3)	(3.7)	(4.2)
Payment of Magnus Contingent Consideration	(65.5)	(48.5)	—
Estimated cash tax on disposal proceeds	—	50.0*	—
Interest received	5.9	10.1	5.3
Payment of obligations under finance leases	(135.7)	(130.1)	(83.1)
Interest paid	(105.9)	(83.2)	(97.0)
Adjusted free cash flow	**300.0**	**53.2**	**8.7**

* Estimated by reference to disposal proceeds of $141.4 million and the EPL tax rate of 35%.

(4) In respect of the year ended December 31, 2023, the unwinding of discount on the Magnus Contingent Consideration was reclassified in the 2024 Group Financial Statements to "other income/expense" from "finance costs" in the income statement to combine it with the other fair value movements. Therefore, these amounts are derived from the unaudited comparative column of the 2024 Group Financial Statements. See also "*Management's discussion and analysis of financial condition and results of operations—Significant factors affecting comparability—Magnus oil field acquisition*" and "*—Explanation of income statement items—Net other income and other expense*."

	For the year ended December 31,		
	2023	**2024**	**2025**
		(in millions of $)	
Loan interest payable	30.7	18.5	6.0
Bond interest payable	59.0	55.0	69.3
Unwinding of discount on decommissioning provisions	24.2	30.3	35.9
Unwinding of discount on other provisions	1.1	0.9	0.8
Debt refinancing fees	—	4.8	—
Finance charges payable under leases	43.8	27.7	25.1
Amortization of finance fees on loans and bonds	7.9	14.5	15.3
Other financial expenses	5.3	7.8	12.2
Total finance costs	**172.1**	**159.4**	**164.6**

(5) EnQuest net debt consists of EnQuest total debt less cash and cash equivalents. EnQuest total debt as of December 31, 2025 includes $58.4 million in borrowings and $649.0 million in bonds. As adjusted total debt consists of EnQuest total debt as of December 31, 2025 adjusted for the Transactions as if the Transactions had occurred on December 31, 2025 and as adjusted net debt consists of our as adjusted total debt less our as adjusted cash and cash equivalents. The table below shows the amounts outstanding under our financing arrangements as of the dates indicated below on a non-adjusted basis. See "*Capitalization*" for a summary of our financing arrangements adjusted for the Transactions.

	As of December 31,		
	2023	**2024**	**2025**
		(in millions of $)	
2021 RBL Facility	135.1	—	—
RBL Facility[(a)]	—	—	—
Term Loan Facility	146.4	—	—
SVT Working Capital Facility	29.8	34.0	36.3
Vendor Loan Facility	—	—	22.1
2027 Notes	294.3	454.3	458.8
9% Retail Notes	169.7	167.1	179.4
Unamortized fees on loans and borrowings[(b)]	8.6	—	—
Unamortized fees on bonds[(c)]	10.7	10.7	6.2
EnQuest total debt	**794.5**	**666.1**	**702.8**
Cash and cash equivalents[(d)]	313.6	280.2	268.8
EnQuest net debt	**480.9**	**385.8**	**433.9**

(a) As of December 31, 2025, the RBL Facility had $381.5 million in letters of credit utilized, with $18.5 million residual availability thereunder. On January 1, 2026, certain of the letters of credit under Facility B were replaced by surety bonds resulting in our decommissioning security obligations being covered by £225.7 million utilization of Facility B and £90.0 million of surety bonds. For a description of the RBL Facility Agreement, see "*Description of certain financing arrangements—RBL Facility*."

(b) Unamortized fees in relation to the 2021 RBL Facility Agreement for the year ended December 31, 2024 were reclassified from "unamortized fees on loans and borrowings" within "loans and borrowings" to "trade and other receivables" in the 2024 Group Financial Statements to better reflect the variable nature of the 2021 RBL Facility, but have not been restated for prior periods as not material. For the year ended December 31, 2023, represents $4.9 million of unamortized fees in respect of the 2021 RBL Facility and $3.6 million of unamortized fees in respect of the Term Loan, which was cancelled on September 24, 2025.

(c) For the year ended December 31, 2025, comprised of $5.8 million of unamortized fees on the 2027 Notes (excluding the Tap Notes), $1.5 million of unamortized original issue discount related to the 2027 Notes (excluding the Tap Notes) and $1.0 million of unamortized issue premium in relation to the Tap Notes. For the year ended December 31, 2024, comprised of $9.7 million of unamortized fees on the 2027 Notes (excluding the Tap Notes), $2.4 million of unamortized original issue discount related to the 2027 Notes (excluding the Tap Notes) and $1.4 million of unamortized issue premium in relation to the Tap Notes. For the year ended December 31, 2023, comprised of $7.4 million of unamortized fees and $3.3 million of unamortized original issue discount related to the 2027 Notes (excluding the Tap Notes).

(d) For the years ended December 31, 2023, 2024 and 2025, cash and cash equivalents included $0.5 million, $53.9 million and $3.0 million of restricted cash, respectively.

(6) The adjusted EBITDA to finance costs ratio is calculated as adjusted EBITDA divided by finance costs per the income statement. The adjusted EBITDA to finance costs ratio is not a measurement of financial performance under IFRS and should not be considered as measures of liquidity or an alternative to operating profit or profit for the period or any other performance measure derived in accordance with IFRS.

(7) The EnQuest net debt to adjusted EBITDA ratio is calculated as net debt divided by adjusted EBITDA. The net debt to adjusted EBITDA ratio and the pro forma net debt to adjusted EBITDA ratio are not measurements of financial performance under IFRS and should not be considered as measures of liquidity or an alternative to operating profit or profit for the period or any other performance measure derived in accordance with IFRS.

(8) As adjusted EnQuest net debt consists of EnQuest net debt as of December 31, 2025, as adjusted to give effect to the uses of funds in the table titled "*Use of Proceeds.*" See "*Use of Proceeds*" and "*Capitalization.*"

(9) As adjusted finance costs consists of our estimated financing interest expense for the year ended December 31, 2025 as adjusted to reflect the issuance of the Notes and the application of the proceeds therefrom (as outlined in the uses of funds in the table titled "*Use of Proceeds*") as if these events had occurred on January 1, 2025. It includes estimated interest on the Notes, the 9% Retail Notes, the SVT Working Capital Facility, the Vendor Loan Facility and assumes the RBL Facility was undrawn during the year ended December 31, 2025. As adjusted finance costs has been presented for illustrative purposes only and does not purport to represent what interest expense would have actually been if the Transactions had occurred on the date assumed or if the RBL Facility had been drawn during the period, and it does not purport to project cash interest payments for any future period or the Company's financial condition at any future date.

SUMMARY RESERVES, RESOURCES, PRODUCTION AND OPERATING DATA

The following table sets forth our summary of oil and gas 1P and 2P Reserves and 2C Resources. The 2C Resources data presented in these Listing Particulars has been prepared by our internal competent and qualified technical personnel and has not been audited by GaffneyCline.

In these Listing Particulars, "**1P Reserves**" are defined as the Proved Reserves. "**2P Reserves**" are defined as the sum of Proved Reserves plus Probable Reserves. Pursuant to the classifications and definitions provided by the PRMS, "**Proved Reserves**" is defined as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations and "**Probable Reserves**" is defined as those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but are more certain to be recovered than Possible Reserves; it is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved Reserves plus Probable Reserves (2P Reserves). In these Listing Particulars, references to "**2C Resources**" are to the "best estimate" of the Contingent Resources. Pursuant to the classifications and definitions provided by the PRMS, Contingent Resources are those quantities estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. The "**2C Resources**" represent the "best estimate" scenario of the Contingent Resources; there is a probability of at least 50% that the amount actually recovered will equal or exceed the 2C Resources estimate, in the event that the development project is undertaken.

Reserves & Contingent Resources

The following table sets forth the 1P Reserves, 2P Reserves and 2C Resources as of the years ended December 31, 2023, 2024 and 2025. Reserves are presented as EnQuest Net Entitlement Reserves volumes according to the PRMS and separately as EnQuest working interest Reserves volumes for comparative purposes. Contingent Resources are presented as EnQuest working interest volumes only.

	EnQuest net working interest Reserves[1]			**EnQuest net entitlement Reserves[3]**		
	2023	**2024**	**2025**	**2023**	**2024**	**2025**
1P Reserves						
Oil (MMbbl)	123	110	105	117	106	102
Gas (Bscf)[4]	60	109	120	53	91	104
Total 1P Reserves (MMboe)	**133**	**129**	**126**	**126**	**121**	**120**
Pro forma Adjustments[2]						
Vietnam Oil (MMbbl)	—	3	—	—	3	—
Vietnam Gas (Bscf)	—	2	—	—	2	—
Total Vietnam 1P Reserves (MMboe)	—	3	—	—	3	—
***Pro forma* Total 1P Reserves (MMboe)**	**n.a.**	**132**	**n.a.**	**n.a.**	**124**	**n.a.**
2P Reserves						
Oil (MMbbl)	161	143	133	153	137	128
Gas (Bscf)[5]	82	147	171	71	118	142
Total 2P Reserves (MMboe)	**175**	**169**	**162**	**165**	**157**	**152**
Pro forma Adjustments						
Vietnam Oil (MMbbl)	—	5	—	—	5	—
Vietnam Gas (Bscf)	—	10	—	—	10	—
Total Vietnam 2P Reserves (MMboe)	—	7	—	—	7	—
***Pro forma* Total 2P Reserves (MMboe)**	**n.a.**	**176**	**n.a.**	**n.a.**	**164**	**n.a.**
2C Resources						
Oil (MMbbl)	336	323	344	n.a.	n.a.	n.a.
Gas (Bscf)	314	178	582	n.a.	n.a.	n.a.
Total 2C Resources (MMboe)	**389**	**354**	**452**	**n.a.**	**n.a.**	**n.a.**
Pro forma Adjustments						
Vietnam Oil (MMbbl)	—	2	—	n.a.	n.a.	n.a.
Vietnam Gas (Bscf)	—	16	—	n.a.	n.a.	n.a.
Total Vietnam 2C Resources (MMboe)	—	5	—	n.a.	n.a.	n.a.
***Pro forma* Total 2C Resources (MMboe)**	**n.a.**	**359**	**n.a.**	**n.a.**	**n.a.**	**n.a.**

(1) EnQuest net working interest Reserves and Contingent Resources are EnQuest's working interest fraction of the gross field reserves and contingent resources.

(2) GaffneyCline's report assessing reserves and resources for Block 12W in Vietnam as of December 31, 2024 was prepared when entitlements of those reserves and resources were attributable to Harbour Energy, up until July 9, 2025, at which time EnQuest completed the transaction that entitled EnQuest to the reserves and resources. Hence the reported year end 2024 Vietnam Reserves do not represent EnQuest Reserves as at December 31, 2024 but are included in table above as "Pro forma adjustments".

(3) For assets governed by Production Sharing Contracts ("**PSC**") (PM8/Seligi in Malaysia and Block 12W in Vietnam), EnQuest Net Entitlement Reserves are EnQuest's net economic entitlement according to the PSC terms, *i.e.*, EnQuest's share of cost and profit oil and gas.

(4) For the years ended December 31, 2023, 2024 and 2025, 1P gas reserves included 40.8 Bscf used for fuel and 19.4 Bscf (working interest) or 12.5 Bscf (net entitlement) used for sales, 36.7 Bscf used for fuel and 72.0 Bscf (working interest) or 54.0 Bscf (net entitlement) used for sales and 38.4 Bscf used for fuel and 81.5 Bscf (working interest) or 65.2 Bscf (net entitlement) used for sales, respectively. *Pro forma* adjustments reflect 1P Vietnam reserves as of December 31, 2024 and included 0 Bscf used for fuel and 2.3 Bscf (working interest) or 2.2 Bscf (net entitlement) used for sales.

(5) For the years ended December 31, 2023, 2024 and 2025, 2P gas reserves included 46.6 Bscf used for fuel and 35.8 Bscf (working interest) or 24.3 Bscf (net entitlement) used for sales, 42.5 Bscf used for fuel and 104.4 Bscf (working interest) or 76.0 Bscf (net entitlement) used for sales and 46.8 Bscf used for fuel and 124.2 Bscf (working interest) or 94.8 Bscf (net entitlement) used for sales, respectively. *Pro forma* adjustments reflect 2P Vietnam reserves as of December 31, 2024 and included 0 Bscf used for fuel and 10.3 Bscf (working interest) or 9.5 Bscf (net entitlement) used for sales.

Production & operating data

The following table details our production, realized prices and operating costs data as of and for the years ended December 31, 2023, 2024 and 2025. For additional information on price calculations, see "*Management's discussion and analysis of financial condition and results of operations*."

	For the year ended December 31,		
	2023	**2024**	**2025**
Net daily average production (boepd)[(1)]	43,812	40,736	42,945
Realized oil price[(2)] ($/bbl)	81.4	80.2	68.8
Average adjusted unit operating costs[(3)] ($/boe)	21.7	25.6	25.1
Adjusted unit production costs[(4)] ($/boe)	19.3	20.6	22.0
Adjusted unit tariff and transportation expenses ($/boe)	2.6	4.7	4.4
Depletion of oil and gas assets ($m)	292.2	263.3	267.3

(1) Export volume. See "*Certain reserves and production information—Hydrocarbon data*." Includes Vietnam production from July 9, 2025, the date on which we completed the acquisition of Harbour Energy's business in Vietnam, including its interest in Block 12W. Our net daily average production *pro forma* for our Vietnam assets for the year ended December 31, 2025 was 45,606 boepd.

(2) Realized oil prices including the impact of hedging in the respective period.

(3) Includes (i) for the year ended December 31, 2023, 220 kboe associated with Seligi gas, (ii) for the year ended December 31, 2024, 724 kboe associated with Seligi gas and (iii) for the year ended December 31, 2025, 3,181 kboe associated with Seligi gas.

(4) Adjusted unit production costs are average adjusted unit operating costs (excluding gains/losses on derivatives) less adjusted unit tariff and transportation expenses.

RISK FACTORS

In addition to the other information contained in these Listing Particulars, you should carefully consider the following risk factors before purchasing the Notes. The risks and uncertainties we describe below are not the only ones we face. Additional risks and uncertainties of which we are not aware or that we currently believe are immaterial may also adversely affect our business, prospects, financial condition and results of operations. If any of the possible events described below were to occur, our business, prospects, financial condition and results of operations could be materially and adversely affected. If that happens, we may not be able to pay interest or principal on the Notes when due and you could lose all or part of your investment. These Listing Particulars also contain forward-looking statements that involve risks and uncertainties. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of various factors, including the risks described below and elsewhere in these Listing Particulars.

Risks relating to the oil and gas industry

Volatility and decreases in oil and gas prices could materially and adversely affect our business, prospects, financial condition and results of operations

Our business, prospects, financial condition and results of operations depend substantially upon oil and gas prices, which may be adversely impacted by unfavorable global, regional and national macroeconomic conditions. Oil and gas are commodities for which prices are determined based on world demand, supply and other factors, all of which are beyond our control. Historically, oil and gas prices have fluctuated widely for many reasons, including:

- global and regional supply and demand, and expectations regarding future supply and demand, for oil and gas products;
- decrease in demand due to increased climate change legislation and/or regulation imposing limits on carbon emissions;
- decrease in demand in countries with weak macro-economic growth;
- evolution of stocks of oil and gas and related products;
- increased production due to new extraction developments and improved extraction and production methods;
- geopolitical uncertainty, including trade disputes and independence movements;
- terrorism, piracy or the threat of terrorism, war or threat of war and cyber-attacks from which some producing areas suffer periodically;
- weather conditions, natural disasters and environmental incidents;
- access to pipeline systems, storage platforms, shipping vessels and other means of transporting and storing oil and gas;
- prices, availability and government subsidies of and competition from alternative fuels and energy sources;
- prices and availability of new and legacy technologies;
- the ability and willingness of the members of OPEC, and other oil producing nations, to set and maintain specified levels of production and prices;
- global and regional economic and social conditions, including economic disruptions or slow-downs, for example as a result of natural disasters, trade wars, including the imposition of new tariffs and additional trade barriers and bilateral trade frictions;

- political, economic and military developments in oil producing regions generally, as well as domestic and foreign governmental regulations and actions, including import and export restrictions, taxes, repatriations and nationalizations; increasing governmental regulations and actions and international treaties and agreements which aim to reduce the environmental impact of oil and gas exploration, development and production activities, including the emission of greenhouse gases and increased expenditure for producers to comply with such regulations, actions, treaties and agreements; and

- market uncertainty and trading and speculative activities by market participants and others either seeking to secure access to oil and gas or to hedge against commercial risks, or as part of investment portfolio activity.

Historically, crude oil prices have been volatile, dependent upon the balance between supply and demand and particularly sensitive to OPEC production levels and the emergence of additional supply sources such as U.S. shale oil and non-OPEC supply. In 2025, Brent crude oil prices experienced notable fluctuations due to a combination of geopolitical tensions, economic factors, and production changes. The average price of Brent crude oil was around $68 per barrel, significantly lower than the average price of the previous year. Prices ranged between $59 and $82 per barrel. Early in the year, Brent prices rose due to heightened geopolitical risks, particularly in the Middle East. Conflict between Israel and Hamas, along with attacks on vessels in the Red Sea, caused significant disruptions and pushed prices higher. In the period from May through September 2025, military action occurred in other states in the region, notably by Israel and the United States; Israel and the United States conducted targeted strikes within Iran and Israel also struck targets in Lebanon, Syria, Yemen and Qatar. However, the second half of 2025 saw a downward trend in prices. Slowing economic growth, especially in China, and reduced demand for liquid fuels contributed to this decline. Furthermore, China's shift towards liquefied natural gas for transportation and the increasing adoption of electric vehicles played a role in limiting the demand for traditional fuels. As a result of such events, there may be disruptions to global shipping that may impact us. In March 2026, U.S. and Israeli airstrikes on Iran and related retaliatory strikes by Iran across the Persian Gulf region, as well as the closing and blockade of the Strait of Hormuz as a result of the conflict have led to increased and volatile oil prices. For instance, Brent crude oil prices rose to $99 per barrel on March 9, 2026, but remain volatile, trading as high as $112 on March 20, 2026, and as low as $88 on March 10, 2026. These conflicts are highly unpredictable and have already resulted in significant volatility in oil and natural gas prices worldwide. The duration, severity and ultimate impact of these events remain uncertain, and future developments could exacerbate price volatility beyond the levels currently observed.

A sustained and significant increase in fuel, oil or gas prices may prompt governments to implement measures to control or reduce prices, including price caps, which could materially and adversely affect our business, prospects and results of operation. Any such measures could be introduced with limited notice and differ across jurisdictions in which we operate. Such government measures have already happened with respect to fuel prices in several jurisdictions and may spread further in the context of ongoing conflict between Russia and Ukraine, the Israel-Hamas conflict and the escalation of conflict within the Middle East and their impact on energy markets and prices. It is also expected that the increased focus of governments, regulators and consumers on the impact of climate change and reducing carbon emissions could reduce demand for oil and gas and suppress oil and gas prices. There can be no assurances as to the level of oil and gas prices that will be achievable in the future.

Our revenues, operating results, profitability, future production capabilities and the carrying value of our oil and gas properties depend heavily on the prices we receive for oil and gas sales. All of our reserves are constrained by a commercial materiality threshold and therefore are impacted by changes in oil prices. In particular, decreases of oil and gas prices could lead to reductions in the economic life of a field, which could, in turn, lead to a decrease in our reserves. Going forward, we may elect not to continue production from certain of our assets in the event of further decreases in oil and gas price, or our license partners may not want to continue production, regardless of our position, and subsequently may seek to sell their interest in a particular license, which could have a material adverse impact on our results of operations.

We are aware that low oil prices, as experienced in 2020 following the outbreak of the COVID-19 pandemic, could return and endure in the future due to climate change driving a reduced demand for oil. Lower oil prices typically result in significant reductions in capital expenditure budgets, cancellation or deferral of projects and reductions in discretionary expenditures. For example, in response to the deterioration in the oil price environment in 2020, we reviewed our spending plans and implemented a material operating costs and capital expenditure reduction program, including an acceleration of cessation of production at a number of our highest

cost assets, a significant reduction in our workforce and deferral or cancellation of drilling and other discretionary activities, which in turn resulted in a reduction in our costs and improved cash flow. Certain development projects could become unprofitable as a result of oil price declines, which could in turn result in us postponing or cancelling a planned project or, if it is not possible to cancel the project, carrying out the project with negative economic impact. In addition, we may face property impairments if prices fall significantly. No assurance can be given that oil prices will remain at levels which will enable us to do business profitably or at levels that make it economically viable to produce from certain wells and any material decline in such prices could result in a reduction of our net production volumes and revenue and a decrease in our reserves and in the valuation of our exploration, appraisal, development and production properties.

A significant and sustained decline in the price of oil and gas could also cause us to fail a liquidity covenant and to request a covenant waiver under the RBL Facility. The liquidity covenant (the "**EnQuest Group Liquidity Test**"), which is tested semi-annually, under the RBL Facility requires that we have sufficient funds available to meet all our liabilities in each three-month period over the next 12 months. Given the volatility in oil prices, there is a risk of a potential liquidity covenant breach under the RBL Facility which would therefore require a covenant waiver to be obtained. As of December 31, 2025, as part of our going concern assessment under the RBL Facility, we calculated a reverse stress test, thereby assuming an average oil price of approximately $45.0/bbl over the assessment period, which showed that we can maintain covenant compliance over such period. However, there is no assurance that we may comply in the future and may, as a result, need a waiver. See "*Description of certain financing arrangements—RBL Facility*" and "*—Risks relating to our business—We may not be able to generate sufficient cash to comply with our financial covenants*, *fund our capital expenditures or sustain our operations*."

To mitigate oil price volatility, we monitor oil price sensitivity relative to our capital commitments and have a policy which allows hedging of our production. We also have an established in-house trading and marketing function to enable us to enhance our ability to mitigate the exposure to volatility in oil prices. However, there can be no assurance that our existing hedging arrangements will be effective or sufficient, or that we will be able to effectively hedge declines in oil prices in the future. See "*—Risks relating to our business—Our commodity hedging activities may not be effective*." If prices for the oil we produce fall, this could materially and adversely affect our business, prospects, financial condition and results of operations.

Climate change legislation*, *the transition to net zero greenhouse gas emissions by 2050 and/or protests and shareholder actions against fossil fuel extraction may have a material adverse effect on our industry

Continued political, societal and commercial attention to climate change, the U.K.'s transition to a "net zero" economy by 2050 and the associated mitigation through regulation of greenhouse gases as part of this transition could have a material adverse effect on our prospects, financial condition and results of operations. Climate change concerns and related regulatory developments could also further impact or amplify a number of our other principal risks, such as Health, Safety and Environment ("**HSE**"), prices and foreign exchange, production, access to capital and liquidity and political, regulatory and fiscal environment disclosed elsewhere in these Listing Particulars.

There have been numerous developments in climate change laws in recent years, at the international, regional and national level.

The Paris Agreement, adopted in December 2015 under the United Nations Framework Convention on Climate Change, sets the overall framework for coordinated global action in relation to climate change mitigation and adaptation. The Paris Agreement aims to limit global temperature increase to well below 2°C compared to pre-industrial levels, and commits the parties to pursue efforts to limit the temperature increase to 1.5°C. The Intergovernmental Panel on Climate Change is currently in its seventh assessment cycle, which formally began in July 2023. This, in conjunction with the stocktake mechanism under the Paris Agreement, may create further pressure for mitigation action by parties to the Paris Agreement.

At the U.K. level, in June 2019, the U.K. amended the legally binding target set out in the Climate Change Act 2008 in order to implement the U.K.'s 2050 net-zero target. Further to this, the U.K.'s Seventh Carbon Budget was published by the Climate Change Committee ("**CCC**"), the government's independent advisor on climate change, in February 2025. The Seventh Carbon Budget provides the U.K. government with advice on the budget of greenhouse gases the U.K. can emit during the period 2038-2042. In addition to the 2050 net zero target, the CCC's recommended pathway requires an 87% reduction in U.K. territorial emissions between 1990 and 2040. The CCC states that meeting the Seventh Carbon Budget requires action across four key areas, namely (1) the

expansion of low-carbon energy supplies (including the complete decarbonization of electricity by 2035 in a balanced net zero pathway), (2) the take-up of low-carbon solutions (including low carbon or electric boilers and vehicles), (3) increased efficiency and resource use (including energy efficiency measures in industrial processes), and (4) land (and removals). In light of the U.K.'s net zero target, in March 2021 the U.K. BEIS (now: DESNZ) co-published with the industry body Oil & Gas U.K. (now: Offshore Energies U.K.) the North Sea Transition Deal which sets out the plan for how the U.K.'s offshore oil and gas sector and the government will work together to deliver the skills, innovation and new infrastructure required to meet stretching greenhouse gas emission reduction targets. This was supported by changes made in 2021 to the OGA Strategy implemented by the U.K. Regulator, the central obligation of which is to maximize the value of economically recoverable petroleum from U.K. waters and, in doing so, take appropriate steps to assist the Secretary of State in meeting the U.K's 2050 net zero target, including by reducing as far as reasonable in the circumstances greenhouse gas emissions from sources such as flaring and venting and power generation and supporting carbon capture and storage projects.

Taken together, these international, regional and national climate change laws and regulations establish the framework for the transition to net zero greenhouse gas emissions in the U.K. by 2050. However, the CCC notes that a major strengthening of U.K. policies is required to reduce emissions and achieve net zero. We cannot predict the timing, scope or final form of future climate-related legislation or regulatory guidance, or its ultimate impact on our operations.

Accordingly, additional laws and regulations are highly likely to be introduced to, amongst other things, reduce greenhouse gas emissions and the demand for fossil fuels and fossil fuel technologies, incentivize renewable and low-carbon energy and electric and low-carbon technologies, and transition to a net zero economy. For example, in relation to our operational emissions, there may be additional restrictions and/or a prohibition on the flaring (the ignition of gas) or venting (the release of unignited gas) of gas in non-emergency situations. Flaring and venting of gas are controlled processes to dispose of gas and are essential for emergency and safety purposes on oil and gas installations, and in situations where it may not be feasible for the gas to be used, exported or re-injected. A "climate compatibility checkpoint" was introduced into the 33rd U.K. Offshore Licensing Round (the "**33rd Round**") in 2022 to determine whether future applications for oil and gas licenses in the North Sea align with wider climate change objectives, such as the reduction of emissions and sustainability. Currently, the U.K. government is considering whether any new offshore oil and gas licenses may be issued, although it has also stated that existing licenses will not be revoked. This, and a generally more active approach from regulators relating to climate issues, may make it more difficult or even impossible for us to secure licenses in the U.K. in the future or make it more expensive or onerous to comply with existing licenses or to obtain regulatory consents for operational issues and new developments, especially in the light of the U.K. Supreme Court's decision in *R (on the application of Finch on behalf of the Weald Action Group) v Surrey County Council and others* (the "**Finch Ruling**"), which introduces a requirement to assess the Scope 3 or downstream emissions impact of any such development when seeking consent. Following the Finch Ruling, on June 19, 2025, DESNZ published supplementary guidance under the Offshore Oil and Gas Exploration, Production, Unloading and Storage (Environmental Impact Assessment) Regulations 2020 to clarify their expectations for assessing the effects of downstream scope 3 emissions on climate from oil and gas projects. While conventional oil and gas activities will play a role in the energy transition, laws, policies and regulations introduced to deliver net zero by 2050 may either directly or indirectly impact the demand for oil and gas and/or fossil fuel-based technologies and products and have a material adverse effect on us. Such laws and regulations may result in substantial capital, compliance, operating and maintenance costs for us or our customers. In addition, there is a possibility that drilling in the North Sea might be restricted in general at some point in the future. This would mean that we would have to cease our operations in the North Sea altogether, which could have a material adverse effect on business, prospects, financial condition and results of operations.

Legal and regulatory changes may also increase the price of, or increase the scope and rate of relevant levies, charges or taxes on carbon, oil and gas, oil and gas products, or other greenhouse gases. It may also be the case that, owing to such laws and regulations, we may not be able to fully exploit all of our reserves. Furthermore, other regulatory changes may demand fuller disclosure and increased reporting, such as the introduction of Listing Rule 9.8, which requires us to include a statement in our annual financial report for the accounting period from January 1, 2021 onwards setting out whether our disclosures are consistent with the recommendations of the Taskforce on Climate-related Financial Disclosures ("**TCFD**"), and to explain if we have not done so. Increased reporting on our exposure to climate change-related risks or failure to meet our environmental, social and governance ("**ESG**") commitments could also make us less attractive to potential investors, lenders, or other bond and capital providers, making it more difficult or costly to raise capital.

At this stage, while the net zero target is established, the rate of legislative change and the potential impact of such a broad range of laws, policies and regulations is difficult to accurately predict. Future international treaties, legislation or other government action may affect the trajectory and impact of such laws, policies and regulations.

As a company with operations in the United Kingdom, we are currently subject to the U.K. Emissions Trading Scheme ("**U.K. ETS**"). Under the U.K. ETS various industrial activities, including offshore oil exploration and production facilities incorporating combustion plants (including flaring) with aggregate thermal ratings of greater than 20 megawatts (thermal input) are regulated. As the U.K. ETS is a smaller carbon market than the European Union Emissions Trading Scheme, there is concern that there may be greater carbon price volatility in the U.K. ETS.

In addition, our operations in Malaysia are subject to Malaysia's environmental laws and regulations, such as the Environmental Quality Act 1974, which prohibits industrial activities that cause pollution without obtaining a valid license, and the Occupational Health and Safety Act 1974. Our recently-acquired operations in Vietnam are subject to Vietnam's environmental laws and regulations, such as the Law on Environmental Protection 2020, the primary legal framework for environmental protection in Vietnam that covers environmental impact assessments, pollution control and waste management, and the National Strategy on Environmental Protection to 2020 With Visions to 2030 that sets out the country's goals to reduce the increase of greenhouse gas emissions. Our operations in Indonesia will be subject to Indonesia's environmental laws and regulations, such as Law No. 32 of 2009 on Environmental Protection and Management, Law no. 11 of 2020 on Cipta Kerja (Omnibus Law), the principal environmental law in Indonesia and the Presidential Regulation No. 61 of 2011 on the National Action Plan for Greenhouse Gas Emission Reduction, which outlines Indonesia's commitment to reducing greenhouse gas emissions and addressing climate change. In Brunei, our operations are governed by the Environmental Protection and Management Act 2022 which provides an overarching framework for environmental protection, requiring environmental impact assessments for projects with significant environmental impact. The level of expenditure required to comply with such laws and regulations, including to obtain any license, permit or approval required under such laws and regulations, is difficult to accurately predict and may result in substantial capital and operating costs. Any amendments to current laws, regulations, licenses, permits or approvals could also have a material adverse effect on our operations and increase our cost structure. Additional requirements may also be enacted in the jurisdictions in which we choose to operate in the future.

In July 2025, the International Court of Justice issued an advisory non-binding opinion finding that states have binding legal obligations under international law to address climate change and protect the environment. This opinion, and similar political and legal attention, point to a growing focus on climate change and environmental concerns, particularly in industries such as ours, and may influence policies and regulatory initiatives, including in the U.K.

In addition, we may be subject to activism, including from groups campaigning against fossil fuel extraction and climate change, which could negatively affect our reputation, dissuade investors from investing in our business, persuade shareholders to sell their holdings, encourage or require us to make decisions to reduce emissions or change business strategy in light of climate change concerns, dissuade contractors from working with us, reduce demand for our products, disrupt our operations or development programs, induce our employees and/or directors to cease working or acting for us or otherwise negatively impact our business. We may also be the subject of legal proceedings and strategic litigation, including those designed to constrain the extraction of oil and gas, impact on our various licenses, permissions or consents to operate or seek reparations for loss and damage in respect of climate change. Shareholders may also bring action, for example demanding greater transparency and fuller disclosures on climate change related risks, and require us to adapt our business strategy to mitigate these risks and provide a more resilient investment for shareholders.

The levels of our 1P and 2P Reserves and Contingent Resources, their quality and production volumes may be lower than estimated or expected

The 1P and 2P Reserves and Contingent Resources set forth in these Listing Particulars represent estimates only and are based on our internal assessments and only the 1P and 2P Reserves have been audited by GaffneyCline. The standards utilized to prepare the 1P and 2P Reserves and Contingent Resources information set forth in this document are in accordance with resource definitions jointly set out by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists & Engineers in June 2018 in the "Petroleum

Resources Management System," which may be different from the standards of reporting adopted in the United States and other jurisdictions. Investors, therefore, should not assume that the data found in the reserves and resources information set forth in these Listing Particulars is directly comparable to similar information that has been prepared in accordance with the reserve and resource reporting standards of other jurisdictions.

In general, estimates of economically recoverable oil reserves are based on a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates (which have inherent uncertainties), historical production from the properties, the assumed effects of regulation by governmental agencies and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. Underground accumulations of hydrocarbons cannot be measured in an exact manner and estimates thereof are a subjective process aimed at understanding the statistical probabilities of recovery. The variables and assumptions upon which estimates of economically recoverable oil reserves depend include, among others, the following:

- production history from the properties compared with production from other comparable producing areas;
- interpretation of the available geological and geophysical data;
- quality and quantity of available data;
- geological and engineering estimates (which have inherent uncertainties);
- effects of regulations adopted by governmental agencies;
- future percentages of international sales;
- future oil and other commodity prices;
- capital investments;
- effectiveness of the applied technologies and equipment;
- future operating costs, tax on the extraction of commercial minerals, development costs and workover and remedial costs; and
- the judgment of the persons preparing the estimates.

As all reserve estimates are subjective, each of the following items may differ materially from those assumed in estimating reserves:

- the quantities and qualities of oil reserves that are ultimately recovered;
- the timing of the recovery of oil reserves;
- the production and operating costs incurred;
- the amount and timing of additional exploration and future development expenditures;
- future hydrocarbon sales prices; and
- decommissioning costs.

Many of the factors in respect of which assumptions are made when estimating reserves are beyond our control and therefore these estimates may prove to be incorrect over time. Evaluation of reserves necessarily involves multiple uncertainties. The accuracy of any reserves or resources evaluation depends on the quality of available information and oil engineering and geological interpretation. Exploration drilling, interpretation, testing and production after the date of the estimates may require substantial upward or downward revisions in our reserves or resources data. Moreover, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves

and resources will vary from estimates and the variances may be material. Therefore, potential investors should not place undue reliance on reserves or resources data contained herein or on any specific field, reservoir, fluid or production profile or reserve estimate.

The uncertainties in relation to the estimation of reserves summarized above also exist with respect to the estimation of Contingent Resources. The probability that 2C Resources will be economically recoverable is considerably lower than for 2P Reserves. Volumes and values associated with Contingent Resources should be considered highly speculative.

If the assumptions upon which the estimates of our oil reserves and resources have been based prove to be incorrect or if the actual reserves or recoverable resources available to us are otherwise less than the current estimates or of lesser quality than expected, we may be unable to recover and produce the estimated levels or quality of oil and other hydrocarbons set out in these Listing Particulars and this may materially and adversely affect our business, prospects, financial condition and results of operations.

If we are unable to replace the 2P Reserves that we produce through exploration, development or acquisitions, our future production levels and revenues could decline

Our future success depends on our ability to develop or acquire additional 2P Reserves that are economically recoverable, which is dependent on oil and gas prices. See "*—Volatility and decreases in oil and gas prices could materially and adversely affect our business, prospects, financial condition and results of operations.*" While well supervision and effective maintenance operations can contribute to sustaining production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and we target maturing fields that typically have fewer reserves than could be expected in new discoveries. Without continued successful exploration, development and acquisition activities, our reserves and revenues will decline as a result of our current reserves being depleted by production. Future increases in our reserves will depend not only on our ability to appraise, develop and explore our existing assets but also on our ability to select and acquire suitable assets either through awards at licensing rounds or through acquisitions. Any failure to successfully replace reserves could materially and adversely affect our business, prospects, financial condition and results of operations.

Our current strategy includes increasing our 2P Reserves and 2C Resources through value-accretive acquisitions and potential life extensions of relatively mature assets. For example, in July 2025 we completed the acquisition of Harbour Energy's business in Vietnam, which, as of January 1, 2026, had net working interest 2P Reserves and 2C Resources across the fields totaling 7.4 MMboe and 5.3 MMboe, respectively. Although we continue to evaluate further acquisition opportunities, we will be highly selective in the acquisitions we pursue. See "*Summary—Recent Developments—Acquisition of equity interest in the Block 12W production fields in Vietnam.*"

As part of our strategy of acquiring relatively mature assets, we frequently hold assets with declining production that, prior to our ownership, have not been drilled, developed or maintained for significant periods of time. We use improved recovery methods to increase the production of oil at these fields, including the injection of water into formations to provide pressure support and sweep oil towards production wells and the injection of gas into production wells to facilitate lifting of oil and water. If our improved recovery methods do not allow for the extraction of oil in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially and adversely affected.

Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves and resources, exploration potential, future oil prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and cannot be made with a high degree of accuracy. While we routinely perform due diligence reviews of all potential acquisition targets, such reviews will not reveal all existing or potential problems or liabilities. In addition, our review may not permit us to become sufficiently familiar with the assets or properties to fully assess their deficiencies and capabilities. We have not entered into any binding agreements, memoranda of understanding or other commitments in respect of any such opportunities, and there can be no assurances that we will be successful in identifying and completing further acquisitions. See "*—Risks relating to our business—There are risks inherent in our acquisitions of appraisal, development and production assets.*"

In light of the increased regulatory environment with regards to environmental, social and governance factors in which banks operate and the volatility of oil prices, there has been a reduction in certain banks'

willingness or ability to lend to entities in the oil and gas industry. Accordingly, there is a risk that even if we identify an appropriate acquisition target, we may not be able to secure financing on commercially acceptable terms, or at all.

Any failure to successfully replace our reserves, whether through further exploring and developing our existing assets or through the award or acquisition of additional assets, could materially and adversely affect our business, prospects, financial condition and results of operations.

We face drilling, exploration and production risks and hazards that may affect our ability to produce oil and gas at expected levels, quality and costs and that may result in additional liabilities to us

Our oil and gas production operations are subject to numerous risks common to our industry, including subsurface uncertainties, operating in a mature field environment, premature decline of reservoirs, insufficient addition of new resources, invasion of water into producing formations, encountering unexpected formations or pressures, low permeability of reservoirs, contamination of oil and gas, blowouts, oil and other chemical spills, explosions, fires, equipment damage or failure, natural disasters, geological uncertainties, unusual or unexpected rock formations and abnormal geological pressures, uncontrollable flows of oil, gas or well fluids, unexpected shutdowns, unplanned expenditures (particularly where remediation may be dependent on suitable weather conditions offshore), adverse weather conditions, shortages of skilled labor, pollution and other environmental risks. For example, extreme weather conditions in the U.K. North Sea affected our operations in January and February 2026. Storm damage to the third-party-operated Ninian Central Platform, which was caused by a once-in-a-decade wave, resulted in an unplanned outage for all system users, including Magnus, in mid-January 2026. Following the completion of remedial works, Magnus production was reinstated in the early hours of February 22, 2026.

As all of our production is offshore, our facilities are also subject to hazards inherent in marine operations, such as capsizing, sinking, grounding, vessel collision and damage from natural catastrophes, severe storms or other severe weather conditions, the frequency and severity of which may be impacted by climate change. The offshore drilling we conduct could involve increased risks due to risks inherent in the nature of drilling in complicated and harsh environments and complex geological formations including blowouts, encountering formations with abnormal pressure and oil spills. In particular, our hub-based model requires that substantially all our production is produced through a limited number of offshore facilities, so any technical failure or accident involving these facilities could have a material adverse effect on our production from multiple fields and our resulting cash flow therefrom. Unplanned partial or full shutdowns could adversely impact our financial performance if such shutdowns require substantial costs to remediate or continue for an extended period of time and such outages coincide with a period of relatively higher prices with production only returning in a period of relatively lower prices. For example, in the first half of 2025, the Magnus field was shut in for five weeks due to an unplanned outage of the third-party operated Ninian central pipeline. This outage had the effect of reducing our production by approximately 3.5 Kboepd for the six months ended June 30, 2025. Such hazards could have a material adverse effect on our business, prospects, financial condition and results of operations.

We seek to maintain a high degree of operational control over production assets in our portfolio, and we continually assess the condition of our assets and operate extensive maintenance and inspection programs designed to minimize the risk of unplanned shutdowns and expenditure. However, if an accident or failure occurs, environmental damage, including biodiversity loss or habitat destruction, injury to persons and other species and organisms, loss of life, failure to produce oil and gas in commercial quantities or an inability to fully produce discovered reserves could result. Such technical failure or accident may also result in unplanned expenditure, in particular where remediation may be dependent on suitable weather conditions offshore. Furthermore, we are not the operator of the Golden Eagle Asset, Alba or Cendramas, limiting our ability to direct or control operations, the timing and performance of activities or the costs thereof. There could therefore be a delay by the relevant operator in responding to risks or hazards at the Golden Eagle Asset, Alba or Cendramas, which could have a material adverse effect on our business, prospects, financial condition and results of operations.

These events could also cause substantial damage to our property and our reputation and put at risk some or all of our license interests, which enable us to explore and produce, and could result in us incurring fines or penalties, criminal sanctions against us and our management, as well as other governmental and third-party claims. Consequent production delays and declines from normal field operating conditions and other adverse actions taken by host governments and third parties may result in revenue and cash flow levels being adversely affected. Moreover, should any of these risks materialize, we could incur legal defense costs, remedial costs and substantial losses, including those due to injury or loss of life, human health risks, severe damage to or destruction of property,

natural resources and equipment, environmental damage, unplanned production outages, cleanup responsibilities, regulatory investigations and penalties, increased public interest in our operational performance and suspension of operations. Similar hazards and impacts from third-party operations could also result in increased regulatory costs and operational restrictions impacting our operations.

We face uncertainty as to the success of project execution and delivery

Our success depends in part upon the successful execution and delivery of development and decommissioning projects, decarbonization and new energy opportunities and the efficient delivery of short-cycle, quick payback projects which are key features of our long-term strategy. Oil development activities are capital intensive and subject to financing limitations and successful outcomes cannot be assured. Many of our assets, including the Bressay and Bentley discoveries, DEWA in Malaysia and our interests in Indonesia and Brunei, along with our decarbonization initiatives at SVT and our Veri Energy projects on Shetland, have future development potential which may expose us to project execution risks.

We have detailed controls, systems and monitoring processes in place in an effort to meet deadlines, control costs and adhere to and implement design concepts. We also engage third-party assurance experts to review, challenge and, where appropriate, make recommendations to improve the processes for project management, cost control and governance of major projects. For example, within Veri Energy, we are working with experienced third-party organizations to develop new energy and decarbonization opportunities. However, development activities may also be subjected to unexpected problems and delays, and incur significant costs which can differ significantly from estimates, with no guarantee that such expenditure will result in the recovery of oil in sufficient quantities to justify our investments. We may be required to curtail, delay or cancel any development operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, breaches of security, title problems, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment. Any such curtailment, delay or cancellation could delay or prevent production, which reduces cash flows and can lead to impairment charges. Many of our assets have future development potential which may expose us to risks.

In addition, our appraisal activities may not be successful or may incur unexpected costs that differ significantly from estimates. Appraisal and development activities involving the drilling of wells across a field may be unpredictable and may not result in the outcome planned, targeted or predicted, as only by extensive testing can the properties of an entire field be more fully understood. We may also be required to curtail, delay or cancel any drilling operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, breaches of security, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment.

Much of our success is dependent on us bringing both re-developments and new developments of oil fields to production on budget and on schedule. Even if our development operations lead to wells that are productive, these wells may not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of our development plans does not assure a profit on the investment or recovery of drilling, completion and operating costs and drilling hazards and environmental damage can further increase the cost of operations to be recovered. In addition, various field operating conditions may also adversely affect production from successful wells including delays in obtaining governmental approvals, permits, licenses, authorizations or consents, shut-ins of connected wells, insufficient storage or transportation capacity or other geological and mechanical conditions.

In connection with our medium- to long-term business plan, we are assessing and delivering new energy opportunities to create a renewable energy and decarbonization hub through the repurposing of SVT and associated infrastructure. This is focused on carbon capture and storage, electrification through onshore wind, and the production of e-fuels. Veri Energy, which builds on the work previously undertaken by our infrastructure and new energy business, is a wholly owned subsidiary focused on delivering scalable decarbonization and renewable energy projects, supporting our Board-approved commitment to reach net zero in terms of Scope 1 and Scope 2 emissions by 2040. We are the operator of SVT and will continue to support existing users with high levels of operating efficiency while supporting Veri Energy to progress new energy opportunities at the terminal. The repurposing of SVT, Veri Energy or entry into any other new business areas in the future, may expose us to additional business risks that are different from those that we have experienced to date. In particular, we expect demand for renewable energy sources to continue to grow in the coming years, including as a result of evolving

regulatory requirements. However, this market may not grow as quickly or develop in a way that we expect. Our ability to successfully expand our business capabilities to enable this transition may be limited by many factors, and we may not be successful in our efforts to estimate the financial effects and/or synergies of such a transition on our business. In addition, our focus on repurposing SVT may divert management attention, financial and human resources or other capabilities away from our existing business or require additional expenditures. Such developments could have a material adverse effect on our business, results of operations and financial conditions.

We carry out business in a highly competitive industry

The oil industry is highly competitive, including in our key jurisdictions of operation, the UKCS and South East Asia. The key areas in respect of which we face competition include:

- engagement of third-party service providers whose capacity to provide key services may be limited;
- purchasing, leasing, hiring, chartering or other procuring of equipment that may be scarce;
- acquisition of existing hydrocarbon assets;
- acquisition of exploration and production licenses, or interests in such licenses, at auctions or sales run by governmental authorities;
- ability to sell assets;
- marketing of oil and gas;
- access to key skilled personnel;
- differentiating technologies;
- access to bank lending and bond market capacity; and
- access to capital markets.

Competition in our markets is intense and depends, among other things, on the number of competitors in the market, their financial power, their degree of geological, geophysical, engineering and management expertise, their degree of vertical integration, pricing policies, their ability to develop properties on time and on budget, their ability to select, acquire and develop reserves and their ability to foster and maintain relationships with host governments of the countries in which they have assets. We operate in a mature industry and our competitors include well-established entities with greater technical, physical and financial resources. When looking at acquisition opportunities, we also compete with major national and state-owned enterprises and may also compete with private equity backed companies, which typically possess significant financial resources and are able to offer attractive and favorable prices to sellers. We rely on equity and debt financing to fund acquisitions, which may not always be available and larger and better capitalized competitors may be in a position to outbid us for particular licenses and acquisition opportunities. The effects of operating in a competitive industry may include higher than anticipated prices for the acquisition of licenses or assets, the hiring by competitors of key management or other personnel, competitors being able to secure rigs for drilling operations preferentially to us and restrictions on the availability of equipment or services.

Larger and better capitalized competitors may also be better able to withstand sustained periods of suppressed oil prices. They may also be more successful in diversifying and reducing risk and may be able to absorb the burden of any changes in law and regulations more easily than us, which would adversely affect our competitive position. In addition, many of our competitors have been operating for a much longer time and have demonstrated the ability to operate through industry cycles.

If we are unsuccessful in competing against other companies, our business, prospects, financial condition and results of operations could be materially and adversely affected.

We may not be able to keep pace with technological developments in our industry

The oil and gas industry is characterized by significant technological advancements and introductions of new services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages, which may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost, particularly due to our strategy of acquiring relatively mature assets. If one or more of the technologies we use now or in the future were to become obsolete, our business, prospects, financial condition and results of operations could be materially and adversely affected. In addition, any new technology that we implement may have unanticipated or unforeseen adverse consequences, either to our business or the industry as a whole.

Risks relating to our business

We may not be able to generate sufficient cash to comply with our financial covenants, fund our capital expenditures or sustain our operations

Historically, significant leverage has been required to fund our growth and this may continue as we make value-accretive acquisitions and undertake developments. We have significantly reduced our levels of debt in recent years, but we are not debt-free and retain debt service requirements. As of December 31, 2025, on a *pro forma* basis after giving effect to the Transactions, we would have had an aggregate principal amount of $912.8 million of debt outstanding, represented by the Notes, the 9% Retail Notes, the Vendor Loan Facility and the SVT Working Capital Facility.

As of December 31, 2025, Facility B of the RBL Facility Agreement utilization was $381.5 million. The amount of letters of credit outstanding corresponds to the security in place supporting our decommissioning obligations outstanding as of December 31, 2025. As of December 31, 2025, $400.0 million remained available for drawdown under Facility A of the RBL Facility Agreement.

We are permitted to borrow substantial additional indebtedness, including secured debt, in the future under the terms of the Indenture. See "*Description of certain financing arrangements—RBL Facility.*"

Our liquidity requirements also arise from our need to fund capital expenditure and working capital. A significant part of our capital expenditures is contracted or necessary in order to maintain our business. For the year ended December 31, 2025, our cash capital and decommissioning expenses were $236.1 million.

Our ability to make payments on and refinance our indebtedness and to fund our capital expenditures, working capital and requirements in relation to our surety bonds for decommissioning security agreement purposes and other expenses will depend on our future operating performance and ability to generate cash from operations. Our ability to generate cash from operations is subject, in large part, to general competitive, legislative, regulatory and economic factors that are beyond our control, including the price of crude oil. Significant reductions in the oil price, production or the funds available under the RBL Facility, or further changes in the United Kingdom's fiscal environment, could have a material impact on our ability to repay or refinance our existing credit facilities and invest in our asset base. Prolonged low oil prices, cost increases, including those related to an environmental incident, and production delays or outages, could threaten our liquidity or ability to comply with relevant covenants. This risk is not expected to inhibit our ability to meet our present working capital requirements or our working capital requirements for at least 12 months from the date of these Listing Particulars but may impact us over the longer term.

We are continuing to enhance our financial position through maintaining a focus on controlling and reducing costs through supplier renegotiations, assessing counterparty credit risk, hedging and trading and shutting down uneconomic operations and rationalization. However, if market conditions deteriorate or production falls below expectations, this could affect our ability to fund financial commitments, maintain adequate cash flow and liquidity and/or reduce costs in the longer term which could have a material adverse effect on our business, financial condition, prospects and/or results of operations.

We may not be able to repay our indebtedness currently scheduled to be repayable

Our ability to refinance or amend and extend our existing indebtedness on acceptable terms or at all is not assured. The success of any such refinancing or amendment and extension will depend on a number of factors, including our financial condition and prospects at the time, market conditions at the time and our ability to obtain holders' consent to any such extensions and amendment and/or successfully complete a new bond offering on terms attractive to investors, taking account of the willingness of investors to subscribe for new bonds which will rank junior to the rights of lenders under the RBL Facility Agreement and with a maturity date such that they will only be repayable after the lenders under the RBL Facility Agreement.

All of our production comes from a small number of offshore assets in the UKCS and South East Asia, making us vulnerable to risks associated with having significant production in two regions and only a small number of assets

Our assets are concentrated in the UKCS and South East Asia around a limited number of infrastructure hubs and existing production (principally only oil) is from mature fields. This amplifies our exposure to key infrastructure (including aging pipelines and terminals), political/fiscal changes and oil price movements.

Our UKCS assets accounted for 72% (31,122 boepd) and our South East Asia assets accounted for 28% (11,823 boepd), respectively, of our production in the year months ended December 31, 2025. A significant proportion of our current production is from Kraken and Magnus. In the year ended December 31, 2023, Kraken and Magnus produced 13,580 and 15,933 net daily average boepd, respectively, comprising 31.0% and 36.4%, respectively, of our total production. In the year ended December 31, 2024, Kraken and Magnus produced 12,759 and 14,173 net daily average boepd, respectively, comprising 31.3% and 34.8%, respectively, of our total production. In the year ended December 31, 2025, Kraken and Magnus produced 10,948 and 15,335 net daily average boepd, respectively, comprising 25.5% and 35.7%, respectively, of our total production.

We are and will still continue to be, disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells caused by processing or transportation capacity constraints, governmental regulation, political changes, availability of equipment, facilities, personnel or services, infrastructure disruptions, natural disasters, weather events or interruption of the processing or transportation of oil as a result of our geographic concentration of assets, particularly in the UKCS. Interruptions affecting shared infrastructure may have a disproportionate impact on multiple assets simultaneously. The UKCS and South East Asia are prone to difficult weather conditions that can in some cases prevent us from shipping supplies, personnel and fuel to our facilities, each of which can cause production shutdowns or slowdowns.

Unusually difficult weather conditions may lead to a heightened risk of the floating facility at Kraken detaching from its moorings and difficulties in supplying this facility with fuel and there can be no assurances that the floating facility will not be affected in the future. Adverse changes in weather and natural hazards, including the occurrence of monsoon seasons, typhoons and tsunamis in South East Asia, may cause damage to our vessels resulting in delays or suspension in our operations. In addition, if mechanical problems, storms or other events curtail a substantial portion of our production in the UKCS or cause damage to any of our facilities, our results of operations and financial condition could be adversely affected.

Mechanical problems, accidents, oil leaks or other events at any of our installations, floating facility or the related pipeline systems or subsea infrastructure or third-party operated infrastructure on which we rely, may cause a widespread, unexpected production shutdown of our operations in the UKCS. Our hub-focused model means that we leverage our infrastructure to service multiple fields, which magnifies the impact of any unexpected shutdowns at our infrastructure. Most of our producing assets in the UKCS are connected via pipeline systems or subsea tie-back so that we export oil from multiple fields to shore. For example, in the first half of 2025, the Magnus field was shut in for five weeks due to an unplanned outage of the third-party operated Ninian central pipeline. This outage had the effect of reducing our production by approximately 3.5 Kboepd for the period. See also "*—Risks relating to the oil and gas industry—We face drilling, exploration and production risks and hazards that may affect our ability to produce oil at expected levels, quality and costs and that may result in additional liabilities to us*."

Due to the concentration of our assets in two regions, a number of our assets could experience any of the above conditions at the same time, resulting in a relatively greater impact on our results of operations than might be experienced by companies that have a more diversified portfolio of producing assets and wider geographic exposure. We would also be disproportionately affected by a decrease in production volumes or reserve estimates

at one of our assets. Such circumstances could have a material adverse effect on our business, prospects, financial condition and results of operations. See also "*—Our business is subject to licensing and other regulatory requirements and fiscal regimes, which are subject to change, in the countries in which we operate, and we are subject to the risks of licenses or other agreements being withheld, suspended, revoked or terminated and of our failing to comply with relevant licenses, agreements or other regulatory requirements*."

Significant expenditure is required to maintain operability and operations integrity, we rely upon infrastructure which is old and/or operated and owned by third parties, and improper maintenance and repair could harm our operations

As our strategy depends in part on acquiring relatively mature assets, we frequently own assets which utilize equipment that has had substantial prior use. In addition, many of the assets, prior to our ownership, had not been drilled, developed or maintained for significant periods of time and in some cases the equipment at such assets had been subject to lengthy periods out of commercial operation. Such equipment can be subject to higher levels of wear and tear, be subject to a greater risk of failure and outage, give rise to higher maintenance costs and may need to be replaced more quickly than newer assets. There are inherent risks involved with the operation of this equipment, and any unexpected failures or outages leading to additional expenses could have a negative impact on our production in UKCS, Malaysia and Vietnam and our exploration activities in Indonesia and Brunei. In addition, part of our business strategy is to re-use, retrofit or refurbish producing assets where possible to maximize the efficiency of our operations while avoiding significant expenses associated with purchasing new equipment. There can be no assurances that such re-use, retrofitting or refurbishment will be commercially feasible to undertake in the future and there can be no assurances that we will not face unexpected costs during the re-use, retrofitting or refurbishment process. There can be no assurances that we will not be subject to such unexpected costs in the future and such costs could have a material adverse effect on our results of operation and financial condition.

Our current production in the UKCS also relies on some third-party owned and controlled infrastructure that is old. Our limited ability to maintain or repair infrastructure that we do not own or operate may exacerbate the risks of relying on mature assets described above. The Ninian pipeline system, for instance, was first constructed in the 1970s. We currently rely on the Ninian pipeline system for transport of oil produced at Magnus. As the Ninian pipeline systems have been extensively used, they require regular maintenance to maintain efficiency and there is a risk that the systems enter decommissioning before we have finalized an alternative export route. The pipeline systems may also need to be shut down to stop hydrocarbon leaks. Storm damage to the third party-operated Ninian Central Platform, which was caused by a once-in-a-decade wave, resulted in an unplanned outage for all system users, including Magnus, in mid-January 2026. Following the completion of remedial works, Magnus production was reinstated in the early hours of February 22, 2026. To proactively address the risk of third party equipment downtime on Magnus production, we are well advanced with plans to bypass Ninian Central Platform during 2027. In Malaysia, crude oil from PM8/Seligi is transported via the Tapis platform (operated by ExxonMobil) to the Terengganu Crude Oil Terminal (operated by PETRONAS Carigal Sdn. Bhd.) for processing and sale to the domestic market or export and in Vietnam, gas is exported via pipeline to Vung Tau near Ho Chi Minh City. Our ability to maintain and repair infrastructure which we do not operate is limited. If the owners or operators of these pipelines, as well as of other, old third-party infrastructure upon which our operations rely, fail to adequately maintain their integrity, we may not be able to efficiently deliver oil to onshore terminals for sale.

There are also extensive maintenance obligations in respect of assets operated by us. For example, a significant proportion of our current production in the UKCS passes through SVT, an oil terminal located in the Shetland Islands that receives oil from 10 fields from the Ninian and Clair pipeline systems and the Shetland Gas Plant. We also operate (on behalf of owner bp) gas reception facilities located at SVT which receives gas produced from the bp operated Clair Quad 204 fields. Gas is treated to grid specification and exported to market via the East of Shetland Pipeline System ("**EOSPS**"), which we operate, although an ongoing project led by bp as Clair operator is creating a new export pipeline which will reduce reliance on EOSPS. We rely on third-party suppliers for most of our information technology infrastructure, including cloud services, which we may be required to update from time to time. If one or more of the technologies we use now or in the future were to become obsolete, our business, prospects, financial condition and results of operations could be materially adversely affected.

We rely on third party suppliers for most of our information technology infrastructure, including cloud services, which we may be required to update from time to time. If one or more of the technologies we use now or in the future were to become obsolete, our business, prospects, financial condition and results of operations

could be materially adversely affected. In addition, any changes in existing technology or the implementation of new technology, such as moving our systems to the cloud, may have unanticipated or unforeseen adverse consequences, such as being incompatible with our existing information technology infrastructure, which could impact our business, financial condition and results of operations. If the infrastructure which we rely on experiences mechanical problems, an explosion, adverse weather conditions, a cyber-attack, a terrorist or piracy attack or any other event that causes an interruption in operations or a shutdown, our ability to transport our oil could be severely affected.

Any decrease in our ability to transport our oil or the efficiency of our operations could have a material adverse effect on our business, prospects, financial condition and results of operations.

Our use of third-party infrastructure is also subject to tariff charges which are required to be paid in order to maintain continued operations. These charges can be substantial and the per barrel charge of third-party infrastructure is not subject to our direct control. Our tariff costs have increased in recent years from approximately $2.4/boe on average in 2021 to $4.4/boe on average in 2025, in each case on a working interest basis, largely reflecting a planned increase in our share of throughput at SVT ahead of future forecast cost and emission reductions at the terminal following the completion of the current decarbonization projects on site. A significant increase of our tariff charges could have a material adverse effect on our business, prospects, financial condition and results of operations.

Our business is subject to licensing and other regulatory requirements and fiscal regimes, which are subject to change, in the countries in which we operate, and we are subject to the risks of licenses or other agreements being withheld, suspended, revoked or terminated and of our failing to comply with relevant licenses, agreements or other regulatory requirements

Unanticipated changes in the regulatory or fiscal environment, including as a result of varying or changing interpretations of applicable laws and regulations or regulatory practice, can affect our ability to access funding and liquidity, deliver our strategy and business plan and potentially impact revenue and future developments. Our current operations are, and our future operations will be, subject to licenses, approvals, authorizations, consents and permits from governmental authorities for exploration, development, construction, operation, production, marketing, pricing, transportation and storage of oil and other hydrocarbons, taxation and environmental and health and safety matters. Relevant legislation provides that fines may be imposed and a license may be suspended or terminated if a license holder, or party to a related agreement, fails to comply with its obligations under such license or agreement, or fails to make timely payments of levies and taxes for the licensed activity, provide the required geological information or meet other reporting requirements. It may from time to time be difficult to ascertain whether we have complied with obligations under licenses as the extent of such obligations may be unclear or ambiguous and regulatory authorities may not be forthcoming with confirmatory statements that work obligations have been fulfilled, which can lead to further operational uncertainty. In addition, we and our commercial partners, as applicable, have obligations to develop the fields in accordance with specific requirements under certain licenses and related agreements, field development plans, laws and regulations. If we or they were to fail to satisfy such obligations with respect to a specific field, the license or related agreements for that field may be suspended, revoked or terminated or the operator may be removed.

With regard to our operations in the UKCS, U.K. authorities are typically authorized to, and do from time to time, undertake inspections to verify compliance by us or our commercial partners, as applicable, with relevant laws and the licenses or the agreements pursuant to which we conduct our business. The views of the relevant government agencies regarding the exploration, appraisal, development, operation and abandonment of the fields that we or our commercial partners operate or the compliance with the terms of the licenses pursuant to which we conduct such operations may not coincide with our views, which might lead to disagreements that may not be resolved. A "climate compatibility checkpoint" was introduced into the 33rd Round in 2022 to determine whether future applications for oil and gas licenses in the North Sea align with wider climate change objectives, such as the reduction of emissions and sustainability. Currently, the U.K. government is considering whether any new offshore oil and gas licenses may be issued, although it has also stated that existing licenses will not be revoked. The U.K. Labour Party's 2024 manifesto included a commitment to cease issuing new oil and gas exploration licenses in the U.K., including the UKCS. If implemented, this policy would materially impact our ability to expand upstream operations within the UKCS and reduce our long-term reserve replacement rates, as well as potentially cause us to have to cancel or postpone future projects. This, and other changes in government policies and legislation, may make it more difficult for us to procure licenses in the future or make it more expensive or onerous to comply with existing licenses.

With regard to our operations in Malaysia, upstream petroleum activities in Malaysia are primarily regulated by Petroliam Nasional Berhad ("**PETRONAS**"), which derives its powers from the Petroleum Development Act 1974 and the Petroleum Regulations 1974. Pursuant to the terms of the PM8/Seligi production sharing contract with PETRONAS (the "**PM8Extension PSC**"), PETRONAS regulates the petroleum operations through its approval of well locations, area and field development plans, production operations, annual work programs and budget, and procurement of goods and services above a certain monetary threshold. PETRONAS' approval is also required for the disclosure of any data from the PM8Extension PSC contract areas, for any public announcement or for the sale or assignment of any of the interest in the PM8Extension PSC. The PM8Extension PSC and the PETRONAS Procedures and Guidelines for Upstream Activities contain strict provisions relating to procurement of goods and services. The Petroleum Regulations 1974 stipulates that all goods and services for upstream petroleum operations in Malaysia can only be supplied by companies which are licensed by PETRONAS. Non-compliance with the guidelines or procurement of goods and/or services from non-licensed companies would bar the relevant PSC contractor from recovering their costs under a PSC. All PSC accounts are subject to annual audits by PETRONAS. Any contractors or consultants hired by us under a PSC who fail to fulfill their obligations could cause us to be in breach under a PSC.

Additionally, pursuant to the terms of the PM8Extension PSC and the Cendramas PSC with PETRONAS, PETRONAS regulates the petroleum operations. In the event of a state of national emergency or shortage of supply of crude oil to the nation for whatever reason, as declared by the Government of Malaysia, PETRONAS would have the right to pre-empt part of or all the crude oil produced from the PM8Extension PSC and the Cendramas PSC, payment for which would be in Malaysian ringgit (unless payment in another currency is agreed by the parties to the PSCs), which would expose us to currency risks. Such pre-emption could have a material effect on our profits from the PM8Extension PSC and the Cendramas PSC.

Our operations in Vietnam are primarily regulated by the Ministry of Industry and Trade ("**MOIT**"), which is responsible for formulating and implementing policies related to the oil and gas sector. Key legislation includes the Petroleum Law, which outlines the legal basis for exploration, production, and distribution activities. The Vietnam Oil and Gas Group ("**PetroVietnam**"), a state-owned enterprise, oversees exploration and production activities and enters into partnerships with international oil companies, engaging in all stages of the oil and gas value chain and partnering with international companies through PSCs. These contracts allow foreign entities to invest and operate in Vietnam while sharing profits with the government.

The operation in Brunei is primarily regulated by The Petroleum Authority of Brunei Darussalam Act, Chapter 231, which provides the establishment of Petroleum Authority ("**PA**"), a statutory body, acting as a central authority (regulator) to regulate and supervise the upstream, midstream and downstream oil and gas operations in Brunei Darussalam. PA is the technical arm of the Department of Energy, Prime Minister's Office, advising on matters relevant to the oil and gas industry in Brunei Darussalam to ensure the sustainable development of all hydrocarbon resources and value chain.

The operation in Indonesia is primarily regulated by the Special Task Force for Upstream Oil and Gas Activities ("**SKK Migas**"), an institution established by the Government of the Republic of Indonesia under Presidential Regulation Number 9 of 2013 on Management of Upstream Oil and Gas Activities. SKK Migas is assigned to manage upstream oil and gas activities under PSCs. SKK Migas is monitored through an Oversight Committee chaired by MEMR, under which is the Directorate General of Oil and Gas.

Our rights to exploit many of our oil and gas assets are limited in time. There can be no assurance that such rights can be extended or that new rights can be obtained to replace any rights that expire. A portion of the licenses pursuant to which we conduct operations may from time to time be solely exploration licenses, and as such the assets which are the subject of such licenses are not currently producing, and may never produce commercial quantities of oil. Rather, these licenses have a limited life before we are obliged to seek to convert the license to a production license, extend the license or relinquish the license area. If hydrocarbons are discovered during the exploration license term, we or our commercial partners, as applicable, may be required to apply for a production license before commencing production. If we or our commercial partners, as applicable, comply with the terms of the relevant license, we would normally expect that a production license would be issued; however, no assurance can be given that any necessary production licenses will be granted by the relevant authorities.

Each of the exploration and production licenses or related agreements pursuant to which we conduct operations have incorporated detailed work programs which are required to be fulfilled, normally within a specified timeframe. These may include seismic surveys to be performed, wells to be drilled, production to be attained, limits to production levels and construction matters. Material non-compliance with these work programs

within the required timeframes, or failure to successfully negotiate extensions to the time permitted to carry out these work programs, could result in the premature termination, suspension or withdrawal of licenses and our losing the associated resource potential therein. It may also restrict the ability to obtain new licenses in the relevant jurisdictions.

The suspension, revocation, withdrawal or termination of any of the licenses or related agreements pursuant to which we conduct business, as well as any delays in the continuous development of or production at our fields caused by the issues detailed above, or by similar issues caused by a third-party incident (such as a significant spill), could materially and adversely affect our business, prospects, financial condition and results of operations. In addition, failure to comply with the obligations under the licenses or agreements pursuant to which we conduct business, whether inadvertent or otherwise, may lead to fines, penalties, restrictions, withdrawal of licenses and termination of related agreements, which could materially and adversely affect our business, prospects, financial condition and results of operations.

Moreover, we are subject to extensive government laws and regulations governing prices, taxes, royalties, allowable production, waste disposal, pollution control and similar environmental laws, the export of oil and other hydrocarbons and many other aspects of the oil and gas business. These laws and regulations are subject to change as the political and regulatory landscape evolves, and any amendments to or reforms of the laws and regulations to which we are subject could make compliance with them more challenging, onerous or expensive. The actions of present or future governments in the countries in which we do business or of governments of other countries in which we may acquire assets in the future may materially and adversely affect our business, prospects, financial condition and results of operations.

Our oil exploration and production operations are principally subject to the laws and regulations of the United Kingdom, Malaysia, Vietnam, Indonesia and Brunei, including those relating to health and safety and the production, pricing and marketing of oil. The grant, continuity and renewal of the necessary approvals, permits, licenses and contracts, including the timing of obtaining such licenses and the terms on which they are granted, are subject to the discretion of the relevant governmental and local authorities in the United Kingdom, Malaysia, Vietnam, Indonesia and Brunei.

The U.K.'s transition to a 'net zero' economy by 2050 is likely to have an impact on the licensing and other regulatory requirements and obligations applying to oil and gas companies. In particular, the North Sea Transition Deal and the OGA Strategy require oil and gas companies to take steps to assist the government to achieve the net zero carbon target, and the U.K. government is currently considering whether to make further changes relating to decarbonization, licensing or other regulatory requirements.

Similarly, our U.K. Midstream and Veri Energy business units are also subject to licensing and regulatory requirements. For example, we have secured exclusivity from the Shetland Islands Council to progress new energy opportunities on the site. We hold two carbon capture and storage ("**CCS**") licenses, awarded in May 2022 as part of the first round of UK carbon sequestration licenses issued by the North Sea Transition Authority ("**NSTA**") and looking to develop an onshore wind farm at the Sullom Voe Terminal. However, our ability to progress our medium- to long-term plans to repurpose SVT is dependent on our ability to obtain, maintain and comply with these licenses and other regulatory requirements. There can be no assurance that we will be able to maintain our CCS licenses nor obtain further licenses at SVT.

If we are unable to obtain, maintain or comply with necessary licenses or comply with other applicable regulatory requirements, or if any of the licensing or other regulatory requirements to which we are subject are amended in a way that makes compliance with them more difficult or expensive, this could have a material adverse effect on our business, prospects, financial condition and results of operations.

In addition, the change to the EPL announced in the Autumn Statement 2022 materially impacted the borrowing base of our 2021 RBL Facility and associated amortization schedule. For further detail, see "*—Our tax liability is subject to estimation and we may be adversely affected by changes to tax legislation or its interpretation or increases in effective tax rates in the jurisdictions in which we do business*". Further fiscal changes could be enacted that could have a material adverse effect on our business, prospects, financial condition and results of operations.

Our strategy of delivering sustainable and transformative growth through transformative consolidation transactions may increase our debt and the complexity of our operations

We have sought, and continue to seek, transformative consolidation opportunities, the timing of which is not necessarily within our control and which may take the form of majority asset or share purchase agreements or joint ventures that could be material relative to our existing business. As the U.K. Government and other regulators in the North Sea increase financial and environmental burdens on energy producers, including the EPL and its successors, changed conditions are leading many North Sea energy producers to seek economies of scale via consolidation transactions. In addition, we may seek to achieve further scale in South East Asia under the right conditions. We continuously consider, and may in the future enter into, these types of transactions, with the aim of further enhancing our production and reserves base and maintaining the longevity of our business model. These activities involve risks and uncertainties, including as discussed under "*—If we fail to integrate acquisitions successfully, our financial condition and future performance could be adversely affected*," and the risk of the joint venture partner failing to satisfy its obligations, which may result in certain liabilities to us for guarantees or other commitments. These types of transactions are also generally highly capital-intensive, and could result in a material increase in our secured debt and leverage if completion of such transactions occurs, which could adversely affect our business, financial condition, results of operations and our ability to satisfy our obligations under our existing debt, including the Notes.

Additional risks to these types of transactions, including those that result in joint control or a non-controlling interest in a joint venture or other business unit, derive from the challenges in achieving strategic objectives and expected benefits of the business arrangement, including the risk of conflicts arising between us and others, the difficulty of managing and resolving such conflicts and the difficulty of managing or otherwise monitoring such business arrangements. Additionally, these types of transactions may increase the complexity of our operations, and we may not be able to realize the anticipated synergies that would allow such a transaction to be profitable. Production may be lower than expected, and we may be required to fund development earlier than anticipated, or in amounts greater than expected, which may strain existing operations and could have a material adverse effect on our business, results of operations, financial condition and/or prospects. There is no guarantee that such a consolidation transaction would result in sufficient cost savings or revenue growth to offset the significant investment likely required. See also "*—Risks relating to the Notes and our structure—There are circumstances other than repayment or discharge of the Notes under which the Note Guarantees will be released automatically, without your consent or the consent of the Trustee*."

Failure to meet ESG expectations or standards or achieve our ESG goals could adversely affect our business, results of operations, or financial condition, and could negatively impact our ability to make payments on the Notes

There remains heightened focus from regulators and stakeholders on ESG matters, including greenhouse gas emissions and climate-related risks; diversity, equity, and inclusion; responsible sourcing and supply chain; human rights and social responsibility; risk management; and corporate governance and oversight. This has resulted in expanding and increasingly complex mandatory and voluntary reporting, diligence, and disclosure on ESG topics. These developments and other rapidly changing laws, regulations, policies and related interpretations, as well as increased enforcement actions by various governmental and regulatory agencies, may create challenges for us, including our compliance and ethics programs, may alter the environment in which we do business and may increase the ongoing costs of compliance, which could adversely impact our results of operations and cash flows or force earlier than planned cessation of production of fields. Given our commitment to ESG, we actively manage ESG issues through various initiatives which we may refine or even expand further in the future. These initiatives reflect our current plans and aspirations and are not guarantees that we will be able to achieve them.

Our failure or perceived failure to achieve our ESG goals, maintain ESG practices, or comply with emerging ESG regulations that meet evolving regulatory or stakeholder expectations could harm our reputation, adversely impact our ability to attract and retain customers and talent, and expose us to increased scrutiny from the investment community and enforcement authorities. Our reputation also may be harmed by the perceptions that our stakeholders have about our action or inaction on ESG-related issues. Damage to our reputation may reduce demand for our products and services and thus have an adverse effect on our future financial results, as well as require additional resources to rebuild our reputation and could also negatively impact our ability to make payments on the Notes.

There are risks inherent in our acquisitions of appraisal, development and production assets

Prior to entering into an agreement to acquire an oil and gas asset (or companies holding such assets), we perform due diligence on the proposed acquisition. However, reviews of properties prior to acquisitions in the oil industry are inherently incomplete, even if consistent with market practice. Even an in-depth review of all properties and records may not reveal existing or potential problems, nor will it always permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Physical inspections may not be performed on every well and other infrastructure, and structural or environmental problems are not necessarily observable even when an inspection is undertaken. There can be no assurance that the due diligence carried out by ourselves or by third parties on our behalf in connection with any acquisition will reveal all of the risks associated with that asset, or the full extent of such risks. To the extent that we or third parties acting on our behalf underestimate or fail to identify risks and liabilities associated with an acquisition or overestimate the value of an acquisition to our business, we may be subject to one or more of the following risks:

- environmental, structural or operational defects or liabilities requiring remediation or decommissioning;
- an inability to obtain (or secure the transfer of) or maintain licenses or other relevant agreements enabling us to use or develop the asset as intended;
- defects in title;
- the asset containing fewer oil reserves than anticipated or not being commercially viable to develop; and
- acquiring assets that are not consistent with our strategy or that fail to perform in accordance with our expectations.

We have historically undertaken a number of acquisitions of oil and gas assets (and of companies holding such assets) as part of our strategy of maintaining and growing our reserves, including our acquisition of Harbour Energy's business in Vietnam in 2025. We may consider further acquisition opportunities inside and outside of the UKCS and South East Asia, in respect of assets that fit within our overall strategy or which enhance our overall reserve base and production capability. However, there can be no assurances that we will be successful in identifying and completing further acquisitions. For example, we may be required to assume pre-closing liabilities with respect to an acquisition, including known and unknown environmental and decommissioning liabilities, and may acquire interests in properties on an "as is" basis without recourse to the seller of such interest. Actual decommissioning costs may differ from current estimates due to changes in regulatory requirements, technical assumptions, timing and market conditions. In addition, equity or debt financing may not be available to us in order to complete acquisitions in the future. There may also be additional risks associated with any acquisitions outside our core geographies in the UKCS and South East Asia, such as a potential lack of synergies with existing operations or regulatory or production risks associated with a new geography. See also "*—Our strategy of delivering sustainable and transformative growth through transformative consolidation transactions may increase our debt and the complexity of our operations*."

If any other of our historic or future acquisitions fail to perform as expected, or give rise to significant unforeseen costs or liabilities, this could have a material adverse effect on our business, prospects, financial condition and results of operations.

We conduct most of our operations with commercial partners which may increase the risk of delays, additional costs and the suspension or termination of the licenses or the agreements that govern our assets

We have entered into business ventures with commercial partners in respect of most of our assets. While we are typically the operator of our assets, we require cooperation from our commercial partners in obtaining approval of field development plans and in funding the development of and production from an asset. The relevant operating agreement typically provides that the project partner(s) must be consulted or that they must provide their consent in relation to significant matters. Where there is a lack of cohesive collaboration between operators, such behavior can lead to increased costs and delays and, ultimately, the lower recovery of oil. There is also a risk that a commercial partner with interests in our properties may fail to fund their obligations under our operating or joint venture agreements or may elect not to participate in certain activities relating to those properties that require that party's consent (including decisions relating to drilling programs, decisions on the number, identity and

sequencing of wells, appraisal and development decisions and decisions relating to production). In these circumstances, it may not be possible for such activities to be undertaken by us alone or in conjunction with other commercial partners at the desired time or at all, or otherwise, to the extent permitted, such activities may be undertaken with us bearing a greater proportion of the cost involved in the project.

Currently our only non-operated producing assets are Alba, in relation to which we are dependent on our commercial partner, Ithaca Energy Limited, which acts as operator, Golden Eagle, in relation to which we are dependent on our commercial partner, CNOOC, which acts as operator, and the Cendramas PSC in relation to which we are dependent on our commercial partner, Medco Asia Pacific Limited, which acts as operator. Thus we are not able to direct or control operations, the timing and performance of activities or the costs thereof at Alba, Golden Eagle or Cendramas as we often would if we were the operator. The terms of our agreements with operators generally impose standards and requirements in relation to the operatorship of the relevant oil field. However, there can be no assurance that the operator will observe such standards or requirements. To the extent that our operations are delayed, incur additional costs or any relevant licenses or agreements that govern our assets were to be suspended or terminated as a result of our dependence on commercial partners, this could have a material adverse effect on our business, prospects, financial condition and results of operations.

Our exit strategy in relation to any particular hydrocarbon interest may also be subject to the prior approval of our commercial partners. The terms of operating agreements often require commercial partners to approve of an incoming participant to the business venture or provide our commercial partners with preemption rights with respect to the transfer of our interest, either of which could affect our ability to sell or transfer an interest

We may suffer unexpected costs or other losses if a commercial partner does not meet obligations under agreements governing our relationship. For example, commercial partners who have invested in our properties may default in their obligations to fund capital, or other funding obligations, in relation to such properties. In such circumstances, we may be required under the terms of the relevant operating agreement to contribute all or part of any such funding shortfall, regardless of the percentage interests that we agreed with such commercial partner under such arrangements. Additionally, we may be required to increase our ownership stake and fundraising commitments in respect of assets to the extent our commercial partners exit their investment sooner than anticipated. For example, in respect of Kraken, as a result of our then-partner First Oil PLC going into administration, we were obliged to take up an additional 10.5% interest in Kraken in February 2016, which at the time increased the proportion of the development costs on Kraken that we were required to bear. There are also credit risks of commercial counterparties including exposures in respect of outstanding receivables. As of December 31, 2025, there were nil joint venture receivables past due compared to nil as of December 31, 2024. It is apparent that we must accept a degree of exposure to the creditworthiness of partners and evaluate this aspect carefully as part of every investment decision.

We may also be subject to claims by our commercial partners regarding potential non-compliance with our obligations. It is also possible that our interests, on the one hand, and those of our commercial partners, on the other, may not be aligned, resulting in possible project delays, additional costs or disagreements. Failure by our commercial partners to comply with obligations under relevant licenses or the agreements pursuant to which we operate may lead to fines, penalties, restrictions and withdrawal of licenses or the agreements under which we operate. If any of our commercial partners becomes insolvent or otherwise unable to pay debts as they fall due, licenses or agreements awarded to them may revert to the relevant governmental authority who will then reallocate the license. Although we anticipate that the relevant governmental authority may permit us to continue operations at a field during a reallocation process, there can be no assurances that we will be able to continue operations pursuant to these reclaimed licenses or that any transition related to the reallocation of a license would not materially disrupt our operations or development and production schedule. The occurrence of any of the situations described above could materially and adversely affect our business, prospects, financial condition and results of operations.

We rely on relatively few customers for a significant portion of our outstanding trade and other receivables

We are subject to customer concentration risk as a result of our reliance on relatively few numbers of customers for a significant portion of our revenues. For the year ended December 31, 2025, we had one customer accounting for 65% of outstanding trade receivables as a result of settlement of most cargo sales ahead of year end. Additionally, in the year ended December 31, 2025, revenue from three customers each exceeded 10% of our consolidated revenue arising from sales of crude oil.

If some or all of these customers which account for a significant portion of our revenues were to cease to continue to do business with us, this could have a material adverse effect on our business, prospects, financial condition and results of operations.

We are subject to counterparty credit risk in respect of our outstanding trade and other receivables

We are subject to agreements with a number of contractual counterparties in relation to the sale and supply of our production volumes. Therefore we are subject to the risk of a counterparty not meeting its obligations under such agreements, such as delayed payment for delivered production volumes or counterparty default. Such delays or defaults could have a material adverse effect on our business, prospects, financial condition and results of operations.

Failure by us, our contractors or our primary offtaker to obtain access to necessary equipment and transportation systems could materially and adversely affect our business, prospects, financial condition and results of operations

We rely on oil field suppliers and contractors to provide materials and services in conducting our exploration and production activities. Any competitive pressures on the oil field suppliers and contractors, or substantial increases in the worldwide prices of commodities, such as steel, could result in a material increase of costs for the materials and services required to conduct our business. Such equipment, personnel and services can be scarce and may not be readily available at the times and places required. Future increases could have a material adverse effect on our operating income, cash flows and borrowing capacity and may require a reduction in the carrying value of our properties, our planned level of spending for exploration and development and the level of our reserves. Prices for the materials and services we depend on to conduct our business may not be sustained at levels that enable us to operate profitably. In certain cases, we may extend or provide financing to such parties in connection with the equipment or services they provide, sell or lease to us. See "*Management's discussion and analysis of financial condition and results of operations—Qualitative and quantitative disclosures about market risk—Credit risk management*."

Oil development and exploration activities are dependent upon the availability of drilling rigs and related third-party equipment. High demand for equipment such as drilling rigs or access restrictions, which may be exacerbated by rising oil prices, may affect the availability and cost of, and our access to, such equipment and may delay our development and exploration activities. Additionally, the wage rates of qualified drilling rig crews generally rise in response to the increased number of active rigs in service and could increase sharply in the event of a shortage. Failure by us or our contractors to secure necessary equipment and services or a material increase in the costs of such equipment and services could materially and adversely affect our business, prospects, financial condition and results of operations.

Any future offtakers will rely upon the availability of storage tanks and transportation systems, such as pipeline systems and oil tankers, including such infrastructure systems that are owned and operated by third parties. We may be unable to access such infrastructure and systems that we use currently or alternative infrastructure or systems, or may otherwise be subject to interruptions or delays in the availability of infrastructure which could result in disruptions to our projects thereby impacting our ability to deliver oil to commercial markets. See "*—Significant expenditure is required to maintain operability and operations integrity, we rely upon infrastructure which is old and/or operated and owned by third parties, and improper maintenance and repair could harm our operations*."

If we fail to integrate acquisitions successfully, our financial condition and future performance could be adversely affected

Historically, we have acquired interests in new assets on a regular basis. In 2025, we closed the acquisition of an equity interest in the Block 12W PSC in Vietnam. We will continue to consider acquisition opportunities that fit within our overall strategy. Integrating operations, technology, systems, management, personnel and pre- or post-completion costs for future acquisitions may prove more difficult or expensive than anticipated, thereby rendering the value of any company or assets acquired less than the amount paid. The integration of acquired businesses requires significant time and effort on the part of our management. Integration of new businesses can be difficult and disrupt our own business because our operational and business culture may differ from the cultures of the businesses we acquire, unpopular cost-cutting measures may be required, internal controls may be more difficult to maintain and control over cash flows and expenditures may be difficult to establish. We could experience difficulties in successfully integrating future acquisitions, which could materially

and adversely affect our business, prospects, financial condition and results of operations. See also "*—Our strategy of delivering sustainable and transformative growth through transformative consolidation transactions may increase our debt and the complexity of our operations*."

We may face unanticipated increased or incremental costs in connection with decommissioning obligations

We are obliged under U.K. law to dismantle and remove equipment, to cap or seal wells and generally to remediate production sites. Although we typically aim to and have contracted for limited decommissioning liabilities when acquiring assets, often assuming responsibility for a fraction of the costs relative to our working interest, we may retain additional potential liability to third parties under applicable regulations. Once we are required to submit a decommissioning plan, we will be jointly and severally liable for implementing that plan with former or current commercial partners. If our commercial partners default on their obligations, we will remain liable, and our decommissioning liabilities could be magnified significantly through such default. Where the U.K. Secretary of State deems that a party with liability for a decommissioning program is unlikely to be able to fulfil that liability, it is empowered to require the provision of appropriate financial security to cover those decommissioning costs. Any material unanticipated increase or incremental costs, fines or sanctions in connection with such decommissioning obligations may materially and adversely affect our business, prospects, financial condition and results of operations.

EnQuest manages a complex, multi-asset program of facilities removal and well P&A activity; as part of this program, EnQuest engages regularly with the NSTA (who may seek further information from operators regarding the scheduling of P&A of certain wells). As part of this process, the NSTA has investigated our compliance with P&A deadlines for certain wells and on April 2, 2026, we received a formal Sanction Notice from the NSTA in respect of alleged non-compliance in relation to the timing of the plugging and abandonment of 33 wells across four licenses. The Sanction Notice includes a fine of £500,000 in respect of each of the wells. We prioritize our P&A work on the basis of asset integrity to minimize risk to human life and the environment and as a result, our scheduling can differ from the date-driven and more mechanistic approach taken by the NSTA's sanction team. We are considering all options with regard to formally appealing the sanction and the fine.

In Malaysia, PETRONAS regulates decommissioning of oil and gas structures through PSCs and PETRONAS's Guidelines for Decommissioning of Upstream Installations as part of its Procedure and Guidelines for Upstream Activities. Our obligation under the PM8Extension PSC includes the decommissioning of all assets approved by PETRONAS under the PM8Extension PSC as well as an annual contribution of a decommissioning fund for the PM8Extension PSC assets. This obligation to decommission the assets ceases at the expiry of the PM8Extension PSC or when the assets are being used by other PSC operators for their petroleum operations or by PETRONAS. No asset under the PM8Extension PSC is currently approved for decommissioning other than planned P&A of wells approved by PETRONAS. The estimate of costs for the decommissioning of PM8Extension PSC is reviewed annually, with the most recent review taking place earlier in 2025. Any decommissioning activity must be approved by PETRONAS before commencement and must be performed pursuant to a work program and budget, which must include detailed decommissioning plans and itemized cost estimates, approved by PETRONAS. If we are required to undertake decommissioning works during the term of the PM8Extension PSC, we may request from PETRONAS an amount equal to the lower of the cumulative decommissioning fund paid by us and the actual cost of the decommissioning operations. Under the PM8Extension PSC, we are liable for any damages, costs, claims or expenses arising out of any decommissioning operations caused by our willful misconduct or negligence.

In Vietnam, the MOIT regulates the decommissioning of oil and gas structures, along with PetroVietnam on projects in which it is involved. The regulatory framework under Law No. 12/2022/QH15, effective July 1, 2023 (the "**Petroleum Law**") requires us to develop a decommissioning plan that must be sent to PetroVietnam for review and then submitted to MOIT and other relevant authorities (if required) for appraisal and approval. The decommissioning plan must cover areas such as (i) an inventory of facility components, (ii) technical solutions and methods for decommissioning, (iii) plans for waste management, marine environmental pollution control, environmental monitoring, environmental incident prevention and response, and safety assurance during decommissioning, (iv) estimated costs and funding and (v) an execution schedule.

Under the law of the jurisdictions in which we operate, the United Kingdom included, we may be liable for up to 100% of decommissioning liabilities with respect to enhancements that we make to assets after we acquire them. In connection with the sale or transfer of our assets, we may retain or be liable for decommissioning liabilities, even if we have not contractually agreed to accept these liabilities.

Our financial statements for the year ended December 31, 2025 include a provision for decommissioning liabilities, based on internal and third-party estimates taking into account current legal and constructive requirements and current technology and price levels for the removal of facilities and plugging and abandoning of wells. The timing and amount of future expenditures relating to decommissioning and environmental liabilities are reviewed annually. The rate used in discounting the cash flows is reviewed half-yearly. We assess discount rates in each geography in which we operate using an appropriate benchmark, usually government bonds. As such, in the year ended December 31, 2025, the nominal discount rate used to determine the balance sheet obligations ranged from 3.1% to 4.5% (2024: 3.1% to 4.5%). Costs at future prices are determined by applying inflation rates. The inflation rates applied are usually management estimates based on relevant in-country benchmarking, but in certain circumstances inflation is applied in accordance with the relevant operating agreement. As such, where inflation has been applied to decommissioning costs in the year ended December 31, 2025, it has ranged between 1.0% and 2.0% per annum thereafter (2024: 1.0% to 2.0%). As of December 31, 2025, we recorded a decommissioning provision of $915.6 million in respect of our decommissioning obligations under our licenses of which we expect $364.3 million to be utilized between one and five years. Separately, as of December 31, 2025, we recorded a decommissioning liability of $15.3 million in respect of our agreement with bp for the decommissioning at Thistle/Deveron. The ultimate costs of decommissioning wells and sites are difficult to accurately predict and may depend on a number of factors such as competition for decommissioning equipment and services increasing as a result of activity in the oil and gas industry accelerating. The costs of decommissioning may also exceed the value of the long-term provision set aside to cover such decommissioning costs. Our decommissioning provisions may not be sufficient and we may be required to provide new or increased financial security to the U.K. government or to our counterparties. Any increase in estimated decommissioning liability or in the amount of financial security we are required to provide could materially and adversely affect our business, prospects, financial condition and results of operations.

Furthermore, surety bonds used for insuring decommissioning liabilities may become difficult to put in place and we may be required to increase our reliance on letters of credit or escrow accounts. Letters of credit and escrow accounts, which, unlike surety bonds, can require cash collateralization (which restricts the amount of cash we have available to service our other obligations, including our debt facilities) and affect our debt capacity. As such, amounts held as letters of credit or in escrow may limit the amount of debt we could potentially take on and should be included in an existing or potential lender's assessment of our ability to service debt. This could have a material adverse effect on our business, prospects, financial condition and results of operations.

To the extent our costs in connection with decommissioning are higher than anticipated, this could have a material adverse effect on our business, prospects, financial condition and results of operations.

Our commodity hedging activities may not be effective

The nature of our operations results in exposure to fluctuations in commodity prices. Our policy is to have the flexibility to hedge oil prices up to a maximum of 75% of the next 12 months' production on a rolling annual basis, up to 60% in the following 12-month period and 50% in the subsequent 12-month period. We use financial instruments and physical delivery contracts to hedge our exposure to these risks and may continue to do so in the future.

As of April 15, 2026, we have approximately 3.8 MMbbls of production hedged through 2026, utilizing swaps at an average price of $73.2/bbl, and we have approximately 3.5 MMbbls of production hedged for 2027, utilizing swaps at an average price of $64.4/bbl. Finally, we have approximately 0.9 MMbbls of production hedged for 2028, utilizing swaps at an average price of $64.6/bbl.

However, hedging could fail to protect us or could adversely affect us due to, among other reasons:

- the available hedging instruments failing to correspond directly with the risk for which protection is sought;
- the duration or nominal amount of the hedge failing to match the duration or amount of the related liability;
- our hedge counterparty defaulting on its obligation to pay us;
- the credit quality of our hedge counterparty being downgraded to such an extent that it impairs the ability of one of our relevant members to sell or assign our side of the hedging transaction; and

- the value of the derivatives used for hedging being adjusted from time to time in accordance with applicable accounting rules to reflect changes in fair value, and any downward adjustments reducing our net assets and profits.

In addition, hedging involves transaction costs. These costs may increase as the period covered by the hedging increases and during periods of volatility. In periods of extreme volatility, it may not be commercially viable to enter into hedging transactions due to the high costs involved, which may in turn increase our exposure to financial risks. There can be no assurance that we will be able to enter into hedging contracts on suitable terms in the future.

If we experience losses as a result of our hedging activities, or if we are unable to hedge our commodity price effectively in the future, this could have a material adverse effect on our business, prospects, financial condition and results of operations.

We depend on our board of directors, key members of management, independent experts, technical and operational service providers and on our ability to retain and hire such persons to effectively manage our growing business

Our future operating results depend in significant part upon the continued contribution of our board of directors, key senior management and technical, financial and operations personnel. As a low-cost, lean organization, we rely on certain key, high quality employees to achieve our targets and manage our risks. The loss of the services of any of these key personnel or a reduction in the availability of personnel due to climate change perceptions could have a material adverse effect on our business and prospects. Management of our business requires, among other things, stringent control of financial systems and operations, the continued development of our management control, the ability to attract and retain sufficient numbers of qualified management and other personnel, the continued training of such personnel and the presence of adequate supervision.

In addition, the expertise and relationships of our board of directors and key management are important to the conduct of our business. If we were to unexpectedly lose a member of our key management or fail to maintain one of the strategic relationships of our key management team, our business and results of operations could be materially and adversely affected.

We use independent contractors to provide us with certain technical assistance and services. There may be competitive pressures on oil field suppliers and contractors, which could result in a material increase in costs of the services required to conduct our business and operations. In certain cases, we may exercise limited control over the activities and business practices of these providers and any inability on our part to maintain satisfactory commercial relationships with them or their failure to provide quality services could materially and adversely affect our business, prospects, results of operations and financial condition.

Attracting and retaining appropriate skilled personnel and developing organizational capabilities to deliver strategic growth are fundamental to the execution of our strategy and the continued growth of our business. We require skilled personnel in the areas of exploration and development, operations, engineering, business development, oil marketing, finance and accounting relating to our projects. The competition for qualified personnel in the oil and gas industry was, and may be in the future, intense, in particular as the availability of such personnel is impacted by the wider backdrop of economic activity, increasing regulation in the oil and gas industry and changes to government policy and actions. Further, such personnel may not be readily available within the timeframes and locations required. We may not successfully attract new personnel and retain existing personnel required to continue to expand our business and to successfully execute and implement our business strategy; and any inability to do so could have a material adverse effect on our business, prospects, financial condition and results of operations.

Our business reputation is important to our continued viability and any damage to such reputation could materially and adversely affect our business

Our reputation is important to our business for reasons including, but not limited to, finding commercial partners for business ventures, securing licenses with governments, attracting contractors and employees and negotiating favorable terms with suppliers. In addition, as a publicly listed company, we may be subject to shareholder activism, which may have adverse consequences for our reputation and business.

We require adherence to our Code of Conduct, which sets out the behavior which we expect of our directors, managers and employees, and of our suppliers, contractors, agents and partners. However, we have significant reputational and commercial exposures, including to a major offshore incident or non-compliance with applicable laws and regulations or related climate change disclosures. Any damage to our reputation, whether arising from litigation, regulatory, supervisory or enforcement actions, matters affecting our financial reporting, alleged non-compliance with administrative agencies in the jurisdictions in which we do business or environmental or safety incidents, negative publicity, including from environmental activists, or the conduct of our business or otherwise, could materially and adversely affect our business, prospects, financial condition or results of operations.

We do not insure against certain risks and our insurance coverage may not be adequate for covering losses arising from potential operational hazards and unforeseen interruptions

Oil and gas development and production operations are inherently risky and hazardous and involve environmental, technical and logistical difficulties. Losses resulting from the occurrence of any such risks could result in delays, or interruption (permanent or temporary) to production, cost overruns, substantial losses and/or exposure to substantial environmental and other liabilities. We believe that the extent of our insurance cover is reasonable based on the costs of cover, the risks associated with our business, availability of insurance and industry practice. However, insurance is subject to limitations on liability and, as a result, may not be sufficient to cover all of our losses. In addition, the risks and hazards associated with our operations may not in all circumstances be insurable or, in certain circumstances, we may elect not to obtain insurance to deal with certain events due to the high premiums associated with such insurance or for other reasons. Consistent with insurance coverage generally available to the industry, our insurance currently includes cover for damage to physical assets, operator's extra expense (well control, seepage and pollution clean-up and re-drill costs) and third-party liabilities for our global exploration and production activities, in each case subject to excesses, exclusions and limitations. We do not carry loss of production insurance other than for Kraken. There can be no assurance that our insurance will be adequate to cover any losses or exposure for liability, or that we will continue to be able to obtain insurance to cover such risks.

We are unable to give any guarantee that expenses relating to losses or liabilities will be fully covered by the proceeds of applicable insurance. Consequently, we may suffer material losses from uninsurable or uninsured risks or insufficient insurance coverage. We are also subject to the future risk of unavailability of insurance, increased premiums or excesses, and expanded exclusions.

Our operations are subject to the risk of litigation

From time to time, we may be subject to litigation or arbitration arising out of our operations. Damages claimed under such proceedings may be material or may be indeterminate, and the outcome of such litigation or arbitration could materially and adversely affect our business, results of operations and financial condition. While we assess the merits of each lawsuit and defend accordingly, we may be required to incur significant expenses in defending against such litigation or arbitration and there can be no guarantee that a court or tribunal finds in our favor.

We are currently engaged in a dispute with PBJV Group Sdn Bhd ("**PBJV**"), a contractor in Malaysia, concerning approximately RM70 million (being approximately $17 million, of which our partners would be obliged to bear 50% of any such liability) claimed by PBJV which we do not accept is due. A contractor adjudication hearing in 2021 found in favor of PBJV, but we have continued to challenge the requirement to pay the claimed sum to PBJV as a result of the adjudication pending the outcome of the arbitration we initiated in January 2022 at the Asian International Arbitration Center ("**AIAC**"). Two separate arbitration hearings were held in 2024. Arbitrators closed submissions on June 6, 2025 with award anticipated within three months; however, on August 28, 2025, arbitrators requested a further three month extension to submit the award to the AIAC. Arbitrators subsequently requested further submissions on December 15, 2025 following a Federal Court of Malaysia decision that made it likely that any decision of the arbitrators will not be issued until the second quarter of 2026. We had previously paid the disputed funds into an escrow account with AIAC, but in late August 2024 the Malaysian Court of Appeal issued a judgement that the funds, which are reflected in our restricted cash balance at June 30, 2024, should be released to PBJV. The full amount previously held in escrow has been released to PBJV. If the arbitration ruling is in our favor, we will seek recovery of such funds (with our share being approximately $8.6 million) from PBJV. We expect the dispute to be settled in 2026. For further details, see "*Our business—Legal and arbitration proceedings*."

While we assess the merits of each lawsuit and defend accordingly, we may be required to incur significant expenses in defending against such litigation or arbitration and if a court or tribunal fails to find in our favor, it could have a material adverse effect on our business, prospects, financial condition and results of operations.

We are subject to both transactional and translational foreign exchange and inflation risks*, *which might adversely affect our financial condition and results of operations

Substantially all of our revenues are in, and most of our working capital is in, U.S. dollars. However, our operations are entirely outside the United States and a large portion of our operating costs, including labor and employee costs, are typically incurred in local currencies other than U.S. dollars, in particular, pounds sterling and Malaysian Ringgits.

Our transactional foreign currency risk arises primarily from sales or purchases in currencies other than our functional currency, the U.S. dollar. We convert funds to foreign currencies to meet our payment obligations in jurisdictions where the U.S. dollar is not an accepted currency as required. Additionally, a portion of our borrowings are denominated in currencies other than the U.S. dollar. The 9% Retail Notes, the SVT Working Capital Facility, the Vendor Loan Facility and our EPL tax liabilities are denominated in pounds sterling. Our translational foreign currency exposure arises from the translation of assets and liabilities denominated in currencies other than U.S. dollars into U.S. dollars in our financial statements and results.

Exchange rates between pounds sterling and the U.S. dollar have fluctuated significantly in the past and may do so in the future. As of December 31, 2025, the OandA pounds sterling/U.S. dollar exchange rate was $1.35 per £1.00. Consequently, construction, exploration, development, administration and other costs may be lower in terms of U.S. dollars or other relevant currencies. However, if pounds sterling were to strengthen against U.S. dollar, these costs would increase.

We engage in certain currency hedging activities to hedge the risk of substantial fluctuations in the currency markets. The hedging policy agreed by the Board allows for up to 70% of the non-U.S. dollar portion of the denominated operating and capital expenditures to be hedged. For specific contracted capital expenditure projects, up to 100% can be hedged. We have entered into a number of foreign exchange currency forward contracts and structured products to hedge our foreign currency risk. For the year ended December 31, 2025, gains totaling $24.1 million were recognized in respect of commodity contracts designated as fair value through profit or loss. This included gains totaling $20.8 million realized on contracts that matured during the year, and mark-to-market unrealized gains totaling $3.3 million. The mark-to-market value of our open contracts as at December 31, 2025 was an asset of $0.9 million.

As of December 31, 2025, 17% of our sales (2024: 12%) and 98% of our costs (2024: 97%) (including operating and capital expenditure and general and administration costs) were denominated in currencies other than the U.S. dollar. We continually review our currency exposures and when appropriate look at opportunities to enter into foreign exchange hedging contracts. However, our hedging activities do not cover the entirety of the currency exchange risks that we face, and there can be no guarantee that these hedging activities will be effective.

Globally, inflation rates have been higher in recent years and some input costs have risen accordingly and it may be that our operational and capital expenditures increase without a commensurate increase in our revenues. Similar to other exploration and production operations, we are reliant upon goods, services and equipment provided by contractors and other companies to carry out our operations. While we believe we are proactive in engaging our global supply chain to mitigate the impact of cost inflation, if we are unable to obtain the services, goods or equipment necessary to carry out our operations, including our current and future development projects, or if any of our contractors or suppliers are unable or unwilling to carry out our services or deliver goods or equipment to us as planned, our operations or projects may suffer from delays and/or cost increases.

The occurrence of any of the foregoing could materially and adversely affect our business, prospects, financial condition and results of operations.

We may be unable to dispose of assets on attractive terms and may be required to retain liabilities for certain matters

We regularly review our asset base to assess the market value versus holding value of existing assets, with a view to optimally manage our capital structure. The decision to dispose of an asset may be influenced by a variety of factors, including our overall development and production strategy, prioritization of projects and the commercial viability of development or production (which is affected by factors such as the oil price and expected costs). However, there can be no guarantee that we will be able to dispose of assets at the times we want to do so, or that we will be able to dispose of assets on attractive terms. Our ability to dispose of non-strategic assets could be affected by various factors, including the availability of purchasers willing to purchase such assets at prices acceptable to us. Sellers typically retain certain liabilities or agree to indemnify buyers for certain matters and to divest certain assets we may provide an indemnity to a buyer. The magnitude of any such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations. See "*—We may face unanticipated increased or incremental costs in connection with decommissioning obligations*."

We could incur material costs to comply with, or as a result of liabilities under, health and safety and environmental regulations

We operate in an industry that is inherently hazardous, with health and safety and environmental risks covering many areas, including major accident hazards, personal health and safety, compliance with regulatory requirements, asset integrity issues and potential environmental impacts. Consequently, we are subject to comprehensive health and safety and environmental regulation, including those governing discharges of oil and other pollutants to air and water, the management of produced water and wastes and the cleaning of contamination. Failure to adequately assess, mitigate and manage health and safety and environmental risks may result in loss of life, injury, or adverse impacts on the health of employees, contractors and third parties or the environment. Such failure, whether inadvertent or otherwise, by us to comply with applicable legal or regulatory requirements may give rise to significant liabilities, reputational damage and/or the loss of or delays in obtaining necessary licenses or other permits. As of the date of these Listing Particulars, there are no open instances of non-compliance with health and safety regulations. However, there can be no assurances that we will not incur material costs in the future, including clean-up costs, civil and criminal fines, penalties and sanctions and third-party claims, including for personal injury, wrongful death and environmental and property damages, and other environmental, health and safety claims under contract, as a result of violations of our obligations under environmental, health and safety requirements.

Further, health and safety and environmental laws and regulations may expose us to liability for the conduct of others and legal and regulatory changes that are applied retroactively may expose us to liability for acts that complied with all applicable health and safety and environmental laws and regulations when they were performed.

The terms and conditions of licenses, permits, permissions or other authorizations necessary for our operations may include more stringent environmental and/or health and safety requirements over time. Since our operations have the potential to impact air and water quality, biodiversity and ecosystems, obtaining exploration, development or production licenses and permits may become more difficult or may be delayed due to governmental, regional or local environmental consultation, scientific studies, approvals or other considerations or requirements.

We incur, and expect to continue to incur, substantial capital and operating costs in an effort to comply with increasingly complex health and safety and environmental laws and regulations and to develop and implement robust HSE&A systems to enable us to ensure compliance with all applicable requirements as the duty holder at many of our operated interests. Failure to comply with current health, safety and environment laws and regulations may result in regulatory action, the imposition of fines, penalties or sanctions or the payment of compensation to third parties which each could in turn have a material adverse effect on our business, prospects, financial condition and results of operations. Although we believe that being duty holder mitigates some of the risk associated with the lack of direct control over these conditions when the responsibility for them lies with other

entities, it may expose us to more direct liability for HSE&A conditions. Our asset integrity reviews continue to contribute in a positive manner by providing a deeper understanding of areas of improvement and good practice. The key focus through 2025 and into 2026 has been detailed analysis of key risk areas, including those relating to our activity on safety, sustainability and risk in support of our strategic purpose to provide effective solutions through the energy transition.

With regard to our operations in Malaysia, the PM8Extension PSC requires us as contractor to conduct an initial assessment of the environment, health and safety risks involved in the execution of petroleum operations in the relevant contract area. Under the PM8Extension PSC, we are also required to take appropriate measures to prevent any environment, health and safety incidents from occurring offshore and to minimize the consequences of such incidents in the event they do occur. We have to ensure that all our personnel are competent, fully trained, experienced, skilled and certified to carry out the tasks of operating all machinery, equipment and tools offshore, and that our personnel comply with Department of Occupational Safety and Health ("**DOSH**") and PETRONAS' environment, health and safety requirements and all safety manual policies and procedures. These requirements are subject to an annual audit by PETRONAS and/or Offshore Self-Regulation audit by us, and to the extent any gaps are identified, we will be required to ensure that all such gaps are addressed to DOSH and/or PETRONAS' satisfaction.

In Vietnam, the health, safety and environment standards for our operations are overseen under a multi-authorities framework. Among those, the Petroleum Law, administered by the MOIT, includes provisions on safety standards on petroleum activities that we are required to comply with, and the Law on Occupational Safety and Health 2015, administered by the Ministry of Home Affairs (previously known as Ministry of Labor, Invalids and Social Affairs (MOLISA)) requires all companies to formulate and implement an occupational safety and health management plan, conduct risk assessments of occupational safety and hygiene at the workplace, control of dangerous or harmful factors, and establish emergency response plans that are regularly updated and tested.

In Indonesia, the MEMR regulates the health and safety standards for our operations. Ditjen Migas is responsible for establishing and enforcing health and safety regulations for the industry, and SKK Migas oversees compliance with health and safety standards. The Ministry of Manpower is responsible for general occupational health and safety regulations across all industries in Indonesia.

New laws and regulations, the imposition of tougher requirements in licenses, increasingly strict enforcement of, or new interpretations of, existing laws, regulations and licenses, or the discovery of previously unknown contamination may require further expenditures to, for example:

- modify operations;
- install pollution control equipment;
- perform site clean ups;
- curtail or cease certain operations; or
- pay fees or fines or make other payments for pollution, discharges or other breaches of environmental requirements.

Although the costs of the measures taken to comply with environmental and health and safety regulations have not had a material adverse effect on our business, prospects, financial condition or results of operations to date, the costs of such measures and liabilities (including for any environmental damage caused by our operations in the future) may increase, which could materially and adversely affect our business, prospects, financial condition and results of operations. In addition, it is not possible to predict with certainty what future environmental and health and safety regulations will be enacted or how current or future environmental and health and safety regulations will be applied or enforced in the future. Environmental and health and safety laws may result in a curtailment of production and/or a material increase in the cost of production, development or exploration activities.

We are also affected by international treaties on the environment to which the United Kingdom is a party such as the OSPAR Convention. Controls on the quantities of oil that can be discharged in process waters in the course of offshore operations have been implemented in the United Kingdom by the Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005 (the "**OPPC**"). The OPPC was amended by the Offshore

Petroleum Activities (Oil Pollution Prevention and Control) (Amendment) Regulations 2011 which, among other things, extends the scope of the OPPC to apply to all emissions of oil from pipelines used for offshore oil and gas activities and for gas storage and unloading activities.

The Offshore Combustion Installations (Pollution Prevention and Control) Regulations 2013 (the "**PPC**") have been implemented in the United Kingdom and apply to all of our assets. Permits under the PPC have been issued to us by DESNZ (formerly part of BEIS). Applications for these PPC permits normally contain an energy efficiency survey. Energy efficiency surveys that we have conducted as part of the PPC application process have identified potential energy efficiency measures and other upgrades to the installations that may be implemented by us, which have been built into the assets' life-of-field opportunity registers maintained by us, for future investment opportunities for improved performance. We implemented a number of emission reduction opportunities in 2025 and plan to continue to do so through 2026. The costs associated with the PPC permit compliance and other measures to be undertaken may be material for us.

To the extent we incur material costs to comply with the HSE&A regulations, or as a result of liabilities under the HSE&A regulations, this could have a material adverse effect on our business, prospects, financial condition and results of operations.

We are exposed to the risk of violations of anti-corruption laws, related sanctions or other similar regulations

We operate in Malaysia, Vietnam, Indonesia and Brunei, which, like many countries in emerging markets, at times experience high levels of fraud, bribery and corruption. Particularly, oil and gas companies operating in locations such as Malaysia, Vietnam, Indonesia and Brunei may be targets of criminal, corruption or terrorist actions. Criminal, corruption or terrorist action against us and our assets or facilities could materially and adversely affect our business, prospects, financial condition and results of operations.

As a result, we are exposed to a risk of violating anti-corruption laws and sanctions regulations applicable in those countries where we or our joint venture partners or agents do business. Violations of anti-corruption laws and sanctions regulations may be punishable by civil penalties, including fines, denial of export privileges, injunctions, asset and bank account seizures, debarment from government contracts (and termination of existing contracts) and revocations or restrictions of licenses, disgorgements of profits or other gains as well as criminal fines and imprisonment. In addition, any major violations could have a significant impact on our reputation and consequently on our ability to win future business and could also adversely affect our access to financing. In particular, our international operations may be subject to anti-corruption laws and regulations such as the US Foreign Corrupt Practices Act of 1977, the United Kingdom Bribery Act of 2010 ("**United Kingdom Bribery Act**") and the local anti-corruption laws of any jurisdiction applicable to us. Furthermore, our international operations may be affected by sanctions and economic restrictions imposed by the United Kingdom Office of Financial Sanctions Implementation ("**OFSI**"), the United States Office of Foreign Assets Control ("**OFAC**"), the European Union, the United Nations, the World Bank, or other law enforcement agencies or sanctions authorities. Such sanctions or economic restrictions can affect our joint venture partners, host country governments or the oil sector of a host country government, suppliers and other stakeholders. While we review laws and regulations to determine if they are applicable to us, our employees, consultants, agents and third parties engaged by or performing services for us, there can be no guarantee that a court or other enforcement authority will reach the same determination as we do. If we are found to be subject to any laws or regulations which we considered were not applicable, our policies, procedures and actions may be in breach of such law or regulation and we may be subject to censure, prosecution, fine or other negative consequences. While we have what we believe to be appropriate internal policies and procedures, including a Code of Conduct, as well as contractual arrangements in place with our agents and joint venture partners which seek to prevent our agents or joint venture partners (as the case may be) from engaging in illegal or unethical activities, there can be no guarantee our agents or joint venture partners (as the case may be) adhere to such contractual arrangements or policies and procedures and, if they do not, that we will be made aware of any breaches or potential breaches in a timely manner or at all. However, we may, nonetheless, remain liable for the unauthorized actions of our agents or joint venture partners (as the case may be).

In addition, even where we have compliant anti-corruption and other business ethics policies and procedures and we monitor compliance with such policies and procedures, there can be no assurance that such policies and procedures have been or will be followed at all times or have or will effectively detect and prevent all violations of the applicable laws and every instance of fraud, bribery and corruption in every jurisdiction in which one or more of our employees, consultants, agents, joint venture partners, contractors or sub-contractors is located. As a result, we could be subject to penalties and reputational damage, which could have a material adverse

effect on our business, prospects, financial condition and results of operations if we, our employees, agents or other parties we do business with or who have performed services for us have failed or fail to prevent any such violations or are or become the subject of investigations into potential violations.

If adverse investigations or findings are made, either erroneously due to differing but legal business norms or substantiated in the future, against us, our directors, officers, employees or joint venture partners, or such persons or their respective partners are found to be involved in corruption or other illegal activity, this could result in criminal or civil penalties, including substantial monetary fines, against our directors, officers, employees or joint venture partners. Any such investigations or findings, either erroneous or substantiated in the future, could damage our reputation with our investors, potential investors, joint venture partners or potential joint venture partners and our ability to do business, including by affecting our rights under our various production sharing contracts and joint operating agreements or by the loss of key personnel, and could materially and adversely affect our business, prospects, financial condition and results of operations. We may also be subject to allegations of corrupt practices or other illegal activities, which, even if subsequently proved to be unfounded, may damage our reputation and require significant expense and management time to investigate. Furthermore, alleged or actual involvement in corrupt practices or other illegal activities by our joint venture partners, or others with whom we conduct business could also damage our reputation and business and materially and adversely affect our business, prospects, financial condition and results of operations.

Our internal systems may be subject to intentional and unintentional disruption, and our confidential information may be misappropriated, stolen or misused, which could adversely impact our reputation and future sales

We are exposed to risks arising from interruption to or failure of IT infrastructure. The risks of disruption to normal operations range from loss in functionality of generic systems (such as email and internet access) to the compromising of more sophisticated systems that support our operational activities. These risks could result from malicious interventions such as cyber-attacks or phishing exercises designed to penetrate our network security or the security of our internal systems, misappropriate proprietary information and/or cause interruptions to our services. Such attacks could include hackers obtaining access to our systems, the introduction of malicious computer code or denial of service attacks. If an actual or perceived breach of our network security occurs, it could adversely affect our business or reputation, and may expose us to the loss of information, litigation and possible liability. Such a security breach could also divert the efforts of our technical and management personnel. In addition, such a security breach could impair our ability to operate our business. If this happens, our reputation could be harmed, our revenues could decline and our business could suffer. For example, we were subject to a cybersecurity incident in November 2025 that involved a breach of a third party-hosted file transfer protocol server based in Malaysia. Remedial actions have been taken to address vulnerabilities. Our internal systems were not compromised by the incident.

In addition, confidential information that we maintain may be subject to misappropriation, theft and deliberate or unintentional misuse by current or former employees, third-party contractors or other parties who have had access to such information. Any such misappropriation and/or misuse of our information could result in us, among other things, being in breach of certain data protection and related legislation. We expect that we will need to continue closely monitoring the accessibility and use of confidential information in our business, educate our employees and third-party contractors about the risks and consequences of any misuse of confidential information and, to the extent necessary, pursue legal or other remedies to enforce our policies and deter future misuse.

We collect, store and use personal data in the ordinary course of our business operations, and are therefore subject to data protection legislation (including the General Data Protection Regulation (EU 2016/679)). Non-compliance or technical defects resulting in a leak or the misuse of such data could result in fines, damage to our reputation and/or otherwise harm our business.

We do not register trademarks, service marks and trade names that we use in conjunction with the operation of our business

The image and reputation of our company constitutes a significant part of our business. We do not currently register trademarks, service marks and trade names that we use in our business, including the "EnQuest" name and logo. In addition, we cannot assure you that third parties will not infringe on or misappropriate our rights or assert rights in, or ownership of, our trademarks and other intellectual property rights or in trademarks that are similar to trademarks that we use. Litigation may be necessary to enforce our intellectual property rights

or to defend ourselves against claimed infringement of the rights of third parties. If we are unable to protect our intellectual property rights against infringement or misappropriation, or if others assert rights in or seek to invalidate our intellectual property rights, this could materially harm our future financial results and our ability to develop our business.

We may be subject to work stoppages or other labor disturbances, and our employees may become unionized

Work stoppages or other labor disturbances, such as industrial action, with our employees or those of our contractors, suppliers and customers, may occur in the future. Such disturbances could have a material adverse effect on our production and development activities in the periods during which they occur. In addition, our employees, and those employed by our contractors, may become members of or represented by labor unions. If this occurs, we or our contractors may not be able to negotiate acceptable collective bargaining agreements or future restructuring agreements or may become subject to material cost increases or additional work rules imposed by such agreements.

For example, have been the operator of SVT since December 1, 2017 and the technicians employed at SVT, comprising approximately 70% of SVT employees, are covered by a collective agreement with the union UNITE.

Disturbances to our work practices could have a material adverse impact on our production and development activities in the periods during which they occur. In addition, our employees, and those employed by our contractors, may become members of or represented by labor unions. If this occurs, we or our contractors may not be able to negotiate acceptable collective bargaining agreements or future restructuring agreements or may become subject to material cost increases or additional work rules imposed by such agreements.

The occurrence of any of the foregoing could materially and adversely affect our business, prospects, financial condition and results of operations.

Our tax liability is subject to estimation and we may be adversely affected by changes to tax legislation or its interpretation or increases in effective tax rates in the jurisdictions in which we do business

We are subject to corporate income taxes, corporation tax, the supplementary charge ("**SCT**") and EPL in the U.K. as well as petroleum and corporate income taxes in Malaysia, Vietnam, Indonesia and Brunei. Fluctuations in these tax rates can have an impact on projects and make certain projects less economically viable. Our tax rate, including our effective tax rate and VAT, may be affected by changes in tax laws or interpretations of tax laws in any jurisdiction in which we operate and in any financial year will reflect a variety of factors that may not be present in succeeding financial years.

During periods of high profitability in the oil industry, there are often calls for increased or windfall taxes on oil revenue. Taxes have increased or been imposed in the past and may increase or be imposed again in the future.

For example, during 2022, the U.K. government introduced, and subsequently expanded, the EPL on the profits earned from the production of oil and gas in the U.K. The EPL is currently charged at the rate of 38% on taxable profits in addition to ring fence corporation tax ("**RFCT**") of 30% and the SCT of 10%. The U.K. Chancellor announced in the 2024 Spring Budget that the sunset clause for the Energy Profits Levy (providing for the date of its expiry) would be extended to March 31, 2029. The U.K. Chancellor also confirmed in the Autumn Budget 2025 new plans for the Oil and Gas Price Mechanism ("**OGPM**") to replace the Energy Profits Levy. The Energy Profits Levy is currently due to end on March 31, 2030 (following a further extension to the sunset clause), or earlier if both the oil and gas price triggers under the Energy Security and Investment Mechanism (introduced in 2024) are satisfied beforehand in which case the Energy Profits Levy will cease immediately and the new OGPM will come into effect. The price triggers relate to the satisfaction of both (i) the six-month average price falling below $78.65 per barrel for oil and (ii) the six-month average price falling below £0.61 per therm for gas (set for the financial year to March 31, 2027). Like the Energy Profits Levy, the OGPM will act as a windfall tax when oil and gas prices are unusually high. The OGPM will be revenue-based and apply an additional tax rate of 35% above price thresholds of $90 per barrel for oil and £0.90 per therm for gas. The U.K. Government intends to legislate for the OGPM as part of the Finance Bill 2026-2027. See "*Industry and market data—The UKCS—Oil & Gas Price Mechanism ("OGPM")*". Depending on the final design, any replacement mechanism could have an impact on our effective tax rate and cash tax payments during periods of unusually high prices.

Further, changes to global tax laws could adversely affect the Group's tax profile. The OECD and many countries and organizations, have proposed, recommended or (in the case of certain countries) enacted changes to existing tax laws or new tax laws that address issues related to the taxation of multinational corporations. One example is Pillar Two of the OECD's "BEPS 2.0" initiative, which is aimed at ensuring all companies pay a global minimum tax. The United Kingdom enacted legislation implementing the OECD's minimum tax rules effective January 1, 2024. Several other countries have also adopted or proposed legislation to implement the OECD's minimum tax proposal. As a result of these developments and similar developments in other jurisdictions, the tax laws of certain countries in which we do business could change on a prospective or retroactive basis, and any such change could significantly increase our tax obligations in the countries in which we will do business or require us to change the manner in which we operate our business, which may adversely affect our business, prospects, financial condition and results of operations.

Taxes may increase or be imposed again in the future. As a result, our tax rate may increase or tax allowances may be withdrawn or curtailed in future periods, which could have a material adverse effect on our financial results and, specifically, our net income, cash flow and earnings may decrease.

Tax regimes in certain jurisdictions can be subject to differing interpretations and tax rules in any jurisdiction are subject to legislative change and changes in administrative and regulatory interpretation. The interpretation by our relevant subsidiaries of applicable tax law as applied to their transactions and activities may not coincide with that of the relevant tax authorities. As a result, transactions may be challenged by tax authorities and any of our profits from activities in those jurisdictions in which we operate may be subject to additional tax or additional unexpected transactional taxes (*e.g.*, stamp duty, VAT or capital gains tax), which, in each case, could result in significant legal proceedings and additional taxes, penalties and interest, any of which could have a material adverse effect on our business, prospects, financial condition and results of operations. In addition, taxing authorities could review and question our tax returns leading to additional taxes and penalties which could be material.

Additionally, our tax provision is subject to estimation. In the U.K., we prepare our tax provision before we file our U.K. corporation tax and supplementary charge returns with HMRC and thus we must make estimates and judgments on factors in the tax provision process. Such estimates and judgments include those required in calculating the effective tax rate. In considering the tax on exceptional items, we apply the appropriate statutory tax rate to each exceptional item to calculate the relevant tax charge. We also make judgments and assumptions regarding the likelihood of future taxable profits and the amount of deferred tax that can be recognized on unused tax losses where it is probable that future taxable profits will be available for utilization. Although we do not expect to pay material U.K. cash corporation tax on operational activities within the ring fence for the foreseeable future, there can be no assurances that we will not be required to pay taxes under current or future laws.

We and/or our field partners may not have good title to all our and/or their assets and licenses

There can be no assurance that we and/or our field partners have good title to all our and/or their assets and the rights to explore for, develop and produce oil from such assets. Moreover, our predecessors from which we acquired our interests in our assets may not have had good title to those interests.

There may be disputes concerning the validity of our production and exploration licenses in the UKCS, Malaysia, Vietnam, Indonesia, Brunei and in other countries in the future. Changing regulatory and environmental conditions may create disputes with the DESNZ in the United Kingdom or other oil companies with operations in the UKCS. If such disputes concerning the validity of licenses or title to assets are determined adversely against us and/or our field partners, such assets or licenses could be taken away or revoked and/or we could be subject to fines or sanctions without any form of compensation. See "*Regulation—United Kingdom*." Similarly, the same may occur with other regulatory bodies and oil companies in other countries where we currently have assets or interests (currently Malaysia, Vietnam, Indonesia and Brunei). See "*Regulation*."

The occurrence of any of the foregoing could materially and adversely affect our business, prospects, financial condition and results of operations.

Our international operations will require us to comply with various regulatory regimes and subject us to the challenges of running a business with global operations

We currently operate our business in the United Kingdom, Malaysia, Vietnam, Indonesia and Brunei. Accordingly, we are subject to political, economic and social factors affecting South East Asia, regional

diplomatic developments affecting South East Asia, potential cultural and language barriers, and changes in Malaysian, Vietnamese, Indonesian and Bruneian laws, taxation, regulations and policies implemented by the local government from time to time. In addition, our South East Asian operations are potentially subject to some or all of the following risks of doing business internationally, among others:

- foreign laws and governmental regulation, including those governing tax, worker immigration and customs;
- expropriation, confiscatory taxation and nationalization of our assets located in areas in which we operate;
- unfavorable changes in foreign monetary and tax policies, and unfavorable and inconsistent interpretation and application of foreign tax laws;
- increased risk around the security of staff and assets; and
- foreign currency fluctuations and restrictions on currency repatriation.

Our Malaysian, Vietnamese, Indonesian and Bruneian operations are subject to the laws and regulations of Malaysia, Vietnam, Indonesia and Brunei, respectively. If the existing body of laws and regulations in any of these countries are interpreted or applied, or relevant discretions exercised, in an inconsistent manner by the courts or applicable regulatory bodies, this could result in ambiguities, inconsistencies and anomalies in the enforcement of such laws and regulations, which in turn could hinder our long-term planning efforts and may create uncertainties in our operating environment. Additionally, our ability to compete in South East Asian markets may be adversely affected by governmental regulations, disagreements on jurisdiction or other policies that favor the awarding of contracts to contractors in which nationals of those countries have substantial ownership interests. Our South East Asian operations may face governmentally imposed restrictions or taxes from time to time on the transfer of funds to us.

Various national and local taxing authorities may also periodically examine our operations. Such examinations, including audits, may result in an assessment of additional taxes and other costs payable in relation to prior periods.

Any acts of terrorist activity, piracy, social and civil unrest, political upheaval and armed conflicts causing disruptions of oil and gas exports could materially and adversely affect our business, prospects, financial condition and results of operations.

Certain emerging and developing market economies have been, and may continue to be, adversely affected by market downturns and economic slowdowns elsewhere in the world. As has happened in the past, financial problems outside countries with emerging or developing economies or an increase in the perceived risks associated with investing in such economies could discourage foreign investment in and adversely affect the economies of these countries (including countries in which we have assets).

Risks relating to the Notes and our structure

Our leverage and debt service obligations could adversely affect our business, financial condition, results of operations and our ability to satisfy our obligations under our debt, including the Notes and the Note Guarantees

As of December 31, 2025, on a *pro forma* basis after giving effect to the Transactions, we would have had an aggregate principal amount of $912.8 million of unsecured debt outstanding, $675.0 million of which would have been represented by the Notes, $179.4 million of which would have been represented by the 9% Retail Notes, $22.1 million of which would have been represented by the Vendor Loan Facility and $36.3 million related to the SVT Working Capital Facility. As of December 31, 2025, letter of credit utilization under Facility B (as defined herein) of the RBL Facility Agreement was $381.5 million, with $18.5 million residual availability thereunder. Facility A (as defined herein) of the RBL Facility Agreement was undrawn. We will be permitted to borrow substantial additional indebtedness, including secured debt, in the future under the terms of the Indenture.

The degree to which we are leveraged could have important consequences to our business and holders of the Notes, including but not limited to:

- making it difficult for us to satisfy our obligations with respect to the Notes or our other indebtedness;
- increasing our vulnerability to, and reducing our flexibility to respond to, general adverse economic and industry conditions;
- requiring the dedication of a substantial portion of our cash flow from operations to make interest and principal payments on our debt, thereby reducing the availability of such cash flow for other purposes;
- limiting our ability to obtain additional financing to fund working capital, capital investments, acquisitions, debt service requirements, business ventures, or other general corporate purposes;
- limiting our flexibility in planning for, or reacting to, changes in our business, the competitive environment and the industry in which we do business; and
- adversely affecting our competitive position due to our debt burden being higher than that of our competitors.

Any of these or other consequences or events could have a material adverse effect on our business, financial condition and results of operations and our ability to satisfy our obligations under the Notes.

Despite our current level of debt, we may incur substantially more debt in the future, which may make it difficult for us to service our debt, including the Notes

We and our subsidiaries may incur substantial additional indebtedness in the future, including secured indebtedness and indebtedness that is structurally senior to the Notes, which may, among other things, relate to our strategy of delivering transformative transactions. See "*—Risks related to our business—Our strategy of delivering sustainable and transformative growth through transformative consolidation transactions may increase our debt and the complexity of our operations*." Although the Indenture, the 9% Retail Notes and the RBL Facility Agreement contain restrictions governing the incurrence of additional indebtedness, these restrictions are subject to a number of significant qualifications and exceptions and the amount of indebtedness that could be incurred in compliance with these restrictions could be substantial. If we or our subsidiaries incur new debt or other obligations, the related risks that we face, as described in "*—Our leverage and debt service obligations could adversely affect our business, financial condition, results of operations and our ability to satisfy our obligations under our debt, including the Notes and the Note Guarantees*" and elsewhere in these "*Risk factors*," could increase. In addition, the Indenture and the RBL Facility Agreement will not prevent us from incurring obligations that do not constitute indebtedness as defined under those agreements, including in respect of letters of credit and other contingent obligations.

Our non-Guarantor subsidiaries may also incur substantial additional indebtedness in the future, further increasing the risks associated with leverage. If any of our non-Guarantor subsidiaries incur additional indebtedness, the holders of that debt will be entitled to any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of such subsidiaries ahead of the holders of the Notes ("**Noteholders**"). See "*—The Notes and Note Guarantees will be structurally subordinated to the liabilities and preference shares (if any) of our non-Guarantor subsidiaries*."

For further information regarding our leverage and for more information about our outstanding indebtedness, see "*Management's discussion and analysis of financial condition and results of operations*" and "*Description of certain financing arrangements*."

We require a significant amount of cash to service our debt and sustain our operations, and our ability to generate sufficient cash depends on many factors beyond our control

Our ability to make payments on, or repay or refinance, our debt, and to fund working capital and capital investments, will depend on our future operating performance and ability to generate sufficient cash. This depends on the success of our business strategy and on general economic, financial, competitive, market, legislative, regulatory, technical and other factors as well as the risks discussed in these "*Risk factors*," many of which are beyond our control. In addition, our ability to borrow funds in the future to make payments on our debt will depend on the satisfaction of the covenants in the RBL Facility Agreement and our other debt agreements, including the

Indenture, and other agreements we may enter into in the future. Specifically, we are only permitted to draw under the RBL Facility if no default or event of default is continuing or would result from the utilization and certain representations and warranties are true in all material respects. Therefore, we cannot assure you that our business will generate sufficient cash flow from operations or that future debt and equity financings will be available to us in an amount sufficient to enable us to pay our debt, including the Notes, or to fund our other liquidity needs.

Prior to repayment of the Notes, we will be required to refinance or repay certain other debt, including debt under the RBL Facility. See "*Management's discussion and analysis of financial condition and results of operations*." We cannot assure you that we will be able to refinance or repay any of our debt, including the Notes, on commercially reasonable terms or at all. Any refinancing of our debt could be at higher interest rates than our current debt and may require us to comply with more onerous covenants, which could further restrict our business operations. If we are unable to make payments or refinance our debt or obtain new financing under these circumstances, we would have to consider other options, such as:

- selling assets;
- seeking to raise additional capital;
- restructuring or refinancing all or a portion of our debt on or before maturity;
- foregoing opportunities such as acquisitions of other businesses; or
- reducing or delaying our business activities and capital investments.

We cannot assure you that we would be able to accomplish any of these alternatives on a timely basis or on commercially reasonable terms, if at all. Any failure to make payments on our debt, including the Notes, on a timely basis would likely result in a reduction of our credit rating, which could also harm our ability to incur additional indebtedness. In addition, the terms of our debt, including the Indenture and the RBL Facility Agreement, limit and any future debt may also limit, our ability to pursue any of these alternatives. There can be no assurance that any assets that we may elect to sell can be sold or that, if sold, the timing of such sale will be acceptable and the amount of proceeds realized will be sufficient to satisfy our debt service and other liquidity needs. If we are unsuccessful in any of these efforts, we may not have sufficient cash to meet our obligations, which could cause an event of default under our debt and result in:

- our debt holders declaring all outstanding principal and interest to be immediately due and payable;
- the lenders under the RBL Facility Agreement being able to terminate their commitments to lend us money and foreclose against the assets securing our borrowings thereunder; and
- our being forced into bankruptcy or liquidation, which could result in you losing your investment in the Notes.

We are subject to restrictive debt covenants that may limit our ability to finance our future operations and capital needs and to pursue business opportunities and activities

The Indenture, the 9% Retail Notes and the RBL Facility Agreement restrict, among other things, our ability to:

- incur additional debt and issue guarantees and preferred stock;
- make certain payments, including dividends and other distributions, with respect to outstanding share capital;
- repay or redeem subordinated debt or share capital;
- create or incur certain liens;
- in the case of the Indenture, impose restrictions on the ability of our subsidiaries to pay dividends or make other payments to the Company and other subsidiaries;

- make certain investments or loans;
- sell, lease or transfer certain assets, including shares of any of our restricted subsidiaries;
- in the case of the Indenture, guarantee certain types of our other indebtedness without also guaranteeing the Notes;
- expand into unrelated businesses;
- merge or consolidate with other entities; and
- enter into certain transactions with affiliates.

All these limitations are subject to significant exceptions and qualifications. See "*Description of Notes—Certain covenants*." Our compliance with these covenants could reduce our flexibility in conducting our operations, particularly by:

- affecting our ability to react to changes in market conditions, whether by increasing our vulnerability in relation to unfavorable economic conditions or by preventing us from profiting from an improvement in those conditions;
- affecting our ability to pursue business opportunities and activities that may be in our interest;
- limiting our ability to obtain certain additional financing in order to meet our working capital requirements, make investments or acquisitions and carry out refinancings; and
- forcing us to dedicate a significant portion of our cash flows to payment of the sums due for such loans, thus reducing our ability to utilize our cash flows for other purposes.

In addition, we are subject to affirmative and financial covenants contained in the RBL Facility Agreement, including the requirement to maintain a specified ratio of consolidated net financial indebtedness to adjusted EBITDAX. See "*Description of certain financing arrangements*." Our ability to meet financial ratios and other tests can be affected by events beyond our control, and we cannot assure you that we will meet them. A breach of any of those covenants, ratios, tests or restrictions could result in an event of default under the Indenture or the RBL Facility Agreement. Upon the occurrence of any event of default under the RBL Facility Agreement, subject to applicable cure periods and other limitations on acceleration or enforcement, the relevant creditors could cancel the availability of the facilities and elect to declare all amounts outstanding, together with accrued interest, immediately due and payable. Furthermore, the RBL Facility Agreement limits or prohibits us from withdrawing funds from bank accounts that consist of amounts that we have received in connection with certain assets or any disposal of such assets or of any subsidiary that holds, whether directly or indirectly, any such asset. In addition, any default under the 9% Retail Notes or the RBL Facility Agreement could lead to an event of default and acceleration under other debt instruments that contain cross-default or cross-acceleration provisions, including the Indenture. If our creditors, including the creditors under the 9% Retail Notes and the RBL Facility accelerate the payment of those amounts, we cannot assure you that our cash flow or our assets and the assets of our subsidiaries would be sufficient to repay in full such amounts, to satisfy all other liabilities of our subsidiaries which may be due and payable and to repay amounts outstanding under the Notes. If we are unable to repay the amounts due and payable under the RBL Facility, our creditors thereunder could proceed against the collateral that secures such debt. Accordingly, we could be forced into bankruptcy or liquidation, and the Company and Guarantors may not be able to fulfill their respective obligations under the Notes and the Note Guarantees.

Certain of our borrowings bear interest at floating rates, which could rise significantly, thereby increasing our interest cost and reducing cash flow

A portion of our indebtedness, including borrowings under the RBL Facility, bear interest at per annum rates which are not fixed. Interest rates could rise significantly in the future, thereby increasing our interest expenses associated with these obligations, reducing cash flow available for capital investments and limiting our ability to make payments on the Notes. Although we have entered into certain hedging arrangements designed to fix a portion of these rates and may continue to do so, there can be no assurance that hedging will be available or continue to be available on commercially reasonable terms. In addition, hedging itself carries certain risks, including that we may need to pay a significant amount (including costs) to terminate any hedging arrangements.

The Company is a holding company that has no revenue generating operations of its own and will depend on cash from its operating companies to be able to make payments on the Notes

The Company is a holding company with no business operations or significant assets other than the equity interests it holds in its subsidiaries and certain intercompany loans. Following the Transactions, the Company's material liabilities will be the Notes, amounts outstanding under the 9% Retail Notes and any amounts outstanding under the RBL Facility. The Company will be dependent upon cash flows from its operating subsidiaries in the form of loans, dividends or other distributions and payments to meet its obligations, including its obligations under the Notes. However, subsidiaries of the Company that do not guarantee the Notes have no obligation to pay amounts due under the Notes or to make funds available for that purpose. If our subsidiaries do not distribute cash to the Company to make scheduled payments on the Notes, the Company may not have any other source of funds that would allow it to make payments to holders of the Notes.

The amounts of dividends and distributions available to the Company will depend on the profitability and cash flow of its subsidiaries, which, in turn, will be affected by all the factors discussed in these "*Risk factors*" and elsewhere in these Listing Particulars. Even if the subsidiaries of the Company have sufficient cash available, they may be restricted or prevented from distributing dividends or advancing upstream loans to the Company to make payments in respect of its indebtedness, including the Notes. Various agreements governing our debt may restrict, and in some cases, may prevent the ability of the subsidiaries to move cash within their restricted group. Applicable laws may also limit the amounts that our subsidiaries will be permitted to pay as dividends or distributions on their equity interests, or even prevent such payments. Such laws include financial assistance rules, corporate benefit laws, requirements that dividends must be paid out of reserves available for distribution and other legal restrictions which, if violated, might require the recipient to refund unlawful payments. Therefore, even if the Company and its subsidiaries, in aggregate, have sufficient resources to meet their obligations, they may not be permitted to make the necessary transfers from the entity or entities with funds to the entity owing the obligations under the Notes or the Note Guarantees. Applicable tax laws may also subject such payments to further taxation.

Although the Indenture will limit the ability of our restricted subsidiaries to enter into future consensual restrictions on their ability to pay dividends and make other payments to the Company, there are significant qualifications and exceptions to these limitations. Arrangements with the Company's subsidiaries and the funding permitted by the agreements governing existing and future indebtedness of the Company's subsidiaries may not provide the Company with sufficient dividends, distributions and loans to fund payments on the Notes when due. See "*Description of certain financing arrangements*" and "*Description of Notes*."

Each of the Note Guarantees will be subordinated to our existing and future senior debt

The Note Guarantees will each be the senior subordinated obligations of the Guarantors and:

- contractually subordinated in right of payment to all existing and future senior obligations of that Guarantor, including such Guarantor's obligations under the 9% Retail Notes and the RBL Facility;
- *pari passu* in right of payment with all existing and future senior subordinated obligations of that Guarantor;
- senior in right of payment to all future obligations of that Guarantor that are expressly contractually subordinated to that Guarantor's Note Guarantee;
- structurally subordinated to all existing and future obligations of such Guarantor's subsidiaries that do not guarantee the Notes; and
- effectively subordinated to all existing and future secured obligations of that Guarantor (including under the RBL Facility), to the extent of the value of the property and assets securing such obligations, unless such assets also secure the Note Guarantees on an equal and ratable or senior basis.

See "*Description of certain financing arrangements—Guarantee Subordination Agreement" and "Description of Notes*."

In addition, no enforcement action with respect to the Note Guarantees (or any future guarantee of the Notes) may be taken unless (subject to certain limited exceptions): (i) any enforcement action has been taken with respect to a Guarantor in relation to our senior debt (provided that the Trustee on its own behalf and on behalf of the holders of the Notes will be limited to taking the same action against that same Guarantor); (ii) certain insolvency, liquidation or other similar enforcement events with respect to a Guarantor have occurred and such actions are taken with respect to such Guarantor (subject to certain limited exceptions) or (iii) there is a continuing event of default under the Notes after a period of 179 days (or earlier in limited circumstances) from the date the agents with respect to our senior debt received written notice of such default. See "*Description of certain financing arrangements—Guarantee Subordination Agreement*."

Upon any distribution to the creditors of a Guarantor in a liquidation, administration, bankruptcy, moratorium of payments, dissolution or other winding-up of such Guarantor, the holders of senior debt of such Guarantor will be entitled to be paid in full before any payment may be made with respect to the Guarantor's Note Guarantee. In addition, any amount available for distribution to the Noteholders after senior creditors of such Guarantor, including lenders under the RBL Facility, have been repaid in full would be shared on a *pro rata* basis with other creditors of such Guarantor who also benefit from a senior subordinated guarantee of such Guarantor. As a result, holders of the Notes may receive less than the holders of senior debt of the Guarantors and may not be able to recover their investment in full.

There are circumstances other than repayment or discharge of the Notes under which the Note Guarantees will be released automatically, without your consent or the consent of the Trustee

Under various circumstances, the Note Guarantees will be released automatically, including:

- in connection with any sale or other disposition of all or substantially all the properties or assets of the respective Guarantor (including by way of merger, amalgamation or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a restricted subsidiary of the Company, if the sale or other disposition does not violate the "*Asset Sale*" provisions of the Indenture;

- in connection with any sale or other disposition of the capital stock of the respective Guarantor (whether by direct sale or through a holding company) to a person that is not (either before or after giving effect to such transaction) the Company or a restricted subsidiary of the Company, if the sale or other disposition does not violate the "*Asset Sale*" provisions of the Indenture and as a result of such disposition such Guarantor no longer qualifies as a subsidiary of the Company;

- if the Company designates the respective Guarantor (or any parent entity thereof) as an unrestricted subsidiary in accordance with the applicable provisions of the Indenture;

- upon repayment in full of the Notes or upon Legal Defeasance or Covenant Defeasance as described under the "*Legal defeasance and covenant defeasance*" provisions of the Indenture or upon satisfaction and discharge of the Indenture as described under the "*Satisfaction and discharge*" provisions of the Indenture;

- upon release or discharge of the guarantee by, or direct obligation of, such Guarantor that resulted in the creation of such Guarantee;

- upon the liquidation or dissolution of the respective Guarantor; *provided* that no default or event of default has occurred or is continuing;

- as described under the "*Amendment, supplement and waiver*" provision of the Indenture;

- upon the occurrence of certain events constituting a "Permitted Reorganization" under the Indenture, which includes certain events defined as constituting an "Eligible JV Transaction," including certain disposals of capital stock of the respective Guarantor, and certain joint venture and farm-out arrangements; or

- upon the respective Guarantor consolidating or amalgamating with, merging into or transferring all its properties or assets to the Company or another Guarantor, and as a result of, or in connection with, such transaction such Guarantor dissolving or otherwise ceasing to exist.

In addition, the Note Guarantees will be subject to release in connection with certain enforcement actions taken by the security trustee or certain creditors under the Guarantee Subordination Agreement. The Guarantee Subordination Agreement provides that the security trustee or certain creditors named therein shall not, in an enforcement scenario, exercise their rights to release the relevant Note Guarantees unless, with respect to the relevant sale or disposal:

- the proceeds of such sale or disposal are in cash (or substantially in cash);
- all present and future obligations owed to the creditors under certain senior finance documents by a member of our group are unconditionally released and discharged or sold or disposed of concurrently with such sale; and
- such sale or disposal (including any sale or disposal of any claim) is made:
  - (a) pursuant to a public auction; or
  - (b) where an independent investment bank or an internationally recognized firm of accountants selected by such security trustee has delivered an opinion to the trustee of the Notes in respect of such sale or disposal that the amount received in connection therewith is fair from a financial point of view taking into account all relevant circumstances including the method of enforcement and the circumstances giving rise to such sale.

Upon any release of a Note Guarantee by a Guarantor in connection with an enforcement sale as described above, senior creditors of such Guarantor would be entitled to be paid in full before any payment may be made to the holders of the Notes, who would share such proceeds on a *pro rata* basis with other creditors, benefitting from a senior subordinated guarantee of such Guarantor.

The Notes and Note Guarantees will be structurally subordinated to the liabilities and preference shares (if any) of our non-Guarantor subsidiaries

Some, but not all, of our subsidiaries will guarantee the Notes. Generally, claims of creditors of a non-Guarantor subsidiary, including trade creditors, and claims of preference shareholders (if any) of such subsidiary, will have priority with respect to the assets and earnings of such subsidiary over the claims of creditors of its parent entity, including claims by holders of the Notes under the Note Guarantees. In the event of any foreclosure, dissolution, winding-up, liquidation, reorganization, administration or other bankruptcy or insolvency proceeding of any of our non-Guarantor subsidiaries, holders of such subsidiary's indebtedness and its trade creditors will generally be entitled to payment of their claims in full from the assets of such subsidiary before any assets are made available for distribution to its parent entity as equity holder and the creditors of the Company and the Guarantors (including holders of the Notes) will have no right to proceed against such subsidiary's assets except claims as an equity holder to the extent the Company or any of the Guarantors is a direct parent entity of such subsidiary. As such, the Notes and Note Guarantees will be structurally subordinated to the creditors (including trade creditors) and preference shareholders (if any) of our non-Guarantor subsidiaries. Although our non-Guarantor subsidiaries currently represent only a small portion of our revenue and other operating income, the covenants in the Notes will permit these non-Guarantor subsidiaries to incur additional indebtedness, which may also be secured, and will not contain any limitation on the amount of other liabilities, such as trade payables, that may be incurred by these subsidiaries. In the future the revenue and other operating income of such entities could increase, possibly substantially.

As of and for the year ended December 31, 2025, our subsidiaries that are not Guarantors collectively represented 16% of our consolidated total assets. As of December 31, 2025 and on a *pro forma* basis after giving effect to the Transactions, such non-Guarantors were not obligors on any of our consolidated third-party debt, but were in some cases guarantors under the RBL Facility Agreement.

If the non-Guarantor subsidiaries were to incur significant indebtedness and/or grant security over their assets, there is a risk that this would diminish the assets available to the Noteholders should the Company become unable to make payments under the Notes. From time to time, we may conduct internal reorganizations, which may include the merger or liquidation of group entities, including Guarantors.

Claims of the secured creditors of the Company and the Guarantors will have priority with respect to their collateral over the claims of unsecured creditors, such as the holders of the Notes, to the extent of the value of the assets securing such indebtedness

Claims of the secured creditors of the Company and the Guarantors will have priority with respect to the assets securing their indebtedness over the claims of holders of the Notes. As such, the Notes and Note Guarantees will be effectively subordinated to any secured indebtedness and other secured obligations of the Company and the Guarantors (including obligations under the RBL Facility) to the extent of the value of the assets securing such indebtedness or other obligations (except to the extent such assets in the future also secure the Notes and/or the relevant Note Guarantees on an equal and ratable basis or priority basis). In the event of any foreclosure, dissolution, winding up, liquidation, reorganization, administration or other bankruptcy or insolvency proceeding of the Company or any Guarantor that has secured obligations, holders of secured indebtedness will have priority claims to the assets of the Company or such Guarantor that constitute their collateral (other than to the extent such assets in the future also secure the Notes or the relevant Note Guarantees on an equal and ratable basis or priority basis). Subject to the limitations referred to under the caption "*—Each Note Guarantee will be subject to certain limitations on enforcement and may be limited by applicable laws or subject to certain defenses that may limit its validity and enforceability*," the holders of the Notes will participate ratably with all holders of the unsecured indebtedness of the Company or the relevant Guarantor (other than our indebtedness to which the Note Guarantees have been expressly subordinated), and potentially with all their other general creditors, based upon the respective amounts owed to each holder or creditor, in the remaining assets of the Company or the relevant Guarantor. If any of the secured indebtedness of the Company or the relevant Guarantor becomes due or the creditors thereunder proceed against the operating assets that secure such indebtedness, our assets remaining after repayment of that secured indebtedness may not be sufficient to repay all amounts owing in respect of the Notes or the relevant Note Guarantee. As a result, holders of Notes may receive less, ratably, than holders of secured indebtedness of the Company or the relevant Guarantor.

The insolvency laws of England and Wales may not be as favorable to you as insolvency laws of jurisdictions with which you may be familiar and may preclude noteholders from recovering payments due on the Notes

The Company and certain of the Guarantors are organized under the laws of England and Wales. Future subsidiaries of the Company may be incorporated in other jurisdictions and are or may be subject to the insolvency laws of such jurisdictions. Moreover, pursuant to Regulation (EU) 2015/848 of the European Parliament and of the Council of May 20, 2015 on insolvency proceedings (recast) (the "**Recast EU Insolvency Regulation**"), if a company conducts business in more than one Member State of the European Union, the insolvency laws of the Member State (other than Denmark) in which such company's center of main interests ("**COMI**") is found may apply, which could be the laws of a Member State different from the jurisdiction of incorporation.

There are a number of factors that are taken into account to ascertain the COMI, which should correspond to the place where the company conducts the administration of its interests on a regular basis and is therefore ascertainable by third parties. The point at which this issue will be determined is at the time when the relevant insolvency proceedings are opened. The determination of where we or our subsidiaries have our or their COMI would be a question of fact on which the courts of the different EU Member States may have differing and even conflicting views. It should also be noted that no final decisions have been taken in cases that have been brought before the European Court of Justice in relation to questions of interpretation or the effects of the EU Insolvency Regulation throughout the European Union. Furthermore, a company's COMI is not a static concept and may change from time to time.

The insolvency laws of these jurisdictions may not be as favorable to your interests as creditors as the bankruptcy laws of United States, or certain other jurisdictions. If the Company or one or more of the Guarantors experiences financial difficulties, it is not possible to predict with certainty in which jurisdiction the insolvency or similar proceedings would first be commenced or how these proceedings would be resolved. The insolvency, administration and other laws of the jurisdictions in which the respective companies are organized or operate may be materially different from, or conflict with, each other. Any conflict between them could call into question whether, and to what extent, the laws of any particular jurisdiction should apply. There can be no assurance as to how the insolvency laws of these jurisdictions will be applied in relation to one another, which may adversely affect your ability to enforce your rights under the Notes and the Note Guarantees in those jurisdictions or limit any amounts that you may receive. In addition, the grant of the Note Guarantees by the respective Guarantors may be subject to challenge in the relevant local insolvency proceedings.

For a more detailed description of the insolvency laws relevant to the Company and the Guarantors, see "*Certain insolvency law considerations*."

Each Note Guarantee will be subject to certain limitations on enforcement and may be limited by applicable laws or subject to certain defenses that may limit its validity and enforceability

As of the Issue Date, the Guarantors will guarantee the obligations under the Notes on a senior subordinated basis. Each Note Guarantee will provide holders of the Notes with a direct claim against the relevant Guarantor. However, the Indenture will provide that each Note Guarantee will be limited to the maximum amount that can be guaranteed by the relevant Guarantor without rendering the relevant Note Guarantee voidable or otherwise limited or ineffective under applicable law or causing the officers of the Guarantor to incur personal civil or criminal liability, and enforcement of each Note Guarantee will be subject to certain generally defenses available to the Guarantors in the relevant jurisdiction. Although laws differ among jurisdictions, the laws and defenses generally include those that relate to corporate purpose or benefit, fraudulent conveyance or transfer, voidable preference, insolvency or bankruptcy challenges, financial assistance, preservation of share capital, thin capitalization, related third-party transactions, capital maintenance or similar laws, regulations or defenses affecting the rights of creditors generally. If one or more of these laws and defenses are applicable, a Guarantor may have no liability or decreased liability under its Note Guarantee depending on the amounts of its other obligations and applicable law. Limitations on the enforceability of judgments obtained in New York courts in the jurisdiction of incorporation or organization of a Guarantor could also limit the enforceability of the relevant Note Guarantee against such Guarantor.

Although laws differ among jurisdictions, in general, under bankruptcy or insolvency law and other laws, a court could (i) avoid or invalidate all or a portion of a Guarantor's obligations under its Note Guarantee, (ii) direct the holders of the Notes to return any amounts paid under a Note Guarantee to the relevant Guarantor or to a fund for the benefit of the Guarantor's other creditors or (iii) take other action that is detrimental to you, typically if the court found that:

- the relevant Note Guarantee was incurred with actual intent to give preference to one creditor over another, hinder, delay or defraud creditors or shareholders of the Guarantor or, in certain jurisdictions, when the granting of the Note Guarantee has the effect of giving a creditor a preference or when the recipient was aware that the Guarantor was insolvent when it granted the relevant Note Guarantee or became so as a result of it;

- the Guarantor did not receive fair consideration or reasonably equivalent value or corporate benefit for the relevant Note Guarantee and the Guarantor: (i) was insolvent or rendered insolvent because of the relevant Note Guarantee; (ii) was undercapitalized or became undercapitalized because of the relevant Note Guarantee; or (iii) intended to incur, or believed that it would incur, indebtedness beyond its ability to pay at maturity;

- the relevant Note Guarantee was not validly established or authorized or otherwise contravenes the relevant Guarantor's articles of association;

- the relevant Note Guarantee was held to exceed the corporate objects of the Guarantor or not to be in the best interests or for the corporate benefit of the Guarantor; or

- the amount paid or payable under the relevant Note Guarantee was in excess of the maximum amount permitted under applicable law.

These or similar laws may also apply to any future guarantee granted by any of our subsidiaries pursuant to the Indenture.

We cannot assure you which standard a court would apply in determining whether a Guarantor was "insolvent" at the relevant time or that, regardless of the method of valuation, a court would not determine that a Guarantor was insolvent on that date, or that a court would not determine, regardless of whether or not a Guarantor was insolvent on the date its Note Guarantee was issued, that payments to holders of the Notes constituted preferences, transactions at an undervalue, fraudulent transfers or conveyances on other grounds.

The measures of insolvency for purposes of fraudulent transfer laws vary depending upon applicable law. Generally, an entity would be considered insolvent if, at the time it incurred indebtedness:

- the sum of its liabilities, including contingent and prospective liabilities, is greater than the value of all its assets;

- the present fair saleable value of its assets is less than the amount required to pay the probable liability on its existing debts and liabilities, including contingent liabilities, as they become due; or

- it cannot pay its debts as they become due.

The liability of each Guarantor under its Note Guarantee will be limited to the amount that will result in such Note Guarantee not constituting a preference, transaction at an undervalue, fraudulent conveyance or improper corporate distribution or otherwise being set aside. There can be no assurance, however, as to what standard a court will apply in making a determination of the maximum liability of each Guarantor. There is a possibility that the entire Note Guarantee may be set aside, in which case the entire liability of such Guarantor may be extinguished.

If a court decided that a Note Guarantee was a preference, transaction at an undervalue, fraudulent transfer or conveyance and voided such Note Guarantee, or held it unenforceable for any other reason, you may cease to have any claim in respect of a relevant Guarantor and would be a creditor solely of the Company and, if applicable, of the other Guarantors under the relevant Note Guarantees which have not been declared void. If any Note Guarantee is invalid or unenforceable, in whole or in part, or to the extent the agreed limitation of the Note Guarantee obligations apply, the Notes would be effectively subordinated to all liabilities of the applicable Guarantor.

We may not be able to obtain the funds required to repurchase the Notes upon a change of control

The Indenture will contain provisions relating to certain events constituting a "change of control" of the Company. Upon the occurrence of certain events constituting a change of control, we will be required to offer to repurchase all outstanding Notes at a price equal to 101% of the principal amount thereof, plus accrued and unpaid interest and additional amounts, if any, to the date of repurchase.

If a change of control were to occur, we cannot assure you that we would have sufficient funds available at such time to pay the purchase price of the outstanding Notes or that the restrictions in the 9% Retail Notes, the RBL Facility Agreement, the Guarantee Subordination Agreement or our other existing contractual obligations would allow us to make such required repurchases. A change of control may result in an event of default under, or acceleration of, our indebtedness. For example, lenders under the RBL Facility Agreement may require the repayment of their respective loans outstanding thereunder upon the occurrence of a change of control. The repurchase of the Notes pursuant to such a change of control offer could also cause a default under our indebtedness, even if the change of control itself does not. The source of funds for any repurchase required will be available cash or cash generated from operating activities or other sources, including borrowings, sales of assets or sales of equity or funds provided by subsidiaries. The ability of the Company to receive cash from its subsidiaries to allow it to pay cash to the holders of the Notes following the occurrence of a change of control may be limited by our then existing debt instruments as well as applicable law. If we require third-party financing to make an offer to repurchase the Notes upon a change of control, we cannot assure you that we will be able to obtain such financing. Any failure by the Company to offer to purchase the Notes upon a change of control would constitute a default under the Indenture, which would, in turn, trigger a default under the RBL Facility Agreement. See "*Description of Notes—Repurchase at the option of holders—Change of control*."

The change of control provision contained in the Indenture may not necessarily afford you protection in the event of certain important corporate events, including a reorganization, restructuring, merger, recapitalization or other similar transaction involving us that may adversely affect you, because such corporate events may not involve a shift in voting power or beneficial ownership or, even if they do, may not constitute a "change of control" as defined in the Indenture. Except as described under "*Description of Notes—Repurchase at the option of holders—Change of control*," the Indenture will not contain provisions that would require the Company to offer to repurchase or redeem the Notes in the event of a reorganization, restructuring, merger, recapitalization or similar transaction.

The definition of "change of control" in the Indenture will include a disposition of all or substantially all the assets of the Company and its restricted subsidiaries, taken as a whole, to any person (subject to certain exceptions). Although there is a limited body of case law interpreting the phrase "all or substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances, there

may be a degree of uncertainty as to whether a particular transaction would involve a disposition of "all or substantially all" of the assets of the Company and its restricted subsidiaries taken as a whole. As a result, it may be unclear as to whether a change of control has occurred and whether the Company is required to make an offer to repurchase the Notes.

Enforcing your rights as a holder of the Notes or under the Note Guarantees across multiple jurisdictions may prove difficult or provide less protection than U.S. bankruptcy law and may preclude holders of the Notes from recovering payments due on the Notes

The Company is established under the laws of England and Wales and certain of the Guarantors are established under the laws of England and Wales and future Guarantors may be established under the laws of other jurisdictions. In the event of a bankruptcy, insolvency or similar event, proceedings could be initiated in England and Wales or any, all or any combination of the jurisdictions of future guarantors. Such jurisdictions may not be as favorable to investors as the laws of the United States or other jurisdictions with which investors are familiar, and proceedings in these jurisdictions are likely to be complex and costly for creditors and otherwise may result in greater uncertainty and delay regarding the enforcement of your rights. Your rights under the Notes and the Note Guarantees will be subject to the bankruptcy, insolvency and administrative laws of such jurisdictions and there can be no assurance that you will be able to effectively enforce your rights in such multiple, complex bankruptcy, insolvency or similar proceedings. See "*—Each Note Guarantee will be subject to certain limitations on enforcement and may be limited by applicable laws or subject to certain defenses that may limit its validity and enforceability*."

In the event that one or more of the Company, the Guarantors and any future Guarantor, if any, or any of our other subsidiaries experiences financial difficulty, the bankruptcy, insolvency, administrative and other laws of our and the Guarantors' jurisdictions of organization and location of assets may be materially different from, or in conflict with, each other and those of the United States, including in the areas of rights of creditors, priority of governmental and other creditors, ability to obtain post-petition interest and duration of the proceedings. The application of these laws, or any conflict among them, could call into question whether the law of any particular jurisdiction should apply, and may adversely affect your ability to enforce your rights under the Notes and the Note Guarantees in those jurisdictions or limit any amounts that you may receive. See "*Service of process and enforcement of civil liabilities*" with respect to certain of the jurisdictions mentioned above.

You may face currency exchange risks or adverse tax consequences by investing in the Notes denominated in currencies other than your reference currency

The Notes will be denominated and payable in U.S. dollars. If you are a pounds sterling, euro or other non-U.S. dollar investor, an investment in the Notes will entail currency exchange-related risks due to, among other factors, possible significant changes in the value of the U.S. dollar to pounds sterling, euro or other relevant currencies because of economic, political or other factors over which we have no control. Depreciation of the U.S. dollar against pounds sterling, euro or other relevant currencies could cause a decrease in the effective yield of the Notes below their stated coupon rates and could result in a loss to you when the return on the Notes is translated into the currency by reference to which you measure the return on your investments.

There may be tax consequences for you as a result of any foreign currency exchange gains or losses resulting from your investment in the Notes. You should consult your tax advisor concerning the tax consequences to you of acquiring, holding and disposing of the Notes.

Credit ratings may not reflect all risks, are not recommendations to buy or hold securities and may be subject to revision, suspension or withdrawal at any time

One or more independent credit rating agencies may assign credit ratings to the Notes. The credit ratings address our and the Company's ability to perform our obligations under the terms of the Notes and credit risks in determining the likelihood that payments will be made when due under the Notes. The ratings may not reflect the potential impact of all risks related to the structure, market, additional risk factors discussed above and other factors that may affect the value of the Notes. A credit rating is not a recommendation to buy, sell or hold securities and may be subject to revision, suspension or withdrawal by the rating agency at any time. No assurance can be given that a credit rating will remain constant for any given period of time or that a credit rating will not be lowered or withdrawn entirely by the credit rating agency if, in its judgment, circumstances in the future so warrant. A suspension, reduction or withdrawal at any time of the credit rating assigned to the Notes by one or more of the

credit rating agencies may adversely affect the cost and terms and conditions of our financings and could adversely affect the value and trading of the Notes.

The transferability of the Notes may be limited under applicable securities laws, which may adversely affect their liquidity and value

The Notes and the Note Guarantees have not been, and will not be, registered under the U.S. Securities Act or the securities laws of any state or any other jurisdiction. Therefore, you may not transfer or sell the Notes in the United States except pursuant to an exemption from, or a transaction not subject to, the registration requirements of the U.S. Securities Act and applicable state securities laws or laws of any other jurisdiction, or pursuant to an effective registration statement, and you may be required to bear the risk of your investment in the Notes for an indefinite period of time. The Notes are not being offered for sale in the United States except to "qualified institutional buyers" in accordance with Rule 144A, and we have not agreed to or otherwise undertaken to register the Notes with the U.S. Securities and Exchange Commission (including by way of an exchange offer). In addition, by acceptance of delivery of any Notes, the holder thereof agrees on its own behalf and on behalf of any investor accounts for which it has purchased the Notes that it shall not transfer the Notes in an aggregate principal amount of less than $200,000. It is the obligation of holders of the Notes to ensure that their offers and sales of the Notes within the United States and other countries comply with applicable securities laws. See "*Notice to investors*."

You may be unable to enforce judgments obtained in U.S. courts against the Company

The Company, the Guarantors and their respective subsidiaries are organized outside of the United States. Most of our directors and executive officers and the directors and executive officers of the Guarantors are non-residents of the United States and their respective assets will be located outside the United States. As a result, it may not be possible for investors to effect service of process within the United States upon the Company, the Guarantors or their respective directors and executive officers, or to enforce any judgments obtained in U.S. courts predicated upon civil liability provisions of the U.S. securities laws. Additionally, there is doubt as to the enforceability in many foreign jurisdictions of civil liabilities based on the civil liability provisions of the federal or state securities laws of the United States against entities and persons who are not residents of the United States. See "*Service of process and enforcement of civil liabilities*."

The Notes will initially be held in book-entry form, and therefore you must rely on the procedures of the relevant clearing systems to exercise any rights and remedies

The Notes will initially only be issued in global form and held through DTC. We refer to beneficial interests in such global notes as "**Book-Entry Interests**."

Interests in the global notes will trade in book-entry form only, and the Notes in definitive registered form, or Definitive Registered Notes, will be issued in exchange for Book-Entry Interests only in very limited circumstances. Owners of Book-Entry Interests will not be considered owners of the Notes. The nominee for DTC will be the sole registered holder of the global notes representing the Notes. Payments of principal, interest and other amounts owing on or in respect of the global notes representing the Notes will be made to Deutsche Bank Trust Company Americas, as principal paying agent, which will make payments to DTC. Thereafter, such payments will be credited to participants' accounts that hold Book-Entry Interests in the global notes representing the Notes and credited by such participants to indirect participants. After payment to DTC, none of the Company, the Guarantors, the Trustee or any paying agent will have any responsibility or liability for any aspect of the records relating to or payments of interest, principal or other amounts by DTC or to owners of Book-Entry Interests. Accordingly, if you own a Book-Entry Interest, you must rely on the procedures of DTC, and if you are not a participant in DTC, on the procedures of the participant through which you own your interest, to exercise any rights and obligations of a holder of the Notes under the Indenture.

Unlike holders of the Notes themselves, owners of Book-Entry Interests will not have the direct right to act upon our solicitations for consents, requests for waivers or other actions from holders of the Notes (including upon the occurrence of an event of default). Instead, if you own a Book-Entry Interest, you will be reliant on the nominee of DTC (as registered holder of the Notes) to act on your instructions and/or will be permitted to act directly only to the extent you have received appropriate proxies to do so from DTC or, if applicable, from a participant. We cannot assure you that procedures implemented for the granting of such proxies will be sufficient to enable you to vote on any requested actions or to take any other action (including to exercise your rights under the Notes) on a timely basis. See "*Book-entry, delivery and form*."

There may not be an active trading market for the Notes, in which case your ability to sell the Notes may be limited

The Notes are new securities for which there is currently no market. We cannot assure you as to:

- the liquidity of any market in the Notes;
- your ability to sell your Notes or
- the prices at which you may be able to sell your Notes.

Future trading prices for the Notes will depend on many factors, including the liquidity of the market for the Notes, prevailing interest rates, the market for similar securities and other factors, including general economic conditions and our own financial condition, performance and prospects, as well as third-party recommendations. Historically, the market for non-investment grade securities has from time to time been subject to disruptions that have caused substantial volatility in the prices of securities similar to the Notes. The liquidity of a trading market for the Notes will depend on the number of holders of the Notes and may be adversely affected by a general decline in the market for similar securities. In addition, the trading market for the Notes may attract different investors and this may affect the extent to which the Notes may trade. The Initial Purchasers have informed us that they intend to make a market in the Notes. However, they are not obligated to do so and may discontinue such market-making at any time without notice. As a result, we cannot assure you that an active trading market for the Notes will develop or, if one does develop, that it will be maintained, and any disruption in the trading market for the Notes may have a negative effect on your investment regardless of our prospects and financial performance. If no active trading market develops, you may not be able to resell your Notes at fair value, if at all.

The Notes may not remain listed on the Luxembourg Stock Exchange

Application has been made to list the Notes on the Official List of the Luxembourg Stock Exchange and admitted to trading on the Euro MTF market. However, there can be no assurance that the Notes will remain listed. If the Company cannot maintain the listing on the Luxembourg Stock Exchange and the admission to dealing on the Official List thereof, or if it becomes unduly burdensome to make or maintain such listing, the Company may cease to make or maintain such listing on the Official List of the Luxembourg Stock Exchange. Listing of the Notes on the Luxembourg Stock Exchange does not imply that a public offering of the Notes in Luxembourg has been authorized.

Certain covenants may be suspended upon the occurrence of a change in our ratings

The Indenture will provide that, if at any time following the date of the Indenture, the Notes receive a rating as follows by two of the following three rating agencies: Baa3 or better by Moody's, BBB- or better by Standard & Poor's or Fitch, and no default or event of default has occurred and is continuing, then beginning that day the following provisions of the Indenture will not apply to the Notes:

- "*Repurchase at the option of holders—Asset sales*";
- "*Certain covenants—Restricted payments*";
- "*Certain covenants—Incurrence of indebtedness and issuance of preferred stock*";
- "*Certain covenants—Dividend and other payment restrictions affecting subsidiaries*";
- "*Certain covenants—Designation of restricted and unrestricted subsidiaries*";
- "*Certain covenants—Transactions with affiliates*";
- "*Certain covenants—Limitation on guarantees of indebtedness by restricted subsidiaries*";
- clause (4) of the first paragraph of the covenant described under "*Certain covenants—Merger, consolidation or sale of assets*" and
- "*Certain covenants—Limitation on lines of business*."

Notwithstanding the foregoing, if the rating assigned by any such rating agency to such Notes should subsequently decline to below Baa3 or BBB-, as applicable, the foregoing covenants will be reinstituted as of and from the date of such rating decline. If these covenants were to be suspended, we would be able to incur additional debt or make payments, including dividends or investments, without restrictions under the Notes, which may conflict with the interests of holders of the Notes. There can be no assurance that the Notes will ever achieve an investment grade rating or that any such rating will be maintained.

The Indenture will not be qualified under the U.S. Trust Indenture Act of 1939, as amended

The Indenture will not be required to, and will not be, qualified under the U.S. Trust Indenture Act of 1939, as amended (the "**TIA**") and will not incorporate nor include and will not be subject to any of the provisions of the TIA. Consequently, the holders of Notes will not be entitled to the protections provided under the TIA to holders of debt securities issued under a qualified indenture, including those respecting preferential collections by the trustee or conflicting interests of the trustee. See "*Description of Notes*."

Investors in the Notes may have limited recourse against the independent auditors

The audit reports of Deloitte LLP relating to the group financial statements as of and for the years ended December 31, 2023, 2024 and 2025 reproduced herein, in accordance with guidance issued by the Institute of Chartered Accountants in England and Wales, state: "This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed."

The SEC would not permit such limiting language to be included in a registration statement or a prospectus used in connection with an offering of securities registered under the U.S. Securities Act or in a report filed under the U.S. Securities Exchange Act of 1934, as amended (the "**U.S. Exchange Act**"). If a U.S. court (or any other court) were to give effect to the language above, the recourse that holders of the Notes may have against the independent auditors based on their reports or the group financial statements to which they relate could be limited.

The Notes may be issued with original issue discount for U.S. federal income tax purposes

The Notes may be issued with OID for U.S. federal income tax purposes. If the stated principal amount of the Notes exceeds their "issue price" by an amount that is equal to or greater than the statutory *de minimis* amount, the Notes will be treated as issued with OID for U.S. federal income tax purposes in an amount equal to such difference. If the Notes are issued with OID, holders subject to U.S. federal income tax will generally be required to include such OID in gross income (as ordinary income) as it accrues (on a constant yield to maturity basis) for U.S. federal income tax purposes in advance of the receipt of cash payments to which such OID is attributable and regardless of the holder's regular method of accounting for U.S. federal income tax purposes. See "*Taxation—Certain United States federal income tax considerations to U.S. holders—Original issue discount*."

USE OF PROCEEDS

We estimate that our gross proceeds from the sale of the Notes in this offering will be approximately $675.0 million. We intend to use the gross proceeds from the issue of the Notes (i) to redeem the outstanding 2027 Notes in full, (ii) for payment of fees, costs, discounts and expenses in connection with the Transactions and (iii) to replenish cash on the balance sheet. Actual amounts may vary from estimated amounts depending on several factors, including differences from our estimates of fees and expenses, accrued and unpaid interest due in respect of the 2027 Notes and the estimated redemption premium payable in connection with such redemption of the 2027 Notes. The Company issued a notice of redemption of the 2027 Notes on or about April 20, 2026. For descriptions of our current and anticipated indebtedness following the Offering, see "*Description of certain financing arrangements*" and "*Description of Notes*." See also "*Capitalization*."

Sources of funds		**Uses of funds**	
	($ millions)		**($ millions)**
Notes offered hereby[(1)]	675.0	Redemption of 2027 Notes[(2)]	465.0
		Cash to balance sheet[(3)]	193.3
		Fees, costs, discounts and expenses[(4)]	16.7
Total sources	**675.0**	**Total uses**	**675.0**

(1) Represents the aggregate principal amount of the Notes offered hereby. Gross proceeds of the Notes are expected to be approximately $668.5 million.

(2) Represents the aggregate principal amount of 2027 Notes outstanding as of December 31, 2025 expected to be redeemed using the proceeds from the Offering on or about the Issue Date, excluding estimated accrued and unpaid interest through the applicable redemption date of $27.0 million (assuming a redemption date on or about May 1, 2026) and excluding the estimated $13.5 million redemption premium payable in connection with such redemption of the 2027 Notes.

(3) Represents cash on the balance sheet that we expect to use for general corporate purposes. Following the closing of the Offering, the cash on the balance sheet may be used to repay or refinance existing indebtedness (including but not limited to the 9% Retail Notes).

(4) Reflects estimated fees, costs, discounts and expenses payable in connection with the Transactions, reflecting an original issue discount for the Notes, and including approximately $10.3 million of underwriting fees and commissions, other transaction costs and professional fees. This amount may differ from the estimated amount depending on several factors, including differences from our estimate of fees and expenses and the actual fees and expenses as of the completion of the Transactions.

CAPITALIZATION

The following table sets forth our cash and cash equivalents and capitalization as of December 31, 2025 on a historical basis and as adjusted to reflect the Transactions, including the application of the proceeds of the Notes as described in "*Use of proceeds*" as if these events had occurred on December 31, 2025.

This table should be read in conjunction with "*Use of proceeds*," "*Management's discussion and analysis of financial condition and results of operations*," "*Description of certain financing arrangements*" and the Group Financial Statements and the accompanying notes appearing elsewhere in these Listing Particulars. Except as set forth below, there have been no other material changes to our capitalization since December 31, 2025.

Actual amounts may vary from estimated amounts depending on several factors, including differences from our estimate of fees and expenses, fluctuations in cash on hand between December 31, 2025 and the Issue Date, fluctuations in applicable exchange rates and the date of redemption of the 2027 Notes.

	As of December 31, 2025	
	Historical[1]	**As adjusted for the Transactions[1]**
	(in millions of $)	
Cash and cash equivalents[2]	**268.8**	**462.1[3]**
Debt		
RBL Facility[4]	—	—
SVT Working Capital Facility[5]	36.3	36.3
Vendor Loan Facility[6]	22.1	22.1
9% Retail Notes[7]	179.4	179.4
2027 Notes[8]	465.0	—
Notes offered hereby[9]	—	675.0
EnQuest total debt	**702.8**	**912.8**
Total equity	**528.1**	**528.1**
Total capitalization[10]	**1,230.9**	**1,440.9**

(1) Unless otherwise indicated, U.S. dollar equivalents of pound sterling amounts are translated at an exchange rate of $1.3491 to £1.00, which is the OandA Exchange Rate used for our balance sheet as of December 31, 2025.

(2) As of December 31, 2025, cash and cash equivalents included $3.0 million of restricted cash. As Adjusted amount reflects the use of proceeds as outlined in the uses of funds in the table titled "*Use of Proceeds*", which excludes the redemption premium and accrued and unpaid interest in respect of the 2027 Notes as described under "*Use of Proceeds*." Our cash and cash equivalents on the Issue Date and upon completion of the Transactions may differ from the as adjusted cash and cash equivalent amounts described herein and under "*Use of Proceeds*", which does not reflect other transactions that occurred after December 31, 2025.

(3) Does not include the $20.0 million shareholder dividend to be paid in June 2026.

(4) As of December 31, 2025, the RBL Facility had $381.5 million in letters of credit outstanding. For a description of the RBL Facility Agreement, see "*Description of certain financing arrangements—RBL Facility*."

(5) Represents the $36.3 million (£27.0 million converted at an exchange rate of $1.3491 to £1.00, which is the OandA Exchange Rate used for our balance sheet as of December 31, 2025) outstanding under the SVT Working Capital Facility. The facility accrues interest at 2.05% per annum plus SONIA. See "*Description of certain financing arrangements—SVT Working Capital Facility*."

(6) Represents the $22.1 million aggregate outstanding principal amount under the deferred payment facility that the Group entered into in August 2024. See "*Description of certain financing arrangements—Vendor Loan Facilities*."

(7) Represents the $179.4 million (£133.3 million converted at a rate of $1.3491 to £1.00, which is the OandA Exchange Rate used for our balance sheet as of December 31, 2025) aggregate principal amount of the 9% Retail Notes as of December 31, 2025. See "*Use of Proceeds*."

(8) Represents the $465.0 million aggregate principal amount outstanding under the 2027 Notes as of December 31, 2025. The as adjusted column reflects the redemption in full of the 2027 Notes in connection with the Transactions. See "*Use of Proceeds*."

(9) Represents the aggregate principal amount of Notes offered hereby.

(10) Total capitalization is calculated as the sum of total debt and total equity.

SELECTED FINANCIAL DATA

The following tables present our selected Group financial information as of and for the years ended December 31, 2023, 2024 and 2025, which has been derived from our Group Financial Statements as of and for the years ended December 31, 2023, 2024 and 2025. Our Group Financial Statements as of and for the years ended December 31, 2023, 2024 and 2025 should be read in conjunction with the relevant reports of our independent auditor for such periods.

Our Group Financial Statements as at and for the years ended December 31, 2023, 2024 and 2025 included in these Listing Particulars have been prepared in accordance with United Kingdom adopted International Accounting Standards in conformity with the requirements of the Companies Act 2006.

The financial statement data set forth in the following tables should be read in conjunction with "*Presentation of financial and other information*," "*Capitalization*," "*Use of proceeds*," "*Management's discussion and analysis of financial condition and results of operations*" and our annual financial statements and related notes.

In our 2024 Group Financial Statements, we removed the separate disclosure of remeasurements and exceptional items from the presentation of our income statement to simplify their presentation and to align the presentation with industry peers. As a result, unless otherwise indicated, all amounts shown for our financial results of operation for the financial year ended December 31, 2023 presented herein reflect the relevant results of operations "reported in the year/period" for the period. See "*Presentation of financial and other information*."

Historical results may not necessarily be indicative of results that may be expected for any future period.

Selected historical group income statement data

	For the year ended December 31,		
	2023	**2024**	**2025**
		(in millions of $)	
Revenue and other operating income	1,487.4	1,180.7	1,118.3
Cost of sales	(946.8)	(787.4)	(837.5)
Gross profit/(loss)	**540.7**	**393.3**	**280.8**
Net impairment reversal/(charge) on oil and gas assets	(117.4)	(71.4)	5.8
General and administrative expenses	(6.3)	(5.7)	(7.5)
Other income/(expenses)[1][2]	(19.6)	(4.7)	369.7
Profit/(loss) from operations before tax and finance income/(costs)	**397.4**	**311.5**	**648.8**
Finance costs[2]	(172.1)	(159.4)	(164.6)
Finance income	6.5	14.5	9.2
Profit/(loss) before tax	**231.8**	**166.6**	**493.4**
Income tax[3]	(262.6)	(72.8)	(491.9)
Profit/(loss) for the period attributable to owners of the parent	**(30.8)**	**93.8**	**1.6**

(1) "Other income/(expenses)" is shown as the net amount of "other income" and "other expenses" in our 2023 Group Financial Statements.

(2) In respect of the year ended December 31, 2023, the unwinding of discount on the Magnus Contingent Consideration was reclassified in the 2024 Group Financial Statements to "other income/expense" from "finance costs" in the income statement to combine it with the other fair value movements. Therefore, these amounts are derived from the unaudited comparative column of the 2024 Group Financial Statements. See also "*Management's discussion and analysis of financial condition and results of operations—Significant factors affecting comparability—Magnus oil field* acquisition" and "*—Explanation of income statement items—Net other income and other expense*."

(3) For the year ended December 31, 2025, includes a non-cash deferred tax charge of $374.7 million and a current tax charge of $117.2 million.

Selected historical balance sheet data

	As of December 31,		
	2023	2024	2025
		(in millions of $)	
Assets			
Non-current assets			
Property, plant and equipment	2,296.7	2,298.0	2,370.1
Goodwill	134.4	134.4	139.5
Intangible assets	18.3	20.6	24.6
Deferred tax assets	540.1	506.5	271.4
Trade and other receivables	—	2.1[2]	128.2
Other financial assets	36.3	38.5	50.8
	3,025.9	**3,000.0**	**2,984.6**
Current assets			
Intangible assets	0.9	1.1	1.1
Inventories	84.8	49.0	32.8
Trade and other receivables	225.5	231.0[2]	245.5
Current tax receivable	1.9	1.3	2.0
Cash and cash equivalents	313.6	280.2	268.8
Other financial assets	113.3	0.1	59.5
	739.9	**562.6**	**609.7**
TOTAL ASSETS	**3,765.8**	**3,562.6**	**3,594.3**
EQUITY AND LIABILITIES			
Equity			
Share capital and premium	393.8	392.1	392.1
Treasury shares	—	(4.4)	(3.5)
Share-based payment reserve	13.2	13.9	12.4
Capital redemption reserve	—	2.0	2.0
Retained (deficit)/earnings	49.7	138.9	125.1
TOTAL EQUITY	**456.7**	**542.5**	**528.1**
Non-current liabilities			
Loans and borrowings[1]	747.8	621.4[2]	638.2
Lease liabilities	288.9	288.3	285.8
Contingent consideration	461.3	452.9	24.3
Provisions[4]	715.4	711.1	878.0
Deferred income	138.4	138.1	138.1
Trade and other payables	32.9	—	—
Deferred tax liabilities	77.6	104.7	250.4
	2,462.4	**2,316.4**	**2,214.7**
Current liabilities			
Loans and borrowings[1]	27.4	43.4[3]	69.3
Lease liabilities	133.3	47.0	86.3
Contingent consideration	46.5	20.4	60.3
Provisions[4]	79.9	55.1	54.1
Trade and other payables	347.4	414.4[3]	454.7
Other financial liabilities	26.7	21.6	10.4
Current tax payable	185.5	101.9	116.6
	846.7	**703.8**	**851.6**
TOTAL LIABILITIES	**3,309.1**	**3,020.1**	**3,066.3**
TOTAL EQUITY AND LIABILITIES	**3,765.8**	**3,562.6**	**3,594.3**

(1) In our 2023 Group Financial Statements, "loans and borrowings" have been presented separately as "borrowings" and "bonds".

(2) In respect of the year ended December 31, 2024, unamortized fees in relation to the 2021 RBL Facility Agreement for the year ended December 31, 2024 were reclassified from "unamortized fees on loans and borrowings" within "loans and borrowings" to "trade and other receivables" in the 2024 Group Financial Statements (resulting in an increase of non-current assets in an amount of $2.1 million and an increase in current assets in an amount of $1.4 million) but have not been restated for prior periods as not material.

(3) Accrued interest on borrowings for the year ended December 31, 2024 was reclassified from "accrued expenses" within "trade and other payables" to "loans and borrowings" to better reflect the total borrowings balance, but has not been restated for prior periods.

(4) For the year ended December 31, 2025, decommissioning provision includes EnQuest's share of the total Block 12W decommissioning liability, noting $92.1 million has been pre-funded through an abandonment fund held in Vietnam which is disclosed within non-current other receivables.

Summary historical cash flow statement data

	For the year ended December 31,		
	2023	**2024**	**2025**
		(in millions of $)	
OPERATING ACTIVITIES			
Cash generated from operations	854.7	685.9	497.8
Cash received/(paid) on sale/(purchase) of financial instruments	(5.8)	(10.3)	9.1
Net cash received for trading of other intangible assets	—	—	26.8
Cash paid for purchase of other intangible assets	—	(1.1)[1]	(6.5)
Cash paid in relation to amounts previously provided for	—	(9.1)	(0.5)
Cash received from insurance	5.2	—	—
Decommissioning spend	(58.9)	(60.5)	(56.8)
Income taxes paid	(41.0)	(97.3)	(107.2)
Net cash flows from operating activities	**754.2**	**507.6[1]**	**362.7**
INVESTING ACTIVITIES			
Purchase of property, plant and equipment	(141.7)	(249.2)	(175.0)
Proceeds from farm-down	141.4	1.3	—
Vendor financing facility (loaned)/repaid	(141.4)	107.5	—
Purchase of intangible oil and gas assets	(10.5)	(3.7)	(4.2)
Purchase of other intangible assets	(0.9)	—[1]	—
Payment of Magnus Contingent Consideration — Profit share	(65.5)	(48.5)	—
Payment of Golden Eagle contingent consideration — Acquisition	(50.0)	—	—
Interest received	5.9	10.1	5.3
Acquisition	—	—	(20.3)
Net cash flows (used in) investing activities	**(262.7)**	**(182.4)[1]**	**(194.2)**
FINANCING ACTIVITIES			
Proceeds from loans and borrowings	190.8	31.7	152.4
Repayment of loans and borrowings	(427.7)	(162.3)	(146.5)
Payment for repurchase of shares	—	(9.0)	—
Payment of obligations under financing leases	(135.7)	(130.1)	(83.1)
Dividend paid	—	—	(15.3)
Interest paid	(105.9)	(83.2)	(97.0)
Other finance expenses paid	—	—	(3.6)
Net cash flows used in financing activities	**(478.6)**	**(352.9)**	**(193.0)**
Net (decrease)/increase in cash and cash equivalents	**12.9**	**(27.7)**	**(24.5)**
Net foreign exchange on cash and cash equivalents	(1.0)	(5.6)	13.1
Cash and cash equivalents at January 1	301.6	313.6	280.2
Cash and cash equivalents as of December 31	**313.6**	**280.2**	**268.8**
Reconciliation of cash and cash equivalents			
Total cash at bank and in hand	313.0	226.3	265.9
Restricted cash[2]	0.5	53.9	3.0
Cash and cash equivalents per balance sheet	**313.6**	**280.2**	**268.8**

(1) In respect of the year ended December 31, 2024, "purchases of intangible assets" of $1.1 million in investing activities was reclassified to operating activities as "cash paid for purchase of other intangible assets" in the 2025 Group Financial Statements (resulting in a decrease of net cash flows from operating activities in an amount of $1.1 million and a decrease of net cash flows used in investing activities in an amount of $1.1 million), but has not been restated for prior periods as not material.

(2) As of December 31, 2025, restricted cash includes a residual $1.2 million in accounts relating to 2025 decommissioning security agreement obligations and $1.8 million related to the deposit of a performance bond in Indonesia.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following review should be read in conjunction with the sections entitled "Presentation of financial and other information" and "Selected financial data" as well as with our Group Financial Statements and the related notes thereto included elsewhere in these Listing Particulars. The 1P and 2P Reserves data presented in this section have been audited at our request by GaffneyCline in accordance with PRMS guidelines and definitions. Estimated 1P and 2P Reserves presented herein may differ from estimates made in accordance with guidelines and definitions used by other companies in the industry or by the SEC. See "Presentation of financial and other information." Unless otherwise indicated, all production figures are presented on a net to our working interest basis. Where gross amounts are indicated, they are presented on a total basis—i.e., the actual interest of the relevant license holder in the relevant fields and license areas without deduction for the economic interest of our commercial partners, taxes or royalty interests or otherwise. Our legal interest and effective working interest in the relevant fields and license areas are separately disclosed. See "Our business—Material agreements relating to our assets" for a more detailed discussion of the terms of the agreements governing our interests. The following discussion includes forward-looking statements which, although based on assumptions that we consider reasonable, are subject to risks and uncertainties which could cause actual events or conditions to differ materially from those expressed or implied by the forward-looking statements. For a discussion of some of those risks and uncertainties please refer to the sections entitled "Forward-looking statements" and "Risk factors."

Overview

We are a significant independent energy company in the U.K. North Sea and South East Asia, specializing in the operatorship of mature, underinvested hydrocarbon assets. We are a top quartile operator with a track record of materially extending the economic lives of assets through strong uptime performance, production enhancement, cost discipline and reserve replacement. As of December 31, 2025, we had interests in 18 U.K. production licenses (however, as of February 2026, we relinquished license P2632, reducing our total U.K. production licenses to 17), 14 of which we operate, covering 25 blocks or part blocks in the UKCS. We also have an interest in three licenses in Malaysia, one license in Vietnam, two licenses in Indonesia and one license in Brunei, all but one of which we operate.

While our upstream business remains a core focus given its cash-generating capability, we have also made considerable progress in delivering credible and potentially material new energy and decarbonization opportunities, which are now managed by Veri Energy, a wholly owned subsidiary of the Company. Veri Energy is targeting the creation of a clean energy hub at the EnQuest-operated Sullom Voe Terminal on Shetland, primarily through the repurposing of existing infrastructure, underscoring our commitment to a just and sustainable energy transition. In demonstrating our credible transition plan, we were awarded an A- rating in the 2025 CDP Climate Change Survey, becoming the only oil and gas production company globally to achieve this grade.

We also continue to demonstrate our sector-leading capability in decommissioning, which is becoming an ever more significant component of the competency mix for any North Sea operator.

Since our inception, we have increased our net working interest 1P and net working interest 2P Reserves to 126 MMboe and to 162 MMboe, respectively, as of December 31, 2025 from 36 MMboe and 81 MMboe, respectively, as of January 1, 2010, representing a compound annual growth rate for 2P net working interest Reserves of approximately 4% per annum and representing a 2P net working interest reserves replacement ratio of approximately 1.4x since inception. During the period from January 1, 2010 to December 31, 2025, we added net working interest 2P Reserves of approximately 305 MMboe, of which our production was approximately 223 MMboe. Of our year end 2025 2P net working interest Reserves, approximately 78% represented proved (1P) volumes, with the Group also recognizing 452 MMboe of 2C Resources. As of December 31, 2025, approximately 97% of our 2P net working interest Reserves are located in fields operated by us with approximately 75% of our 2P net working interest Reserves located in fields in the U.K. North Sea.

Our producing assets generated revenue and other operating income, gross profit/(loss) and adjusted EBITDA of $1,118.3 million, $280.8 million and $503.8 million, respectively, in the year ended December 31, 2025. In the year ended December 31, 2025, our average adjusted unit operating costs (including hedging) were $25.1/boe.

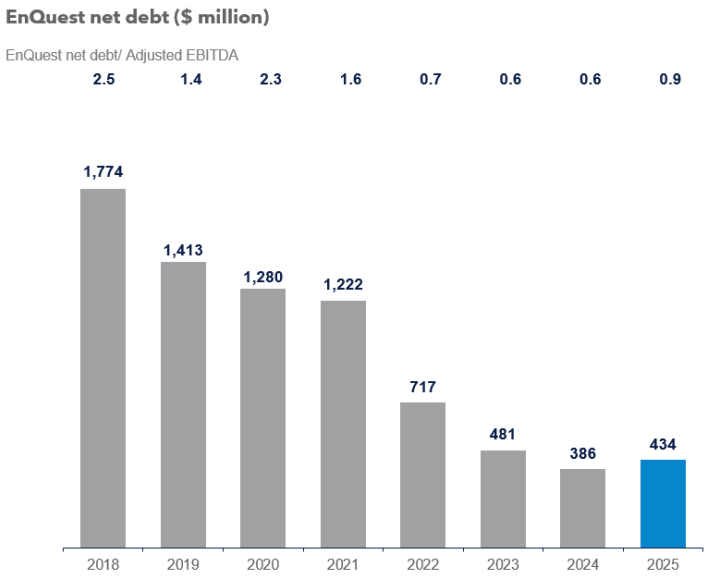
We were founded in 2010 through a combination of Petrofac Energy Developments Limited ("**PEDL**") and certain assets of Lundin Petroleum AB ("**Lundin**"). We purchased PEDL and the UKCS assets of Lundin in

exchange for stock. In 2014, we diversified our geographical footprint by acquiring initial production licenses in Malaysia. Following our initial public offering in April 2010, our shares are listed and trade on the London Stock Exchange. Our shares were also listed on the Stockholm Stock Exchange until December 2023, when the Board decided to delist our shares from the Stockholm Stock Exchange. As of December 31, 2025, our market capitalization was approximately $268.8 million based on the Bloomberg Composite Rate (London) pounds sterling/US dollar exchange rate of $1.3452 per £1.00. In August 2024, our share buy-back program achieved its target of 25 million shares repurchased and held as treasury shares, with all additional shares repurchased immediately cancelled.

We believe that our operational and commercial capabilities, together with experienced technical staff and management, have enabled us to grow production, reserves and resources profitably since 2010. Further, we believe that in the UKCS, South East Asia and potentially other geographic regions, we have, and will continue to have, substantial opportunities for acquisitions and development through low-cost, near-field drilling, well intervention and enhanced oil recovery projects, while maintaining a focus on the health, safety and environmental impacts of our operations. The majority of our existing asset licenses are located in the UKCS in the North Sea. We also have interests in three licenses in Malaysia, one license in Vietnam, two licenses in Indonesia and one license in Brunei. See "*Risk factors—Risks relating to our business—All of our production comes from a small number of offshore assets in the UKCS and South East Asia*, *making us vulnerable to risks associated with having significant production in two regions and only a small number of assets*."

As we navigate the energy transition, one of our top priorities is to achieve and maintain high HSE performance. We believe that we have robust management systems, a culture of positive engagement and a commitment to continuous improvement. We are committed to respecting the people and environments that our business may affect, and we aim to operate our business to achieve safe results, with no harm to people or the environment. To achieve this, we aim to manage our business in compliance with legislation and industry standards, maintain high-quality systems and processes and ensure safe and healthy workplaces. For more information on our health, safety, environment and assurance policies, see "*Our business—Health, safety, environment and assurance*."

As part of our strategy, we aim to maintain a strong balance sheet through consistent deleveraging and prudent capital allocation. In recent years, we have prioritized using free cash flow to reduce our debt. Accordingly, we have significantly reduced our EnQuest net debt from $1.2 billion as of December 31, 2021 to $433.9 million as of December 31, 2025. This represents a reduction of $1.6 billion since peak net debt of $2.0 billion in 2017 and an EnQuest net debt to adjusted EBITDA ratio of 0.9x (compared to 2.5x as of December 31, 2018). The following chart shows the reduction in our EnQuest net debt and EnQuest net debt to adjusted EBITDA ratio for the period indicated:



UKCS

The U.K. North Sea business consists of three directorates:

U.K. Upstream: *Kraken*, *Magnus*, *Golden Eagle, Greater Kittiwake Area*, *Scolty/Crathes*, *Alba*, *Bressay and Bentley*

The U.K. Upstream producing assets are characterized by their high production and operating efficiency. Our strategy is focused on reservoir management and resource development. In the year ended December 31, 2025, daily average net production in the U.K. Upstream directorate was 31,122 boepd, representing 72% of our total daily average net production for that period.

U.K. Midstream: *SVT and pipelines*

Within our Midstream directorate, we operate SVT and approximately 1,000 km of pipelines. Our Midstream business remains focused on the delivery of safe and reliable operations for the processing of East of Shetland and West of Shetland oil and gas, while progressing projects to right-size the terminal to support existing and future upstream operations and significantly lower the terminal's emissions footprint.

In addition, in December 2023, we launched Veri Energy, our wholly owned subsidiary, which is focused on progressing scalable decarbonization and new energy projects. These projects include carbon capture and storage, electrification and e-fuel production by repurposing the existing infrastructure at SVT and connected offshore infrastructure.

U.K. Decommissioning: *Heather/Broom*, *Thistle/Deveron*, *Alma/Galia and the Dons*

The U.K. Decommissioning operations manage end-of-field life decommissioning programs for assets that have already ceased, or are about to cease, production.

South East Asia

Malaysia

We have assets located in Malaysia at PM8/Seligi and DEWA, and we were awarded a PSC partnership for Cendramas in Peninsular Malaysia in February 2026. In the year ended December 31, 2025, daily average net production in Malaysia was 9,201 boepd (including 3,181 boepd associated with Seligi gas in the same period), representing 21% of our total daily average net production for that period.

Vietnam

We also have producing assets located in Vietnam at Chim Sáo and Dua. In the year ended December 31, 2025, daily average net production in Vietnam was 5,283 boepd, with 2,622 attributable to us beginning on July 9, 2025, the completion date of the acquisition of these assets from Harbour Energy.

Indonesia and Brunei

We also have non-producing assets located in Indonesia at Gaea and Gaea II and in Brunei at Block C. See "*Business—Overview of our assets—South East Asia*."

Working interest in producing assets

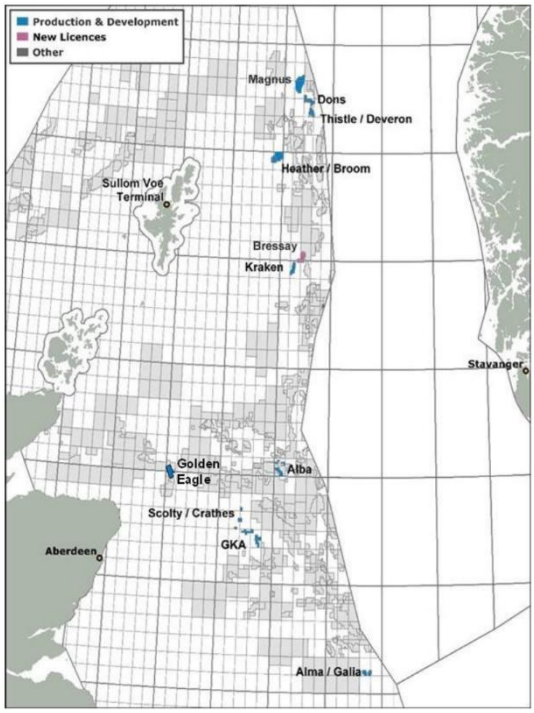
We typically seek to hold a significant working interest in our producing assets and developments, with 100.0% at Magnus, 70.5% at Kraken, 50.0% at GKA, 50.0% at Scolty/Crathes, 85.0% at Bressay, 26.69% at Golden Eagle and 100.0% at Bentley. In Malaysia, we hold a 50.0% working interest in PM8/Seligi, a 42.0% interest in DEWA and from September 2026, a 25.0% participating interest in the Cendramas PSC. In Vietnam, we hold a 53.125% working interest in Chim Sáo and Dua. While we focus on maximizing our operating equity, we have also sought to structure asset acquisitions with significantly lower abandonment equities, in order to minimize our exposure to decommissioning costs.

Through ownership, holding a significant working interest and active participation rights, we are better able to shape the development plan of an asset and influence the timing and method of the extraction of resources than we would be able to if we were passive partners in our fields. As of December 31, 2025, in the U.K., we had ownership interests in 18 producing licenses (however, as of February 2026, we relinquished license P2632, reducing our total U.K. production licenses to 17), 14 of which were operated and 4 of which were partner-operated. We also have an interest in two producing licenses and one non-producing license in Malaysia, one producing license in Vietnam, two non-producing licenses in Indonesia and one non-producing license in Brunei. For the Group, in the year ended December 31, 2025, 93% of our company production was from operated assets

while 7% was from partner-operated assets. We thus have a significant degree of control over the timing and magnitude of operating and capital expenditures for most of our assets. We have the right and obligation under each joint operating agreement to which each asset is a party to take delivery of our share of production from each field for onward sale to third parties of our choice and in the case of Vietnam jointly marketed with our partners. Furthermore, in relation to crude oil, each field temporarily stores production either at the field (such as onboard an FPSO) or at a terminal (such as the SVT). This gives each field owner the ability to accumulate a marketable volume of cargo, which is firstly allocated in full to the field owner with the highest proportionate share of the total stored volume at the time a full cargo accumulates in the first instance. By mutual agreement, field owners may pool their production under a joint operating agreement in order to share in cargoes. With the exception of Vietnam, we have full discretion over the marketing of our attributable volumes across our portfolio and, in relation to assets in which we hold a minority, non-operated stake such as Alba and Golden Eagle, we market our attributable volumes independently of our partners in each field. We market our attributable volumes independently from our field partners to enable us to best leverage our proprietary trading capabilities and substantial industry know-how.

We believe that our existing assets with the highest remaining production potential are Kraken, Magnus and PM8/Seligi. We are also the operator of these assets. There are also material Reserves and Contingent Resources within Kraken, Magnus and PM8/Seligi assets that we believe can be accessed through short-cycle low-cost drilling well intervention and enhanced oil recovery projects. The 2021 acquisitions of approximately 115 MMboe of net 2C Resources associated with our operating interest in Bressay and 131 MMboe of net 2C Resources associated with our operating interest in Bentley provide significant long-term production opportunities that have similarities to our Kraken field. Kraken, Magnus, and the PM8/Seligi fields currently have approximately 33 MMboe, 28 MMboe and 27 MMboe (excluding block PM409, which was relinquished in 2024) of net 2C Resources, respectively. We also have exploration and development potential associated with our interests at DEWA in Malaysia, Gaea and Gaea II in Indonesia and Block C in Brunei.

The following map sets forth the locations of our assets in the UKCS:



The following table sets forth the net daily average production on a working interest basis for each of our producing UKCS operations, our Malaysian operations and our Vietnamese operations for the years ended December 31, 2023, 2024 and 2025:

Region	Working interest	Net daily average production (boepd) For the year ended December 31, 2023	2024	2025
U.K. Upstream		**36,375**	**32,587**	**31,122**
Kraken	70.5	13,580	12,759	10,948
Magnus	100.0	15,933	14,173	15,335
Golden Eagle	26.69	4,199	3,328	2,736
GKA[1]	50.0	946	889	816
Scolty/Crathes	50.0	1,466	1,120	1,009
Alba	8.0	251	319	278
Bentley	100.0	—	—	—
Bressay[2]	85.0	—	—	—
Malaysia		**7,437**	**8,149**	**9,201**
PM8/Seligi[3]	50.0	7,437	8,149	9,201
DEWA[4]	42.0	—	—	—
Vietnam		—	—	**2,622**
Block 12W[5]	53.125	—	—	2,622
Total		**43,812**	**40,736**	**42,945**

(1) GKA production is split across four fields, Mallard, Grouse, Gadwall and Goosander (all at 50.0% working interest), with Kittiwake being the production facility for the hub.

(2) In 2023, we sold 15.0% of the working interest in the Bressay license to RockRose UKCS 10 Ltd, a subsidiary of Viaro Energy.

(3) For the years ended December 31, 2023, 2024 and 2025, respectively, the net daily average production reflects 604 boepd, 1,978 boepd and 3,181 boepd associated with Seligi gas.

(4) DEWA fields acquired with a completion date of October 21, 2024 and are not yet producing.

(5) Production volumes have been calculated from July 9, 2025, the completion date of the acquisition of Block 12W from Harbour Energy. For the year ended December 31, 2025, total net daily average production was 5,283 boepd.

Our production on a working interest basis increased by 5.4% to 42,945 boepd for the year ended December 31, 2025.

Reserves & Contingent Resources

The following table sets forth the 1P Reserves, 2P Reserves and 2C Resources as of the years ended December 31, 2023, 2024 and 2025. Reserves are presented as EnQuest net entitlement Reserves volumes according to the PRMS and separately as EnQuest working interest Reserves volumes for comparative purposes. Contingent Resources are presented as EnQuest working interest volumes only.

	EnQuest net working interest Reserves[1]			EnQuest net entitlement Reserves[3]		
	2023	2024	2025	2023	2024	2025
1P Reserves						
Oil (MMbbl)	123	110	105	117	106	102
Gas (Bscf)[4]	60	109	120	53	91	104
Total 1P Reserves (MMboe)	**133**	**129**	**126**	**126**	**121**	**120**
Pro forma Adjustments[2]						
Vietnam Oil (MMbbl)	—	3	—	—	3	—
Vietnam Gas (Bscf)	—	2	—	—	2	—
Total Vietnam 1P Reserves (MMboe)	—	3	—	—	3	—
***Pro forma* Total 1P Reserves (MMboe)**	**n.a.**	**132**	**n.a.**	**n.a.**	**124**	**n.a.**
2P Reserves						
Oil (MMbbl)	161	143	133	153	137	128
Gas (Bscf)[5]	82	147	171	71	118	142
Total 2P Reserves (MMboe)	**175**	**169**	**163**	**165**	**157**	**152**
Pro forma Adjustments						
Vietnam Oil (MMbbl)	—	5	—	—	5	—
Vietnam Gas (Bscf)	—	10	—	—	10	—
Total Vietnam 2P Reserves (MMboe)	—	7	—	—	7	—
***Pro forma* Total 2P Reserves (MMboe)**	**n.a.**	**176**	**n.a.**	**n.a.**	**164**	**n.a.**

2C Resources						
Oil (MMbbl)	336	323	344	n.a.	n.a.	n.a.
Gas (Bscf)	314	178	582	n.a.	n.a.	n.a.
Total 2C Resources (MMboe)	**389**	**354**	**452**	**n.a.**	**n.a.**	**n.a.**
Pro forma Adjustments						
Vietnam Oil (MMbbl)	—	2	—	n.a.	n.a.	n.a.
Vietnam Gas (Bscf)	—	16	—	n.a.	n.a.	n.a.
Total Vietnam 2C Resources (MMboe)	—	5	—	n.a.	n.a.	n.a.
***Pro forma* Total 2C Resources (MMboe)**	**n.a.**	**359**	**n.a.**	**n.a.**	**n.a.**	**n.a.**

(4) EnQuest net working interest Reserves and Contingent Resources are EnQuest's working interest fraction of the gross field reserves and contingent resources.

(5) GaffneyCline's report assessing reserves and resources for Block 12W in Vietnam as of December 31, 2024 was prepared when entitlements of those reserves and resources were attributable to Harbour Energy, up until July 9, 2025, at which time EnQuest completed the transaction that entitled EnQuest to the reserves and resources. Hence the reported year end 2024 Vietnam Reserves do not represent EnQuest Reserves as at December 31, 2024 but are included in table above as "*Pro forma Adjustments*."

(6) For assets governed by Production Sharing Contracts ("**PSC**") (PM8/Seligi in Malaysia and Block 12W in Vietnam), EnQuest Net Entitlement Reserves are EnQuest's net economic entitlement according to the PSC terms, *i.e.*, EnQuest's share of cost and profit oil and gas.

(4) For the years ended December 31, 2023, 2024 and 2025, 1P gas reserves included 40.8 Bscf used for fuel and 19.4 Bscf (working interest) or 12.5 Bscf (net entitlement) used for sales, 36.7 Bscf used for fuel and 72.0 Bscf (working interest) or 54.0 Bscf (net entitlement) used for sales and 38.4 Bscf used for fuel and 81.5 Bscf (working interest) or 65.2 Bscf (net entitlement) used for sales, respectively. *Pro forma* adjustments reflect 1P Vietnam reserves as of December 31, 2024 and included 0 Bscf used for fuel and 2.3 Bscf (working interest) or 2.2 Bscf (net entitlement) used for sales.

(5) For the years ended December 31, 2023, 2024 and 2025, 2P gas reserves included 46.6 Bscf used for fuel and 35.8 Bscf (working interest) or 24.3 Bscf (net entitlement) used for sales, 42.5 Bscf used for fuel and 104.4 Bscf (working interest) or 76.0 Bscf (net entitlement) used for sales and 46.8 Bscf used for fuel and 124.2 Bscf (working interest) or 94.8 Bscf (net entitlement) used for sales, respectively. *Pro forma* adjustments reflect 2P Vietnam reserves as of December 31, 2024 and included 0 Bscf used for fuel and 10.3 Bscf (working interest) or 9.5 Bscf (net entitlement) used for sales.

Significant factors affecting results of operations

Price of oil

We are exposed to the impact of changes in Dated Brent crude oil prices. Changes in oil prices can impact the levels of our reserves and, therefore, depletion charges, as well as revenues, which in turn would impact our profits and cash flow. Low oil prices typically result in significant reductions in capital expenditure budgets, cancellation or deferral of projects and reductions in discretionary expenditures.

Crude oil prices have historically been volatile, dependent upon the balance between supply and demand and particularly sensitive to OPEC production levels and the emergence of additional supply sources such as US shale oil and non-OPEC supply. During 2023, global markets predominantly operated within a price range of $70/bbl to $90/bbl, except for a short period of escalated prices during September. This range reflected softer pricing than that seen during 2022, with a number of macroeconomic and geopolitical impacts offsetting each other. 2023 saw an increase in demand for hydrocarbons as global economies continued the path of industrial recovery post-pandemic but the impact on commodity prices was offset by an increase in U.S. shale production of around 1.5 million barrels of oil per day, as well as the emergence of additional incremental non-OPEC supply, predominantly from Brazil, Guyana and Canada. These supply impacts led OPEC to implement production cuts, which drove the September 2023 price spike but which ultimately resulted in a stabilization of prices towards the end of the year. The geopolitical environment has also caused uncertainty within global markets amid a continuation of the Russia-Ukraine conflict in Europe and escalating tensions in the Middle East as war broke out between Israel and Hamas in October 2023. Supply concerns escalated and dissipated at various junctures during the fourth quarter of 2023 and continued into 2024 with U.S.-U.K. missile strikes to protect the safe passage of maritime trade in the Red Sea. In 2024, Brent crude oil prices experienced notable fluctuations due to a combination of geopolitical tensions, economic factors, and production changes. The average price of Brent crude oil was around $80 per barrel, slightly lower than the average price of the previous year. Prices ranged between $69 and $92 per barrel, marking the narrowest trading range since 2019. Early in the year, Brent prices rose due to heightened geopolitical risks, particularly in the Middle East. Tensions between Israel and Hamas, along with attacks on vessels in the Red Sea caused significant disruptions and pushed prices higher. In 2025, economic uncertainty and OPEC's decision to unwind voluntary production cuts contributed to a decrease in oil prices. In

March 2026, U.S. and Israeli airstrikes on Iran and related retaliatory strikes by Iran across the Gulf region, as well as the closing of the Strait of Hormuz as a result of the conflict have led to increased and volatile oil prices. See also "*Risk factors—Volatility and decreases in oil prices could materially and adversely affect our business, prospects, financial condition and results of operations*".

Our oil sales for our UKCS assets (excluding Kraken) are primarily priced based on the Platts Dated Brent crude oil benchmark. Differentials to the benchmark price are negotiated with customers driven by market conditions. Prices for our Kraken oil sales are priced against the "very low sulfur (0.5% sulfur) fuel oil" ("**VLSFO**") market, with Kraken oil currently being sold as a key component of IMO 2020 compliant low sulfur fuel oil in the shipping fuel market. Prices for our Malaysian oil sales are set by the Malaysian OSP, which is generally a premium to the Platts Dated Brent benchmark. A Tapis differential is then applied to the Malaysian OSP and further differentials are negotiated with customers. Vietnamese crude oil is generally recognized for its quality and typically commands a premium over Brent, which has historically been approximately 10%.

The average realized price for our oil sales (excluding hedging) decreased by approximately 16.2% to $68.1/boe for the year ended December 31, 2025 from $81.3/boe for the year ended December 31, 2024. The average realized price for our oil sales (excluding hedging) decreased by 1.1% to $81.3/boe for the year ended December 31, 2024 from $82.2/boe for the year ended December 31, 2023.

The average Brent ICE quoted oil price decreased by 13.6% to $68.96/bbl for the year ended December 31, 2025 from $79.86/bbl for the year ended December 31, 2024. The average Brent ICE quoted oil price decreased by 2.8% to $79.86/bbl for the year ended December 31, 2024 from $82.17/bbl for the year ended December 31, 2023. The average U.K. gas price for the year ended December 31, 2025 was £0.883 per therm, a 6% increase from £0.836 per therm in the year ended December 31, 2024.

The following table sets forth information on Brent ICE quoted oil prices for the years ended December 31, 2023, 2024 and 2025.

	For the year ended December 31,		
	2023	2024	2025
		(in $/bbl)	
Average price for the period	82.17	79.86	68.96
Highest price for the period	96.55	91.17	75.00
Lowest price for the period	71.84	69.19	60.84

Source: International Commodities Exchange

Our hedging policy is to attempt to manage the impact of oil prices to protect against volatility and to ensure the availability of cash flow for servicing of debt obligations and investment in capital programs that drive business growth. As part of this strategy, we have entered into commodity hedging contracts. As of April 15, 2026, we have approximately 3.8 MMbbls of production hedged through 2026, utilizing swaps at an average price of $73.2/bbl, and we have approximately 3.5 MMbbls of production hedged for 2027, utilizing swaps at an average price of $64.4/bbl. Finally, we have approximately 0.9 MMbbls of production hedged for 2028, utilizing swaps at an average price of $64.6/bbl. As further mitigation, we have utilized put and call options to implement a collar structure covering 1.8 MMbbl with a floor and ceiling of $50/bbl and $100/bbl, respectively, through 2026, and we will continue to pursue hedging at the appropriate time and price, in line with our established policy.

All of our reserves are assessed using a commerciality threshold and are therefore impacted by changes in oil prices. In particular, decreases of oil prices could lead to reduction in the economic life of a field, which would, in turn, lead to a decrease in reserves. See "*—Reserves*." For example, in 2020 we decided to cease production from the Heather, Broom, Thistle, Deveron, Alma and Galia fields and from the Dons asset in 2021. Decommissioning has commenced and is ongoing in relation to these fields and these decisions follow our assessment that these fields had reached their "economic limit." In the year ended December 31, 2025, we completed the well plug and abandonment of the final seven Heather wells and completed the safe removal of the Heather Alpha topsides. See also "*Our business—Overview of our assets—U.K. Decommissioning—Heather/Broom*".

Production volumes

In addition to oil prices, production volumes are a primary revenue driver. Our production levels also affect the level of reserves and depletion charges. The volume of our oil reserves and resources and production

volumes may be lower than estimated or expected. See "*Risk factors—Risks relating to the oil and gas industry—The levels of our 1P and 2P Reserves and Contingent Resources, their quality and production volumes may be lower than estimated or expected*."

Based on our anticipated production, volumes are nominated for lifting approximately two months in advance. Buyers of our crude oil are invoiced for the volume loaded on tankers as measured by an independent inspector and/or the fiscal meter. Volumes lifted and sold out of the terminals will normally be lower than those fiscally measured as being produced on our platforms, reflecting "shrinkage." Shrinkage may occur from three potential sources – process fuel, terminal flaring and value adjustment. We are required to contribute fuel necessary to process the hydrocarbons at the Kinneil Oil Terminal. There is also flaring at the terminal to which all pipeline entrants are required to contribute. Oil from Magnus is exported through the Ninian pipeline. The SVT uses commingled crude, which results in a "blend" oil price being calculated. Similarly, Greater Kittiwake Area, Scolty and Crathes flow into the Forties Pipeline System and are redelivered as export Forties Blend Crude oil at Hound Point near Edinburgh. Furthermore, production from the Golden Eagle field is delivered by pipeline to the Flotta Terminal in the Orkney Islands where it is blended into Flotta Gold export crude oil. In each case, a value adjustment is then calculated based on the relative quality of our crude against the blend as a whole and this normally results in a further element of shrinkage. For the period from January 1, 2023 to December 31, 2025, our shrinkage factor has been less than 2.5% of produced volumes for total gross production across all of our assets. The resulting invoice volume after deduction of shrinkage, entitlement and over/underlift as applicable to each producing asset is our sales volume.

Our production on a working interest basis increased by 5.4% to 42,945 boepd (including production from our Vietnam assets as of July 9, 2025) for the year ended December 31, 2025 from 40,736 boepd for the year ended December 31, 2024 primarily driven by strong uptime across the portfolio, the contribution from the acquisition of producing assets in Vietnam and investment in low-cost quick-payback well work, partially offset by an approximately five week long shut-down at Magnus due to a third-party infrastructure outage.

Our production on a working interest basis decreased by 7.0% to 40,736 boepd for the year ended December 31, 2024 from 43,812 boepd for the year ended December 31, 2023 primarily driven by the impact of natural field declines across the portfolio, partially offset by strong production efficiencies across the portfolio and our investment in low-cost, quick payback well work and production optimization.

The following table sets forth information on our oil production on a net working interest basis and sales volumes for the years ended December 31, 2023, 2024 and 2025.

	For the year ended December 31,		
	2023	**2024**	**2025**
		(boepd)	
Total average daily production for the period[(1)]	43,812	40,736	42,945
Total average daily sales volume for the period[(2)] …….	48,825	40,859	41,844

(1) Includes Vietnam production from July 9, 2025, the date on which we completed the acquisition of Harbour Energy's business in Vietnam, including its interest in Block 12W.

(2) Includes volumes related to onward sale of third-party gas purchases not required for injection activities at Magnus.

Reserves

We estimate our 1P and 2P reserves, which are reflected in our financial statements, using standard recognized evaluation techniques. This estimate is reviewed internally at least annually and is also audited annually by GaffneyCline. We estimate future development costs, taking into account the level of development required to produce the reserves we have elected to develop. The amount of development costs in turn influences the economic recoverability of the resources and, therefore, what proportion of resources are recognized as reserves.

Separately, the depletion of oil assets charged to our income statement under cost of sales is dependent on the estimate of our oil reserves. An increase in estimated reserves will cause a reduction in the charge to our annual income statement because a larger base exists on which to depreciate the asset. Conversely, a decrease in estimated reserves will cause an increase in the charge to our annual income statement. The estimate of oil reserves

also underpins the net present value of a field used for impairment calculations, and in significant cases a reduction to the reserves estimate can lead to an impairment charge. These impairment charges would not impact our cash flow nor our U.K. tax allowances.

Development and production success and impairment

We face inherent risks in connection with our development and production activities. These risks include the difference between estimated and actual reserves, our cost efficiency in development, timing of production activities and our level of production. We review our development and production projects at least semi-annually for indicators of impairment. Where such an indicator does exist, we compare the net present value of the asset (based on discounted cash flows) with the carrying value on our balance sheet. If the net present value is lower than the carrying value, we record any impairment to the "Net impairment reversal/(charge) to oil and gas assets" line of our income statement.

Following the completion of the original Kraken field development plan in March 2019, our exposure to development risks has been materially reduced. Development of our existing reserves and resources is anticipated to be primarily through short-cycle drilling well intervention and enhanced oil recovery projects. However, all of our production comes from a small number of offshore assets in the UKCS and South East Asia and, therefore, our exposure to risks in our production activities is amplified. In this regard, however, SVT has a good record of operational uptime and availability and its safety and operational performance levels are regularly monitored and challenged by us as well as other terminal owners and users to maintain operational integrity and minimize risks in our production activities. We are also committed to transforming SVT to remain competitive and well placed to maximize its useful economic life and support the future of the North Sea.

In the year ended December 31, 2025, we recognized a non-cash net impairment reversal to our oil and gas assets of $5.8 million compared to a charge of $71.4 million in the year ended December 31, 2024, related to a reduction in the discount rate, lower near-term oil price assumptions based on market dynamics and changes in production and cost profiles, including the impact of a weaker U.S. dollar. In the year ended December 31, 2024, the net impairment charge to our oil and gas assets primarily related to changes to the EPL confirmed by the U.K. government in its Autumn 2024 Budget (including the two-year extension to March 31, 2030), lower short-term oil price assumptions and changes to the production profile of the non-operated Golden Eagle field, partially offset by production profile changes at the GKA hub and a lower discount rate. In the year ended December 31, 2023, the net impairment charge to our oil and gas assets was $117.4 million. This net impairment charge primarily related to production and cost profile updates on non-operated assets, partially offset by higher forecast long-term oil prices.

Acquisitions and disposals

Our results are affected by acquisitions and disposals of assets that take place during the period, although the extent of the impact largely depends on the mix of assets acquired or sold. If we elect to divest an asset, it could impact several line items in our income statement depending, in part, on the stage of the asset's life in which disposal occurs. Any acquisition of or sale of interests in producing assets will affect our production volumes, revenues and operating costs. Acquisitions and disposals also affect our liquidity and cash position in the relevant period to the extent the purchase price is paid in cash. We continually evaluate potential acquisitions and disposals and the timing of any such transaction is uncertain. See "*Risk Factors—Risks relating to our business—Our strategy of delivering sustainable and transformative growth through transformative consolidation transactions may increase our debt and the complexity of our operations*."

Acquisitions and disposals during the periods presented included, among others, the sale of a 15.0% equity share in the Bressay license and the EnQuest Producer Floating, Production, Storage and Offloading vessel ("**FPSO**"), completed in December 2023.

In addition, in July 2025, we completed the acquisition of Harbour Energy's business in Vietnam, which holds a 53.125% equity interest in (and operatorship of) the Chim Sáo and Dua production fields ("**Block 12W**"). See "*Our business—Overview of our assets—South East Asia—Vietnam*".

See "*Our business—Material agreements relating to our assets*." As of December 31, 2025, we had no assets held for sale.

Operating costs

Fixed

Fixed operating costs are substantially independent from production levels and therefore do not automatically increase (or decrease) with an increase (or decrease) of our level of production. Fixed operating costs include routine and non-routine maintenance costs, certain labor costs and power costs. Certain regular maintenance programs also result in the temporary shut-in of production. An increase in fixed operating costs will result in an increase in underlying operating costs per barrel due to higher costs with no associated increase in production.

Variable

The variable element of operating costs will increase (or decrease) with the level of production. An increase (or decrease) in production will result in an increase (or decrease) in underlying variable operating costs. The primary variable operating costs that affect our results include the costs associated with the use of infrastructure (including third-party infrastructure such as pipelines and terminals), consumable well supplies and fuel. We pay tariffs for use of third-party infrastructure based on our proportionate use of the infrastructure. Tariffs are set in part based on the infrastructure operator's total expenses.

Oil produced at Kraken is loaded from the Armada Kraken FPSO onto shuttle tankers and then delivered directly to buyers in Northwest Europe or transferred to other conventional oil tankers for delivery into the United States, the Mediterranean and/or the Asia.

The greatest portion of our transportation and infrastructure costs arise through tariffs charged for the use of the SVT, through which oil from Magnus is transported and marketed. These charges are based on a cost share model.

Oil produced at the Golden Eagle Area Development is processed on the platform and then transported through the Golden Eagle pipeline to the Claymore line, where it is then routed to the Flotta system and processed into stabilized Flotta Gold blend at the Flotta Terminal. All available gas is utilized for fuel.

With respect to production from the Greater Kittiwake Area and Scolty/Crathes, we hold an equity interest in an offshore platform at Kittiwake and a 100% interest in a pipeline linking Kittiwake to the Forties Unity platform. Fields in the Greater Kittiwake Area and Scolty/Crathes are tied via subsea infrastructure to the offshore platform at Kittiwake. Oil from the platform at Kittiwake is transported via pipeline to the Forties Unity platform where it is then transported to shore at Cruden Bay through the Forties Pipeline System. The oil then continues through the pipeline to Hound Point, Scotland, where it is loaded on tankers, and raw gas and natural gas liquids are taken to Grangemouth, Scotland for further processing.

Oil from Alba, where we hold a minority interest, is also transported by shuttle tanker from the Alba Northern platform to onshore terminals.

Production from PM8/Seligi is transported via the Tapis platform (operated by ExxonMobil) to the Terengganu Crude Oil Terminal (operated by PETRONAS Carigali Sdn. Bhd.) for processing and sale.

Oil production from Block 12W is exported via the FPSO *Lewek Emas*, and gas is transported via pipeline to Vung Tau near Ho Chi Minh City for processing and sale.

Derivative financial instruments

Our results are affected by commodity and foreign currency hedging. Our commodity hedging policy is to have the ability to hedge oil prices up to a maximum of 75% of the next 12 months' production on a rolling annual basis, up to 60% in the following 12-month period, and 50% in the subsequent 12-month period.

Under the terms of the RBL Facility Agreement we are required, subject to grace periods where increased required hedge volumes arise, to hedge as follows, where references below to "**total relevant outstandings**" means the aggregate amount of all utilizations under the RBL Facility disregarding Eligible L/Cs and other letters of credit to the extent the same are subject to cash cover:

- From the RBL Effective Date to but excluding June 30, 2029:

- where the total relevant outstandings are 10% or less of the then current Borrowing Base Amount: a minimum of 10% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the (i) 12 months following the relevant quarter date and (ii) from the date 12 months after the relevant quarter date to the date 24 months after that date.

- where the total relevant outstandings are more than 10% but less than 50% of the then current Borrowing Base Amount: a minimum of (i) 30% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months following the relevant quarter date and (ii) 15% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months after the relevant quarter date to the date 24 months after that date.

- where the total relevant outstandings are 50% or more of the then current Borrowing Base Amount: a minimum of (i) 45% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months following the relevant quarter date and (ii) 30% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months after the relevant quarter date to the date 24 months after that date.

- On and from June 30, 2029:

  - where the total relevant outstandings are less than 50% of the then current Borrowing Base Amount: a minimum of (i) 30% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months following the relevant quarter date and (ii) 15% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months after the relevant quarter date to the date 24 months after that date.

  - where the total relevant outstandings are 50% or more of the then current Borrowing Base Amount: a minimum of (i) 45% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months following the relevant quarter date and (ii) 30% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months after the relevant quarter date to the date 24 months after that date.

In all cases, minimum floor protection will be equal to or above the lower of 90% of the economic assumption as to hydrocarbon prices included in the then-current banking case and 90% of the forward price curve at the time of hedge execution.

As of April 15, 2026, we have approximately 3.8 MMbbls of production hedged through 2026, utilizing swaps at an average price of $73.2/bbl, and we have approximately 3.5 MMbbls of production hedged for 2027, utilizing swaps at an average price of $64.4/bbl. Finally, we have approximately 0.9 MMbbls of production hedged for 2028, utilizing swaps at an average price of $64.6/bbl. Our foreign currency hedging policy allows for up to 70% of non-U.S. dollar denominated annual capital budget and operating expenditure to be hedged, although we may hedge up to 100% of non-U.S. dollar capital expenditure in relation to specific contracted capital expenditure projects. As of April 1, 2026, we have £119 million hedged at an average rate of £1.3276 to $1.00.

We hold derivative financial instruments classified as held for trading, not designated as effective hedging instruments. The derivative financial instruments include forward currency contracts and commodity contracts, to address the respective risks. We also enter into forward contracts for the purchase of U.K. emissions

allowances ("**UKAs**") to manage its exposure to carbon emission credit prices. Derivatives are carried as financial assets when the fair value is positive and as financial liabilities when the fair value is negative.

Financial instruments are carried in our balance sheet at fair value with net changes in fair value recognized in our income statement.

Interest rates

Our exposure to the risk of changes in market interest rates relates primarily to our borrowings under the SVT Working Capital Facility, which has a SONIA linked interest rate. The RBL Facility Agreement has a SOFR linked interest rate. See "*—Financing—Debt financing*" and "*Description of certain financing arrangements*."

The RBL Facility Agreement provides for a margin under Facility A of 4.00% per annum for the first two years from the RBL Effective Date, increasing to 4.25% per annum on and from the second anniversary of the RBL Effective Date and further increasing to 4.50% per annum on and from the fourth anniversary of the RBL Effective Date.

Currency exchange rates

Our functional and presentational currency is the U.S. dollar, primarily because we price our oil sales in U.S. dollars and substantially all of our revenues are denominated in U.S. dollars. However, because a significant amount of our staffing and other administration costs is denominated in pounds sterling, our results are affected by changes in the U.S. dollar/pounds sterling exchange rate.

Costs denominated in currencies other than the U.S. dollar were 95%, 97% and 98% for the years ended December 31, 2023, 2024 and 2025, respectively.

The following table sets forth the high, low and average OandA U.S. dollar/pounds sterling exchange rate for the years ended December 31, 2023, 2024 and 2025. The OandA Exchange Rate is the source used in the preparation our financial statements.

	2023	2024	2025
		(in $/£)	
Average rate for the period	1.2391	1.2778	1.3182
Highest rate for the period	1.2882	1.3185	1.3742
Lowest rate for the period	1.2083	1.2511	1.2156

Source: OandA Foreign Exchange Rate

Taxation

Taxation can have a significant impact on our results of operations. We are subject to corporate income taxes, U.K. corporation tax, SCT, and EPL in the U.K. as well as petroleum and corporate income taxes in Malaysia, Vietnam, Indonesia and Brunei. The tax charge for the year ended December 31, 2025 was $491.9 million (2024: $72.8 million tax charge), which includes a current cash tax charge of $117.2 million, of which $84.1 million relates to the 2025 EPL charge. The tax charge for the year ended December 31, 2025 includes a one-off non-cash adjustment of $123.9 million due to the extension of the EPL by two years (from March 31, 2028 to March 31, 2030), which was enacted in March 2025. We also recognized a further non-cash deferred tax charge of $152.4 million, which relates to the Magnus profit share settlement.

Ring Fence Expenditure Supplement ("**RFES**") on U.K. activities, which would historically have provided an offset to the U.K. tax charge, ceased to be available to claim from the end of 2021. We continue to have access to our U.K. North Sea ring-fenced corporate tax losses, subject only to generating suitable future profits, which as of December 31, 2025 were $1,851.3 million (December 31, 2024: $2,066.4 million). We recognize deferred tax assets on unused tax losses where it is probable that future taxable profits will be available for utilization. This requires our management to make judgments and assumptions regarding the amount of deferred tax that can be recognized, as well as the likelihood of future taxable profits.

Other material factors impacting our tax charge include $219.1 million related to the EPL, which includes the non-cash deferred tax impact of the two-year extension to the EPL of $123.9 million, permanent items of $12.9 million relating to non-deductible finance costs, foreign exchange and non-qualifying depreciation and other

adjusting items amounting to $62.5 million, which includes adjustments to prior year tax accruals following a true-up to revised tax estimates and the non-recognition of deferred tax assets in respect of non-oil and gas tax losses.

We have also historically paid Petroleum Revenue Tax ("**PRT**") in respect of our UKCS operations, which is based on taxable profits of individual production fields. However, beginning on January 1, 2016, the PRT rate was reduced to 0%. Therefore, during the year ended December 31, 2025 we paid no PRT in relation to our UKCS operations.

Our taxation is also affected by U.K. tax incentive programs known as investment allowances. This regime essentially provides for a reduction in SCT (10%) where investments in new or existing UKCS assets qualify for a relief known as investment allowances. Investment allowances are activated by revenue generated from the field and are recognized as a reduction in the charge to taxation in the years in which it is utilized.

As of December 31, 2025, we had activated investment allowances of $2,614.3 million and unactivated allowances of $41.7 million, predominately relating to Kraken North. Unactivated allowances refer to tax allowances that have been generated by our investment expenditure but that have not yet been used to reduce tax liability.

With continuing investment in our existing assets, we do not expect to pay material U.K. cash income tax related to U.K. corporation tax and SCT for the foreseeable future. We expect to pay cash taxes in relation to the EPL for the duration of the levy.

With respect to our Malaysian operations, we pay a 38% petroleum income tax on the profit oil derived from the production sharing agreements under which we operate our Malaysian assets in addition to a 10% royalty payable on its oil sales. There are no tax losses carried forward in relation to our Malaysian producing operations. We paid and will continue to pay petroleum income taxes in Malaysia throughout the life of the PSC.

With respect to our Vietnamese operations, as per relevant terms under Block 12W Production Sharing Contract, we pay a 32% corporate income tax in association with the sales of crude oil and export gas, in addition to a royalty and export duties where applicable.

We are subject to various tax claims, including VAT relating to SVT JV invoices and employment tax relating to a secondment to the U.K., all of which arise in the ordinary course of our business. We assess all such claims in the context of the tax laws of the countries in which we operate and, where applicable, make provision for any settlements which we consider to be probable. See "*Regulation—United Kingdom—Tax regulations*," "*Our business—Legal and arbitration proceedings*," "*Risk factors—Risks relating to our business—Our tax liability is subject to estimation and we may be adversely affected by changes to tax legislation or its interpretation or increases in effective tax rates in the jurisdictions in which we do business*."

We may also be affected by how taxes impact our counterparties and contracts. Modifications may cause certain third parties with which we contract to experience increased costs, which they may seek to pass on to us through contractual pass-through provisions or in future negotiations. We may be required to pay some or all of these increased costs.

Significant factors affecting comparability

Changes in tax laws

As mentioned above under "*—Significant Factors affecting results of operation—Taxation*", taxation can have a significant impact on our results of operations. During 2022, the U.K. government introduced, and subsequently expanded, the EPL on the profits earned from the production of oil and gas in the U.K. The EPL is currently charged at the rate of 38% on taxable profits (35% in 2024), in addition to RFCT of 30% and the SCT of 10%. 2023 represented the first full year of the EPL on oil and gas producers, at the increased headline rate of 35%, impacting our profitability. Following the July 2024 U.K. general election, the new U.K. Government announced further proposed changes to the EPL, with an increased rate (to 38%), extended duration (to March 31, 2030) and withdrawal and reduction in certain allowances. The extension was substantively enacted on March 3, 2025, with an impact on tax charge and deferred tax for EPL in the year ended December 31, 2025 of $123.9 million. In addition, the EPL investment allowance has been abolished with effect from November 2024 (although

first year allowances would be retained) and decarbonization relief reduced to 66% (from 80%). As a result of these changes in tax laws, income tax across the periods presented herein may not be comparable to prior periods.

Magnus oil field acquisition

On December 1, 2018, we completed the acquisition from bp of the remaining 75.0% interest in the Magnus oil field, an additional 9.0% interest in the SVT and supply facility and other additional interests in associated infrastructure having acquired a 25.0% interest in the Magnus field and a 3.0% interest in the SVT and supply facility (amongst other assets) (collectively, the "**Magnus Assets**") in December 2017 (the "**Magnus Acquisition**").

The outstanding amount of deferred consideration financed by bp was repaid in full in July 2021. The consideration also included a contingent profit sharing arrangement whereby we and bp share the net cash flow generated by the 75.0% interest on a 50:50 basis, subject to a cap of $1 billion received by bp. The deferred contingent profit sharing arrangement is known as the "**Magnus Contingent Consideration**."

The acquisition of the remaining 75.0% interest was considered a step acquisition as per IFRS 3 *Business Combinations*.

As of December 31, 2023, the Magnus Contingent Consideration was fair valued at $488.0 million. The decrease in fair value in 2023 reflected a 1.3% increase in the discount rate to 11.3% (2022: 10.0%) and changes in the asset cost profile, partially offset by increased oil price assumptions.

As of December 31, 2024, the Magnus Contingent Consideration was fair valued at $451.3 million. The decrease in fair value in 2024 reflected a reduction in our near-term oil price assumptions and changes in the assets cost and production profile.

In February 2026, we agreed with bp to terminate the contingent profit-sharing arrangement in exchange for a fixed cash payment of $60 million, thereby securing 100% of the future cash flows from the Magnus Assets and eliminating the associated liability. Management assessed that this settlement was substantially agreed as of December 31, 2025 and, accordingly, that the agreed price represented a reasonable fair value for the Magnus Contingent Consideration as of that date, in line with IFRS 13.

Following a review of market practice, the unwinding of discount on the Magnus Contingent Consideration was reclassified in the 2024 Group Financial Statements to "other income/expense" from "finance costs" in the income statement to combine it with the other fair value movements. As a result, unless specifically stated otherwise, all amounts shown in these Listing Particulars in respect of "other income/expense" and "finance costs" for the year ended December 31, 2023 refer to such restated information derived from the comparative information found in the 2024 Group Financial Statements.

Magnus oil field decommissioning-linked contingent consideration

As part of the Magnus Acquisition and associated interests acquisition, bp retained the decommissioning liability in respect of the existing wells and infrastructure, and we agreed to pay additional consideration in relation to the management of the physical decommissioning costs of Magnus (the "**Magnus Decommissioning Contingent Consideration**"). As of December 31, 2025, the amount due to bp of $24.6 million was calculated on an after-tax basis by reference to 30% of bp's decommissioning costs on Magnus. The Magnus Decommissioning Contingent Consideration did not form part of the broader Magnus Contingent Consideration package that was settled through the $60 million fixed cash payment agreed with bp in February 2026 and so remains recognized as a contingent consideration liability.

Golden Eagle contingent consideration

On October 22, 2021, we completed the acquisition of a 26.69% non-operated working interest in the Golden Eagle Area Development, comprising the producing Golden Eagle, Peregrine and Solitaire fields. The consideration for the acquisition included an amount that was contingent on the average oil price between July 2021 and June 2023. Over the period July 2021 to June 2023, the average oil price was $89.6/bbl. As such, as of June 30, 2023, the contingent consideration was valued at $50.0 million with settlement of this liability completing in July 2023 (2022: liability of $48.3 million).

Explanation of income statement items

Revenue and other operating income

Oil and gas revenues, our largest sources of revenue, are comprised of our share of sales from the processing or sale of hydrocarbons on an entitlement basis, when the significant risks and rewards of ownership have been passed to the buyer. Tariff revenue is recognized in the period in which the services are provided at the agreed contract rates.

Other operating income is comprised of realized gains and unrealized gains on our commodity hedging contracts.

Revenue from contracts with customers

We generate revenue through contracts with customers for the sale of crude oil, gas and condensate to third parties and for the provision of infrastructure to our customers in exchange for a tariff. Revenue from contracts with customers is recognized when control of the goods or services is transferred to the customer, at an amount that reflects the consideration which we expect to be entitled in exchange for those goods or services. We have concluded that we are the principal in our revenue arrangements because we typically control the goods or services before transferring them to the customer. The normal credit term is 30 days or less upon performance of the obligation.

Sale of crude oil, gas and condensate

We sell crude oil, gas and condensate directly to customers. The sale represents a single performance obligation, which is satisfied when the customer takes physical possession of the commodity or the commodity is delivered to an infrastructure. At this point, the title to the commodity passes to the customer and revenue is recognized. We principally satisfy our performance obligations at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant. Transaction prices are referenced to quoted prices, plus or minus an agreed discount rate when applicable.

Tariff revenue for the use of our infrastructure

Tariffs are charged to customers for the use of infrastructure that we own. The revenue represents the performance of an obligation for the use of our assets over the life of the contract. The use of the assets is not separable as they are interdependent to fulfill the contract and no one item of infrastructure can be individually isolated. Revenue is recognized as the performance obligations are satisfied over the period of the contract, generally a period of 12 months or less, on a monthly basis based on throughput at the agreed contracted rates.

Other operating income

Other operating income also includes gains or losses from oil derivative trading transactions. Other operating income is recognized to the extent that its probable economic benefits will flow to us and the revenue can be reliably measured.

We enter into oil derivative trading transactions which can be settled net in cash. Accordingly, any gains or losses are not considered to constitute revenue from contracts with customers in accordance with the requirements of IFRS 15 *Revenue from Contracts with Customers*, and are included within other operating income.

Cost of sales

Our cost of sales consists of the costs of operations, changes in lifting position, crude oil inventory movements, depletion of oil and gas assets and underlying operating costs such as tariff and transportation expenses charged back to us based on our proportionate use of infrastructure and according to the total costs of the operator of such infrastructure. Inventories of consumable well supplies and inventories of hydrocarbons are stated at the lower of cost and net realizable value, cost being determined on an average cost basis. Oil and gas assets are depleted, on a field-by-field basis, using the unit of production method based on entitlement to proved and probable reserves, taking account of estimated future development expenditure relating to those reserves.

We include in cost of sales an amount for changes in lifting position. Changes in lifting position occur when there has been a change in our cumulative "over-lift" or "under-lift" for the period ending on a balance sheet

date. Over-lifts/under-lifts occur when there is an imbalance during a given period between the amount of saleable production (which is our interest in gross production less shrinkage, *e.g.*, due to process fuel used at the terminal or to value adjustments) and our sales. Such an imbalance occurs because we typically nominate the volume to be lifted and invoiced approximately two months in advance and cannot estimate future saleable production volumes with certainty. Where multiple production companies share the pipeline and processing infrastructure, any over-lift is effectively a sale of another producer's production. The over-lift liability is recorded at the cost of the production imbalance to represent a provision for production costs attributable to the volumes sold in excess of entitlement. The under-lift asset is recorded at the lower of cost and net realizable value, consistent with IAS 2 (an international financial reporting standard produced and disseminated by the International Accounting Standards Board), to represent a right to additional physical inventory. An under-lift of production from a field is included in current receivables and an over-lift of production from a field is included in current liabilities.

Cost of sales also includes gains or losses related to the ineffective portion of our foreign exchange and U.K. Emission Allowances hedging contracts.

Impairment of oil and gas assets

At each balance sheet date, we assess assets or groups of assets, called cash generating units ("**CGUs**"), for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or CGU may not be recoverable. If any such indication exists, we make an estimate of the asset's recoverable amount. An asset's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Discounted cash flow models comprising asset-by-asset life of field projections and risks specific to assets, using Level 3 inputs (based on IFRS 13 *Fair Value Hierarchy*), are used to determine the recoverable amounts. The cash flows have been modelled on a post-tax basis at management's estimate of a market participant WACC. 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 its recoverable amount. An impairment loss is recognized immediately in our income statement.

Where an impairment loss subsequently reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the asset in prior years. A reversal of an impairment loss is recognized immediately in our income statement.

General and administration expenses

General and administration expenses include staff costs, depreciation, other general and administration costs and recharge of costs to operations and joint venture partners. Staff costs are capitalized or expensed when incurred. Capitalized staff costs are included within property, plant and equipment or intangible assets based on the balance sheet classification on the underlying assets on which the employee has worked. With respect to the assets at which we are the operator, our joint venture agreements typically allow us to charge back our expenses as operator to our partners at specified percentages and subject to certain conditions. These agreements typically allow us to charge to our commercial partners an additional amount up to a specified percentage of the total costs at an asset to compensate for parent company overhead. Payments received through such chargebacks offset general and administration costs.

General and administration expenses also include business development costs, such as the costs of evaluating potential acquisitions and disposals.

Net other income and other expenses

For the periods presented, other income is comprised of the change in fair value on the Magnus Contingent Consideration. We also include reductions in decommissioning provisions for assets that have ceased production or are fully impaired, rental income, net foreign exchange gains and one-off items such as insurance income related to the Malaysia PM8/Seligi riser repairs. Other operating income includes vessel rental income, which is recognized to the extent that its probable economic benefits will flow to us and the revenue can be reliably measured.

For the periods presented, other expenses are comprised mainly of increases in the decommissioning provision for assets that have ceased production or are fully impaired, changes in relation to the estimate of the Thistle decommissioning provision, change in fair value on the Magnus Contingent Consideration, net foreign exchange losses and other expenses are costs associated with our Veri Energy business.

Following a review of market practice, the unwinding of discount on the Magnus Contingent Consideration was reclassified in the 2024 Group Financial Statements to "other income/expense" from "finance costs" in the income statement to combine it with the other fair value movements, with comparative information restated. This restatement resulted in a $58.9 million charge for the year ended December 31, 2023 being reclassified from finance costs to other income/expense.

Finance costs

Finance costs primarily include loan and bond interest, unwinding of discount on decommissioning provisions, unwinding of discount on other provisions, unwinding of discount on financial liabilities, finance charges payable under finance leases, and other financial expenses, less any amounts capitalized in relation to the development costs of any qualifying asset.

Finance income

Finance income includes bank interest receivable, unwinding of discount on financial assets and other financial income.

Income tax

Income tax represents the sum of tax currently payable and deferred tax under the laws of each jurisdiction in which we do business. This includes U.K. corporation tax, EPL and SCT as well as PRT which is payable on profits from individual fields in the U.K., Malaysian and Vietnamese petroleum and corporate income taxes.

Results of operations

Results of operations for the years ended December 31, 2024 and 2025

The following table sets forth certain of our historical revenue and expense items for the years ended December 31, 2024 and 2025.

	For the year ended December 31,	
	2024	**2025**
	(*in millions of $*)	
Revenue and other operating income	1,180.7	1,118.3
Cost of sales	(787.4)	(837.5)
Gross profit/(loss)	**393.3**	**280.8**
Net impairment reversal/(charge) to oil and gas assets	(71.4)	5.8
General and administration expenses	(5.7)	(7.5)
Other income/(expenses)	(4.7)	369.7
Profit/(loss) from operations before tax and finance income/(costs)	**311.5**	**648.8**
Finance costs	(159.4)	(164.6)
Finance income	14.5	9.2
Profit/(loss) before tax	**166.6**	**493.4**
Income tax	(72.8)	(491.9)
Profit/(loss) for the year attributable to owners of the parent	**93.8**	**1.6**

Comparison of results of operations for the years ended December 31, 2024 and 2025

Revenue and other operating income

Revenue and other operating income decreased by $62.4 million, or 5.3%, to $1,118.3 million for the year ended December 31, 2025, from $1,180.7 million for the year ended December 31, 2024, primarily reflecting lower oil prices, net of hedging, despite strong production volumes achieved from the acquisition of new assets in Vietnam. Our daily average production on a working interest basis was 42,945 boepd for the year ended December 31, 2025, compared to 40,736 boepd for the year ended December 31, 2024, with strong asset uptime performance, the contribution from the acquisition of producing interests in Vietnam and investment in low-cost, quick-payback drilling and wellwork campaigns partially offsetting the impact of natural field declines.

Our commodity hedges and other oil derivatives generated $8.7 million of realized gains for the year ended December 31, 2025, compared to $12.9 million of realized losses for the year ended December 31, 2024.

Our average realized price per barrel of oil sold (including the impact of hedging) was $68.8/bbl for the year ended December 31, 2025, compared to $80.2/bbl for the year ended December 31, 2024.

Cost of sales

Cost of sales increased by $50.1 million, or 6.4%, to $837.5 million for the year ended December 31, 2025 from $787.4 million for the year ended December 31, 2024, primarily as a result of higher volumes and prices associated with third-party West of Shetland gas that crosses the Magnus facility.

Operating costs, which include production costs, tariff and transportation expenses and the effect of any realized gains or losses on derivatives related to operating costs, increased by $11.2 million, or 2.9%, to $394.0 million for the year ended December 31, 2025 from $382.8 million for the year ended December 31, 2024, primarily due to production growth and the weaker U.S. dollar.

Production costs increased to $344.5 million for the year ended December 31, 2025 from $307.6 million for the year ended December 31, 2024. Tariff and transportation expenses decreased to $69.2 million for the year ended December 31, 2025 from $70.5 million in the year ended December 31, 2024.

Average adjusted unit operating cost decreased by $0.5/boe, or 2.0%, to $25.1/boe for the year ended December 31, 2025 from $25.6/boe for the year ended December 31, 2024, reflecting production growth as well as the weaker U.S. dollar for costs denominated in pounds sterling.

Our depletion expense increased by $4.0 million, or 1.5%, to $267.3 million for the year ended December 31, 2025 from $263.3 million for the year ended December 31, 2024, mainly reflecting the impact of the Vietnam acquisition.

The charge relating to our lifting position and inventory was $17.4 million (2024: charge of $2.2 million), reflecting the optimization of oil sales from Magnus.

Other cost of operations of $179.6 million were higher than in 2024 ($135.0 million), driven predominantly by higher volumes and prices associated with third-party West of Shetland gas that crosses the Magnus facility.

Other cost of sales of a gain of $20.8 million reflects unrealized gains on foreign exchange and UKA forward contracts, compared to a loss of $4.1 million in 2024.

Net impairment reversal/(charge) to oil and gas assets

Net impairment to oil and gas assets was a reversal of $5.8 million for the year ended December 31, 2025 compared to a charge of $71.4 million for the year ended December 31, 2024. The reversal in 2025 was primarily related to a combination of a reduction in the discount rate to 9.0% (from 10.0% as of December 31, 2024), reductions in near-term oil price assumptions (reflecting market dynamics) and updated production and cost profiles, including the impact of a weaker U.S. dollar.

The net impairment charge in 2024 primarily related to an extension of the U.K. EPL (including the two-year extension to March 31, 2030), lower short-term oil price assumptions and changes to the production profile of the non-operated Golden Eagle field, partially offset by production profile changes at the GKA hub and a lower discount rate.

General and administration expenses

General and administration expenses increased by $1.8 million, or 31.6%, to $7.5 million for the year ended December 31, 2025 from $5.7 million reported in the year ended December 31, 2024. The increase was primarily due to lower recharge of costs to operations and joint venture partners, partially offset by a decrease in staff costs from $75.8 million in 2024 to $73.6 million in 2025, as well as decreases in depreciation and other general and administrative costs.

Other income/expenses

Net other income was $369.7 million for the year ended December 31, 2025, compared to net other expenses of $4.7 million for the year ended December 31, 2024. The change was primarily due to a net $387.1 million non-cash credit that was triggered by our agreement with bp to settle the outstanding Magnus profit share element of contingent consideration for $60.0 million. Also included within other expenses are costs associated with our Veri Energy business of $3.6 million (2024: $1.7 million).

Finance costs

Finance costs increased by $5.2 million, or 3.3% to $164.6 million for the year ended December 31, 2025 from $159.4 million for the year ended December 31, 2024 primarily due to an increase in bond interest of $14.3 million, partially offset by a $12.5 million reduction in loan interest.

The following table sets forth additional details on our finance costs for the years ended December 31, 2024 and 2025.

	For the year ended December 31,		
	2024	2025	% Change
	(in millions of $)		
Loan interest payable	18.5	6.0	(67.6)
Bond interest payable	55.0	69.3	26.0
Unwinding of discount on decommissioning provisions	30.3	35.9	18.5
Unwinding of discount on other provisions	0.9	0.8	(11.1)
Debt refinancing fees	4.8	—	(100.0)
Finance charges payable under leases	27.7	25.1	(9.4)
Finance fees on loans and bonds including amortization of capitalized fees	14.5	15.3	5.5
Other financial expenses	7.8	12.2	56.4
Total finance costs	**159.4**	**164.6**	**3.3**

Finance income

Finance income decreased by $5.3 million, or 36.6%, to $9.2 million for the year ended December 31, 2025 from $14.5 million for the year ended December 31, 2024 primarily due to lower interest receivable from bank balances.

The following table sets forth additional details on our finance income for the years ended December 31, 2024 and 2025.

	For the year ended December 31,		
	2024	2025	% Change
	(in millions of $)		
Bank interest receivable	11.1	6.5	(41.4)
RockRose loan interest	3.3	2.6	(21.2)
Other financial income	0.1	0.1	—
Finance income	**14.5**	**9.2**	**(36.6)**

Income tax

Income tax increased by $419.1 million, or 575.7%, to $491.9 million for the year ended December 31, 2025 from $72.8 million for the year ended December 31, 2024, primarily due to a non-cash deferred tax charge of $374.7 million. The non-cash deferred tax charge includes the non-cash impact of the two-year extension to the EPL and the non-cash impact of the Magnus profit share settlement, as well as other non-cash tax charges that reflect the utilization of our strategic U.K. North Sea tax asset in the period and tax on unrealized hedge gains.

Results of operations for the year ended December 31, 2023 and 2024

The following table sets forth certain of our historical revenue and expense items for the years ended December 31, 2023 and 2024.

	For the year ended December 31,	
	2023	2024
	(*in millions of $*)	
Revenue and other operating income	1,487.4	1,180.7
Cost of sales	(946.8)	(787.4)
Gross profit/(loss)	**540.7**	**393.3**
Net impairment reversal/(charge) to oil and gas assets	(117.4)	(71.4)
General and administration expenses	(6.3)	(5.7)
Other expenses[(1)]	(19.6)[(2)]	(4.7)
Profit/(loss) from operations before tax and finance income/(costs)	**397.4**	**311.5**
Finance costs	(172.1)[(2)]	(159.4)
Finance income	6.5	14.5
Profit/(loss) before tax	**231.8**	**166.6**
Income tax	(262.6)	(72.8)
Profit/(loss) for the year attributable to owners of the parent	**(30.8)**	**93.8**

(1) "Other expenses" is shown as the net amount of "other income" and "other expenses" in our 2023 Group Financial Statements.

(2) In respect of the year ended December 31, 2023, the unwinding of discount on the Magnus Contingent Consideration was reclassified in the 2024 Group Financial Statements to "other income/expense" from "finance costs" in the income statement to combine it with the other fair value movements. Therefore, these amounts are derived from the comparative column of the 2024 Group Financial Statements.

Comparison of results of operations for the years ended December 31, 2023 and 2024

Revenue and other operating income

Revenue and other operating income decreased by $306.7 million, or 20.6%, to $1,180.7 million for the year ended December 31, 2024, from $1,487.4 million for the year ended December 31, 2023, primarily reflecting lower volumes and commodity prices, including lower gas prices from the onward sale of gas purchased from third-party West of Shetland fields under the terms of the Magnus Acquisition. The contribution of these volumes to revenue is therefore offset through a charge to cost of sales. Our daily average production on a working interest basis was 40,736 boepd for the year ended December 31, 2024, compared to 43,812 boepd for the year ended December 31, 2023, with strong uptimes across the portfolio and investment in low-cost, quick-payback drilling and wellwork campaigns partially offsetting the impact of natural field declines.

Our commodity hedges and other oil derivatives generated $12.9 million of realized losses for the year ended December 31, 2024, compared to $11.3 million of realized losses for the year ended December 31, 2023.

Our average realized price per barrel of oil sold (including the impact of hedging) was $80.2/bbl for the year ended December 31, 2024, compared to $81.4/bbl for the year ended December 31, 2023.

Cost of sales

Cost of sales decreased by $159.4 million, or 16.8%, to $787.4 million for the year ended December 31, 2024 from $946.8 million for the year ended December 31, 2023, primarily as a result of lower production costs and lower depletion expense, partially offset by higher operating costs.

Operating costs, which include production costs, tariff and transportation expenses and the effect of any realized gains or losses on derivatives related to operating costs, increased by $35.6 million, or 10.3%, to $382.8 million for the year ended December 31, 2024 from $347.2 million for the year ended December 31, 2023, primarily due to an increase in our share of throughput at SVT, resulting in higher tariff costs.

Production costs slightly decreased to $307.6 million for the year ended December 31, 2024 from $308.3 million for the year ended December 31, 2023. Tariff and transportation expenses increased to $70.5 million for the year ended December 31, 2024 from $41.7 million in the year ended December 31, 2023.

Average adjusted unit operating cost (including hedging) increased by $3.9/boe, or 18.0%, to $25.6/boe for the year ended December 31, 2024 from $21.7/boe for the year ended December 31, 2023, reflecting higher tariffs and lower production volumes.

Our depletion expense decreased by $28.9 million, or 9.9%, to $263.3 million for the year ended December 31, 2024 from $292.2 million for the year ended December 31, 2023, mainly reflecting lower production.

The charge relating to our lifting position and inventory was $2.2 million (2023: credit of $4.2 million).

Other cost of operations of $136.3 million were significantly lower than in 2023 ($305.9 million), driven predominantly by lower gas prices impacting the cost of Magnus-related third-party gas purchases which are sold on.

Net impairment charge to oil and gas assets

Net impairment charge to oil and gas assets was a charge of $71.4 million for the year ended December 31, 2024 compared to a charge of $117.4 million for the year ended December 31, 2023. The charge in 2024 was primarily related to an extension of the U.K. EPL (including the two-year extension to March 31, 2030), lower short-term oil price assumptions and changes to the production profile of the non-operated Golden Eagle field, partially offset by production profile changes at the GKA hub and a lower discount rate.

The net impairment charge in 2023 primarily related to oil and gas assets ($123.5 million) and right-of-use assets ($6.1 million reversal) within the North Sea reportable segment and primarily due to production and cost profile updates on non-operated assets, partially offset by higher forecast long-term oil prices.

General and administration expenses

General and administration expenses decreased by $0.6 million, or 9.5%, to $5.7 million for the year ended December 31, 2024 from $6.3 million reported in the year ended December 31, 2023. The decrease was primarily due to lower charge out of share-based payments.

Other income/expenses

The impact of both the unwind of discount and other changes in fair value of Magnus Contingent Consideration have been combined in other income and expenses following a review of market practice. This required a $58.9 million charge for 2023 being reclassified from finance costs. See also "*Explanation of income statement items—Net other income and other expenses*."

Net other expenses decreased by $14.9 million to $4.7 million for the year ended December 31, 2024, from net other expenses of $19.6 million for the year ended December 31, 2023, primarily due to the unwinding of discounting offset by changes in the near-term oil price assumptions and production and cost profiles. Also included within other expenses are costs associated with our Veri Energy business of $1.7 million (2023: $1.6 million).

Finance costs

Finance costs decreased by $12.7 million, or 7.4% to $159.4 million for the year ended December 31, 2024 from $172.1 million for the year ended December 31, 2023 primarily due to a lower overall interest charge as a result of a significantly lower level of outstanding loans and borrowings, which was partially offset by higher refinancing fees of $19.3 million, including the accelerated amortization of the remaining initial term loan fees and the early redemption fee paid following the repayment in full of the then outstanding term loan in October 2024.

The following table sets forth additional details on our finance costs for the years ended December 31, 2023 and 2024.

	For the year ended December 31,		
	2023	**2024**	**% Change**
	(in millions of $)		
Loan interest payable	30.7	18.5	(39.7)
Bond interest payable	59.0	55.0	(6.8)
Unwinding of discount on decommissioning provisions	24.2	30.3	25.2
Unwinding of discount on other provisions	1.1	0.9	18.2
Debt refinancing fees	–	4.8	–

	For the year ended December 31,		
	2023	2024	% Change
	(in millions of $)		
Finance charges payable under leases	43.8	27.7	36.8
Finance fees on loans and bonds including amortization of capitalized fees	7.9	14.5	83.5
Other financial expenses	5.3	7.8	47.2
Total finance costs	**172.1**	**159.4**	**(7.4)**

Finance income

Finance income increased by $8.0 million, or 62.5%, to $14.5 million for the year ended December 31, 2024 from $6.5 million for the year ended December 31, 2023 primarily due to higher bank interest receivable from additional cash on deposit and accrued interest on the RockRose vendor loan.

The following table sets forth additional details on our finance income for the years ended December 31, 2023 and 2024.

	For the year ended December 31,		
	2023	2024	% Change
	(in millions of $)		
Bank interest receivable	6.5	11.1	261.1
RockRose loan interest	—	3.3	—
Other financial income	—	0.1	—
Finance income	**6.5**	**14.5**	**62.5**

Income tax

Income tax decreased by $189.8 million, or 72.3%, to $72.8 million for the year ended December 31, 2024 from $262.6 million for the year ended December 31, 2023, primarily due to a decrease in current income tax, partially offset by an increase in non-cash deferred tax relating to the EPL.

Liquidity

We closely monitor and manage our funding position and liquidity risk throughout the year, including monitoring forecast covenant results to ensure we have access to sufficient funds to meet forecast cash requirements. Cash forecasts are regularly produced and sensitivities considered for, but not limited to, changes in crude oil prices (adjusted for the hedging we undertake), production rates and costs.

Our liquidity requirements arise principally from our capital investment and working capital requirements. For the periods presented, we met our working capital requirements primarily from oil revenues from our producing assets and debt financing through ongoing drawings on the RBL Facility and through other debt financing.

We held cash and cash equivalents of $313.6 million, $280.2 million and $268.8 million as of December 31, 2023, 2024 and 2025, respectively, which included restricted cash of $0.5 million, $53.9 million and $3.0 million, respectively. As of December 31, 2025, restricted cash includes $1.2 million placed in escrow accounts for 2025 decommissioning security agreement obligations and $1.8 million related to the deposit of a performance bond in Indonesia.

As of December 31, 2025, letter of credit utilization was $381.5 million, and $400.0 million remained available for drawdown under the RBL loan facility.

Cash flow

The following table sets forth group cash flow information for the years ended December 31, 2023, 2024 and 2025.

	For the year ended December 31,		
	2023	2024	2025

			(in millions of $)
OPERATING ACTIVITIES			
Cash generated from operations	854.7	685.9	497.8
Cash paid in relation to amounts previously provided for	—	(9.1)	(0.5)
Net cash received for trading of other intangible assets	—	—	26.8
Cash paid for purchase of other intangible assets	—	(1.1)[1]	(6.5)
Cash received from insurance	5.2	—	—
Cash received/(paid) on sale/(purchase) of financial instruments	(5.8)	(10.3)	9.1
Decommissioning spend	(58.9)	(60.5)	(56.8)
Income taxes paid	(41.0)	(97.3)	(107.2)
Net cash flows from operating activities	**754.2**	**507.6[1]**	**362.7**
INVESTING ACTIVITIES			
Purchase of property, plant and equipment	(141.7)	(249.2)	(175.0)
Proceeds from farm-down	141.4	1.3	—
Vendor financing facility (loaned)/repaid	(141.4)	107.5	—
Purchase of intangible oil and gas assets	(10.5)	(3.7)	(4.2)
Purchase of other intangible assets	(0.9)	—[1]	—
Payment of Magnus Contingent Consideration — Profit share	(65.5)	(48.5)	—
Payment of Golden Eagle contingent consideration — Acquisition	(50.0)	—	—
Interest received	5.9	10.1	5.3
Acquisition	—	—	(20.3)
Net cash flows (used in) investing activities	**(262.7)**	**(182.4)[1]**	**(194.2)**
FINANCING ACTIVITIES			
Proceeds from loans and borrowings	190.8	31.7	152.4
Repayment of loans and borrowings	(427.7)	(162.3)	(146.5)
Payment for repurchase of shares	—	(9.0)	—
Payment of obligations under financing leases	(135.7)	(130.1)	(83.1)
Dividend paid	—	—	(15.3)
Interest paid	(105.9)	(83.2)	(97.0)
Other finance expenses paid	—	—	(3.6)
Net cash flows used in financing activities	**(478.6)**	**(352.9)**	**(193.0)**
Net (decrease)/increase in cash and cash equivalents	**12.9**	**(27.7)**	**(24.5)**
Net foreign exchange on cash and cash equivalents	(1.0)	(5.6)	13.1
Cash and cash equivalents at January 1	301.6	313.6	280.2
Cash and cash equivalents as of December 31	**313.6**	**280.2**	**268.8**
Reconciliation of cash and cash equivalents			
Total cash at bank and in hand	313.0	226.3	265.9
Restricted cash[2]	0.5	53.9	3.0
Cash and cash equivalents per balance sheet	**313.6**	**280.2**	**268.8**

(1) In respect of the year ended December 31, 2024, "purchases of intangible assets" of $1.1 million in investing activities was reclassified to operating activities as "cash paid for purchase of other intangible assets" in the 2025 Group Financial Statements (resulting in a decrease of net cash flows from operating activities in an amount of $1.1 million and a decrease of net cash flows used in investing activities in an amount of $1.1 million), but has not been restated for prior periods as not material.

(2) As of December 31, 2025, restricted cash includes $1.2 million placed in escrow accounts for 2025 decommissioning security agreement obligations and $1.8 million related to the deposit of a performance bond in Indonesia.

Net cash flows from operating activities

Net cash flows from operating activities was $362.7 million for the year ended December 31, 2025 compared to $507.6 million generated for the year ended December 31, 2024. The decrease in net cash flows from operating activities was primarily driven by lower oil revenues due to the year-on-year decline in Brent prices.

Net cash flows from operating activities was $507.6 million for the year ended December 31, 2024 compared to $754.2 million generated for the year ended December 31, 2023. The decrease in net cash flows from operating activities was primarily driven by lower revenue, higher cash tax payments, unwinding of the joint venture advance cash call received in 2023, one-off payments relating to the rig cancellation and funds released from escrow in relation to a dispute with a third party supplier in Malaysia.

Net cash flows used in investing activities

Net cash flows used in investing activities was $194.2 million for the year ended December 31, 2025, compared to $182.4 million for the year ended December 31, 2024 and $262.7 million for the year ended December 31, 2023.

The net cash flows used in investing activities for the year ended December 31, 2025 were primarily related to:

- the acquisition of Harbour Energy's business in Vietnam;
- Magnus and Malaysia well campaigns; and
- SVT projects.

The net cash flows used in investing activities for the year ended December 31, 2024 were primarily related to:

- Magnus five-yearly rig recertification;
- Golden Eagle well campaign;
- SVT projects;
- the emissions reducing flare gas recovery project on Magnus; and
- Magnus profit share payments.

These cash flows used in investment activities were partially offset by the repayment of a vendor loan provided to RockRose.

Net cash used in financing activities

Net cash flows used in financing activities amounted to $193.0 million for the year ended December 31, 2025 compared to $352.9 million for the year ended December 31, 2024. This change was primarily driven by a decrease in repayment of loans and borrowings in 2025 and lower lease payments, primarily reflecting the approximately 70% contractual step down in charges relating to the Kraken FPSO, partially offset by lease payments associated with the Vietnam FPSO, slightly offset by the net cash outflow related to a dividend declared and paid in 2025.

Net cash flows used in financing activities amounted to $352.9 million for the year ended December 31, 2024 compared to $478.6 million for the year ended December 31, 2023.

For a more detailed description of our recent financing activities, see "*—Financing*."

Capital investment

The primary objective of our capital management is to optimize the return on investment, by managing our capital structure to achieve capital efficiency while maintaining flexibility for the investment of additional capital where required. We regularly monitor the capital requirements of the business over the short, medium and long term, in order to enable us to better anticipate the timing of requirements for additional capital.

Cash capex represents investing activities on a cash basis, while cash capital and decommissioning expense represents cash capex plus our cash spend on decommissioning activities. The following table sets forth

a reconciliation of our reported net cash flows used in investing activities to cash capex and cash capital and decommissioning expense for the years ended December 31, 2023, 2024 and 2025.

	For the year ended December 31,		
	2023	**2024**	**2025**
		(in millions of $)	
Reported net cash flows used in investing activities	(262.7)	(182.4)	(194.2)
Adjustments			
Purchase of other intangible assets.....	0.9	—	—
Payment of Magnus Contingent Consideration – Profit share	65.5	48.5	—
Payment of Golden Eagle contingent consideration – Acquisition costs	50.0	—	—
Bressay-related vendor financing facility loaned / (received)	—	(107.5)	—
Proceeds from farm down activities.....	—	(1.3)	—
Acquisition.....	—	—	20.3
Interest received.....	(5.9)	(10.1)	(5.3)
**Cash capex..... **	**(152.2)**	**(252.9)**	**(179.2)**
Decommissioning spend	(58.9)	(60.5)	(56.8)
**Cash capital and decommissioning expense..... **	**(211.1)**	**(313.4)**	**(236.1)**

Capital investment has historically comprised the costs of construction of oil and gas facilities, the acquisition of interests in new assets and farm-ins to additional equity in existing assets, costs of technical services and studies, seismic acquisition and interpretation, and exploratory, appraisal, development and productivity enhancement drilling and well testing.

The following table sets forth our cash capex by asset level for the years ended December 31, 2023, 2024 and 2025.

	For the year ended December 31,		
	2023	**2024**	**2025**
U.K. North Sea.....	124.2	230.5	128.0
Malaysia and Vietnam	21.0	19.0	48.5
Exploration and evaluation	7.0	3.5	2.7
**Cash capex..... **	**152.2**	**252.9**	**179.2**

Cash capex in the year ended December 31, 2025 principally related to the Magnus and Malaysia well campaigns and SVT projects.

Cash capex in the year ended December 31, 2024 principally related to the Magnus five-yearly rig recertification, Golden Eagle drilling, decarbonization projects at SVT and the emission-reducing Magnus flare gas recovery project.

Cash capex in the year ended December 31, 2023 principally related to the Magnus, Golden Eagle and Malaysia well campaigns and SVT projects.

Future capital investment

Our capital investments are largely focused on low-cost, short-cycle drilling projects to develop our existing material reserves and resources. Our 2026 capital expenditure program is primarily related to the Magnus well campaign and further evaluation of our Bressay and South East Asian organic development opportunities.

Contractual obligations and contingent liabilities

The following table sets forth our remaining contractual maturity for our non-derivative financial liabilities with contractual repayment periods as of December 31, 2025. The table reflects the undiscounted cash

flows of financial liabilities based on the earliest date on which we could be required to pay including interest projected to be paid thereon.

	Payments due by period					
Contractual obligations	**On demand**	**Up to 1 year**	**1-2 years**	**2-5 years**	**More than 5 years**	**Total**
			(in millions of $)			
Loans	—	60.8	—	—	—	60.9
Notes[(1)]	—	69.9	714.3	—	—	784.3
Contingent considerations	—	60.3	6.7	1.4	65.6	134.0
Obligations under leases	—	97.4	231.2	59.5	26.3	414.4
Trade and other payables	—	446.5	—	—	—	446.5
Total	**—**	**735.1**	**952.2**	**60.9**	**91.9**	**1,840.1**

(1) Includes the 9% Retail Notes and the 2027 Notes. Maturity analysis profile for the 9% Retail Notes and 2027 Notes includes semi-annual coupon interest.

As is common within our industry, we have entered into various commitments related to the exploration and evaluation of, and production from, commercial oil and gas properties. As of December 31, 2023, 2024 and 2025, we had future capital commitments of $43.8 million, $13.3 million and $48.4 million, respectively. These amounts represent our obligations during the course of the following years to fulfill our contractual commitments. It is expected that such commitments will be met from cash from operations and other available liquidity without a material adverse effect on our financial position, results of operations or cash flows.

We also have potential liability for decommissioning our assets. We make full provision for the future costs of decommissioning our oil production facilities and pipeline systems on a discounted basis based on our decommissioning liability.

With respect to Heather, GKA, Thistle/Deveron, Magnus, Block 12W and PM8/Seligi, the decommissioning provisions are based on our contractual obligations rather than our working interest in the fields. We make decommissioning provisions on a working interest basis for Golden Eagle, the Dons, Broom, Alma/Galia, Alba, Kraken, Scolty/Crathes and part of the working interest in the SVT.

Our total provision represents the present value of decommissioning costs which are expected to be incurred up to 2050, assuming no further development of our assets. As of December 31, 2025, $364.3 million is expected to be utilized between one and five years (December 31, 2024: $281.1 million; December 31, 2023: $175.7 million), $373.1 million within six to ten years (December 31, 2024: $280.0 million; December 31, 2023: $355.6 million), and the remainder in later periods.

We enter into surety bonds principally to provide security for our decommissioning obligations. See "*—Financing—Letters of credit, surety bonds and restricted cash.*"

These provisions have been created based on internal and third-party estimates. Assumptions based on the current economic environment have been made which we believe are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. We cannot assure you, however, that actual decommissioning costs will not be materially greater than our estimates. See "*Risk factors*"

Financing

Our liquidity requirements arise principally from our capital investment and working capital requirements. For the periods presented, we met our capital investment and working capital requirements primarily from oil sales revenues and the proceeds of debt financing. After the completion of this Offering, we expect to meet our liquidity requirements through cash generated from our operations and oil hedge proceeds.

Our actual financing requirements will depend on a number of factors, many of which are beyond our control, including the price of crude oil. See "*Risk factors—Risks relating to the Notes and our structure—Our leverage and debt service obligations could adversely affect our business*, *financial condition*, *results of operations and our ability to satisfy our obligations under our debt*, *including the Notes and the Note Guarantees*."

Equity financing

As of December 31, 2025, EnQuest had an issued share capital of 1,885,029,503 allotted and fully paid ordinary shares of 5 pence each, of which 20,000,000 ordinary shares were held in Treasury.

Debt financing

EnQuest total debt as of December 31, 2025 amounted to $702.8 million.

The Company currently has the RBL Facility available to it which provides for aggregate commitments split as to $400.0 million in respect of a secured multicurrency revolving loan facility ("**Facility A**") and $400.0 million in respect of a secured multicurrency revolving letter of credit facility ("**Facility B**"). As of December 31, 2025, there were no drawdowns under Facility A, while the Facility B utilization was $381.5 million. See "*Description of certain financing arrangements—RBL Facility*."

As of December 31, 2025, the amount outstanding of the 2027 Notes was $465.0 million. As of December 31, 2025, the amount outstanding of the 9% Retail Notes was $179.4 million.

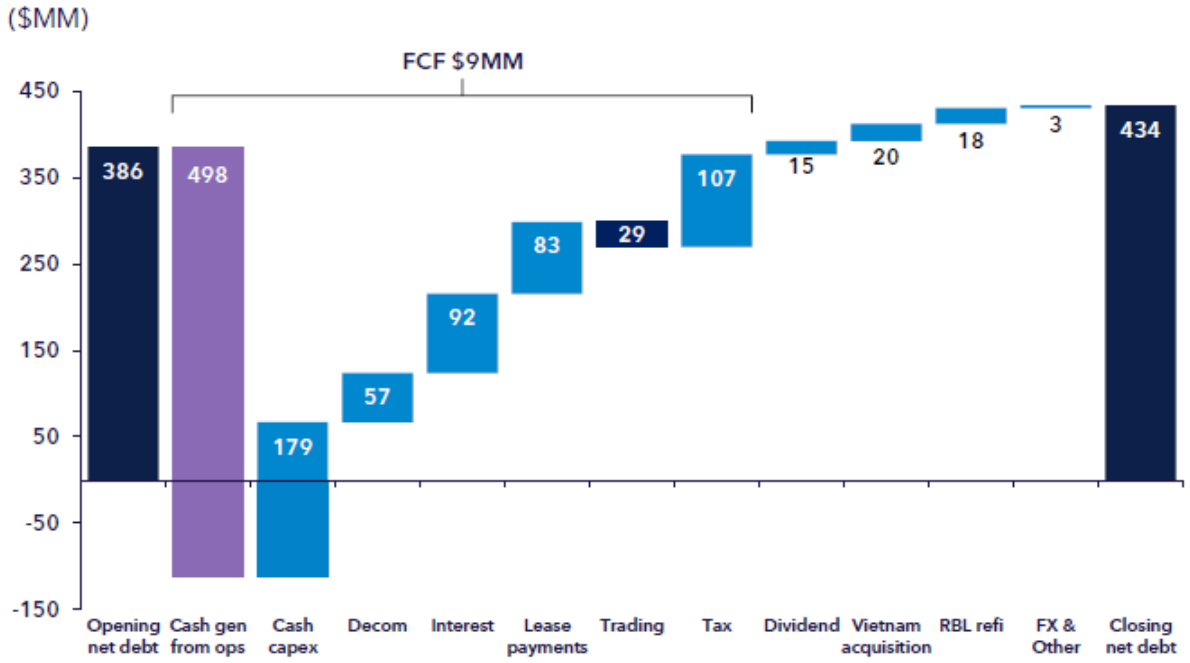
The following table sets forth our remaining contractual maturity for debt (including unamortized arrangement fees) as of December 31, 2025, on a *pro forma* basis after giving effect to the Transactions. The table has been compiled based on the undiscounted cash flows of financial liabilities on the earliest date on which we can be required to pay.

	***Pro forma* as of December 31, 2025**
	(in millions of $)
Due within one year	58.4
Due within two to five years	854.4
Due after five years	—
Total	912.8

For a more detailed description of our financing arrangements, see "*Description of certain financing arrangements*."

As part of our strategy, we aim to maintain a strong balance sheet by consistently deleveraging and making disciplined capital allocation. Since 2021, we significantly reduced our EnQuest net debt from $1.2 billion as of December 31, 2021 to $433.9 million as of December 31, 2025, representing a net debt to adjusted EBITDA ratio of 0.9x (compared to 2.5x as of December 31, 2018), primarily as a result of adjusted free cash flow generation.

The following graphic shows the evolution of EnQuest net debt during the year ended December 31, 2025.



Letters of credit, surety bonds and restricted cash

We enter into surety bonds, letters of credit and guarantees principally to provide security for our decommissioning security agreement obligations. As of December 31, 2025, we did not hold any surety bonds or cash, compared to surety bonds totaling $277 million and $250.4 million as of December 31, 2024 and 2023, respectively.

As of December 31, 2025, Facility B under the RBL Facility Agreement had $381.5 million utilized, with $18.5 million residual availability thereunder. See also above under "*—Debt financing*".

As of December 31, 2025, we did not have letters of credit or surety bonds in respect of our other assets. On January 1, 2026, certain of the letters of credit under Facility B were replaced by surety bonds resulting in our decommissioning security obligations being covered by £225.7 million utilization of Facility B and £90.0 million of surety bonds. See "*Risk factors—Risks relating to our business—We may face unanticipated increased or incremental costs in connection with decommissioning obligations*."

Qualitative and quantitative disclosures about market risk

Credit risk management

Credit risk refers to the risk that a counterparty will fail to perform or fail to pay amounts due, resulting in financial loss. We have a credit policy that governs the management of credit risk, including the establishment of counterparty credit limits and specific transaction approvals. We trade only with recognized international oil and gas operators, commodity traders and shipping companies. As of each of December 31, 2025, 2024 and 2023, we had nil trade receivables past due but not impaired. We had nil joint venture receivables past due but not impaired as of each of December 31, 2025, 2024 and 2023.

As of December 31, 2025, we had one customer accounting for 65% of outstanding trade and other receivables (2024: two customers, 91%; 2023: one customer, 58%) and four joint venture partners accounting for over 75% of outstanding joint venture receivables (2024: four joint venture partners, over 70%; 2023: no joint venture partners). We sell our production lifted to buyers in ports in Northwest Europe, the United States, the Mediterranean and/or Asia.

With respect to credit risk arising from our other financial assets, which comprise cash and cash equivalents, our exposure to credit risk arises from default of the counterparty, with a maximum exposure equal to the carrying amount of these instruments.

With respect to our decommissioning obligations, we are exposed to the risk of our commercial partners defaulting on their proportionate share of decommissioning costs once such costs became payable, which could result in us being required to bear such costs.

Cash balances can be invested in short term bank deposits and AAA rated liquidity funds, subject to Board approved limits and with a view to minimizing counterparty credit risks.

Liquidity risk management

Liquidity and refinancing risks refer to the risk that we will not be able to obtain sufficient financing from lenders and the capital markets to meet our working capital and project financing and refinancing requirements. We monitor our liquidity risk by reviewing our cash flow requirements on a regular basis relative to our existing bank facilities and outstanding debt instruments and the maturity profile of these facilities and instruments. We closely monitor and manage our liquidity requirements through the use of both short-term and long-term cash flow projections, supplemented by maintaining debt financing plans and active portfolio management. Cash forecasts are regularly produced and sensitivities considered for, but not limited to, changes in crude oil prices (adjusted for hedging undertaken by us), production rates and costs. In addition to our operating cash flows, portfolio management opportunities are reviewed to potentially enhance our financial capacity and flexibility. Ultimate responsibility for liquidity risk management rests with our board of directors, which has built a liquidity risk management framework which we believe to be appropriate for the management of all our funding and liquidity management requirements. Throughout the year ending and as of December 31, 2025, we were in compliance with all applicable financial covenant ratios agreed and we continue to manage ongoing compliance. See "*Risk factors—Risks relating to the Notes and our structure—Our leverage and debt service obligations could adversely affect our business*, *financial condition*, *results of operations and our ability to satisfy our obligations under our debt*, *including the Notes and the Note Guarantees*."

Foreign currency risk management

We are exposed to foreign currency risk arising from movements in currency exchange rates. Our functional currency is the U.S. dollar, primarily because we price our oil in U.S. dollars; however, our operations are entirely outside the United States and the majority of our costs are denominated in currencies other than the U.S. dollar. Additionally, our 9% Retail Notes, the SVT Working Capital Facility, the vendor financing facility and any U.K. EPL cash tax payments are denominated in pounds sterling. As a result, we are exposed to both transactional and translational foreign exchange risk.

Our transactional foreign currency risk arises primarily from sales or purchases in currencies other than our functional currency, the U.S. dollar. We manage this risk by converting U.S. dollar receipts at spot rates periodically and as required for payments in other currencies. For the years ended December 31, 2025, 2024 and 2023, 17%, 12% and 22%, respectively, of our sales and 98%, 97% and 95%, respectively, of costs (including operating and capital expenditure and general and administration costs) were denominated in currencies other than the U.S. dollar.

Our translational foreign currency exposure arises from the translation of assets and liabilities denominated in currencies other than U.S. dollars. To mitigate the risks of substantial fluctuations in the currency markets, our hedging policy allows for up to 70% of the non-U.S. dollar portion of our annual capital budget and operating expenditure to be hedged. For specific contracted capital expenditure projects, up to 100% can be hedged.

We will continue to consider opportunities to enter into foreign exchange hedging contracts. The following table sets forth the impact on our pre-tax profit (due to change in the fair value of monetary assets and liabilities) of the variations in the U.S. dollar to pound sterling exchange rate covered below.

	Pre-tax profit	
	+10% dollar rate increase	**−10% dollar rate decrease**
	(*in $ millions*)	
December 31, 2025	(22.2)	22.2
December 31, 2024	(28.3)	28.3
December 31, 2023	(34.9)	34.9

We cannot assure you that our financial condition and results of operations will not be negatively affected by risks related to foreign currency movements. See "*Risk factors—Risks relating to our business— We are subject to both transactional and translational foreign exchange and inflation risks, which might adversely affect our financial condition and results of operations*."

Commodity price risk management

Oil price hedging

We are exposed to the impact of changes in Brent crude oil prices on our revenue and profits. Our policy is to have the flexibility to hedge oil prices up to a maximum of 75% of the next 12 months' production on a rolling annual basis, up to 60% in the following 12-month period, and 50% in the subsequent 12-month period.

Under the terms of the RBL Facility Agreement, we are required, subject to grace periods where increased required hedge volumes arise, to hedge as follows, where references below to "**total relevant outstandings**" means the aggregate amount of all utilizations under the RBL Facility disregarding Eligible L/Cs and other letters of credit to the extent the same are subject to cash cover :

- From the RBL Effective Date to but excluding June 30, 2029:
    - where the total relevant outstandings are 10% or less of the then current borrowing base amount: a minimum of 10% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the (i) 12 months following the relevant quarter date and (ii) from the date 12 months after the relevant quarter date to the date 24 months after that date.
    - where the total relevant outstandings are more than 10% but less than 50% of the then current borrowing base amount: a minimum of (i) 30% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months following the relevant quarter date and (ii) 15% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months after the relevant quarter date to the date 24 months after that date.
    - where the total relevant outstandings are 50% or more of the then current borrowing base amount: a minimum of (i) 45% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months following the relevant quarter date and (ii) 30% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months after the relevant quarter date to the date 24 months after that date.
- On and from June 30, 2029:
    - where the total relevant outstandings are less than 50% of the then current borrowing base amount: a minimum of (i) 30% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months following the relevant quarter date and (ii) 15% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months after the relevant quarter date to the date 24 months after that date.

where the total relevant outstandings are 50% or more of the then current borrowing base amount: a minimum of (i) 45% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months following the relevant quarter date and (ii) 30% of forecast volumes of net crude oil and natural gas entitlement production

related to borrowing base assets which are not development assets expected to be produced in the 12 months after the relevant quarter date to the date 24 months after that date.

This requirement ceases at maturity of the RBL Facility.

In all cases, minimum floor protection will be equal to or above the lower of 90% of the economic assumption as to hydrocarbon prices included in the then-current banking case and 90% of the forward price curve at the time of hedge execution.

As of April 15, 2026, we have approximately 3.8 MMbbls of production hedged through 2026, utilizing swaps at an average price of $73.2/bbl, and we have approximately 3.5 MMbbls of production hedged for 2027, utilizing swaps at an average price of $64.4/bbl. Finally, we have approximately 0.9 MMbbls of production hedged for 2028, utilizing swaps at an average price of $64.6/bbl. See "*Risk factors—Risks relating to our business—Our commodity hedging activities may not be effective*."

The following table sets forth the impact on our pre-tax profit of the variations in crude oil prices covered below, with all other variables held constant.

	Pre-tax profit,	
	+$10/bbl increase	**−$10/bbl decrease**
	(in $ millions)	
December 31, 2025	(42.6)	42.9
December 31, 2024	(47.6)	47.2
December 31, 2023	(4.0)	7.4

Commodity derivative contracts at fair value through profit or loss

Commodity derivative contracts are designated as at fair value through profit or loss, and gains and losses on these contracts are recognized as a component of revenue. These contracts typically include bought and sold call options, bought put options and commodity swap contracts.

The mark-to-market value of our open contracts as of December 31, 2025 was a net asset of $34.8 million.

For the year ended December 31, 2025, gains totaling $53.9 million were recognized in respect of commodity contracts designated as fair value through profit or loss. This included gains totaling $8.7 million realized on contracts that matured during the year and mark-to-market unrealized gains of $45.2 million.

For the year ended December 31, 2024, losses totaling $9.8 million were recognized in respect of commodity contracts designated as fair value through profit or loss. This included losses totaling $12.9 million realized on contracts that matured during the year ended December 31, 2023, and mark-to-market unrealized gains totaling $3.1 million.

The mark-to-market value of our open contracts as of December 31, 2024 was a liability of $10.4 million.

For the year ended December 31, 2023, gains totaling $17.2 million were recognized in respect of commodity contracts designated as fair value through profit or loss. This included losses totaling $11.3 million realized on contracts that matured during the year ended December 31, 2023, and mark-to-market unrealized gains totaling $28.5 million.

The mark-to-market value of our open contracts as of December 31, 2023 was a liability of $13.9 million.

Interest rate risk management

Interest rate risk refers to the risk that market interest rates will increase, resulting in higher borrowing costs under our credit facilities which have floating interest rates, including the RBL Facility, and also including the SVT Working Capital Facility, each of which has a SOFR or SONIA linked interest rate.

We may be affected by changes in market interest rates at the time we need to refinance any of our indebtedness. See "*Risk factors—Risks relating to the Notes and our structure—Certain of our borrowings bear interest at floating rates, which could rise significantly, thereby increasing our interest cost and reducing cash flow*."

Critical accounting estimates and judgments

This "*Management's discussion and analysis of financial condition and results of operations*" discusses our Group Financial Statements, which have been prepared in accordance with IFRS. Accounting estimates are an integral part of the preparation of the financial statements and the financial reporting process and are based upon current judgments. The preparation of financial statements in conformity with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. Certain accounting estimates are particularly sensitive because of their complexity and the possibility that future events affecting them may differ materially from our current judgments and estimates. See "*Risk factors—Risks relating to our business—Our tax liability is subject to estimation and we may be adversely affected by changes to tax legislation or its interpretation or increases in effective tax rates in the jurisdictions in which we do business*."

This listing of critical accounting policies is not intended to be a comprehensive list of all our accounting policies, and outlines the critical accounting estimates and judgments as described in the 2025 Group Financial Statements. In many cases, the accounting treatment of a particular transaction is specifically dictated by IFRS, with no need for management's judgement regarding accounting policy. We believe that of our significant accounting policies, the following policies may involve a higher degree of judgement and complexity.

We do not consider deferred taxation (including EPL) to represent a significant estimate or judgement as the estimates and assumptions relating to projected earnings and cash flows used to assess deferred taxation are the same as those applied in our impairment process as described below.

Recoverability of asset carrying values

Judgments

We assess each asset or cash-generating unit ("**CGU**") (excluding goodwill, which is assessed annually regardless of indicators) in each reporting period to determine whether any indication of impairment exists. Assessment of indicators of impairment or impairment reversal and the determination of the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment purposes require significant management judgment. For example, individual oil and gas properties may form separate CGUs while certain oil and gas properties with shared infrastructure may be grouped together to form a single CGU. Alternative groupings of assets or CGUs may result in a different outcome from impairment testing.

Estimates

Where an indicator of impairment exists, a formal estimate of the recoverable amount is made, which is considered to be the higher of the FVLCD and value in use ("**VIU**"). The assessments require the use of estimates and assumptions, such as the effects of inflation and deflation on operating expenses, cost profile changes including those related to emission reduction initiatives such as alternative fuel provision at Kraken, discount rates, capital expenditure, production profiles, reserves and resources and future commodity prices, including the outlook for global or regional market supply-and-demand conditions for crude oil and natural gas. Such estimates reflect management's best estimate of the related cash flows based on management's plans for the assets and their future development.

As described above, the recoverable amount of an asset is the higher of its VIU and its FVLCD. When the recoverable amount is measured by reference to FVLCD, in the absence of quoted market prices or binding sale agreement, estimates are made regarding the present value of future post-tax cash flows. These estimates are made from the perspective of a market participant and include prices, life of field production profiles, operating costs, capital expenditure, decommissioning costs, tax attributes, risking factors applied to cash flows and discount rates. Reserves and resources are included in the assessment of FVLCD to the extent that it is considered probable that a market participant would attribute value to them.

The estimates for assumptions made in impairment tests in 2024 and 2025 relating to discount rates and oil prices are discussed below. Changes in the economic environment or other facts and circumstances may necessitate revisions to these assumptions and could result in a material change to the carrying values of our assets within the next financial year.

Discount rates

For discounted cash flow calculations, future cash flows are adjusted for risks specific to the CGU. Fair value less costs of disposal ("**FVLCD**") discounted cash flow calculations use the post-tax discount rate. The discount rate is derived using the weighted average cost of capital methodology. The discount rates applied in impairment tests are reassessed each year and, in 2025, the post-tax discount rate was estimated at 9.0% (2024: 10.0%) reflecting the impact from our reduced debt position and clarity over the U.K. fiscal system.

Oil prices

The price assumptions used for FVLCD impairment testing were based on the latest internal forecasts as of December 31, 2025, which assume short-term market prices will revert to our assessment of long-term oil price. These price forecasts reflect our long-term views of global supply and demand, including the potential financial impacts of climate change and the transition to a low carbon economy and are benchmarked with external sources of information such as analyst forecasts. Our price forecasts are reviewed and approved by management, the audit committee and the board of directors.

We revised our oil price assumptions for FVLCD impairment testing compared to those used in 2024, with nearer-term prices reflecting current market dynamics and external forecasts. Our oil price assumptions, which represent management's best estimate of future prices, sit within the range of external forecasts. Discounts or premiums are applied to price assumptions based on the characteristics of the oil produced and the terms of the relevant sales contracts.

When compared to the latest available Paris-consistent climate scenario modelling data released by the World Business Council of Sustainable Development in May 2024, our assumption is broadly aligned with the top end of a range of Paris-consistent scenarios. When compared to the International Energy Agency's ("**IEA**") forecast prices under its Net Zero Emissions by 2050 Scenario ("**NZE**") published in November 2025, which is also considered a Paris-consistent scenario and maps out a pragmatic but ambitious global pathway for the energy sector to achieve net zero CO_2 emissions by 2050 and is consistent with a long-term goal of limiting the rise in global average temperatures to 1.5°C (with a 50% probability), our short-term assumptions are below those assumed under the NZE, while our medium and longer-term prices are significantly higher. We believe a 10% reduction in crude oil price assumptions to be a reasonably possible change.

An inflation rate of 2% (2024: 2%) is applied from 2030 onwards to determine the price assumptions in nominal terms (see table below). The price assumptions used in 2024 were $75.0/bbl (2025), $75.0/bbl (2026), $75.0/bbl (2027) and $76.5/bbl real thereafter, inflated at 2.0% per annum from 2028.

	2026	2027	2028	2029>[1]
Brent oil ($/bbl)	65.0	67.5	72.5	75.0

(1) Inflated at 2% from 2030.

Oil and natural gas reserves

Hydrocarbon reserves are estimates of the amount of hydrocarbons that can be economically and legally extracted from our oil and gas properties. Our business is to responsibly optimize production, leverage existing infrastructure, deliver a strong decommissioning performance and explore new energy and decarbonization opportunities. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity and drilling of new wells all impact on the determination of our estimates of our oil and gas reserves and result in different future production profiles affecting prospectively the discounted cash flows used in impairment testing and the calculation of contingent consideration, the anticipated date of decommissioning and the depletion charges in accordance with the unit of production method, as well as the going concern assessment. Economic assumptions used to estimate reserves change from period-to-period as additional technical and operational data is generated. This process may require complex and difficult geological judgments to interpret the data.

We use 2P Reserves and, for the Kraken CGU, 2C Resources associated with the Bressay gas well as an alternative fuel provision for the Kraken FPSO, as the basis for calculations of expected future cash flows from underlying assets because this represents the reserves and resources management intends to develop and it is

probable that a market participant would attribute value to them. Third-party audits of our reserves are conducted annually.

Sensitivity analysis

Changes in price and its consequential impact on impairment and deferred tax, along with the discount rate impact on impairment and decommissioning are considered to be the only key sources of estimation uncertainty, although other sensitivities not considered to have a significant risk of resulting in material changes to carrying amounts in the next 12 months, may also be provided.

We tested the impact of a change in cash flows in FVLCD impairment testing arising from a 10% reduction in price assumptions, which we believe to be a reasonably possible change given the prevailing macroeconomic environment.

Price reductions of this magnitude in isolation could indicatively lead to a further reduction in the carrying amount of our oil and gas properties by approximately $198.7 million, which is approximately 8% of the net book value of property, plant and equipment as of December 31, 2025.

The oil price sensitivity analysis above does not, however, represent our best estimate of any impairments that might be recognized as it does not incorporate consequential changes that may arise, such as reductions in costs and changes to business plans, phasing of development, levels of reserves and resources, and production volumes. As the extent of a price reduction increases, the more likely it is that costs would decrease across the industry. The oil price sensitivity analysis therefore does not reflect a linear relationship between price and value that can be extrapolated.

We also tested the impact of a one percentage point change in the discount rate used of 9.0% for FVLCD impairment testing of oil and gas properties, which is considered a reasonably possible change given the prevailing macroeconomic environment. If the discount rate was 1% higher across all tests performed, the net impairment charge recognized in the year ended December 31, 2025 would have been approximately $51.9 million higher. If the discount rate was 1% lower, the net impairment reversal recognized in the year ended December 31, 2025 would have been approximately $24.3 million higher.

Goodwill

Irrespective of whether there is any indication of impairment, we are required to test annually for impairment of goodwill acquired in business combinations. As of December 31, 2025, we carried goodwill of $139.5 million on our balance sheet (December 31, 2024: $134.4 million), principally relating to the acquisition of Magnus oil field (acquired in 2018) in the UK and Block 12W in Vietnam (acquired in 2025).

Deferred tax

We assess the recoverability of our deferred tax assets at each period end.

Magnus Acquisition contingent consideration

Judgement: During 2025, management commenced discussions with bp to settle the Magnus contingent consideration arrangement. Management assessed that the agreement to settle the Magnus contingent consideration, signed and concluded in February 2026, was substantially agreed with bp as of December 31, 2025. Therefore, the agreement price of $60.0 million was deemed to be a reasonable fair value in line with IFRS 13, for the contingent consideration as of December 31, 2025, resulting in a pre-tax gain of $391.3 million. If management had concluded the agreement was not substantially complete at year end, the contingent consideration would have continued to be valued based on the present value of the future expected cash flows from the Magnus field, which on June 30, 2025 resulted in a provision of $432.9 million being recorded.

Provisions

Estimates

We incur decommissioning costs at the end of the operating life of some of our oil and gas production facilities and pipelines. We assess our decommissioning provision at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors, including changes

to relevant legal requirements, estimates of the extent and costs of decommissioning activities, the emergence of new restoration techniques and experience at other production sites. The expected timing, extent and amount of expenditure may also change, for example, in response to changes in oil and gas reserves or changes in laws and regulations or their interpretation. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning. As a result, there could be significant adjustments to the provisions established which would affect future financial results, although this is not expected within the next year.

The timing and amount of future expenditures relating to decommissioning and environmental liabilities are reviewed annually. The rate used in discounting the cash flows is reviewed half-yearly. We assess discount rates in each geography in which we operate using an appropriate benchmark, usually government bonds. As such, the nominal discount rate used to determine the balance sheet obligations ranged from 3.1% to 4.5% in the year ended December 31, 2025 (2024: 3.1% to 4.5%). Costs at future prices are determined by applying inflation rates. The inflation rates applied are usually management's estimate based on relevant in-country benchmarking, but in certain circumstances inflation is applied in accordance with the relevant operating agreement. As such, where inflation has been applied to decommissioning costs, it has ranged between 1.0% and 2.0% per annum thereafter (2024: 1.0% to 2.0%). The weighted average period over which North Sea decommissioning costs are generally expected to be incurred is estimated to be approximately 12 years.

Changes in assumptions could result in a material change in their carrying amounts within the next financial year. A sensitivity has only been run for the U.K. North Sea segment given its materiality compared to Malaysia and Vietnam. A 1% decrease in the nominal discount rate applied, which is considered a reasonably possible change given the prevailing macroeconomic environment, could increase our provision balances by approximately $58.6 million as of December 31, 2025. The pre-tax impact on our income statement would be a charge of approximately $57.5 million as of December 31, 2025, reflecting the change in estimates for assets which have already ceased production.

Business combination

Judgement

We determined that the acquisition of Block 12W in Vietnam during the year was the acquisition of a business, due to the acquired set of activities and assets including inputs and processes critical to the ability to continue producing outputs.

Estimates

While the risk that the acquisition fair value of Block 12W in Vietnam materially changes in the next 12 months is low and so is not considered a key source of estimation uncertainty, for business combinations we determine the fair value of property, plant and equipment acquired based on the discounted cash flows at the time of acquisition from the proved and probable reserves. In assessing the discounted cash flows, the estimated future cash flows attributable to the asset are discounted to their present value using a discount rate that reflects the market assessments of the time value of money and the risks specific to the asset at the time of the acquisition. In calculating the asset fair value, we applied oil price assumptions representing management's view of the long-term oil price.

INDUSTRY AND MARKET DATA

Certain of the projections and other information set forth in this section have been derived from external sources including IEA (the monthly oil market report published in March 2026 (the "March 2026 IEA Oil Market Report"), the Oil 2024 report published in June 2024 (the "June 2024 IEA Oil 2024 Report"), the monthly oil market report published in September 2024 (the "September 2024 IEA Oil Market Report") and the IEA Global EV Outlook 2024 report (the "IEA Global EV Outlook")); IMF (World Economic Update by the IMF published in July 2024 (the "IMF World Economic Outlook Update")); OPEC (The monthly oil market report published in September 2024 (the "September 2024 OPEC Monthly Oil Market Report") and OPEC Press Release No. 13/2024 published in September (the "September 2024 OPEC Press Release")); OEUK (OEUK Business Outlook 21 report (the "2021 OEUK Business Outlook") OEUK Business Outlook 2023 report (the "2023 OEUK Business Outlook"), OEUK Business Outlook 2026 report (the "2026 OEUK Business Outlook"), OEUK Economic Report 2025 (the "2025 OEUK Economic Report"), OEUK Economy & People Outlook 2024 report (the "OEUK Economy & People Outlook 2024"), OEUK Decommissioning Report 2025 (the "2025 OEUK Decommissioning Report"), OEUK "Roadmap2035", originally launched in 2019 ("OEUK Roadmap 2035")); North Sea Transition Authority (the 2025 UKCS decommissioning cost estimates report (the "2025 UKCS Decommissioning Cost Estimates Report"), the 2025 UKCS decommissioning benchmarking report (the "2025 UKCS Decommissioning Benchmarking Report"), the 2024 update on decommissioning cost and performance (the "2024 UKCS Decommissioning Cost and Performance Update"), the 2023 UKCS decommissioning insights (the "2023 UKCS Decommissioning Insights") and the 2021 final report (the "2021 UKCS Final Report")); EMIS (EMIS, Malaysia Oil & Gas Section 2022/2023 (the "EMIS Malaysia Report")); IGU (IGU World LNG Report 2024 published by IGU (the "2024 IGU World LNG Report")); U.S. EIA (the U.S. Energy Information Administration Short-Term Energy Outlook published in February 2026 (the "February 2026 EIA STEO"), the U.S. Energy Information Administration Short-Term Energy Outlook published in April 2026 (the "April 2026 EIA STEO"), U.S. Energy Information Administration Weekly Petroleum Status Report released on September 5, 2024 (the "U.S. EIA Weekly Petroleum Status Report"), U.S. Energy Information Administration 2024 Country Analysis: Malaysia (the "2024 U.S. EIA Malaysia Report"), US Energy Information Administration January 2021 – Country Analysis Executive Summary: Malaysia (the "2021 U.S. EIA Malaysia Report")); U.K. government (U.K. government (U.K. government's March 2026 Energy Trends Report (the "U.K. 2026 Energy Trends Report") and U.K. government's March 2024 Energy Trends Report (the "U.K. 2024 Energy Trends Report")); Oil & Gas U.K. (2024 Oil & Gas U.K. Business & Supply Chain Outlook Report (the "2024 O&G U.K. Report", the 2021 U.K. economic business outlook report (the "2021 O&G U.K. Economic Business Outlook Report" and the decommissioning and insight report for 2021 (the "2021 O&G U.K. Decommissioning Insight Report)); Energy Institute Energy Institute Statistical Review of World Energy 2025 (the "2025 Statistical Review of World Energy"); Commons Library (Commons Library Research Briefing on 28 May 2024 (the "2024 Commons Library Briefing"); and OGA ((2021 overview report (the "2021 OGA Overview Report").

The projections and forward-looking statements in this section are not guarantees of future performance and actual events and circumstances could differ materially from current expectations. Numerous factors could cause or contribute to such differences. See "Risk factors" and "Forward-looking statements."

Introduction and macroeconomic backdrop

The global oil market entered 2026 with a well-supplied balance, characterized by growing production outpacing modest demand growth, leading to rising inventories and baseline expectations of softening oil prices in the medium term. As of February 11, 2026, the EIA was estimating Brent crude prices to fall from an average of $69/bbl in 2025 to $58/bbl in 2026 and $53/bbl in 2027.

However, the macroeconomic backdrop has been significantly disrupted by escalating geopolitical tensions in the Middle East between Iran, the U.S. and Israel. On February 28, 2026, the U.S. and Israel initiated coordinated airstrikes targeting Iran's military infrastructure and nuclear sites. Iran responded by launching attacks on Israel and U.S.-allied states in the region, as well as attacking several vessels in the Strait of Hormuz. On March 2, 2026, the Iranian Revolutionary Guard Corps announced a de-facto blockage of the Strait of Hormuz, leading to a near-halt of shipping traffic and a sharp decrease in Gulf crude exports/loadings via the waterway. Under normal circumstances, around 20% of the world's crude oil and liquefied natural gas ("**LNG**") passes through the Strait of Hormuz.

The blockage of the Strait of Hormuz has removed a significant amount of supply from the global oil market, with key Middle East producers forced to curtail production given limited capacity available to bypass

the Strait of Hormuz, and storage infrastructure filling up. The IEA estimates Gulf countries have cut total oil production by at least 10 mb/d as of March 2026, with major supply reductions in Iraq, Qatar, Kuwait, the United Arab Emirates and Saudi Arabia. The IEA estimates global oil supply to reduce by 8 mb/d in March 2026, with curtailments in the Middle East partly offset by higher output from non-OPEC+ producers such as Kazakhstan and Russia.

The supply-side disruption has led to increased crude oil prices, with Brent averaging $99.60/bbl in March 2026, with a peak of $118.35/bbl, the highest level since March 2022 following the Russia/Ukraine conflict.

The ultimate impact on oil prices and markets from the conflict remains highly dependent on the damage to energy assets and on the duration of disruptions to shipping through the Strait of Hormuz.

As of April 7, 2026, the EIA estimates Brent crude oil prices will gradually decrease to an average of $88/bbl in the fourth quarter of 2026. The estimate is based on the assumption that the conflict will not persist past April 2026 and that traffic through the Strait of Hormuz will gradually resume (but does not return to pre-conflict levels until late 2026), and shut-in oil production gradually returns as flows through the Strait of Hormuz resume, with oil trade flows adjusting accordingly. Given the relatively long adjustment period anticipated after flows through the Strait of Hormuz resume, the EIA expects oil prices to remain elevated, with Brent crude oil prices averaging $76/bbl in 2027, which is $23/bbl higher than the previous EIA forecast as of February 11, 2026.

On the demand side, higher oil prices and a deteriorating macroeconomic outlook are expected to erode consumption across the refined product spectrum. Consumer countries have significant amounts of oil in storage to bridge temporary supply shortages. Global observed inventories of crude and products are assessed at more than 8.2 billion barrels, the highest level since February 2021. Roughly half of these are held in OECD countries, of which 1.25 billion barrels by governments for emergency purposes, with a further 600 million barrels of industry stocks held under government obligation. On March 11, 2026, IEA member countries agreed to make an unprecedented 400 million barrels of oil from their emergency reserves available to the market as a temporary buffer to supply disruptions. Based on reports of government initiatives to reduce fuel use, fuel shortages and the curtailing of refined oil product exports, the EIA estimates global oil demand growth will average 0.6 mb/d in 2026, down from an average of 1.2 mb/d in the previous EIA forecast as of February 11, 2026. The EIA assumes reductions in demand to occur primarily in Asia, which is reliant on crude oil supplies from the Middle East. The EIA assumes oil demand will rebound in 2027 once supply flows return later in 2026, with oil demand growing by 1.6 mb/d in 2027 to 106.2 mb/d.

Introduction

The UKCS

Introduction

The UKCS can be broadly divided into five main areas: the Central North Sea, the Northern North Sea, the Southern Gas Basin, the West of Britain and the Atlantic Margin. The first offshore license was granted to bp on September 17, 1964 in what was to become the West Sole gas field in the Southern Gas Basin. Amoco discovered the first oil in the U.K. sector of the North Sea in 1969 in what is now the Arbroath field, with the first U.K. offshore oil production commencing in June 1975 from the Argyll field. After early exploration success, the surge in activity led to more than 40 billion boe produced by the beginning of the 1980s.

Oil and gas exploration and production activities in the UKCS are governed primarily by the Petroleum Act 1998, as amended from time to time (the "**Petroleum Act**"). The Petroleum Act vests ownership of the petroleum resources in the U.K. sectors of the North Sea in the Crown and, pursuant to the Energy Act 2016, the NSTA was granted the authority to grant licenses that confer on the licensee for a limited time the right to search for and bore for and get petroleum in the areas governed by the license. Licenses also require various approvals from the NSTA, the DESNZ and other government departments for a number of license-related activities.

The DESNZ is the United Kingdom's ministerial department charged with overseeing the government's energy policy framework, ensuring secure energy supply, advancing decarbonization and guiding the country toward its obligation to meet net zero carbon emissions by 2050. DESNZ sets priorities and implements policies in areas including energy generation (renewables, nuclear, hydrogen), grid infrastructure, energy efficiency, low-

carbon innovation and carbon budgets. The current UK Secretary of State for Energy Security and Net Zero is Ed Miliband, who was appointed in July 2024 and now leads the DESNZ in executing its mandate.

For more information relating to regulation relating to oil and gas in the U.K., see "*Regulation.*"

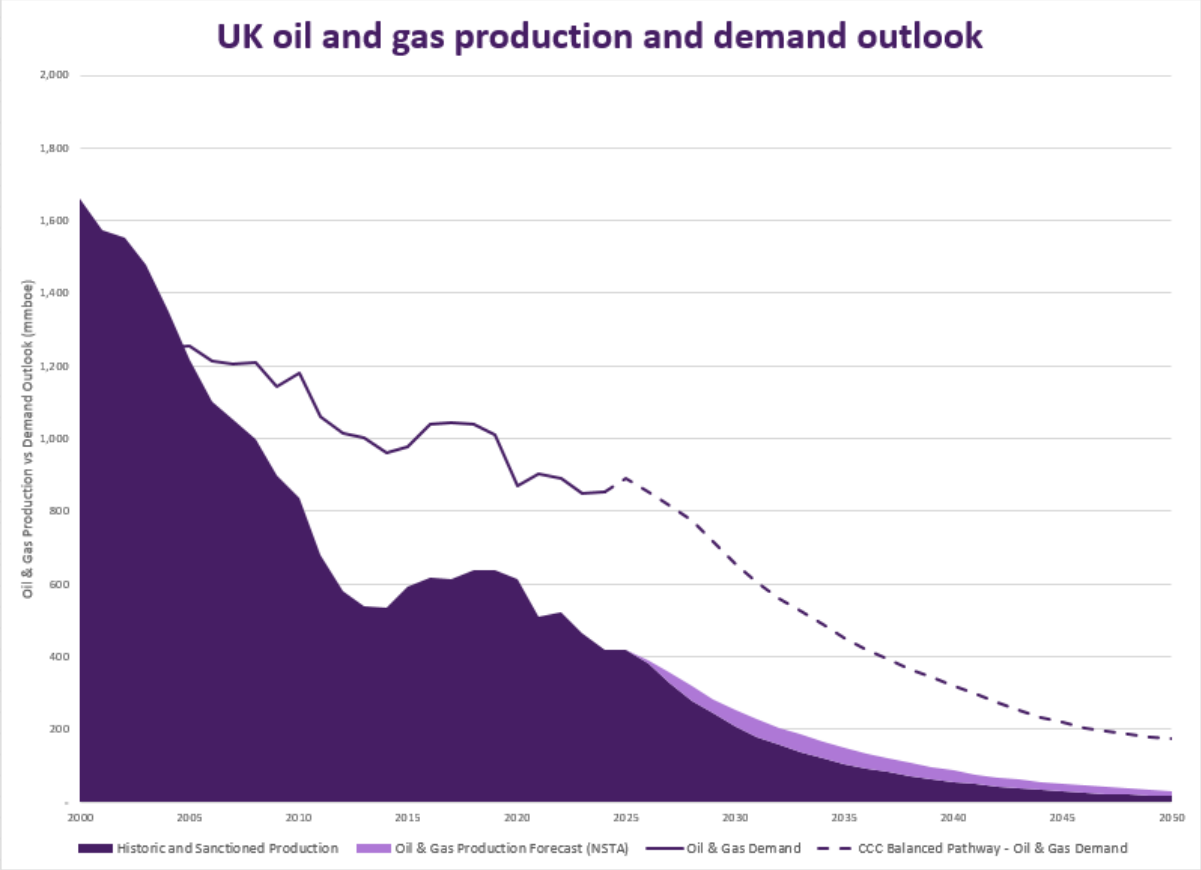
UKCS outlook

According to the U.K. 2026 Energy Trends Report, total U.K. energy production in 2025 was 94.0 million tonnes of oil equivalent, 1.0% lower than in 2024 and 68% lower than when U.K. production peaked in 1999. Production levels for all fuels except coal and oil were down in 2025 as compared to 2024, with nuclear output at record low, while output from wind, solar and hydro reached record highs.

U.K. energy consumption in 2025 was 0.1% lower than in 2024, according to the U.K. 2026 Energy Trends Report. Transport consumption rose by approximately 2.4%, whilst domestic consumption fell by approximately 0.7%, industrial consumption fell by 6.1% to a record low and other final users' consumption fell by approximately 0.3%. On a seasonally- and temperature-adjusted basis, final energy consumption fell by 0.5%. The U.K. has been a net importer of energy since 2004, meaning that the country uses more energy than is supplied from domestic resources and relies on other countries to meet its energy needs. Net import dependency was stable at 43.5% in 2025, according to the U.K. 2026 Energy Trends Report.

According to the 2026 OEUK Business Outlook Report, offshore activities in the UKCS have decreased in recent years, with drilling activity falling and the number of new project approvals also decreasing. The UKCS still plays a vital role in the U.K.'s energy system, supplying just over 50% of total demand for oil and gas. Oil and gas continue to supply approximately 75% of domestic energy needs. This trend of declining domestic supply is expected to continue throughout the coming years and decades as domestic resources continue to decline at a faster rate than demand falls, according to the 2025 OEUK Economic Report.

The 2025 OEUK Economic Report states that in 2024, the U.K.'s total energy production was at a historic low, with over 40% of the U.K.'s energy needs met through imports. Without sustained investment, the U.K. will be reliant on imports for 70% of its oil and gas demand by 2030. The NSTA projected that 6.5 billion boe could be recovered from the UKCS between 2025 and 2050 in 2019, but that projection has since been revised down to 3.8 billion boe, reflecting investor confidence rather than a reassessment of the basin's geological potential, according to the 2025 OEUK Economic Report.



Capital investment

The amount of oil and gas produced in the UKCS throughout the middle of this decade will depend on how much is invested in new fields and on the upgrades and extensions of existing assets approved in the near-term. Domestic oil and gas production is not expected to exceed demand, according to the 2025 OEUK Economic Report. Current projections indicate the UKCS is on track to supply only a quarter of the U.K.'s oil and gas demand out to 2050, despite having the potential to produce half of the demand.

Creating a more diverse energy system will require significant capital expenditure across a range of sources, including oil and gas, offshore wind, hydrogen and carbon capture. Under the current regulatory and fiscal regimes, OEUK's risked pipeline of projects identifies capital expenditure exceeding £110 billion over the next 10 years (2025-2035), across fixed-bottom and floating offshore wind, CCS (transport and storage) and hydrogen, according to the 2025 OEUK Economic Report. In a scenario supporting the entire offshore energy sector – achieving 50 GW of offshore wind, 30 $MtCO_2$ storage, 10 GW of hydrogen and a managed decline to 700,000 boe/day oil and gas production – the U.K. could see workforce demand growth of up to 38% compared to 2024 levels.

The level of capital invested in the basin typically follows commodity price trends, with periods of higher prices associated with the UKCS' ability to attract greater levels of investment, according to the 2021 OEUK UK Business Outlook Report. During these times, companies benefited from greater levels of cash generation and looked to approve and execute projects which may have more challenging economics at lower prices. Declines in investment have generally lagged the onset of price falls by 12 to 24 months. For example, 2013 and 2014 each saw capital investment reach over £16 billion (in 2020 terms) following annual Brent price highs of between $120/bbl and $140/bbl during the preceding years, according to the 2021 OEUK U.K. Business Outlook Report. However, the dramatic nature of the 2020 price decline coupled with the relatively low level of new investment approvals in recent years led to a sharper and faster investment decline.

Currently, new projects are scheduled to start up but on too small a scale to maintain overall output. Without sustained investment, the U.K. could see its reliance on imports rise to 70% of total oil and gas demand by 2030. The U.K.'s energy import gap currently stands at 42% and is expected to remain around 40% for most

of this decade, exposing the nation to ongoing geopolitical conflicts. Industry data signals oil and gas production falling between 450,000-600,000 boe/day by 2030, compared to the NSTA's 2019 projection of 1.3 MMboe/day by 2030. According to the 2025 OEUK Economic Report, with a return to a competitive and stable fiscal and regulatory environment, the UKCS could unlock up to 7.5 billion boe, compared to 4.3 billion boe under the current regime, and could deliver over half of the U.K.'s oil and gas demand between now and net zero in 2050.

Exploration and appraisal drilling

Exploration drilling peaked in 1990 at approximately 150 wells before steadily declining to current levels. Appraisal drilling has also seen a gradual decline since 1990, falling steadily over the last decade to current levels. The lack of new approvals continues to impact drilling activity, which is only around one quarter of the rate of well decommissioning. According to the 2026 OEUK Business Outlook Report, 2025 marked the lowest year for well activity since the inception of the U.K.'s offshore oil and gas sector, with just two appraisal wells, 39 development wells and, for the first time on record, zero exploration wells drilled, totaling only 41 wells.

Decommissioning

According to the 2025 UKCS Decommissioning Cost and Performance Update, the forecast cost of decommissioning the remaining UKCS scope, from 2025 onwards, is £44 billion (in constant 2024 prices), reflecting challenging economic conditions, including inflation and increased global demand for critical supply chain resources. This represents a significant increase from the 2022 baseline estimate of £37 billion (in 2021 prices). The growth in the overall forecast is dominated by an increase in estimated costs for the period 2023-2032, now estimated at £27 billion (in 2024 prices). According to the 2025 OEUK Decommissioning Report, decommissioning work over the next decade (2025-2034) includes approximately 1,224 platform wells, around 674 subsea wells and 85 exploration and appraisal wells, 127 topsides and 114 substructure removals, with total forecast expenditure of £25.5 billion. The actual UKCS decommissioning spend in 2024 was £2.1 billion, the highest recorded rate of spend to date.

The Maximizing Economic Recovery Strategy for the U.K. ("MER")

The MER, which was drafted in accordance with section 9A(2) of the Petroleum Act 1998, obligates the Secretary of State to produce one or more strategies supporting the principal objective of maximizing the economic recovery of U.K. petroleum in line with the following high-level principles:

- All stakeholders should be obliged to maximize the expected net value of economically recoverable petroleum from relevant U.K. waters, not the volume expected to be produced;
- Compliance with the MER is intended to lead to investment and operational activities that, on an expected basis, add net value overall to the U.K.;
- Compliance with the MER may oblige individual companies to allocate value between them, matching risk to reward. However, while the net result should deliver greater value overall, it will not be the case that all companies will always be individually better off;
- Compliance with the MER will not lead to any individual company investing in a project or operating existing assets where there is not a satisfactory expected commercial return on that investment or activity. Such a return does not necessarily mean a return commensurate with the overall corporate return on their portfolio of investment (e.g., a low risk investment could give low returns);
- In determining whether something is consistent with the principal objective, the U.K. Regulator will need to balance the benefit of economic recovery of petroleum with the need to maintain the confidence of new and current investors to invest in exploration and production of petroleum from relevant U.K. waters, taking into account market conditions at the time of making its determination.

Transferable tax history ("TTH")

The Finance Act 2019 enacted TTH for UKCS asset deals approved by the U.K. Regulator on or after November 1, 2018. TTH provides an additional tool to move late-life assets into the hands of those that are best suited to prolong the life of the field. TTH is an optional joint election that permits a seller to transfer to a buyer

some of its historical profit chargeable to ring fence corporation tax and supplementary charge (the "**TTH Amount**"). The TTH Amount is subject to commercial negotiation between the seller and the buyer and is capped at the lower of (i) an uplifted estimated cost to decommission per a decommissioning security agreement or (ii) the seller's eligible historical ring fence profits from April 17, 2002. The buyer can utilize losses arising on decommissioning expenditure by offsetting them against such TTH Amount. The buyer then tracks the profits of the acquired field as a shadow calculation to their annual tax return. Before the TTH Amount becomes part of the buyer's tax history, the field must cease production, and the buyer must incur a net loss after decommissioning, thereby activating the TTH.

Energy Profits Levy

Companies engaged in activities relating to the production of oil and gas in the U.K. and in the UKCS are subject to an oil taxation regime which generally consists of four elements: ring fence corporation tax ("**RFCT**"), a supplementary charge, petroleum revenue tax ("**PRT**") and energy (oil and gas) profits levy (the "**EPL**"). See "*Regulation—United Kingdom—Tax regulations.*" The EPL was introduced in response to the rising cost of energy and Russia's invasion of Ukraine in February 2022. The EPL added a 25% (subsequently increased to 38%) tax to the existing ring fence corporation tax and supplementary charge that is levied on North Sea oil and gas production, bringing the headline tax rate to 78%. The EPL has been extended to 2030. See "*Regulation—United Kingdom—Energy Profits Levy*". The ESIM threshold prices are $76.12 per barrel for oil and £0.59 per therm for gas.

To incentivize new investments, there is an additional investment allowance for expenditure on upstream decarbonization. This means that until October 31, 2024, investments in the decarbonization of oil and gas production will benefit from the allowance at a rate of 80% according to the 2024 Commons Library Research Briefing.

Oil & Gas Price Mechanism ("OGPM")

In November 2025, as part of the Autumn Budget, the U.K. Government announced its intention to introduce a revenue-based oil and gas fiscal mechanism to replace the EPL, which is set to expire after March 31, 2030 (or earlier if the energy security investment mechanism is triggered). The revenue-based oil and gas fiscal mechanism (also known as "**Oil & Gas Price Mechanism**" or "**OGPM**"), is envisaged to have the following features:

- a revenue-based model, with revenues above certain thresholds subject to additional taxation;
- a taxation rate of 35% on revenue above the set thresholds;
- separate thresholds for crude oil and natural gas (with natural gas liquids to be taxed under the crude oil regime);
- for financial year 2026/27, the thresholds will be $90/bbl for crude oil and £0.90/therm for natural gas; and
- the thresholds will be adjusted annually in line with consumer price inflation.

The U.K. Government intends to legislate for the OGPM in the next Finance Bill (2026-27).

Decommissioning relief deeds ("DRD")

A DRD is a contract between the U.K. government and companies operating in the UKCS. It provides companies with certainty as to their entitlement to tax relief on future decommissioning costs. A DRD is available where:

- Decommissioning tax relief available is reduced in the future compared to the 2013 position due to a change in tax law (not a change in tax rates); and
- A company has to pick up another company's decommissioning liabilities where the other company defaulted on its own liabilities.

Energy Transition and ESG in the United Kingdom and UKCS

It is widely believed that oil and gas will continue to play a key role in an increasingly diverse energy mix, so it is important that domestic production continues accordingly to support energy security. In addition, many of the skills, expertise and technologies held within the oil and gas industry will be crucial in the development of net zero solutions at scale.

Although the U.K. energy and gas industry is committed to delivering net zero greenhouse gas emissions by 2050, the U.K. will continue to need oil and gas alongside its expansion into cleaner energy sources like wind and hydrogen. In 2025, natural gas represented a 31.5% share of U.K. electricity generation, while wind achieved a record 30.0% share, according to the 2026 Energy Trends Report. In 2025, domestic gas production remained equivalent to just under half of U.K. gas demand, according to the 2026 Energy Trends Report. Oil and gas continue to supply approximately 75% of domestic energy needs today and are expected to provide about half of the energy required over the next 25 years and still meet about one-fifth of U.K. energy demand in 2050, according to the 2026 OEUK Business Outlook Report.

There has been growing investor focus on reporting of ESG metrics and alignment with UN sustainable development goals. This has centered on environmental impacts of business operations in the context of net zero greenhouse gases and the COVID-19 pandemic's impact on social risks. Attention to ESG reporting has been driven by changing investor appetite in recent years and is an increasingly common element in many of the industry's financial reports.

The oil and gas industry in the United Kingdom was one of the first industrial sectors to embrace the commitment to net zero greenhouse gases. For the sector, the focus of investors' expectations in particular on environmental factors creates an audience for operators to showcase their ongoing commitments and progress towards emission reduction targets under the OEUK Roadmap 2035, which outlines contributions the oil and gas sector can make throughout the transition. The key themes within the OEUK Roadmap 2035 are:

- helping meet energy needs in the United Kingdom;
- supporting net zero;
- developing people and skills;
- driving technology and innovation; and
- growing the economy and exports.

There are very significant opportunities for oil and gas companies and members of their supply chain to diversify across the energy landscape. Developments in new technologies are progressing across the United Kingdom, from Shetland to South Wales.

In early 2021, the U.K. oil and gas industry reached the flagship North Sea Transition Deal ("**NSTD**") with the U.K. Government. The NSTD is a transformational partnership between the U.K. government and the U.K. oil and gas industry. It is helping the U.K. progress towards net zero by harnessing the skills and expertise of the people and companies in the oil and gas industry to support the development of CCS, hydrogen and other decarbonizing technologies. One of the key performance indicators of the deal is for 50% U.K. content over the lifecycle of all related new energy projects, as well as oil and gas decommissioning, including 30% locally-provided technology. It aims to grow the economy, sustain high-skilled jobs, establish new energy businesses, attract investment and grow exports while still reducing emissions. It is also expected to open up new markets for the domestic supply chain at home and abroad.

As explained in the 2021 OGA Overview, 2021 UKCS Final Report, the 2021 O&G U.K. Economic Business Outlook Reports and the 2021 O&G U.K. Decommissioning Insight Report, emission considerations are now also playing a part in contract wins. Continuing to strive for cost effective decommissioning will also release additional capital that can be invested in ensuring that the U.K. maintains its domestic oil and gas supply and in emission reduction projects such as carbon capture, utilization and storage ("**CCUS**") and hydrogen and geothermal projects.

On October 19, 2021, BEIS published the U.K. government's Net Zero Strategy as required under the CCA, in which it set out the policies needed to achieve a 100% reduction in net GHG emissions by 2050 (taking into account the effect of carbon trading), relative to 1990 levels ("**Net Zero**") (the "**Net Zero Strategy**"). A key policy under the Net Zero Strategy is to fully decarbonize the U.K. power system by 2035, subject to security of supply.

The U.K. has one of the largest CO_2 offshore storage potential in Europe at 78 gigatons. The successful deployment of CCUS technologies in the U.K. is important for the country to reach net zero. It is needed to decarbonize hard-to-abate industrial sectors, like cement and steel production, and will also play a significant role in the U.K.'s energy security as an enabler of low-carbon hydrogen production and dispatchable low-carbon power generation. Given that most renewable generation is intermittent in nature, the remaining generation will need to be supported by flexible, complementary renewable or low carbon sources such as biomass, hydro and pumped storage. The government is supporting the development of CCS clusters this decade. HyNet and the East Coast Cluster were selected as Track 1 projects, reaching Final Investment Decision, and are set to remove 8.5 million tonnes of CO_2 per year by 2030. Acorn and Viking were selected as Track 2, with development funding confirmed in the 2025 Spending Review, according to the 2025 OEUK Economic Report.

Malaysia

Introduction

Malaysia has adopted a PSC fiscal regime under which contractors bear exploration and development risk but recover allowable costs from production and share residual profit with Malaysia's national oil and natural gas company, Petroliam Nasional Berhad ("**PETRONAS**"). The majority of the existing PSCs are premised on a "Revenue over Cost (R/C)" structure with profit tranches based on the ratio of revenue against cost incurred and additional claw back functions built in.

As of the end of 2024, Malaysia was the fifth largest liquid natural gas ("**LNG**") exporter globally, with 27.73 MT of exports (6.7% of global LNG trade), according to the 2025 IGU World LNG Report. It is strategically located on important routes for the seaborne energy trade. Malaysia's energy industry is an important sector of growth for the economy, and the government continues to focus on increasing hydrocarbon production through upstream investment and exploration as drivers. Malaysia's oil and natural gas production peaked at 2 MMboepd in 2024, according to PETRONAS. Malaysia is heavily dependent on oil and natural gas, which together accounted for approximately 73% of its primary energy consumption in 2024, according to the 2025 Statistical Review of World Energy.

Upstream Sector Overview

Energy policy in Malaysia is set and overseen by the Economic Planning Unit ("**EPU**") and the Implementation and Coordination Unit ("**ICU**"), which both report directly to the Office of the Prime Minister.

Malaysia's Petroleum Development Act ("**PDA**") passed in 1974, led to the formation of PETRONAS. The PDA granted PETRONAS ownership and exclusive rights to all oil and gas resources in Malaysia, both onshore and offshore. PETRONAS' Petroleum Management Unit ("**PMU**") is responsible for managing all upstream licensing procedures. Companies interested in undertaking exploration and production activities in Malaysia are required to form a joint venture with PETRONAS and must allow PETRONAS to have an equity interest stake. ExxonMobil, Shell and ConocoPhillips are the major international oil companies in Malaysia, according to Rystad Energy's production estimates. Murphy Oil divested its Malaysian assets through a share repurchase agreement with Thailand's PTT Exploration and Production Public Company Limited ("**PTTEP**") and left the country in 2019. New opportunities for investment in Malaysia's energy sector have attracted other foreign oil independents and national oil companies such as the Spanish Repsol, Indonesian Pertamina, Vietnamese PetroVietnam and Japanese JX Nippon Oil and Gas, according to the EMIS Malaysia Report, and the 2021 U.S. EIA Malaysia Report.

Liquid Exploration and Production

Malaysia produces a number of different crude oil blends, which are mainly medium to light sweet blends. Malaysia's Tapis blend, which is extracted from the Tapis field located offshore in the Malay Basin, generally commands a relatively strong price premium as compared to other crude oils on the market, according to the EMIS Malaysia Report; the 2022 bp Report and the 2021 U.S. EIA Malaysia Report.

In 2024, oil production continued to decline. According to the 2024 U.S. EIA Malaysia Report, Malaysia's petroleum and other liquids production was approximately 597,000 barrels per day in 2023, a decline attributable to maturing fields. At the end of 2023, Malaysia had proved oil reserves of 2.7 billion barrels – the second-largest oil reserve in South East Asia. Although reserves have declined since 2022, there were 19 new discoveries in 2023, which could add over 1 billion barrels of oil equivalent. From 2024 through 2026, PETRONAS expects more than 25 wells (oil and natural gas) to be drilled per year, according to the 2024 U.S. EIA Malaysia Report.

Gas Exploration and Production

Malaysia's natural gas production reached 80.4 bcm in 2024, up 3.1% from 78.0 bcm in 2023, supported by greenfield project developments including the Jerun gas field brought online by SapuraOMV in 2024, which is expected to reach peak production of 550 million cubic feet per day by 2030. At the end of 2023, Malaysia had proved natural gas reserves of 32 trillion cubic feet ("**Tcf**"). Natural gas is expected to have robust demand in Malaysia this decade due to its use as the primary fuel for electricity generation and as a feedstock for the country's growing petrochemical industry, according to the 2025 Statistical Review of World Energy, 2024 U.S. EIA Malaysia Report and the EMIS Malaysia Report.

Malaysia remained the world's fifth largest exporter of LNG in 2024, with total exports of 27.73 MT (an increase of 0.97 MT from 2023), representing 6.7% of global LNG exports. The top three major export destinations of Malaysia's LNG in 2024 were Japan (10.51 MT), South Korea (6.26 MT) and China (7.82 MT). Malaysian LNG exports climbed driven by improved feed gas supply from greenfield gas projects. Malaysia has 32 MTPA of operational liquefaction capacity. PETRONAS is the dominant player in the natural gas sector and has historically held a monopoly on all upstream natural gas developments because of its role as the national oil company and as a regulator for upstream activity. It also plays a leading role in midstream and downstream activities, as well as the liquefied natural gas trade. Petroleum Sarawak Berhad ("**Petros**"), Sarawak's state-owned oil and natural gas company, was established in March 2018 and was declared to have equal status with PETRONAS by the Chief Minister of Sarawak. In February 2020, Petros signed a domestic natural gas agreement with PETRONAS and took control of the sale, distribution and supply of natural gas in Sarawak, according to the 2025 IGU World LNG Report, 2025 Statistical Review of World Energy, EMIS Malaysia Report and 2024 U.S. EIA Malaysia Report.

Indonesia

Indonesia is the largest oil and gas producer in South East Asia. Hydrocarbon production is, however, in decline and the Indonesian Government has set an output target of 1 mb/d of oil and 12 bcf per day of gas by 2030, as part of a plan to reverse declining production rates. In 2024 Indonesia produced 0.6 mb/d of crude oil and natural gas liquids, and 6.8 bcf per day of natural gas. Indonesia's year-end 2024 proved hydrocarbon reserves stood at 2.4 billion bbl for oil and natural gas liquids, and at 30.9 trillion cubic feet for natural gas.

The legal framework for upstream activities in Indonesia provides that oil and gas resources located in Indonesia are national assets controlled by the State. The Indonesian Government oversees and regulates the upstream oil and gas industry through the MEMR Ministry (Ministry of Energy and Mineral Resources) and SKK Migas (Special Task Force for Upstream Oil and Gas Business Activities). The MEMR determines upstream work areas, which can be offered either via a tender or a direct offer. Once awarded a working area, the awardee will enter into a cooperation contract (in the form of a production sharing contract or "**PSC**") with the Government, represented by SKK Migas, pursuant to which the awardee will act as a contractor (a "**PSC Contractor**") to SKK Migas. PSCs are usually awarded for 30 years (typically consisting of a 10-year period for exploration, followed by a 20-year period for exploitation). There are currently two types of PSCs in Indonesia: Cost-Recovery PSCs and Gross-Split PSCs. In Cost-Recovery PSCs, contractors are entitled to obtain reimbursement of their operating costs and capital expenditures through the production of hydrocarbons. Under Gross-Split PSCs, contractors are responsible for paying all costs and expenses, without the option for cost recovery. Instead, they participate in a gross production sharing arrangement, where their portion of the production is determined by fixed percentages.

PT Pertamina ("**Pertamina**") is Indonesia's state-owned oil and gas company, and it (along with its subsidiaries) participates in a number of PSCs. These subsidiaries act as both operators and non-operators of PSCs. Pertamina enjoys certain special rights conferred by the Government, such as right of first refusal and option to assume operations of a work area once the PSC expires (regardless of whether the original PSC Contractor seeks an extension).

Beyond Pertamina, a large number of international and local companies are active in upstream oil and gas operations in Indonesia. Key international companies operating in Indonesia include bp, eni, ExxonMobil and CNOOC. A notable local player is Medco Energi.

Brunei

Despite its modest population size (0.5 million as of 2024), Brunei is a sizeable hydrocarbon producer in South East Asia. In 2024, Brunei produced 90 kb/d of crude oil and natural gas liquids, and 0.9 bcf per day of natural gas. Brunei's year-end 2024 proved hydrocarbon reserves stood at 1.1 billion bbl for oil and natural gas liquids, and at 7.8 Tcf for natural gas.

Hydrocarbon production is a major contributor to Brunei's economy, accounting for 47% of Brunei's GDP in 2024. The Petroleum Authority of Brunei Darussalam is the regulatory body for the oil and gas industry in Brunei. Upstream activities in Brunei are regulated by PSCs, usually with a royalty component. The contractor pays royalties to the Government, and is entitled to recover operating and capital costs through the production of hydrocarbons (Cost Oil/Gas), while residual profits are shared between the contractor and the Government (Profit Share). PetroleumBRUNEI, the national oil company, represents the Brunei Government in such PSCs.

The upstream oil and gas corporate landscape in Brunei is varied, with the largest player being Brunei Shell Petroleum ("**BSP**"), a 50:50 joint venture between the Government of Brunei and Shell. BSP is the largest oil producer in Brunei and contributes to around 90% of Brunei's hydrocarbon revenues. Beyond BSP, other oil and gas companies operating in Brunei include Murphy Oil, Mitsubishi Corporation, Petronas Carigali and Hibiscus Petroleum.

Vietnam

Introduction

Vietnam's upstream oil and gas sector operates under a PSC regime, under which contractors assume exploration and development risk, are entitled to recover allowable costs from production and share residual profits with the state-owned national oil, gas and energy industry corporation of Vietnam, PetroVietnam ("**PetroVietnam**"). Compared to regional peers such as Indonesia, Malaysia, and Thailand, Vietnam is among the smallest producers and holds relatively modest proved reserves. In recent years the government has shifted its strategic focus toward the development of natural gas resources. Despite its current production profile, Vietnam possesses significant untapped hydrocarbon potential.

In line with its COP26 commitments and the broader energy transition, Vietnam commenced LNG imports in 2023, marking a shift away from coal and towards increased gas utilization. To further incentivize investments, the government introduced a series of updates to the PSC framework in 2023, including longer contract terms, enhanced cost recovery mechanisms and reduced tax rates for designated incentivized blocks.

Upstream Sector Overview

The Ministry of Industry and Trade is the primary regulatory body in the Vietnam oil and gas industry. PetroVietnam, the national oil company, also plays a central role in the industry, operating and holding equity stakes in all upstream projects and retaining the right to take direct equity in any asset under the terms of the PSC regime. The majority of producing assets in Vietnam are developed and managed under a Joint Operating Company model, a structure that is distinctive to the Vietnamese market and facilitates collaboration between PetroVietnam and international partners. Key international companies with a significant presence in Vietnam's upstream sector, in terms of reserves and resources, include ExxonMobil, eni, Essar, Mitsui, and Murphy Oil.

Liquid Exploration and Production

Vietnam's crude oil production has been in structural decline as its key legacy fields, such as the Bach Ho field (Block 09-1) and the Rang Dong field (Block 15-2), have matured, passed peak output and are now in the later stages of their productive life. Recent exploration successes in the Cuu Long Basin have provided some short-term relief to this downward trajectory. A prominent example is Murphy Oil's discovery of the Hai Su Vang field in 2025, which is estimated to hold approximately 400 million barrels of recoverable oil. While such discoveries are significant and may help to partially offset the decline in national production in the near term, sustained growth will depend on further large-scale discoveries and successful development of new acreage.

Vietnam's total oil production has continued its structural decline, falling to approximately 177,000 barrels per day in 2024 (down from 188,000 barrels per day in 2023), representing a 6.1% year-on-year decline, according to the 2025 Statistical Review of World Energy. Vietnamese crude oil is generally recognized for its quality and typically commands a premium over Brent, reflecting its desirable characteristics in the international market.

Vietnam's natural gas production has also declined, falling to 6.1 bcm in 2024 (down 15.6% from 7.2 bcm in 2023), according to the 2025 Statistical Review of World Energy. Generally, the Vietnamese government has prioritized gas-to-power as part of its energy strategy, and to supplement domestic production, Vietnam began importing LNG and commissioned its first regasification terminal (Thi Vai LNG) in 2023. In 2024, Vietnam imported 0.29 MT of LNG, with a second terminal (Cai Mep LNG) under construction and expected to come online in 2025.

Gas Exploration and Production

Vietnam's natural gas sector is positioned for significant growth, underpinned by substantial undeveloped reserves and the advancement of several major projects. The country's gas production outlook is supported by the long-awaited sanctioning of the Block B gas project in the Malay Basin in 2024. This project is expected to deliver first gas in 2027 and has the potential to double Vietnam's national gas output, marking a transformative development for the sector. In addition to Block B, other key upstream gas developments include Jadestone's Nam Du–U Minh fields and Vietsovpetro's Thien Nga–Hai Au (Block 12/11) that are expected to contribute meaningfully to future supply. These projects collectively signal a new phase of growth for Vietnam's gas industry, leveraging the country's considerable resource base. Notwithstanding this momentum, some of Vietnam's largest gas discoveries, such as Eni's Ken Bau field in the Song Hong Basin and ExxonMobil's Ca Voi Xanh, have encountered delays primarily due to appraisal difficulties, high carbon dioxide (CO_2) content in the gas and infrastructure constraints.

OUR BUSINESS

In these Listing Particulars, the words "we," "us," and "our" refer to EnQuest PLC together with its subsidiaries on a consolidated basis, except where otherwise specified or clear from the context. The 1P and 2P Reserves data presented in this section have been audited at our request by GaffneyCline in accordance with PRMS guidelines and definitions. Estimated 1P and 2P Reserves presented herein may differ from estimates made in accordance with guidelines and definitions used by other companies in the industry or by the SEC. See "Presentation of financial and other information." Unless otherwise indicated, all production figures are presented on a net to our working interest basis. Where gross amounts are indicated, they are presented on a total basis—i.e., the actual interest of the relevant license holder in the relevant fields and license areas without deduction for the economic interest of our commercial partners, taxes or royalty interests or otherwise. Our legal interest and effective working interest in the relevant fields and license areas are separately disclosed. See "—Material agreements relating to our assets" for a more detailed discussion of the terms of the agreements governing our interests. Any projections and other forward-looking statements in this section are not guarantees of future performance and actual results could differ materially from current expectations. Numerous factors could cause or contribute to such differences. See "Risk factors" and "Forward-looking statements."

Overview

We are a significant independent energy company in the U.K. North Sea and South East Asia, specializing in the operatorship of mature, underinvested hydrocarbon assets. We are a top quartile operator with a track record of materially extending the economic lives of assets through strong uptime performance, production enhancement, cost discipline and reserve replacement. As of December 31, 2025, we had interests in 18 U.K. production licenses (however, as of February 2026, we relinquished license P2632, reducing our total U.K. production licenses to 17), 14 of which we operate, covering 25 blocks or part blocks in the UKCS. We also have an interest in three licenses in Malaysia, one license in Vietnam, two licenses in Indonesia and one license in Brunei, all but one of which we operate.

While our upstream business remains a core focus given its cash-generating capability, we have also made considerable progress in delivering credible and potentially material new energy and decarbonization opportunities, which are now managed by Veri Energy, a wholly owned subsidiary of the Company. Veri Energy is targeting the creation of a clean energy hub at the EnQuest-operated Sullom Voe Terminal on Shetland, primarily through the repurposing of existing infrastructure, underscoring our commitment to a just and sustainable energy transition. In demonstrating our credible transition plan, we were awarded an A- rating in the 2025 CDP Climate Change Survey, becoming the only oil and gas production company globally to achieve this grade.

We also continue to demonstrate our sector-leading capability in decommissioning, which is becoming an ever more significant component of the competency mix for any North Sea operator.

Since our inception, we have increased our net working interest 1P and net working interest 2P Reserves to 126 MMboe and to 162 MMboe, respectively, as of December 31, 2025 from 36 MMboe and 81 MMboe, respectively, as of January 1, 2010, representing a compound annual growth rate for 2P net working interest Reserves of approximately 4% per annum and representing a 2P net working interest reserves replacement ratio of approximately 1.4x since inception. During the period from January 1, 2010 to December 31, 2025, we added net working interest 2P Reserves of approximately 305 MMboe, of which our production was approximately 223 MMboe. Of our year end 2025 2P net working interest Reserves, approximately 78% represented proved (1P) volumes, with the Group also recognizing 452 MMboe of 2C Resources. As of December 31, 2025, approximately 97% of our 2P net working interest Reserves are located in fields operated by us with approximately 75% of our 2P net working interest Reserves located in fields in the U.K. North Sea.

Our producing assets generated revenue and other operating income, gross profit/(loss) and adjusted EBITDA of $1,118.3 million, $280.8 million and $503.8 million, respectively, in the year ended December 31, 2025. In the year ended December 31, 2025, our average adjusted unit operating costs (including hedging) were $25.1/boe.

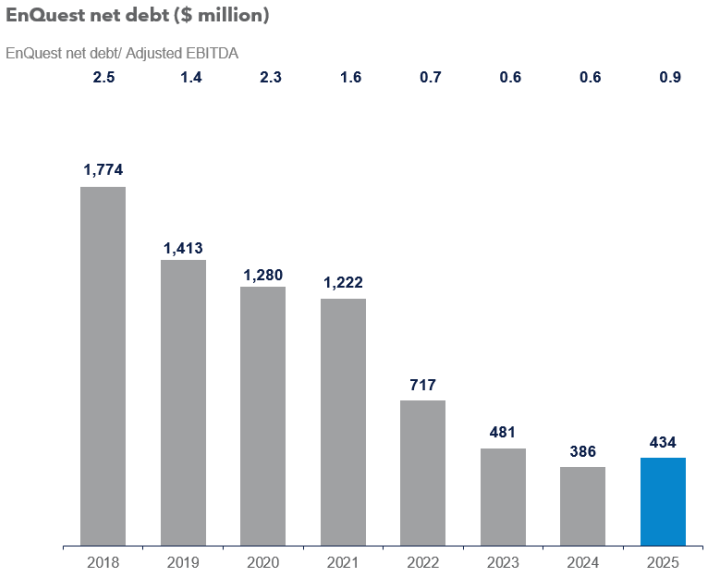
We were founded in 2010 through a combination of Petrofac Energy Developments Limited ("**PEDL**") and certain assets of Lundin Petroleum AB ("**Lundin**"). We purchased PEDL and the UKCS assets of Lundin in exchange for stock. In 2014, we diversified our geographical footprint by acquiring initial production licenses in Malaysia. Following our initial public offering in April 2010, our shares are listed and trade on the London Stock Exchange. Our shares were also listed on the Stockholm Stock Exchange until December 2023, when the Board

decided to delist our shares from the Stockholm Stock Exchange. As of December 31, 2025, our market capitalization was approximately $268.8 million based on the Bloomberg Composite Rate (London) pounds sterling/US dollar exchange rate of $1.3452 per £1.00. In August 2024, our share buy-back program achieved its target of 25 million shares repurchased and held as treasury shares, with all additional shares repurchased immediately cancelled.

We believe that our operational and commercial capabilities, together with experienced technical staff and management, have enabled us to grow production, reserves and resources profitably since 2010. Further, we believe that in the UKCS, South East Asia and potentially other geographic regions, we have, and will continue to have, substantial opportunities for acquisitions and development through low-cost, near-field drilling, well intervention and enhanced oil recovery projects, while maintaining a focus on the health, safety and environmental impacts of our operations. The majority of our existing asset licenses are located in the UKCS in the North Sea. We also have interests in three licenses in Malaysia, one license in Vietnam, two licenses in Indonesia and one license in Brunei. See "*Risk factors—Risks relating to our business—All of our production comes from a small number of offshore assets in the UKCS and South East Asia, making us vulnerable to risks associated with having significant production in two regions and only a small number of assets*."

As we navigate the energy transition, one of our top priorities is to achieve and maintain high HSE performance. We believe that we have robust management systems, a culture of positive engagement and a commitment to continuous improvement. We are committed to respecting the people and environments that our business may affect, and we aim to operate our business to achieve safe results, with no harm to people or the environment. To achieve this, we aim to manage our business in compliance with legislation and industry standards, maintain high-quality systems and processes and ensure safe and healthy workplaces. For more information on our health, safety, environment and assurance policies, see "*Our business—Health, safety, environment and assurance*."

As part of our strategy, we aim to maintain a strong balance sheet through consistent deleveraging and prudent capital allocation. In recent years, we have prioritized using free cash flow to reduce our debt. Accordingly, we have significantly reduced our EnQuest net debt from $1.2 billion as of December 31, 2021 to $433.9 million as of December 31, 2025. This represents a reduction of $1.6 billion since peak net debt of $2.0 billion in 2017 and an EnQuest net debt to adjusted EBITDA ratio of 0.9x (compared to 2.5x as of December 31, 2018). The following chart shows the reduction in our EnQuest net debt and EnQuest net debt to adjusted EBITDA ratio for the period indicated:



UKCS

The U.K. North Sea business consists of three directorates:

U.K. Upstream: *Kraken*, *Magnus*, *Golden Eagle, Greater Kittiwake Area*, *Scolty/Crathes*, *Alba*, *Bressay and Bentley*

The U.K. Upstream producing assets are characterized by their high production and operating efficiency. Our strategy is focused on reservoir management and resource development. In the year ended December 31, 2025, daily average net production in the U.K. Upstream directorate was 31,122 boepd, representing 72% of our total daily average net production for that period.

U.K. Midstream: *SVT and pipelines*

Within our Midstream directorate, we operate SVT and approximately 1,000 km of pipelines. Our Midstream business remains focused on the delivery of safe and reliable operations for the processing of East of Shetland and West of Shetland oil and gas, while progressing projects to right-size the terminal to support existing and future upstream operations and significantly lower the terminal's emissions footprint.

In addition, in December 2023, we launched Veri Energy, our wholly owned subsidiary, which is focused on progressing scalable decarbonization and new energy projects. These projects include carbon capture and storage, electrification and e-fuel production by repurposing the existing infrastructure at SVT and connected offshore infrastructure.

U.K. Decommissioning: *Heather/Broom*, *Thistle/Deveron*, *Alma/Galia and the Dons*

The U.K. Decommissioning operations manage end-of-field life decommissioning programs for assets that have already ceased, or are about to cease, production.

South East Asia

Malaysia

We have assets located in Malaysia at PM8/Seligi and DEWA, and we were awarded a PSC partnership for Cendramas in Peninsular Malaysia in February 2026. In the year ended December 31, 2025, daily average net production in Malaysia was 9,201 boepd (including 3,181 boepd associated with Seligi gas in the same period), representing 21% of our total daily average net production for that period.

Vietnam

We also have producing assets located in Vietnam at Chim Sáo and Dua. In the year ended December 31, 2025, daily average net production in Vietnam was 5,283 boepd, with 2,622 attributable to us beginning on July 9, 2025, the completion date of the acquisition of these assets from Harbour Energy.

Indonesia and Brunei

We also have non-producing assets located in Indonesia at Gaea and Gaea II and in Brunei at Block C. See "*Business—Overview of our assets—South East Asia*."

Working interest in producing assets

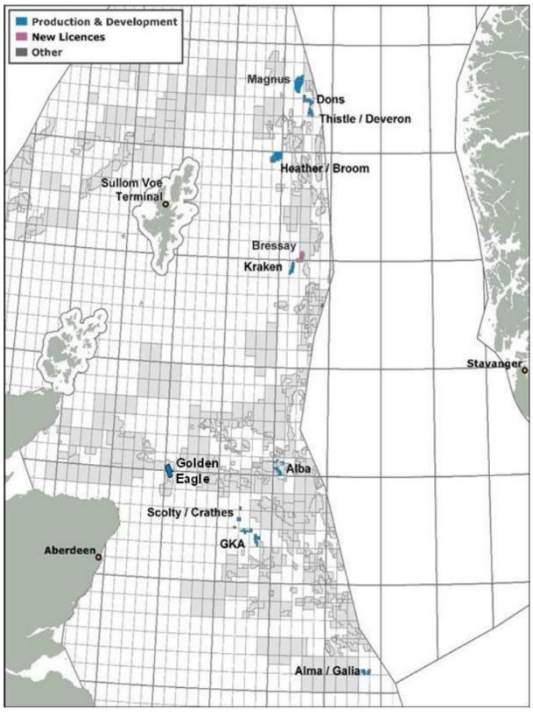
We typically seek to hold a significant working interest in our producing assets and developments, with 100.0% at Magnus, 70.5% at Kraken, 50.0% at GKA, 50.0% at Scolty/Crathes, 85.0% at Bressay, 26.69% at Golden Eagle and 100.0% at Bentley. In Malaysia, we hold a 50.0% working interest in PM8/Seligi, a 42.0% interest in DEWA and from September 2026, a 25.0% participating interest in the Cendramas PSC. In Vietnam, we hold a 53.125% working interest in Chim Sáo and Dua. While we focus on maximizing our operating equity, we have also sought to structure asset acquisitions with significantly lower abandonment equities, in order to minimize our exposure to decommissioning costs.

Through ownership, holding a significant working interest and active participation rights, we are better able to shape the development plan of an asset and influence the timing and method of the extraction of resources than we would be able to if we were passive partners in our fields. As of December 31, 2025, in the U.K., we had ownership interests in 18 producing licenses (however, as of February 2026, we relinquished license P2632, reducing our total U.K. production licenses to 17), 14 of which were operated and 4 of which were partner-operated. We also have an interest in two producing licenses and one non-producing license in Malaysia, one producing license in Vietnam, two non-producing licenses in Indonesia and one non-producing license in Brunei. For the Group, in the year ended December 31, 2025, 93% of our company production was from operated assets while 7% was from partner-operated assets. We thus have a significant degree of control over the timing and magnitude of operating and capital expenditures for most of our assets. We have the right and obligation under

each joint operating agreement to which each asset is a party to take delivery of our share of production from each field for onward sale to third parties of our choice and in the case of Vietnam jointly marketed with our partners. Furthermore, in relation to crude oil, each field temporarily stores production either at the field (such as onboard an FPSO) or at a terminal (such as the SVT). This gives each field owner the ability to accumulate a marketable volume of cargo, which is firstly allocated in full to the field owner with the highest proportionate share of the total stored volume at the time a full cargo accumulates in the first instance. By mutual agreement, field owners may pool their production under a joint operating agreement in order to share in cargoes. With the exception of Vietnam, we have full discretion over the marketing of our attributable volumes across our portfolio and, in relation to assets in which we hold a minority, non-operated stake such as Alba and Golden Eagle, we market our attributable volumes independently of our partners in each field. We market our attributable volumes independently from our field partners to enable us to best leverage our proprietary trading capabilities and substantial industry know-how.

We believe that our existing assets with the highest remaining production potential are Kraken, Magnus and PM8/Seligi. We are also the operator of these assets. There are also material Reserves and Contingent Resources within Kraken, Magnus and PM8/Seligi assets that we believe can be accessed through short-cycle low-cost drilling well intervention and enhanced oil recovery projects. The 2021 acquisitions of approximately 115 MMboe of net 2C Resources associated with our operating interest in Bressay and 131 MMboe of net 2C Resources associated with our operating interest in Bentley provide significant long-term production opportunities that have similarities to our Kraken field. Kraken, Magnus, and the PM8/Seligi fields currently have approximately 33 MMboe, 28 MMboe and 27 MMboe (excluding block PM409, which was relinquished in 2024) of net 2C Resources, respectively. We also have exploration and development potential associated with our interests at DEWA in Malaysia, Gaea and Gaea II in Indonesia and Block C in Brunei.

The following map sets forth the locations of our assets in the UKCS:



The following table sets forth the net daily average production on a working interest basis for each of our producing UKCS operations, our Malaysian operations and our Vietnamese operations for the years ended December 31, 2023, 2024 and 2025:

Region	Working interest	Net daily average production (boepd) For the year ended December 31, 2023	2024	2025
U.K. Upstream		**36,375**	**32,587**	**31,122**
Kraken	70.5	13,580	12,759	10,948

Region	Working interest	Net daily average production (boepd) For the year ended December 31, 2023	2024	2025
Magnus	100.0	15,933	14,173	15,335
Golden Eagle	26.69	4,199	3,328	2,736
GKA[1]	50.0	946	889	816
Scolty/Crathes	50.0	1,466	1,120	1,009
Alba	8.0	251	319	278
Bentley	100.0	—	—	—
Bressay[2]	85.0	—	—	—
Malaysia		**7,437**	**8,149**	**9,201**
PM8/Seligi[3]	50.0	7,437	8,149	9,201
DEWA[4]	42.0	—	—	—
Vietnam		—	—	**2,622**
Block 12W[5]	53.125	—	—	2,622
Total		**43,812**	**40,736**	**42,945**

(1) GKA production is split across four fields, Mallard, Grouse, Gadwall and Goosander (all at 50.0% working interest), with Kittiwake being the production facility for the hub.

(2) In 2023, we sold 15.0% of the working interest in the Bressay license to RockRose UKCS 10 Ltd, a subsidiary of Viaro Energy.

(3) For the years ended December 31, 2023, 2024 and 2025, respectively, the net daily average production reflects 604 boepd, 1,978 boepd and 3,181 boepd associated with Seligi gas.

(4) DEWA fields acquired with a completion date of October 21, 2024 and are not yet producing.

(5) Production volumes have been calculated from July 9, 2025, the completion date of the acquisition of Block 12W from Harbour Energy. For the year ended December 31, 2025, total net daily average production was 5,283 boepd.

Our production on a working interest basis increased by 5.4% to 42,945 boepd for the year ended December 31, 2025.

Reserves & Contingent Resources

The following table sets forth the 1P Reserves, 2P Reserves and 2C Resources as of the years ended December 31, 2023, 2024 and 2025. Reserves are presented as EnQuest net entitlement Reserves volumes according to the PRMS and separately as EnQuest working interest Reserves volumes for comparative purposes. Contingent Resources are presented as EnQuest working interest volumes only.

	EnQuest net working interest Reserves[1]			EnQuest net entitlement Reserves[3]		
	2023	2024	2025	2023	2024	2025
1P Reserves						
Oil (MMbbl)	123	110	105	117	106	102
Gas (Bscf)[4]	60	109	120	53	91	104
Total 1P Reserves (MMboe)	**133**	**129**	**126**	**126**	**121**	**120**
Pro forma Adjustments[2]						
Vietnam Oil (MMbbl)	—	3	—	—	3	—
Vietnam Gas (Bscf)	—	2	—	—	2	—
Total Vietnam 1P Reserves (MMboe)	—	3	—	—	3	—
***Pro forma* Total 1P Reserves (MMboe)**	**n.a.**	**132**	**n.a.**	**n.a.**	**124**	**n.a.**
2P Reserves						
Oil (MMbbl)	161	143	133	153	137	128
Gas (Bscf)[5]	82	147	171	71	118	142
Total 2P Reserves (MMboe)	**175**	**169**	**163**	**165**	**157**	**152**
Pro forma Adjustments						
Vietnam Oil (MMbbl)	—	5	—	—	5	—
Vietnam Gas (Bscf)	—	10	—	—	10	—
Total Vietnam 2P Reserves (MMboe)	—	7	—	—	7	—
***Pro forma* Total 2P Reserves (MMboe)**	**n.a.**	**176**	**n.a.**	**n.a.**	**164**	**n.a.**
2C Resources						
Oil (MMbbl)	336	323	344	n.a.	n.a.	n.a.
Gas (Bscf)	314	178	582	n.a.	n.a.	n.a.

Total 2C Resources (MMboe)	**389**	**354**	**452**	**n.a.**	**n.a.**	**n.a.**
Pro forma Adjustments						
Vietnam Oil (MMbbl)	—	2	—	n.a.	n.a.	n.a.
Vietnam Gas (Bscf)	—	16	—	n.a.	n.a.	n.a.
Total Vietnam 2C Resources (MMboe)..	—	5	—	n.a.	n.a.	n.a.
***Pro forma* Total 2C Resources (MMboe)**	**n.a.**	**359**	**n.a.**	**n.a.**	**n.a.**	**n.a.**

(7) EnQuest net working interest Reserves and Contingent Resources are EnQuest's working interest fraction of the gross field reserves and contingent resources.

(8) GaffneyCline's report assessing reserves and resources for Block 12W in Vietnam as of December 31, 2024 was prepared when entitlements of those reserves and resources were attributable to Harbour Energy, up until July 9, 2025, at which time EnQuest completed the transaction that entitled EnQuest to the reserves and resources. Hence the reported year end 2024 Vietnam Reserves do not represent EnQuest Reserves as at December 31, 2024 but are included in table above as "*Pro forma Adjustments*."

(9) For assets governed by Production Sharing Contracts ("**PSC**") (PM8/Seligi in Malaysia and Block 12W in Vietnam), EnQuest Net Entitlement Reserves are EnQuest's net economic entitlement according to the PSC terms, *i.e.*, EnQuest's share of cost and profit oil and gas.

(4) For the years ended December 31, 2023, 2024 and 2025, 1P gas reserves included 40.8 Bscf used for fuel and 19.4 Bscf (working interest) or 12.5 Bscf (net entitlement) used for sales, 36.7 Bscf used for fuel and 72.0 Bscf (working interest) or 54.0 Bscf (net entitlement) used for sales and 38.4 Bscf used for fuel and 81.5 Bscf (working interest) or 65.2 Bscf (net entitlement) used for sales, respectively. *Pro forma* adjustments reflect 1P Vietnam reserves as of December 31, 2024 and included 0 Bscf used for fuel and 2.3 Bscf (working interest) or 2.2 Bscf (net entitlement) used for sales.

(5) For the years ended December 31, 2023, 2024 and 2025, 2P gas reserves included 46.6 Bscf used for fuel and 35.8 Bscf (working interest) or 24.3 Bscf (net entitlement) used for sales, 42.5 Bscf used for fuel and 104.4 Bscf (working interest) or 76.0 Bscf (net entitlement) used for sales and 46.8 Bscf used for fuel and 124.2 Bscf (working interest) or 94.8 Bscf (net entitlement) used for sales, respectively. *Pro forma* adjustments reflect 2P Vietnam reserves as of December 31, 2024 and included 0 Bscf used for fuel and 10.3 Bscf (working interest) or 9.5 Bscf (net entitlement) used for sales.

Strengths

We believe that the combination of our high-quality asset portfolio, operational expertise, financial strength and differentiated tax position will position us to deliver on our strategy and take advantage of organic and inorganic production and development opportunities in the U.K. North Sea, South East Asia and beyond.

Track record of value creation with a demonstrated ability to execute value-accretive transactions across commodity price volatility

We have an attractive portfolio of operated producing and non-producing assets located in the U.K. North Sea and across South East Asia. We employ a rigorous framework for all M&A that we believe delivers value accretive acquisitions, including the Magnus and Golden Eagle asset acquisitions, which re-weighted our portfolio toward mid-life assets. Our acquisitions in prior years have typically achieved payback within 12 to 18 months, and we take an entrepreneurial, innovative approach to structuring deals, with limited upfront consideration and a focus on value. As part of our strategy to diversify and grow our asset base, we have expanded our operational footprint beyond our core regions in the U.K. North Sea and Malaysia. In July 2025, we completed the acquisition of Harbour Energy's business in Vietnam (the "**Vietnam Acquisition**"), securing a 53.125% equity interest and operatorship in the Chim Sáo and Dua production fields ("**Block 12W**"). The Vietnam Acquisition was largely self funded by interim free cash flow, highlighting the deal's strong economics and rapid payback. In the year ended December 31, 2025, Block 12W produced 5,283 boepd, 2,622 of which was attributable to us following the completion of the acquisition on July 9, 2025. Block 12W had EnQuest working interest 2P Reserves of 7.4 MMboe and 2C Resources of 5.3 MMboe as of December 31, 2025, adding significant resources to our existing reserves.

In addition, we have entered into new production sharing contracts ("**PSCs**") for appraisal and development in Indonesia, Malaysia and Brunei, including the Seligi 1B gas project in Malaysia, where approximately 6 kboepd of gas production was brought onstream approximately nine months ahead of schedule, with gas production beginning in December 2025. Optimized gas production has enabled us to satisfy higher demand, which has exceeded the base delivery requirement by up to 40% since the start of the conflict in the Middle East. In July 2025, we were awarded the Block C PSC in Brunei, which hosts condensate-rich gas discoveries with a pathway to development and supply to both domestic and international LNG markets. In August 2025, we signed PSCs for the Gaea and Gaea II exploration blocks in Papua Barat, Indonesia, marking our entry into a region with significant multi-Tscf unrisked resource potential near bp-operated LNG infrastructure. These

new country entries reflect our disciplined approach to value-accretive growth, enhance our geographic and commodity diversification and position us to leverage our technical and operational expertise in emerging South East Asian markets, where there is strong demand for energy.

These transactions have resulted in Group-wide growth, with our liquidity (being total cash and available facilities) increasing by over $200 million, from $474 million in 2024 to $679 million in 2025. This increase in liquidity was due in large part to the refinancing of our 2021 RBL Facility, which was completed in November 2025. The refinanced RBL Facility comprises a $400 million secured multicurrency revolving loan facility and a $400 million secured multicurrency revolving letter of credit facility, with an accordion option of up to $800 million (consisting of an accordion option of up to $400 million in respect of each of the revolving loan facility and the revolving letter of credit facility) to support, among other things, larger M&A transactions. See "*—Recent Developments—RBL Facility Agreement*" and "*Risk Factors—Risks relating to our business— Our strategy of delivering sustainable and transformative growth through transformative consolidation transactions may increase our debt and the complexity of our operations*." Our production also increased by more than 5%, from 40,736 boepd for the year ended December 31, 2024 to 42,945 boepd for the year ended December 31, 2025, despite natural field declines in the U.K. North Sea and third-party equipment outages. We also successfully navigated a weaker U.S. dollar environment and lower oil prices in 2025, reducing unit operating costs (including hedging) to $25.1/bbl from $25.6/bbl in 2024.

On February 26, 2026, we signed an agreement to settle the Magnus Contingent Consideration for $60 million, representing the final settlement of the profit share liability related to Magnus, thereby securing 100% of future Magnus cash flows and removing the associated $433 million liability that was on our balance sheet as of June 30, 2025. There is no resulting change to the decommissioning arrangements, which require us to pay an effective 9% of decommissioning obligations. This settlement not only simplifies our balance sheet and enhances our credit profile by removing a significant liability but is also expected to unlock $777 million of incremental undiscounted life-of-field free cash flow over the remaining life of Magnus.

Strong, resilient free cash flow generation that facilitates both reinvestment and deleveraging, aided by an advantageous tax position

We generated adjusted EBITDA of $503.8 million during the year ended December 31, 2025. Our cash generated from operations for the years ended December 31, 2023, 2024 and 2025 was $854.7 million, $685.9 million and $497.8 million, respectively. We also generated adjusted free cash flow for the year ended December 31, 2025 of $8.7 million, contributing to $1.3 billion of total free cash flow generated since the start of 2021. Our strong cash flow performance during the periods under review enabled us to refinance and repay certain components of our indebtedness. This led to a simplified capital structure with a lower-than-expected utilization and enabled the full repayment of the 2021 RBL Facility in early 2024 and its cancellation on November 20, 2025. As of December 31, 2025 we had total cash and available facilities of $678.6 million. Facility B (as defined herein) under the RBL Facility Agreement had $381.5 million letter of credit utilization, with $18.5 million residual availability thereunder. Facility A (as defined herein) remained undrawn. See "*Description of certain financing arrangements—RBL Facility*."

We also reduced our costs significantly in the year ended December 31, 2025, including the previously negotiated 70% reduction in the Kraken FPSO lease cost as of April 1, 2025, equivalent to approximately $80 million in savings per year.

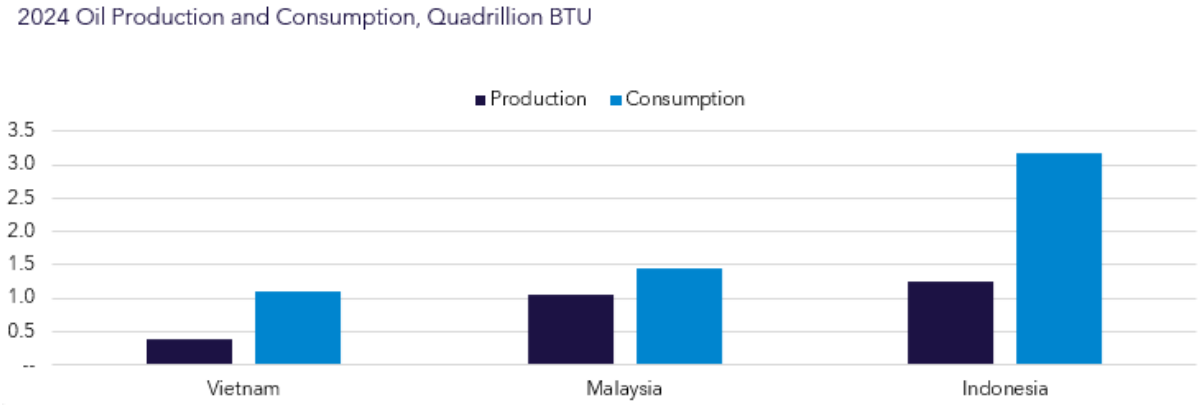
In the U.K., we have a $3 billion tax loss position equating to $1.2 billion in tax shield value built up through material U.K. investment. This tax loss position comprises readily accessible recognized tax assets of $1,851.3 million as of December 31, 2025 and a further $1,118 million not yet recognized. These tax assets shelter EnQuest's U.K. operations from corporation tax (30%) and supplementary charge (10%), with the Group only paying the EPL (38%). This results in a differentiated post-tax cash flow of approximately 62% for EnQuest, more than 2.8x higher than the differentiated post-tax cash flow for full U.K. tax payers paying headline rates. In addition, we have unused U.K. mainstream corporation tax losses of $578.4 million as of December 31, 2025 (December 31, 2024: $496.1 million). We believe that our capital structure, strong liquidity and our tax assets will provide us with the financial flexibility to implement our strategy and, in turn, deliver increased cash flows.

Well-positioned to capitalize on the strategic importance of hydrocarbons and the positive commercial landscapes in the U.K. and South East Asia

Throughout 2025, the U.K. Government clarified the fiscal and regulatory regime for oil and gas activity, creating a more supportive economic environment. In June 2025, the U.K. Government published their Scope 3 guidance, providing emissions framework clarity and removing the risk of retrospective compliance obligations. In November 2025, the U.K. Government announced the Oil and Gas Price Mechanism ("**OGPM**") as the successor to the EPL, representing a more pragmatic and predictable windfall tax mechanism. In addition, the NSTA approved further developments in the North Sea, including granting a license extension for the Cambo field and approving the Tornado and Fotla development concepts (all operated by Ithaca Energy), while the Rosebank field (operated by Equinor) continues to progress in line with its timeline, targeting first oil by 2026–2027, together providing a clear pathway to future production. We believe that our continued focus on established jurisdictions with developed petroleum markets, including the United Kingdom, provides us with an attractive operating environment underpinned by a stable and consistent regulatory regime and fiscal environment.

As oil prices surged following events in the Middle East in the first quarter of 2026, the U.K. Government accelerated the momentum toward greater affordability and security of supply. Concerns regarding future supply and domestic energy prices led the government to make announcements favoring domestic production. Europe's energy dependency, already sharply exposed by the ongoing Russia-Ukraine conflict, is further compounded as Middle East instability threatens a second major supply axis. As a result, North Sea oil and gas output has been recognized as a strategic national asset with cross-party support, reinforcing the investment case for new developments and life extension projects in the North Sea.

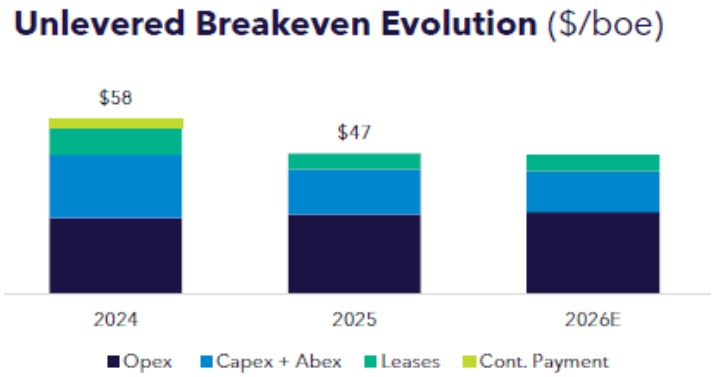
In South East Asia, structural tailwinds favor domestic upstream production. Vietnam, Malaysia and Indonesia all have growing economies, based on increased gross domestic product per capita from 2021 to 2024, but are simultaneously structurally short energy, with total gas demand historically above gas supply. With our presence in four South East Asian countries, we are well-positioned to capitalize on this structural imbalance.



Source: EIA, World Bank

Robust free cash flow potential as a result of enhanced margins, material tax losses and oil price leverage

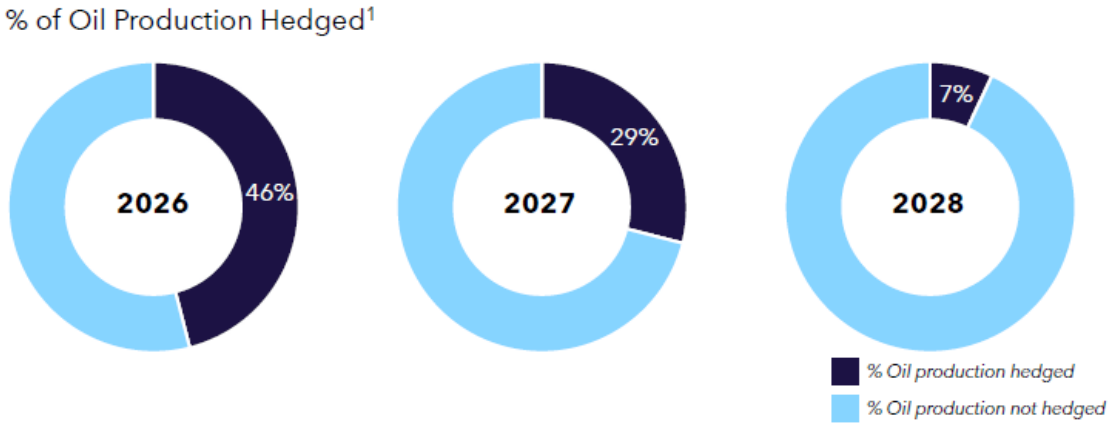
In the year ended December 31, 2025, we generated adjusted free cash flow of $8.7 million, contributing to $1.3 billion of total free cash flow generated since the start of 2021. This strong performance has been in part due to reducing asset break-even levels and substantial U.K. tax loss assets, which together provide leverage to current oil price strength. Our overall pre-tax unlevered breakeven costs have decreased from $58.3/boe in the year ended December 31, 2024 to $46.8/boe in the year ended December 31, 2025.



Note: 2026E column based on 45 kboepd of targeted production and assumes 2026 lease costs in line with 2025 lease costs.

Additionally, average oil prices are expected to increase in 2026, due in part to the conflict in the Middle East, with Bloomberg's consensus forecast, as of March 2026, projecting an average oil price of approximately $90/bbl for 2026, compared to less than $70/bbl in 2025. We estimate that if oil prices had been $10/bbl higher in the year ended December 31, 2025, this would have resulted in approximately $100 million of additional adjusted free cash flow during that year, based on our 2025 production and unit operating costs (including adjustments for hedging to, and excluding tax impacts on, the additional revenue), with further upside in the event of additional oil price increases. As we aim to increase our production and decrease our costs in 2026, increased oil prices would allow us to target an increase in profitability.

Our active hedging strategy also enables resilient cash flows, even at lower oil prices. We are well-hedged, while maintaining upside price exposure. We typically maintain unhedged exposure in near months, complemented by a rolling hedge portfolio across outer periods in order to opportunistically lock in volumes for near-term price lifts during periods of price strength. In 2024, we refreshed our hedging strategy, with a focus on underpinning our budget for the following 24 months and on maximizing RBL Facility capacity. As of April 15, 2026, we have approximately 3.8 MMbbls of production hedged through 2026, utilizing swaps at an average price of $73.2/bbl, and we have approximately 3.5 MMbbls of production hedged for 2027, utilizing swaps at an average price of $64.4/bbl. Finally, we have approximately 0.9 MMbbls of production hedged for 2028, utilizing swaps at an average price of $64.6/bbl. The figure below shows our hedging as a percentage of production.



Note: 2026 includes approximately 1.1MMbbls of hedges from the first quarter of 2026.
(1) At illustrative 2026 mid-point oil production.

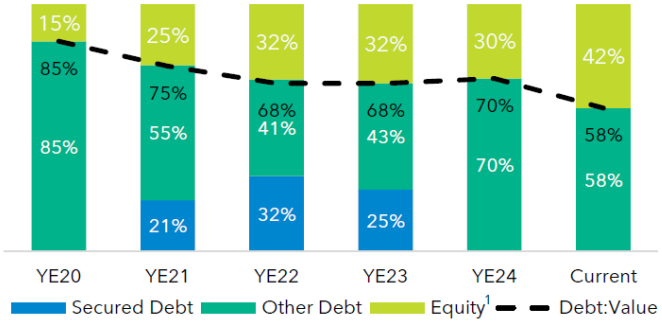
Flexible and simplified capital structure designed for disciplined capital decisions

In the year ended December 31, 2025, we simplified our capital structure, through a combination of our existing 2027 Notes ($465 million as of December 31, 2025), our existing 9% Retail Notes ($179 million as of December 31, 2025) and the refinancing of our 2021 RBL Facility in November 2025. The refinanced RBL Facility provides $800 million of financing capacity, comprising a $400 million secured multicurrency revolving loan tranche, which remained undrawn as of December 31, 2025, and a $400 million secured multicurrency letter of credit facility that simplifies the provision of decommissioning security. In addition, the RBL Facility includes an accordion option of up to $800 million (consisting of an accordion option of up to $400 million in respect of

each of the revolving loan facility and the revolving letter of credit facility), to support, among other things, larger M&A transactions. With a strong cash balance and funds remaining available to draw down under the RBL Facility, our total cash and available facilities totaled $679 million at December 31, 2025 (including $269 million in cash), an increase from $474 million as of December 31, 2024 and from $284 million as of December 31, 2020, supporting disciplined capital allocation and providing significant flexibility to pursue value-accretive opportunities.

Balance sheet strength, active management of capital structure and financial discipline remain key priorities. Through our entry into multiple countries in South East Asia, we have been growing through diversification and internationalization, allowing us to strategically focus on investments with fast payback times and attractive risk-adjusted returns. Within this framework of capital discipline, we seek to deploy capital selectively and prioritize opportunities that enhance resilience and reduce concentration risk. As a result, we were able to issue our first shareholder dividend of $15.3 million in 2025. Further to this, we announced our intention to pay an increased dividend of $20 million in 2026, subject to shareholder approval at our annual general meeting on May 22, 2026.

We have significantly strengthened our capital structure since December 31, 2020, primarily through a reduction in net debt and growth in equity value. Between December 31, 2020, and December 31, 2025, net debt decreased by 66%, supported by a 21% increase in cash (including restricted cash) and a 139% increase in liquidity, improving financial flexibility and reducing leverage. In the period from December 31, 2020 to March 31, 2026, our market capitalization increased by 92%, further contributing to a stronger equity base. As a result, the equity share of our enterprise value increased from 17% to 54%, a 37% increase. The graph below shows the increasing equity component of our capital structure from 2020 to 2025.



	YE2020	*Current*	*Change*
Net Debt	1,280	434	- 66%
Cash[2]	223	269	+ 21%
Liquidity	284	679	+ 139%
Equity (Market Cap.)	262	504[3]	+ 92%
Equity % of Enterprise Value	17%	54%	+ 37%[4]

(1) Market value of equity.
(2) Includes restricted cash
(3) Market capitalization as of March 31, 2026 (21p/share x 1.85bn s/o, GBPUSD 1.29).
(4) Stated on an absolute basis.

Strategy

We aim to remain one of the U.K.'s leading independent energy companies, utilizing our top quartile operating performance and differentiated U.K. tax position to rescale the business through transformative M&A. We are focused on growing scale through diversification and internationalization across our U.K. North Sea and South East Asian operations, delivering value and reducing emissions, while maintaining balance sheet discipline. We intend to deliver sustainable and transformative growth by targeting the acquisition of flowing barrels, with robust production profiles and low capital requirements, while continuing to exploit our existing reserves, commercializing and developing discoveries and converting our significant Contingent Resources into reserves. In addition, we will continue to assess renewable energy and decarbonization opportunities, prioritizing those that leverage existing infrastructure. We are developing cost-effective and efficient plans to transform SVT and prepare and repurpose the site to progress decarbonization opportunities at scale, focused on carbon capture and storage, electrification through onshore wind, and the production of e-fuels.

Continued operational excellence with a focus on ESG and sustainability

We have a strong track record of conducting our operations in a safe and environmentally responsible manner and seek to maintain the highest safety standards. As an energy company, safely improving the operating, financial and environmental performance of mature and late-life assets remains a key focus. Our highly skilled and integrated teams strive to enhance hydrocarbon recovery through focused improvement programs, prioritizing employee safety and mitigating the effects of climate change. We recognize that industry, along with other key stakeholders such as governments and regulators, must contribute to reducing the impact of carbon-related emissions on climate change. We are committed to playing our part in achieving national emission reduction targets and the drive to net-zero, with our wholly owned subsidiary, Veri Energy, having overall responsibility for delivering our emission reduction objectives. Through our environmental management system ("**EMS**"), we strive to ensure that our operations are undertaken in a manner that manages and mitigates our impact on the environment. The EMS is aligned with the requirements of the International Organization for Standardization's environmental management system—ISO 14001—and is independently verified every two years, the last time being in September 2025. In the United Kingdom, we will continue to publish our annual Environmental Statement, and in Malaysia, environmental management and reporting are undertaken through PETRONAS Malaysia Petroleum Management. Additionally, we intend to produce environmental reports that include our Vietnam, Indonesia and Brunei assets going forward.

Our in-house technical and operations teams underpin our development and operations-focused strategies. We believe that we are differentiated from our peers by the breadth and depth of these teams, their knowledge and experience in engineering, subsurface, execution and operations and our leadership in innovative integrated developments, such as Magnus. We have a spectrum of integrated technical capabilities, combining subsurface, production operations, facilities, management, project management, planning and drilling, providing us with the right mix of capabilities to deliver new oil field developments and optimize production from producing assets in maturing basins by leveraging our differentiated operating capabilities. Our oil and gas reserves and resources increased by approximately 18% for the year ended December 31, 2025, compared to 2024, reflecting the impact of our focused development and portfolio strategy. We are a top-quartile operator, increasing our production by approximately 5.4% over the same period and achieving underlying asset uptime of approximately 89% (92% excluding the impact of the third-party outage at Magnus in the first half of 2025). We have delivered these results while reducing Scope 1 and Scope 2 CO_2 equivalent emissions and operating costs, extending field life and demonstrating sector-leading decommissioning performance.

Our operational expertise also enabled us to deliver three years and over six million man-hours of lost time incident frequency ("**LTI**")-free performance in Malaysia, and we received the 'HSE Excellence Award' at the PETRONAS Emerald Awards in May 2025. We continue to prioritize focus across the organization on driving personal responsibility for safety, increasing hazard awareness and providing excellent supervision at the worksites. Our operating capabilities have been recognized through prestigious industry awards. At the PETRONAS Emerald Awards in June 2025, we were named "Operator of the Year" for the second consecutive year, underscoring our commitment to operational excellence in the region. In addition, we received recognition for "Abandonment Excellence," reflecting our sector-leading performance in well P&A activities. These accolades from PETRONAS serve as strong validation of our expertise, dedication to safety and ability to deliver complex projects efficiently and responsibly in one of South East Asia's key energy markets.

The Board added its support to our sustainability plan during 2023 by approving a commitment to reach net zero Scope 1 and Scope 2 emissions by 2040 and will work closely with management to ensure that appropriate and credible milestones are set for the journey to net zero. As part of this journey, we have set annual interim targets to reduce Group-wide Scope 1 and Scope 2 emissions by 10% across a rolling three-year period. These targets, which started in 2020, are linked to compensation across the Group. In the United Kingdom, by December 31, 2025, we had reduced our Scope 1 and Scope 2 emissions by approximately 46% compared to 2018. In addition, we were awarded a sector-leading A- rating for our 2025 CDP Climate Change submission ("**CDP**"), an improvement from our B rating in 2024, which we believe validates our continued focus on the impact of our business on climate change. CDP represents the pre-eminent ESG rating used by investors and financial institutions, and the overall improvement in our scoring in recent years has been driven by recognition of our credible transition plan and defined actions to pursue progress towards net zero.

As the energy transition progresses and other industry operators continue to shift their focus from mature basins within various geographies, it is expected that there will be further opportunities for us to access additional oil and gas reserves and resources. We are focused on expanding our footprint in South East Asia, delivering

geographic diversification as well as increasing the gas component of our portfolio commodity mix. However, we will aim to ensure we identify the right opportunities where we can deliver incremental emission reductions relative to the carbon footprint of the seller. In addition, we will continue to assess renewable energy and decarbonization opportunities that would leverage existing infrastructure.

We are developing cost-effective and efficient plans to transform SVT, right-sizing and repurposing the site to progress decarbonization opportunities at scale. These plans are centered on carbon capture and storage, electrification via onshore wind, and the production of e-fuels. The availability of the deep-water port and jetties and a pipeline network linked to several well-understood offshore reservoirs presents the opportunity to repurpose infrastructure to import and permanently store material quantities of CO_2 from isolated emitters in the U.K., Europe or further afield. Veri Energy holds two U.K. carbon storage licenses, awarded by the U.K. Regulator, covering locations which are accessible from our existing infrastructure. Initial study work suggests a project with the potential for up to 10 million tonnes per annum of storage and in excess of 200 million tonnes of total capacity at our two licensed storage sites, ramping up from as early as 2028. We also remain focused on right-sizing SVT for future operations and are progressing two major projects; the construction of new stabilization facilities ("**NSF**"), and a strategic project to connect the terminal to the U.K.'s electricity grid. It is expected that the NSF will right-size the terminal's oil stabilizing (removing gas from the oil so that it is safe for onwards transportation) and processing capacity to meet the future production profile associated with the East of Shetland offshore fields.

The safety of our people and operations is and will continue to be integral to our values. We have a group-wide health, safety, environment and assurance policy. We undertake ongoing improvement activities in support of the 'SAFE' behaviors: (i) standards (following rules and procedures), (ii) awareness (understanding the hazards and controls), (iii) fairness (adopting the correct behaviors) and (iv) engagement (communicating effectively).

Maintain a disciplined approach to financial management and a strong balance sheet that provide optionality around organic and inorganic opportunities

We aim to have a conservative financial profile and strong balance sheet with ample liquidity. Debt reduction and active management of our debt maturities will remain a priority. We have reduced our EnQuest net debt to $433.9 million as of December 31, 2025, significantly lower than $1.2 billion as of December 31, 2021, which resulted in a corresponding reduction of leverage to 0.9x, calculated using EnQuest net debt as of December 31, 2025 over adjusted EBITDA for the year ended December 31, 2025. This is down from a peak of 6.6x at December 31, 2017. Our consistent deleveraging is driven by total free cash flow of $1.3 billion generated since the start of 2021, and our prudent approach to capital allocation. While we intend to use debt financing and access to capital markets when appropriate, we will seek to manage the business with leverage levels that are reflective of the financial capacity of our assets.

With a strong cash balance and funds remaining available to draw down on the RBL Facility, our total cash and available facilities totaled $679 million at December 31, 2025, an increase from $474 million at December 31, 2024.

We will continue to focus our capital allocation strategy on identifying investments that prioritize positive cash flow generation. With a focus on short-cycle projects, we can adjust our capital allocation decisions to match the prevailing oil demand and price environment and are actively and continuously assessing program optimization in light of the Energy Profits Levy ("**EPL**") and the subsequent OGPM in the United Kingdom. In the year ended December 31, 2025, our cash outflow on capital expenditure ("cash capex") was $179.2 million, excluding acquisitions. In the year ended December 31, 2024, our cash outflow on capital expenditure ("cash capex") was $252.9 million, excluding acquisitions, as compared to $152.2 million in the year ended December 31, 2023.

As part of our prudent risk management program, we actively hedge our exposure to oil prices on a graduated rolling basis to provide strong price protection throughout the economic cycle. Liquidity risk will continue to be monitored closely through cash flow forecasts and sensitivity analysis. We will also continue to manage credit risk by assessing the creditworthiness of potential counterparties before entering into transactions with them and by continuing to evaluate their creditworthiness after transactions have been initiated.

We will continue to drive organic growth by prioritizing fast payback infill drilling across our core portfolio. In addition, we are focused on unlocking upside on our existing assets, for instance via the Kraken EOR project and the Seligi 1B gas project, where approximately 6 kboepd of gas production was brought onstream

approximately nine months ahead of schedule. We are working to convert our significant Contingent Resources into reserves, notably at Bressay & Bentley, DEWA and Block C.

We continue to evaluate potentially transformative inorganic acquisition opportunities in the U.K. and South East Asia. Our focus is to identify assets that fit our business model, including those that can best utilize our U.K. tax losses and create synergies for our tax credits under the EPL. With a total of over $3 billion in tax assets in the United Kingdom as of December 31, 2025, we have set the conditions to deliver value-accretive and transformative inorganic growth and, even in a fiscally volatile environment, our growth strategy remains robust. We will also continue to evaluate and pursue cost optimization initiatives, including through selective acquisitions with vendor loan structures, partnership opportunities and business combinations, in each case which may be material, in order to secure an adequate supply of resources, rigs or other infrastructure used or useful in the business when we believe to do so will be value-accretive and enhance our long-term growth and strategic objectives. See "*—Track record of value creation with a demonstrated ability to execute value-accretive transactions across commodity price volatility*" and "*Risk Factors—Risks relating to our business—Our strategy of delivering sustainable and transformative growth through transformative consolidation transactions may increase our debt and the complexity of our operations.*"

Maximize the performance of our existing asset portfolio and deliver innovative value-add initiatives

We aim to employ a cost-conscious approach to our operations and implement innovative initiatives to enhance their value. Since 2015, we have significantly reduced our capital expenditure. We have also reduced our unit operating costs (including hedging) from $25.6/bbl in the year ended December 31, 2024 to $25.1/bbl in the year ended December 31, 2025, and continue to target cost-reduction strategies. We also strive to utilize innovative transaction structures to facilitate the transfer of the right assets into the right hands.

We believe we are strongly positioned to be an energy transition leader by responsibly optimizing production at our existing assets, leveraging existing infrastructure, delivering strong decommissioning performance and exploring new energy and further decarbonization opportunities. In December 2023, we launched Veri Energy, which builds on work undertaken by our infrastructure and new energy business, and is focused on progressing scalable decarbonization and new energy projects. These projects include carbon capture and storage, electrification via onshore wind, and the production of e-fuels and are focused on repurposing the existing infrastructure at SVT and connected offshore infrastructure. We bring the infrastructure, key relationships and project delivery expertise and will look to engage strategic and financial partners to progress these projects, enabling us to employ a capital-light approach.

Leverage integrated technical capabilities

We believe we have the right mix of integrated technical capabilities to select appropriate development and production options, deliver high levels of underlying asset uptime and control costs to realize value from maturing and underdeveloped assets. We aim to leverage our differentiated operational capabilities to responsibly optimize production across our portfolio to achieve asset life extension and maximize economic recovery from those assets to enable future growth. Similarly, we are using our skills to assess repurposing opportunities of existing infrastructure and progress scalable new energy and decarbonization opportunities.

Our history

We were founded in 2010 through a combination of Petrofac Energy Developments Limited ("**PEDL**") and certain assets of Lundin Petroleum AB ("**Lundin**"). We purchased PEDL and the UKCS assets of Lundin in exchange for stock. Following our initial public offering in April 2010, our shares are listed and trade on the London Stock Exchange. Our shares were also listed on the Stockholm Stock Exchange until December 2023, when the Board decided to delist our shares from the Stockholm Stock Exchange. In 2014, we diversified our geographical footprint through acquiring initial production licenses in Malaysia.

We believe that our operational capabilities and experienced technical staff and management have allowed us to grow production, reserves and resources since 2010 and that in the UKCS, South East Asia, and potentially other geographic regions we have, and will continue to have, substantial opportunities for development through low-cost, near-field drilling, well intervention and enhanced oil recovery projects, while maintaining a focus on the health, safety and environmental impacts of our operations.

In December 2023, we launched Veri Energy, our wholly owned subsidiary, which is focused on progressing scalable decarbonization and new energy projects. These projects include carbon capture and storage, electrification and the production of e-fuels by repurposing the existing infrastructure at SVT and connected offshore infrastructure.

In October 2024, we expanded our operations in Malaysia when we were awarded the PSC for DEWA, a complex cluster consisting of 12 discovered fields off the coast of Sarawak. In July 2025, we expanded for the first time into Vietnam via our acquisition of Harbour Energy's Vietnam business and into Brunei via our PSC award for Block C. In August 2025, we expanded for the first time into Indonesia with our joint venture partners via two PSCs for the Gaea and Gaea II exploration blocks located in Papua Barat. Effective September 23, 2026, we will take up a 25.0% participating interest in the Cendramas PSC in Peninsular Malaysia.

Summary of historical reserves, resources and operating data

We retain GaffneyCline as our independent reserve engineer for the purposes of auditing our 1P and 2P Reserves. We estimate our reserves and resources internally. Our 1P and 2P reserve estimates, but not our 2C resource estimates, are audited by GaffneyCline. Our 1P and 2P Reserves and 2C Resources are estimated using the classifications as defined by the PRMS and supporting guidelines issued by the Society of Petroleum Engineers.

Typical to the industry in which we operate, there are a number of uncertainties inherent in estimating quantities of 1P and 2P Reserves. Therefore, the reserve information in the Reserves Reports represents only estimates. Reserve assessment is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of a number of variable factors and assumptions, many of which are beyond our control, including the quality of available data and of engineering and geological interpretation and judgment and assumptions as to oil price. As a result, estimates of different reserve assessors may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, due to the inherent uncertainties and the limited nature of reservoir data and the inherently imprecise nature of reserves estimates, the initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The significance of such estimates depends primarily on the assumptions upon which they were based. For a summary of certain assumptions used in reporting our estimates, see "*Certain reserves and production information—Hydrocarbon data*." Thus, you should not place undue reliance on the accuracy of the Reserves Reports in predicting actual reserves or on comparisons of similar reports concerning companies established in other economic systems. In addition, except to the extent that we acquire additional properties containing 1P and 2P Reserves or conduct successful appraisal and development activities, or both, our 1P and 2P Reserves will decline as reserves are produced. The following reserve information should be read along with the sections entitled "*Risk factors—Risks relating to the oil and gas industry*" and "*Risk factors—Risks relating to our business*."

Potential investors should note that the Reserves Reports have not estimated 1P and 2P Reserves under the standards of reserves measurement applied by the SEC (the "**SEC basis**") for any of the relevant periods reviewed in the Listing Particulars, or otherwise. The SEC basis differs from PRMS. See "*Certain reserves and production information*."

Pursuant to the classifications and definitions provided by the PRMS, 1P Reserves are defined as those quantities of oil which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations ("**Proved Reserves**", or "**1P Reserves**"). If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Pursuant to the classifications and definitions provided by the PRMS, 2P Reserves are defined as those quantities of oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods and government regulations ("**Proved Reserves**"), plus those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves ("**Probable Reserves**"); it is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved Reserves plus Probable Reserves (2P Reserves). See "*Certain reserves and production information*."

Pursuant to the classifications and definitions provided by the PRMS, Contingent Resources are those quantities estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. The 2C Contingent Resources represent the "best estimate" scenario of Contingent Resources (the "**2C Resources**"); there is a probability of at least 50% that the amount actually recovered will equal or exceed the 2C Resources estimate, in the event that the development project goes ahead.

The following tables set forth certain information with respect to our 2P Reserves and 2C Resources as of the years ended December 31, 2023, 2024 and 2025 and as at January 1.

(MMboe)	2P Reserves[1] January 1	Production[2]	Net Revisions	2P Reserves December 31	Reserve life (years)[3]
2023	190	(16)	1	175	11
2024	175	(14)	8	169	11
2025	169	(14)	8	163	10

(1) Reserves presented here are EnQuest working interest volumes. The corresponding EnQuest Net Entitlement 2P Reserves are 179 MMboe (January 1, 2023), 165 MMboe (December 31, 2023/January 1, 2024), 157 MMboe (December 31, 2024/January 1, 2025) and 152 MMboe (December 31, 2025).

(2) Sales volume for the period.

(3) Based on year end reserves divided by the prior year average net working interest production.

(MMboe)	2C Resources January 1	Transferred to 2P Reserves	Net revisions	2C Resources December 31	Resource life (years)
2023	393	(4)	-	389	24
2024	389	-	(35)	354	25
2025	354	(1)	99	452	29

Internal controls over reserves estimates

Our policy regarding internal controls over the recording of reserves is structured to objectively and accurately estimate our oil reserve quantities and values in compliance with the PRMS. These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. Each of our assets is managed by a dedicated asset team staffed with technically qualified industry professionals and led by a highly experienced team leader. Preliminary reserve estimates are prepared by the asset teams for review with the regional senior management and with technical advisers based in our head office. All staff are graduates in a relevant technical discipline and have substantial industry experience. The review teams in particular are typically comprised of individuals with over thirty years' experience in reservoir and petroleum engineering and include experts in reserves auditing standards.

1P Reserves are estimated using standard recognized evaluation techniques. The estimates for each asset are reviewed by GaffneyCline annually or more frequently upon the occurrence of a material change or acquisition. We provide GaffneyCline technical information including production, geological, geophysical, petrophysical, engineering and financial data as well as fiscal terms applicable to the various assets. Future development costs are provided consistent with the activities required to produce the 1P Reserves. GaffneyCline audits the information provided and recommends changes to the technical assumptions as required. Approved profiles and cost estimates are used to carry out economic modeling to determine economic cut-offs of profiles, and forward oil prices recommended by GaffneyCline. These models are provided to GaffneyCline, which then reviews the models and reports 1P reserve figures.

2P Reserves are estimated using standard recognized evaluation techniques. The estimates for each asset are reviewed by GaffneyCline annually or more frequently upon the occurrence of a material change or acquisition. We provide GaffneyCline technical information including production, geological, geophysical, petrophysical, engineering and financial data as well as fiscal terms applicable to the various assets. Future

development costs are provided consistent with the activities required to produce the 2P Reserves. GaffneyCline audits the information provided and recommends changes to the technical assumptions as required. Approved profiles and cost estimates are used to carry out economic modeling to determine economic cut-offs of profiles. These models are provided to GaffneyCline, which then reviews the models and reports 2P reserve figures.

In addition, the Sustainability and Risk Committee (a sub-Committee of the Board of Directors), comprises Board members with technical backgrounds and associated knowledge, provides oversight and review of our annual reserves report.

Qualifications of third-party engineers

The technical personnel responsible for auditing the reserve estimates at GaffneyCline meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the PRMS. GaffneyCline is an independent international energy advisory company; it does not own an interest in our properties and is not employed on a contingent fee basis. See "*Certain reserves and production information*."

Production and development

Our production on a net working interest basis for the year ended December 31, 2025 was 42,945 boepd (including production from our Vietnam assets as of July 9, 2025). Our production on a working interest basis increased by 5.4% from the year ended December 31, 2024.

The following table provides a summary of our production and development portfolio by asset as of December 31, 2025.

Asset	Working interest (%)	Operator	Production (boepd) for the year ended December 31,		
			2023	2024	2025
U.K. North Sea upstream production and development					
Kraken & Kraken North.....	70.5	EnQuest	13,580	12,759	10,948
Magnus[1]	100.0	EnQuest	15,933	14,173	15,335
Golden Eagle	26.69	CNOOC	4,199	3,328	2,736
GKA[2]	50.0	EnQuest	946	889	816
Scolty/Crathes.....	50.0	EnQuest	1,466	1,120	1,010
Alba	8.0	Ithaca Oil and Gas Limited	251	319	277
Bressay[3]	85.0	EnQuest	–	–	–
Bentley.....	100.0	EnQuest	–	–	–
Malaysia production and development					
Seligi, North & South Raya, Lawang, Langat, Yong & Serudon[4]	50.0	EnQuest	7,437	8,149	9,201
DEWA[5]	42.0	EnQuest	–	–	–
Vietnam production and development					
Block 12W[6].....	53.125	EnQuest	–	–	2,622

(1) For the years ended December 31, 2023, 2024 and 2025, bp was entitled to 37.5% of free cash flow from the assets subject to the terms of the transaction documents between bp and us. In February 2026, this contingent consideration was settled, removing bp's entitlement.

(2) GKA production is split across four fields, Mallard, Grouse, Gadwall and Goosander (all at 50.0% working interest), with Kittiwake being the production facility for the hub.

(3) In 2023, we sold 15.0% of the working interest in the Bressay license to RockRose UKCS 10 Ltd, a subsidiary of Viaro Energy.

(4) For the twelve months ended December 31, 2024 and the twelve months ended December 31, 2025, respectively, the net daily average production reflects 1,978 boepd and 3,181 boepd associated with Seligi gas.

(5) DEWA fields acquired with a completion date of October 21, 2024 and are not yet producing.

(6) Production volumes have been calculated from July 9, 2025, the completion date of the acquisition of Block 12W from Harbour Energy. For the year ended December 31, 2025, total net daily average production was 5,283 boepd.

The following table sets forth certain information with respect to our production volumes and realized pricing (which reflects the impact of derivatives) for the years ended December 31, 2023, 2024 and 2025.

	For the year ended December 31,		
	2023	2024	2025
Production/Sales:			
Sales volume (MMboe)	17.8	15.0	15.3
Realized oil price ($/Boe)	81.4	80.2	68.8
Average unit operating expenses including hedging ($/Boe)	21.7	25.6	25.1
Average adjusted unit operating costs (not including hedging) ($/Boe)	21.9	25.3	26.4

The following table sets forth information on our production and sales volumes for the years ended December 31, 2023, 2024 and 2025:

(boepd)	For the year ended December 31,		
	2023	2024	2025
Total average daily production for the period[1]	43,812	40,736	42,945
Total average daily sales volume for the period[2]	48,825	40,859	41,844

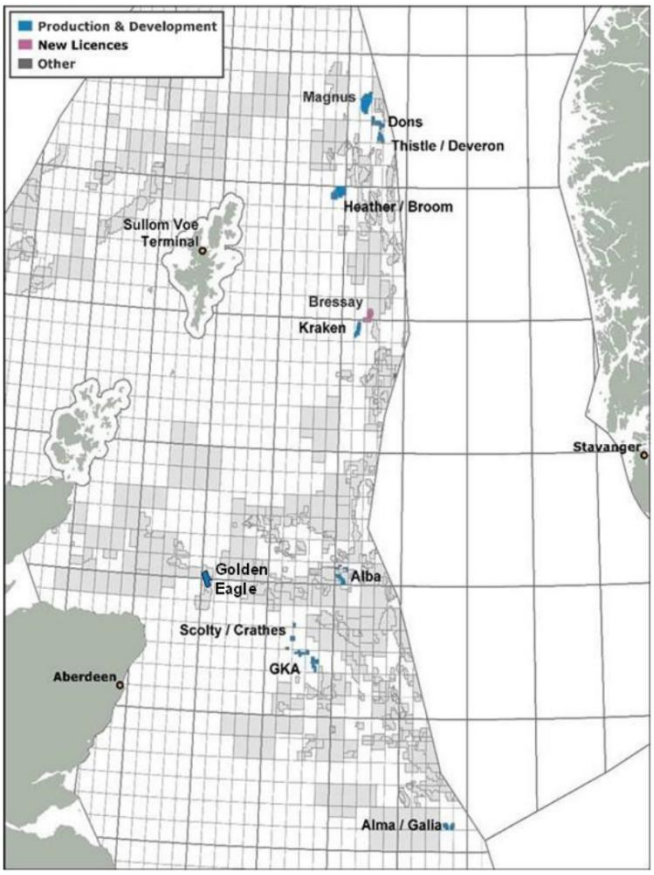
(1) Includes Vietnam production from July 9, 2025, the date on which we completed the acquisition of Harbour Energy's business in Vietnam, including its interest in Block 12W.

(2) Includes volumes related to onward sale of third-party gas purchases not required for injection activities at Magnus.

Overview of our assets

We have an asset portfolio of producing assets and development and appraisal opportunities, which are primarily located in the UKCS with others in South East Asia. For operational review purposes, we divide our assets into three U.K. directorates (U.K. Upstream, U.K. Decommissioning and U.K. Midstream) and South East Asia. Additionally, in the U.K., Veri Energy, our wholly owned subsidiary, was launched in December 2023.

The following map sets forth the locations of our assets in the UKCS:



Overview of our UKCS assets

The U.K. North Sea business is organized into three directorates:

- **U.K. Upstream**: *Kraken, Magnus, Greater Kittiwake Area, Scolty/Crathes, Alba, Bressay and Golden Eagle*

  The U.K. Upstream producing assets are characterized by their high production and operating efficiency, focusing on reservoir management and resource development. In the year ended December 31, 2025, daily average net production attributable to the U.K. Upstream directorate was 31,122 boepd, representing 72% of our total daily average net production for that period.

- **U.K. Decommissioning**: *Heather/Broom*, *Thistle/Deveron*, *Alma/Galia, the Dons and Broom*

  The U.K. Decommissioning operations manage end of field life decommissioning programs for assets that have already ceased, or are about to cease, production.

- **U.K. Midstream**: *SVT and pipelines*

  Within our U.K. Midstream directorate, we operate SVT and approximately 1,000 km of pipelines. Our Midstream business remains focused on the delivery of safe and reliable operations for the processing of East of Shetland and West of Shetland oil and gas, while progressing projects to right-size the terminal to support existing and future upstream operations and significantly lower the terminal's emissions footprint.

In addition to these directorates, in December 2023, we launched Veri Energy, our wholly owned subsidiary, which is focused on progressing scalable decarbonization and new energy projects. These projects include carbon capture and storage, electrification and the production of e-fuels by repurposing the existing infrastructure at SVT and connected offshore infrastructure.

U.K. Upstream

Our U.K. upstream assets are as follows: (a) Kraken, our largest project to date and one of the largest projects in the UKCS in recent years, (b) Magnus, in which we acquired a 100.0% working interest from bp in two tranches in 2017 and 2018, (c) Golden Eagle, in which we acquired a 26.69% working interest in October 2021 and (d) other U.K. North Sea assets (comprising the Greater Kittiwake Area, Scolty/Crathes and Alba offshore producing assets, and the undeveloped Bressay field and Bentley discovery).

The U.K. upstream assets contributed 31,122 boepd of average net production for the year ended December 31, 2025 (92% liquids and 8% gas), a decrease of 1,465 boepd compared to the year ended December 31, 2024. The decrease in the average production of U.K. upstream assets in the year ended December 31, 2025 was primarily driven by an unplanned third-party outage of the Magnus export route.

Kraken

Our Kraken operations produced a net average of 10,948 boepd in the year ended December 31, 2025, reflecting a decrease of approximately 14.2% compared to the net average of 12,759 boepd in the year ended December 31, 2024, primarily due to natural field decline. As of December 31, 2025, Kraken had approximately 80 MMboe of 2P and 2C resources.

Production facility	Kraken FPSO
Working interest (%)	70.5
Operator	EnQuest Heather Limited
Field partner	Waldorf Production Limited
Decommissioning liability	As per working interest

Overview

Kraken is a large heavy oil accumulation in the East Shetland Basin, located in block 9/2b to the west of the North Viking Graben located approximately 350 kilometers northeast of Aberdeen, Scotland. Our interest in Kraken is governed by license P1077, which expires on September 30, 2029. We are the operator of the asset. First oil was delivered in June 2017, with the field development plan completed at approximately the end of the first quarter of 2019. We completed the drilling program at Worcester in the western area of the field in the first half of 2020, with a new producer-injector pair coming on-stream late in the second quarter. As of December 31, 2025, 14 production wells and 12 injection wells were on-stream.

The Kraken FPSO is connected to wells via subsea infrastructure. Offload tankers transport produced oil from the Kraken FPSO to buyers.

In 2023, our production was impacted by an outage after the anomalous failure of HSP transformer units in May 2023. Reduction on a phased basis resumed within 30 days of the outage and through refurbishment, rebuild and reinstatement of transformer units, Kraken returned to full production in early August 2023, with top quartile performance for the final four months of 2023 with FPSO delivering uptime and water injection efficiency of 98% and 99%, respectively. The water injection efficiency for 2025 was 93%.

In the second half of 2023 our production benefited from the removal of two planned periods of single train operations, where we have executed maintenance work while production at FPSO was shut-in. In addition, delivery and deployment of new HSP transformer units has provided increased resilience to production capacity. With approximately 40 MMboe of 2C Resources, we believe that there remains significant potential of main field side-track drilling opportunities, along with further drilling within the Heimdal and Maureen sands and the potential for Enhanced Oil Recovery ("**EOR**"). Final investment decision is expected in 2026.

In May 2024, Kraken production reached the milestone of over 70 million barrels produced since its inception. Hydrogenated vegetable oil remains a viable alternative to diesel once the Bressay gas supply has been utilized. The planned Kraken maintenance shutdown was completed in September 2024.

In the year ended December 31, 2025, the FPSO delivered uptime (including shutdowns) of 95%, which is approximately 30% above the NSTA benchmark average for floating hubs of 67%.

We continue to optimize Kraken cargo sales into the shipping fuel market with Kraken oil a key component of IMO 2020 compliant low-sulfur fuel oil. As such, we avoid refining-related emissions.

Recent developments

Work is ongoing to mature the EOR project, which presents a material upside to the existing Kraken base reservoir performance. Following an initial round of polymer testing, further work is ongoing to ensure the compatibility of reservoir chemicals with topside process equipment. We are advancing the Bressay gas import project as a subsea tie-back to Kraken, which will displace the majority of the diesel currently used to power Kraken operations and drive a material reduction both in terms of FPSO emissions and operating costs. The project is expected to remove approximately 125 $ktCO_2e$ per year from the Kraken carbon footprint, equating to an approximately 3-5 $kgCO_2e$/boe in reduction of Group emissions intensity. The Bressay gas import project has seen significant progress in aligning the technical development scenario with the NSTA, and both a Bressay Field Development Plan and a Kraken Field Development Plan Addendum are at an advanced stage. We are also in the early stages of assessing a flare gas recovery solution for Kraken, which has the potential to provide another source of gas for powering FPSO operations. We are also pursuing infill drilling opportunities in the main Kraken field reservoir, including Pembroke and Cumbria & Maureen, in 2028 and 2029, respectively. In 2025, Kraken production was subject to natural field decline and the impact of a three-day maintenance shutdown that occurred in the second quarter of the year. As of April 1, 2025, the Kraken FPSO lease cost decreased by 70%, equivalent to approximately $80 million in savings per year.

Magnus

Production facility	Magnus platform
Working interest (%)	100.0
Operator	EnQuest Heather Limited
Decommissioning liability	bp has retained the decommissioning liability in respect of the existing Magnus wells and infrastructure. We will pay bp additional deferred consideration by reference to 30.0% of bp's actual decommissioning costs on an after-tax basis, which we estimate will result in a payment equivalent to approximately 9.0% of the gross estimated decommissioning costs. The additional consideration payable is capped at the amount of cumulative positive cash flows received by us from Magnus, SVT and the associated infrastructure assets.

Overview

Magnus is the U.K.'s most northerly field, located 160 kilometers northeast of the Shetland Islands, mainly in Block 211/12a. The Magnus field is governed by license P193, which expires on cessation of production.

Well M67:E4 drilled in 2023 (North West Magnus injector) has the longest 8½ inch hole action (that includes the reservoir section) at 2,461 meters ever drilled in Magnus. The longest 8½ inch hole section (that includes the reservoir section) for a production well is M68:B6 at 2,136 meters, also drilled in 2023.

Overall, the Magnus field has approximately 2.0 Bnboe hydrocarbons initially in place, with just over 57% Recovery Factor as of December 31, 2025 and approximately 28 MMboe of 2C Resources. Over 100 well penetrations have been drilled in 42 years of operations, and there are 29 platform slots and three subsea wells. It has 16 active gas-lifted producers and seven available injectors.

At Magnus, average adjusted unit operating costs have been lowered from approximately $60/boe in the year ended December 31, 2015 to less than $32/boe in the year ended December 31, 2025, leading to a 47% reduction in average adjusted unit operating costs. We also improved our uptime from 59% in the year ended December 31, 2017 to 83% for the year ended December 31, 2025, including the effect of the unplanned third-party outage (93% excluding the third-party outage). Between 2021 and December 31, 2025, we have received approximately $1.7 billion of oil revenue from Magnus generated by the life extension.

In 2023, we executed an extensive wellwork program, with three wells returned to service following the adoption of various measures, including P-seal repair and replacement works and the completion of an infill drilling program which included the North West Magnus injector in May 2023 and two further infill wells which came online in the second half of the same year. The planned annual maintenance shutdown for 2023 was completed in 20 days, faster than the planned duration of 24 days.

The five-yearly rig re-certification of Magnus commenced in early January 2024 and was completed in June 2024 with infill drilling activities recommencing thereafter. Following the completion of the re-certification, one sidetrack well was drilled, well interventions were carried out and multiple scale squeeze activities were completed in December 2024. Drilling activities continued during 2025, with two further sidetrack wells drilled. We remain focused on the management of key Magnus topside infrastructure and targeted investment to optimize equipment, reduce obsolescence and continue to deliver top quartile operational uptimes. We also focused on enhanced water injection and reservoir sweep including the 2024 conversion of a high water cut production well to water injection, which increased pressure within that area of the reservoir to boost production. The Magnus maintenance shutdown commenced on August 19, 2024 and was completed within 18 days against the original 21-day plan.

Average production of 15,335 boepd for the year ended December 31, 2025 was 8.2% higher than the average production of 14,173 boepd for the year ended December 31, 2024, driven by a successful two-well infill drilling program, with both wells producing above mid-case expectations, and well interventions and well optimization work. Additionally, in the period from June to August 2025, we delivered the best three-monthly oil production rate at Magnus since early 2020, peaking at approximately 19 Kboed in mid-July. Further, the recommissioning of a fifth water injection pump provided a 20% uplift in Magnus water injection capacity, with field average water cut reduced back to 2017 pre-acquisition levels of approximately 85%. In the first half of 2025, the Magnus field was shut in for five weeks due to an unplanned outage of the third-party operated Ninian central pipeline. This outage had the effect of reducing our production by approximately 1.7 Kboepd for the year ended December 31, 2025.

Recent developments

We executed an infill drilling program and production-enhancing well intervention campaign at Magnus in May 2025, which was successful with both wells producing above expectations. In addition, the utilization of a fifth water injector provided a 20% increase in Magnus water injection capacity, with field average water cut reduced back to 2017 pre-acquisition levels of 85%. The asset took an approximately 500-day break from drilling activity, with production to be improved through increasing water injection and sweep efficiencies. We are aiming to return to drilling at Magnus in the second quarter of 2026 and 2027 with a six-well infill drilling program (including one injector well) and a production-enhancing well intervention campaign targeting 10.7 MMboe of 2P Reserves and 1.3 MMboe of 2C Resources. Having proactively completed key maintenance scopes during the production shut-in, the seven-day maintenance shutdown originally planned for the second half of 2025 was no longer required. Accordingly, the next planned shutdown at Magnus will be in the third quarter of 2026.

Our commitment to the decarbonization of our portfolio is demonstrated at Magnus, where a combination of compressor modifications and flare system upgrades is expected to reduce our carbon intensity from 55 to approximately 40 kgCO_2e/boe.

In January 2026, storm damage to the third-party operated Ninian central platform resulted in an unplanned outage to Magnus. Following the completion of remedial works, Magnus production was reinstated on February 22, 2026. To proactively address the risk of third-party equipment downtime on Magnus production, we are progressing the Ninian bypass project, which involves the subsea bypass of the Ninian central platform, which is planned for cessation of production in 2027. Alongside ongoing work at the SVT on the new stabilization facility, this project is expected to secure a long-term export pathway for Magnus oil. Final investment decision is targeted for the second quarter of 2026, and the bypass pipeline is targeted to be in service in the first half of 2027.

On February 26, 2026, we paid bp $60.0 million as final settlement of the profit share contingent consideration liability, securing 100.0% of future Magnus cash flows and removing a significant liability, which at June 30, 2025 was valued at $432.9 million. This settlement reinforces our belief in the long-term value of Magnus, and we will commence the next phase of asset life through the six-well infill drilling program that is scheduled to start in the second quarter of 2026. The first targets in this program will be a producer and an injector well in the Lower Kimmeridge Clay Formation reservoir, which is estimated to have 300-400 MMboe in place, with a low recovery factor to this point.

Golden Eagle Area Development

Production facility	Golden Eagle platform
Working interest (%)	26.69
Operator	CNOOC

Field partners	NEO Energy; ONE DYAS
Decommissioning liability (%)	26.69

Overview

The Golden Eagle Area Development comprises three fields; namely, Golden Eagle, Solitaire and Peregrine located approximately 110 kilometers northeast of Aberdeen, Scotland, offshore in the UKCS in water depths of up to 114 meters. The Golden Eagle field was discovered in 2007 and first oil was produced in 2014 following development by Nexen Oil, and the Solitaire and Peregrine fields were subsequently developed as satellites with subsea wells tied back to the Golden Eagle field facilities. The Golden Eagle Area Development covers two U.K. licenses, namely P300 and P928. The free cash flow to us from Golden Eagle, which we acquired for a cash consideration of approximately $250 million (and a contingent payment), from the time of its acquisition to the end of 2024 was $345 million, resulting in a payback period of approximately fourteen months.

Crude oil from the Golden Eagle Area Development is processed on the platform and then transported through the Golden Eagle pipeline to the Claymore line, where it is then routed to the Flotta system and processed into stabilized Flotta Gold blend at the Flotta Terminal. In 2022, the joint venture approved a two infill well drilling campaign, which was completed in the first half of 2023, followed by another drilling campaign for the years 2023 and 2024. Following the arrival of the drilling rig in August 2023, drilling of the first well in the platform drilling program commenced in October 2023 and the well was brought into production in January 2024. The 2023/24 platform drilling program on this non-operated asset concluded in early August 2024. Two of the three planned producers were successfully brought online alongside the planned water injector, although overall production rates were below expectations.

Net average production of 2,736 boepd for the year ended December 31, 2025 was lower than for the year ended December 31, 2024 (3,328 boepd). The decrease in net average production was primarily driven by natural field decline.

Recent developments

A 15-day shutdown occurred during the third quarter of 2025. The operator also executed well intervention work in the form of mud acid stimulations in June 2025.

Greater Kittiwake Area (GKA)

	Kittiwake	**Gadwall**	**Grouse**	**Goosander**	**Mallard**
Production facility	Kittiwake platform				
Working interest (%)	50.0	50.0	50.0	50.0	50.0
Operator	EnQuest				
Field partner	Dana Petroleum (E&P) Limited				
Decommissioning liabilities (%)	25.0	50.0	50.0	50.0	30.9

Overview

GKA is located in UKCS blocks 21/12a, 21/18a, 21/19a and 21/19b, and our assets there comprise the Kittiwake production facility and four offshore oil fields: Mallard, Gadwall, Goosander and Grouse. Our interest in GKA is governed by licenses P238 and P073, which expire on cessation of production.

GKA lies in water at depths ranging from 85 to 90 meters while the oil reservoir lies at depths ranging between approximately 2,800 meters and 3,900 meters. These fields have been developed as subsea tie-backs to a steel offshore platform located at Kittiwake. Oil from GKA is processed at the offshore platform and then exported via a 33 kilometer 10” pipeline, in which we hold a 100.0% interest, to the Forties Unity platform. From there, the oil is exported to shore at Cruden Bay via the Forties Pipeline System and then on to Grangemouth for further processing.

We received payback on the Scolty/Crathes original drilling and sub-sea tie back development costs within 24 months and the subsea tie-back targeted an original life extension of the GKA hub by four years, which has been exceeded.

Average production of 816 boepd for the year ended December 31, 2025 was 8.2% lower than for the year ended December 31, 2024, driven by natural field decline.

We and our partners are focused on extending field life and executing an efficient glide path to decommissioning, including plans for early plugging and abandonment of platform wells prior to cessation of production. This process will be managed in full by us, with Shell having transferred its decommissioning operator role to us during 2024. The planned annual maintenance shutdown at GKA was delivered in August 2025, on schedule, and with all scopes completed.

Scolty/Crathes

Production facility	Kittiwake platform
Working interest (%)	50.0
Operator	EnQuest
Field partner	MOL GROWEST (II) Limited
Decommissioning liability	As per working interest

The Scolty/Crathes assets are in blocks 21/8a (Scolty) and 21/12c and 21/13a (Crathes) of the UKCS. Scolty was discovered in 2007 by well 21/8-3 and Crathes was discovered in 2011 by well 21/13a-5. We have a 50% working interest in each of Scolty and Crathes and are the operator of both. Our interest in Scolty/Crathes is governed by licenses P1107/1617, which expire on September 30, 2029 and February 11, 2035, respectively.

The Scolty/Crathes development received regulatory approval and was sanctioned by us in the second half of 2015 and consists of single horizontal wells, equipped with gas lift, drilled in each of the Scolty and Crathes fields. The fields are tied back to the Kittiwake platform, in the Greater Kittiwake Area, where the fluids are processed and the oil exported to shore via the Forties Pipeline System. On November 21, 2016, we delivered first oil from Scolty/Crathes.

Average production of 1,010 boepd for the year ended December 31, 2025 was 9.8% lower than for the year ended December 31, 2024, driven by natural field decline.

Alba

Production facility	Alba Northern platform
Working interest (%)	8.0
Operator	Ithaca Oil and Gas Limited
Field partner	Ithaca Oil and Gas Limited, Waldorf Production, NEO Energy, Mitsui E&P UK Limited and Spirit Energy
Decommissioning liability	As per working interest

Alba is located in block 16/26a in the UKCS, approximately 209 kilometers northeast of Aberdeen, Scotland. Alba was discovered in 1984 and first produced oil in 1994. Ithaca Energy is the operator of the Alba oil field. Our interest in Alba is governed by license P213, which expires on cessation of production.

The field includes 13 active platform production wells, six platform injector wells, six subsea production wells and three subsea injector wells. There are also six shut in wells (three platform wells and three subsea wells) and six suspended platform wells. The Alba Northern offshore platform is located in the northern area of the oil field, and there are two subsea manifolds located in the south of the field that are tied back to the platform. Oil is exported from the Alba Northern platform by offload tankers and delivered to onshore oil terminals.

In 2025, a 28-day shutdown was executed.

Average production of 277 boepd for the year ended December 31, 2025 was 13.2% lower than for the year ended December 31, 2024 due to the shutdown.

Bressay

Production facility	N/A
Working interest (%)	85.0
Operator	EnQuest
Field partners	RockRose UKCS 10 Ltd
Decommissioning liability	N/A

In January 2021, we completed the transaction to acquire a 40.8% interest and operatorship in the Bressay oil field, from Norwegian oil company Equinor, which retained a 40.8% interest in the field at that time. The remaining 18.4% interest were held by Harbour Energy. In December 2022, we assumed 100.0% of the working interest following the withdrawal of Equinor and Harbour Energy. In 2023, we sold 15.0% of our interest in the Bressay license to RockRose UKCS 10 Ltd, a subsidiary of Viaro Energy, which closed in December 2023. As part of the same transaction, we also sold a 15.0% share in our FPSO vessel, the 'EnQuest Producer'.

Bressay is a heavy oil field east of the Shetland Islands, approximately 12 kilometers northeast of the Kraken field. Discovered in 1976, Bressay is believed to be one of the largest undeveloped oil fields in the UKCS, with approximately 115 MMboe of net 2C Resources. Bressay is estimated to have stock-tank oil initially in place ("**STOIIP**") of approximately 600 to 1,050 MMbbls. As of December 31, 2025, Bressay was estimated to have approximately 19 Bcf of 2C gas resources.

Detailed analysis of existing reservoir data and an assessment of potential development options, one of which is a potential tie back to Kraken, has continued. We are working with our joint venture partners to progress field development studies and we continue working towards the development of the wider Kraken area, including a Bressay gas tie-back solution, which is expected to significantly reduce emissions at Kraken with gas as a replacement for diesel fuel. Once approvals are in place for the gas tie-back, we intend to progress a phased oil development project at Bressay. The Bressay gas import project has seen significant progress in aligning the technical development scenario with the NSTA, and both a Bressay Field Development Plan and a Kraken Field Development Plan Addendum are at an advanced stage.

Bentley

Production facility	n/a
Working interest (%)	100.0
Operator	EnQuest
Field partners	n/a
Decommissioning liability	n/a

In July 2021, we completed the transaction to acquire a 100.0% equity interest in the P1078 license containing the proved Bentley heavy-oil discovery from Whalsay Energy Holdings Limited ("**WEL**"). Upon completion, we funded certain accrued costs and obligations of WEL, which amounted to less than $2 million.

Bentley is a heavy oil field in the U.K. North Sea located in 113 meters water depth, 15 kilometers east of the Kraken heavy oil field and 8 kilometers southeast of the Bressay field, both of which are operated by us. Bentley is one of the largest undeveloped oil fields in the UKCS with the previous operator estimating STOIIP of approximately 900 MMbbls and we reported net 2C Resources of approximately 131 MMboe as at December 31, 2025.

The initial evaluation of the development potential commenced in the first quarter of 2022, with the Bentley project team primarily focused on re-evaluation of the existing subsurface data and incorporating any learnings from the Bressay evaluation work. A second license extension to September 30, 2028, was awarded in March 2026.

South East Asia

Our South East Asian assets are located in Malaysia, Vietnam, Indonesia and Brunei. We have three assets in Malaysia, one of which is producing, one producing asset in Vietnam and one non-producing asset in each of Indonesia and Brunei.

The South East Asian assets contributed 11,823 boepd of average net production for the year ended December 31, 2025, an increase of 3,674 boepd compared to the year ended December 31, 2024. The increase in the average production of South East Asia assets in the year ended December 31, 2025 was primarily driven by the Vietnam Acquisition. We are targeting 35,000 boepd of average production in South East Asia by 2030.

Malaysia

Our Malaysian operations include the PM8 Extension PSC, comprising the PM8 and Seligi fields located off the east coast of the Malaysian peninsular, the DEWA Complex Cluster Small Field Asset PSC located off the coast of Sarawak and the Cendramas PSC in peninsular Malaysia. As of December 31, 2025, we had 33.6 MMboe

of net working interest 2P Reserves related to our Malaysian assets. Below is an overview of each of the assets included in our Malaysian operations, including recent developments and performance.

PM8/Seligi

	PM-8 including North Raya, South Raya, Lawang, Langat, Yong and Serudon producing fields	Seligi
Location	Offshore Malaysia	Offshore Malaysia
Production facility	Raya Alpha, Raya Bravo, Lawang, Serudon platforms	Seligi platforms (Alpha, Bravo, Charlie, Delta, Echo, Foxtrot, Golf, Hotel)
Working interest	50.0	50.0
Operator	EnQuest	EnQuest
Field partners	PETRONAS Carigali Sdn. Bhd.	PETRONAS Carigali Sdn. Bhd. (40.0%) E&P Malaysia Venture Sdn. Bhd. (10.0%)
Decommissioning liabilities	As per working interest	EnQuest is liable for legacy (pre-2014) Seligi petroleum facilities decommissioning of 3.6% of the actual decommissioning cost during the PSC term. For newly installed wells during the PSC term, EnQuest is liable for 100% of the costs. For PM8 petroleum facilities, EnQuest is liable as per working interest. Decommissioning costs will be drawn down from the abandonment fund.

Overview

We assumed operatorship in October 2014 and the overall transition was completed in December 2014. Our interest in PM8/Seligi is governed by the PM8Extension PSC, which expires on March 31, 2033. We achieved payback on our initial cash consideration following the acquisition of PM8/Seligi within 12 months contributing net cash flow equivalent to a multiple of the $25 million cash consideration paid for it.

The production sharing contract for PM8/Seligi covers a group of oil fields, including the producing Seligi oil field. The Seligi oil field is located in the Malay basin, approximately 240 kilometers offshore from Peninsular Malaysia in a water depth of 73 meters. The field was discovered in 1971 through the Seligi-1 exploration well, and a total of 11 appraisal wells were drilled to delineate the fields. First oil at Seligi oil field was achieved in 1988. The Seligi oil field encompasses approximately 80 square kilometers and was developed via two central processing platforms and seven satellite wellhead platforms which were installed between 1988 and 2001. A total of more than 230 wells have been drilled to date.

PM8 comprises six developed fields: Lawang, Langat, Serudon, North Raya, South Raya and Yong. PM8 fields together encompass approximately 20 square kilometers. PM8 fields are developed via four unmanned minimum facility wellhead platforms (installed between 1998 and 2001) which are linked back to the Seligi central processing facility. A total of 22 wells have been drilled to date at PM8, while we have drilled a further 14 wells at the Seligi field. At PM8/Seligi, average adjusted unit operating costs have been lowered from approximately $30/boe in the year ended December 31, 2014 to $15/boe in the year ended December 31, 2025, representing an approximately 50% reduction in average adjusted unit operating costs.

After separation, crude oil from PM8/Seligi is transported via the Tapis platform (operated by ExxonMobil) to the Terengganu Crude Oil Terminal (operated by PETRONAS Carigali Sdn. Bhd.) for processing and sale to the domestic market or export.

Following the assumption of operatorship, we safely improved production performance through a number of initiatives, including drilling of new production wells, idle well restoration activities, low cost well interventions, facility projects and process simplification to improve plant reliability and uptime.

Following the mobilization and installation of the drilling rig at the Seligi-C satellite platform and the drilling of a pilot hole, our first horizontal well at PM8/Seligi was brought on stream in July 2022. The drilling

rig subsequently mobilized to the Seligi-D satellite platform, where two more horizontal wells were delivered in the second half of 2022.

We successfully executed a three-well infill drilling program during 2024, with realized production rates. Three well workovers were also completed, and we continued work on the PM8/Seligi idle well restoration program. Six wells were plugged and abandoned in accordance with the planned decommissioning program. The 2024 shutdown was completed during the third quarter of 2024, with all critical integrity and maintenance works, including a turbine control panel upgrade, delivered on schedule.

In December 2024, we were awarded an agreement to develop approximately 155 Bscf (approximately 27 million barrels of oil equivalent) of additional Seligi field gas resources, with a 50% equity share, effective from January 1, 2025. This equates to approximately 14 MMboe of 2P Reserves. The agreement allows for the annexation of Seligi Field Non-Associated Gas and Condensate to be part of PM8E PSC (Addendum No. 1). In addition, the parties to the agreement also signed a gas sales agreement for the PM8E relating to the supply of natural gas produced from PM8E PSC. The agreement enables the PM8E PSC parties to develop and commercialize the non-associated gas resources in the PM8E PSC contract area and, in line with expected demand, a contracted nomination to supply around 70 mmscf per day of sales gas, which is the equivalent of approximately 6 Kboepd for us, with first gas achieved on December 23, 2025. These new volumes are expected to reduce the emissions intensity of our Malaysian operations by approximately 4 $kgCO_2e$/boe.

Recent developments

In the year ended December 31, 2025, PM8/Seligi produced an average of 9,201 boepd (approximately 39.1% gas), a 12.9% increase from an average production of 8,149 boepd in the year ended December 31, 2024. The delivery also includes Seligi 1a gas, to which Petronas holds the entitlement, and which is produced and handled by us in exchange for a gas handling and delivery fee. Underlying asset uptime in the year ended December 31, 2025 remained high at 93%.

A two-week shutdown at PM8/Seligi to undertake asset integrity and maintenance activities was completed ahead of schedule in July 2025.

We were awarded two accolades at the PETRONAS Emerald Awards in June 2025, being named ‘Operator of the Year’ for the second year in a row and receiving recognition for ‘Abandonment Excellence’.

Demonstrating our project delivery expertise, work to drill recompletions on five existing wells and execute infrastructure modifications on our Seligi 1b project was completed nine months ahead of schedule, with gas production beginning in December 2025. We commenced full production at 70 mmscf/day in January 2026, with capacity proven to increase gross production to approximately 100 mmscf/day, supporting Peninsular Malaysian demand and helping the nation meet its growing energy needs. These volumes also increase the gas component of our production, which aligns with our strategic aim to reduce our overall carbon intensity. A two-well gas infill drilling campaign is planned for the second half of 2026.

DEWA

Location	Offshore Malaysia
Production facility	Anticipated 3 wellhead platforms connected to nearby facility
Working interest (%)	42.0
Operator	EnQuest
Field partners	Petroleum Sarawak Exploration & Production Sdn Bhd (30%) Seascape Energy (DEWA) Ltd (28%)
Decommissioning liability	Estimated $100 million (gross) to be paid by annual contribution starting first production

Overview

Effective from October 21, 2024, we became the operator of the DEWA Complex Cluster Small Field Asset PSC. DEWA consists of 12 discovered fields in an area approximately 50 kilometers off the coast of Sarawak, Malaysia, in water depths of 40 to 50 meters. The block is in a proven hydrocarbon area containing undeveloped discoveries, providing potential low-cost development options to provide gas supply into the Sarawak gas system.

Within the initial two-year pre-development term of the PSC, we are committed to completing the resource assessment of the fields and submitting a field development and abandonment plan for the first cluster of fields, which carries risked gross 2C Resources of approximately 350 Bscf of gas and approximately 6 MMstb of condensate based on the latest resources assessment study, with approximately 500 Bscf of gas in place overall, with the potential for 7.5 Kboepd net EnQuest production. Petrophysical, geophysical, and resource assessment work on the DEWA PSC cluster has been completed, with dynamic modelling in place for the six highest-priority fields. After initial development and concept planning, we have identified options for produced gas to be transported to the MLNG plant in Bintulu, with technical and economic viability screening ongoing.

The anticipated first gas date is planned by the end of 2028. Other fields within the PSC area are also being evaluated for future phased development. Our aim is to execute the Field Development and Abandonment Plan and the Final Investment Decision in the second half of 2026, subject to partner and regulator reviews and approvals.

Cendramas

Location	Peninsular Malaysia
Production facility	Cendor, West Desaru, East Cendor
Working interest (%)	25
Operator	Medco Asia Pacific Limited
Field partners	Medco Asia Pacific Limited (50%) and DIALOG Resources Sdn Bhd (25%)
Decommissioning liability	Yearly abandonment Cess payment; Current Cess balance approximately MYR 710 million (approximately $175 million)

In February 2026 we received a Letter of Award ("**LOA**") as a partner in the Cendramas PSC in peninsular Malaysia, in partnership with Medco Asia Pacific Limited and DIALOG Resources Sdn Bhd by Petroliam Nasional Berhad (PETRONAS) through Malaysia Petroleum Management. The Joint Operating Agreement and the Cendramas PSC were signed in March and will be effective from September 23, 2026.

The Cendramas PSC consists of six discovered and producing fields in an area approximately 140 kilometres off the coast of Peninsular Malaysia in shallow water depths of 60 to 70 meters.

Current volumes of approximately 7.5 Kboed (gross) are produced across five platforms, a mobile offshore production unit and a floating production storage and offloading vessel.

Vietnam

Block 12W

Location	Offshore Vietnam
Production facility	Lewek Emas FPSO
Working interest (%)	53.125
Operator	EnQuest
Field partners	Bitexco (31.875%) PetroVietnam Exploration Production Corporation Ltd (15%)
Decommissioning liability	Remaining $6.1 million (EnQuest share as of December 31, 2025) paid by annual contribution

Overview

As of July 9, 2025, we became the operator of the Chim Sáo and Dua fields ("**Block 12W**"), via our acquisition of Harbour Energy's business in Vietnam for an aggregate consideration of $25.7 million, including an initial deposit in January 2025. Block 12W is made up of three producing oil and gas fields: Chim Sáo, Chim Sáo North West ("**CSNW**") and Dua, located in the Nam Con Son Basin, approximately 400 kilometers south west of Vung Tau, Vietnam. The Chim Sáo oil field was discovered in 2006 and first oil was achieved in October 2011. Having been developed via a single wellhead platform, Chim Sáo and CSNW oil production is exported via the Lewek Emas FPSO, and gas is exported by pipeline to Vung Tau near Ho Chi Minh City. Chim Sáo currently has 12 active oil producers and six water injectors. The Dua oil and gas field was subsequently developed as a subsea tie-back to Chim Sáo, with first production achieved in July 2014. Dua production is via three subsea oil producers. Block 12W production has responded positively to the drilling of three infill wells during 2023 and a series of well interventions undertaken in 2023, 2024 and 2025.

Oil (approximately 73% of output) is high quality and has historically realized an approximately 10% premium to Brent. Gas is commercialized via an Associated Gas Gathering Agreement. Field volumes are produced at a life of field asset breakeven of approximately $40/boe, with minimal capital requirements and a decommissioning liability that is covered via a PSC fund. The resulting free cash flow underpins Chim Sáo's and Dua's value, making them strong anchor assets for our entry into Vietnam.

Block 12W operations in the year ended December 31, 2025 were strong, with a planned annual maintenance shutdown completed on time and within budget during June 2025. The successful execution of three of six scheduled well intervention scopes added approximately 1,200 boepd of gross production. Underpinned by uptime of 100% since we took over operatorship, net asset production in 2025 totaled 2,622 Kboepd from July 9, 2025, the date on which we completed the acquisition of Harbour Energy's interest in Block 12W, with the potential for natural field declines to be offset by further upside relating to well intervention activity and performance and the positive impact of a production-enhancing chemical soaking process undertaken during the shutdown.

Recent developments

On February 9, 2026, we were awarded a four-year extension to the Block 12W PSC by PetroVietnam. Granted on the PSC's existing terms, this extension runs to July 2034 and provides us the opportunity to access upside across Block 12W, with prospectivity spread across three gas discoveries and several additional targets. See "*Summary—Recent Developments—Acquisition of equity interest in the Block 12W production fields in Vietnam.*" Since the completion of the acquisition of Block 12W in July 2025, we have completed three proactive well interventions that added 10.3 Kboed (5.5 Kboed net to EnQuest) to our 2025 production.

Indonesia

Gaea/Gaea II

Location	Papua Barat, Indonesia
Production facility	n/a
Working interest (%)	40.0
Operator	EnQuest
Field partners	Tangguh Joint Venture (40%) PT Agra Energi Indonesia (20%)
Decommissioning liability	n/a

Overview

Effective from August 26, 2025, we became the operator of the PSCs for the Gaea and Gaea II exploration blocks. The Gaea and Gaea II blocks present a multi-Tscf unrisked resource potential for us, estimated to be in excess of 100 Tscf by the Ministry of Energy and Mineral Resources of Indonesia and are located in proximity to the bp-operated Tangguh LNG facility.

At this stage, the focus of the joint venture is on maturing targets for further geological and geophysical study, seismic reprocessing and future 2D seismic acquisition across both blocks, with the potential for exploration targeting large potential gas volumes in a frontier region.

Brunei

Block C

Location	Darussalam, Brunei
Production facility	n/a
Working interest (%)	100.0
Operator	EnQuest
Field partners	n/a
Decommissioning liability	n/a

Overview

In July 2025, we were awarded a PSC for Block C in Brunei by the Petroleum Authority of Brunei Darussalam. Block C is located offshore Brunei Darussalam and hosts the condensate-rich gas discovered fields

of Merpati, Meragi and Juragan. We intend to develop these fields in stages, beginning with Merpati. The produced gas and liquids from the fields are targeted for use in the domestic market and the Brunei LNG plant, which supplies the international LNG markets.

We are the operator of Block C on a 100% working interest basis, with the aim of having the operatorship assumed by a 50:50 joint venture company ("**JV**") between us and the Government of Brunei. Incorporation of the JV is planned for the third quarter of 2026. Additionally, work has commenced to finalize the resources and evaluate gas development concepts for delivery to the Brunei LNG ("**BLNG**") plant in Lumut, Brunei. We estimate that potential first gas from Block C could occur during 2029, with a potential 12 Kboepd net to EnQuest. We will also assess additional fields in the block concurrently, in order to evaluate future development plans.

U.K. Decommissioning

Our U.K. Decommissioning directorate manages the decommissioning programs for assets that have ceased production and our mature producing assets which are between one and five years from cessation of production.

The timely transfer of assets to the directorate allows for effective end of life field management and the development of relevant decommissioning programs. Our U.K. Decommissioning directorate oversees the safe and efficient execution of these work programs and is committed to delivering them in a responsible manner, which includes minimizing emissions and maximizing the recycle and reuse of recovered materials.

We continue to demonstrate top quartile performance in delivering our significant decommissioning projects at Heather and Thistle and we successfully abandoned 84 North Sea wells (including 41 at Heather and 42 at Thistle) between June 30, 2021 and December 31, 2025. This work is being executed at sector leading cost by our dedicated in-house team with EnQuest having completed 47% of all well P&A across the northern and central North Sea from 2022 to 2024, and we delivered well P&A at an estimated 15% below NSTA benchmark cost (according to the 2024 NSTA decommissioning benchmark data). This underlines our market leading decommissioning performance, enabling us to deliver material reductions in project costs and leading to a competitive advantage for acquiring late-life assets.

We are also planning the P&A of Magnus subsea wells, commencing in 2027, to be followed by a 33 subsea well P&A program across the Alma/Galia, Dons and Broom fields. We continue to work on the basis that subsea decommissioning activities can be optimized by utilizing a portfolio approach across the fields, with the scheduling of activity primarily driven by well integrity.

On August 28, 2024, we announced that we were appointed by the joint venture to continue as GKA decommissioning operator for the full decommissioning scope, with Shell transferring its decommissioning management role to us. The GKA infrastructure is expected to continue production into the late 2020s, with our U.K. Decommissioning directorate proactively planning for a managed decommissioning program post cessation of production.

Recent developments

The Heather team permanently disembarked the platform in April 2025, while Thistle is scheduled for disembarkation in the first half of 2026. Both projects remain in line with the respective removals contract dates, with Heather topside removals completed in August 2025 and Thistle topside removals scheduled in 2027.

In August 2025, we signed a multi-year contract with Well-Safe, which secures the Well-Safe Defender rig for a minimum of 230 days across 2026 and 2027. The contract also includes options for us to add further activities, creating the potential for a strategic partnership. We will utilize this rig to complete the proactive P&A of Magnus subsea wells, expected to commence in the second quarter of 2026. This will be followed by the P&A of 9 Alma/Galia wells in 2028.

Heather/Broom

	Heather	Broom
Location	Offshore, UKCS	Offshore, UKCS
Production facility	Heather A platform	Heather A platform
Operator	EnQuest	EnQuest

	Heather	Broom
Field partners	BG Great Britain Limited, Harbour Energy	MOL GROWEST (I) Limited, MOL GROWEST (II) Limited and Ithaca Minerals (North Sea) Limited
Decommissioning liabilities (%)	37.5[1]	63.0

(1) Our decommissioning liability for Heather as acquired is 37.5%, with 100.0% decommissioning liability for any developments we undertook from acquisition to cessation of production.

Heather and Broom are adjacent oil fields that were produced through Heather Alpha, a fixed steel offshore platform, with Broom connected via a subsea tie-back.

In February 2020, we confirmed we would not re-start production from the Heather field following production being shut down in late 2019. The cessation of production application at Heather was accepted by the regulator in June 2020, reducing our share of costs from 100.0% to 37.5% and allowed decommissioning to commence.

In 2023 and 2024, our Heather P&A campaign progressed well with 12 wells completed and one partially completed as of December 31, 2023 and 11 wells completed as of December 31, 2024, resulting in the completion of all abandonment work to Phase 2 and the commencement of the final well decommissioning scope, Phase 3 conductor recovery. We permanently disembarked the respective platforms in mid-April 2025, having completed a 39 well P&A campaign.

In the second half of 2023, the contract for the disposal of the Heather jacket was awarded to Saipem with work expected to commence in 2027. The early placing of this contract secured favorable market rates and allowed for the interface with jacket and conductor removal scopes to be optimized. The removal of the platform jacket was completed in a single lift in August 2025 utilizing the Pioneering Spirit heavy lift vessel, making it the largest single lift planned in the North Sea in 2025. The Heather jacket was transferred by barge to Frederikshavn, Denmark, where the structure is in the process of being dismantled. It is expected that more than 95% of the structure will be recycled and repurposed, ensuring maximum material recovery and minimizing the carbon footprint of the project. The Heather Jacket is scheduled for removal in 2027.

In November 2025, we were awarded the Offshore Energies UK award for Excellence in Decommissioning in recognition of our sector-leading work on the Heather Decommissioning Project. The Heather topside removal was the heaviest lift executed in the UKCS in 2025. This is the second time in four years that we have won this award, the first being for the successful removal of the Northern Producer Floating Production Facility from the Dons in 2022.

Thistle/Deveron

	Thistle	Deveron
Location	Offshore, UKCS,	Offshore, UKCS
Production facility	Thistle Alpha platform	Thistle Alpha platform
Operator	EnQuest	EnQuest
Field partners	Britoil Limited, Harbour Energy	Britoil Limited, Harbour Energy
Decommissioning liabilities	We are liable for the decommissioning costs associated with investment since we assumed operatorship, with the balance remaining with the former owners. Following the exercise of the Thistle decommissioning options in January and October 2018, we will undertake the management of the physical decommissioning of Thistle/Deveron and are liable to make payments to bp by reference to 7.5% of bp's decommissioning costs of Thistle/Deveron, which equates to 6.1% of the gross decommissioning costs.	

With the field having been shut-in since October 2019, in March 2020 we announced we no longer intended to re-start production at the Thistle field. A cessation of production application was approved by the regulator in June 2020, with an effective decommissioning date of May 31, 2020, reducing our share of post-tax costs 6.1% from 99.0%.

The first phase of the platform rehabilitation was successfully completed in June 2021, in line with expectations. The subsea integrity campaign concluded in September 2021 and platform reactivation and hydrocarbon removal was completed in October 2021.

Between 2022 and 2025, the Thistle P&A campaign progressed well with 42 wells completed and the drilling rig down manned. The team is on track to complete disembarkation in the first quarter of 2026.

In 2023, we awarded the contract for the Thistle topsides and jacket Engineering, Preparation, Removal and Disposal works to Saipem, with removal operations being due to take place from 2027 onwards. EnQuest and Saipem teams have worked closely together, progressing engineering and planning for the nine-month pre-disembarkation preparation phase in 2025 and the future topside and jacket heavy lift campaigns. An extensive module void inspection campaign was successfully completed, which involved accessing, inspecting and clearing void spaces between modules. This enables module separation for the removals phase of the project by providing access to disconnect structure, piping and cabling. Subsea campaigns were also completed covering essential inspection, repair and maintenance activities and preparatory work for future conductor removal activities using bespoke tooling developed with the subsea contractor.

We are on track to complete disembarkation in the first half of 2026, following the P&A of 41 wells in total. Preparatory works have commenced in support of the platform's removal.

Alma/Galia

	Alma	Galia
Location	Offshore, UKCS	Offshore, UKCS
Production facility	N/A	N/A
Operator	EnQuest	EnQuest
Field partner	KUFPEC	KUFPEC
Decommissioning liabilities	65.0	65.0

The Alma and Galia fields were re-developed as a single joint development, revitalizing reservoirs where production had previously been shut-in, and tied back to the EnQuest Producer FPSO vessel.

On June 30, 2020, cessation of production occurred as planned. As of the date of these Listing Particulars, the EnQuest Producer FPSO remains in warm stack at Nigg, noting that in December 2023, we farmed-down a 15.0% interest in the vessel to RockRose UKCS 10 Ltd.

The Eclipse Group is progressing with the detailed planning and engineering work on the subsea wells at Alma/Galia and in 2026, the Alma/Galia joint venture exercised the Well-Safe rig option to undertake well P&A work commencing in 2028.

The Dons

	Don Southwest	West Don	Conrie	Ythan
Location	Offshore, UKCS	Offshore, UKCS,	Offshore, UKCS	Offshore, UKCS
Production facility	N/A	N/A	N/A	N/A
Operator	EnQuest	EnQuest	EnQuest	EnQuest
Field partners	Ithaca Energy (UK) Limited	Ithaca Energy (UK) Limited	Ithaca Energy (UK) Limited	Ithaca Gamma Limited
Decommissioning liabilities	60.0	78.6	60.0	60.0

The Dons are a collection of offshore oil fields that were produced via subsea tie-backs to the Northern Producer Floating Production Facility.

At the Dons, production in 2020 was impacted by a lack of gas lift which is no longer available from Thistle, combined with underlying natural declines. As such, preparations commenced in 2020 for the field to cease production. Following regulatory approvals in February 2021, cessation of production activities concluded in March 2021. The Northern Producer floating production facility was used for initial decommissioning activities, such as flushing of the subsea infrastructure and to support implementation of effective well isolations. These activities were completed; the vessel has departed the field and was handed back to its owner. The U.K. Regulator recognized the floating production facility off station project as an example of exemplary execution and best-in-class performance in the North Sea for prompt asset removal, reduction of post-cessation of production operation expense and CO_2 reduction and in recognition of our top quartile project delivery, we were awarded the "Offshore Energies UK Award for Excellence in Decommissioning" for our work at the Dons.

Subsea infrastructure removal within the 500-meter zone was completed on time and budget, with the final phase executed in October 2022. Our decommissioning liability is in line with our equity working interest in

each of the fields. In 2025, we further progressed detailed planning engineering work on the subsea well at the Dons, while continuing to discuss the future work programs with the U.K. Regulator.

U.K. Midstream

Our U.K. Midstream operations include our SVT, the East of Shetland Pipeline System ("**EOSPS**"), which transports purchased gas from the bp sweetening facility to Magnus, the Ninian Pipeline System ("**NPS**"), which transports crude oil to SVT, and the Northern Leg Gas Pipeline ("**NLGP**"), which transports natural gas via the Brent A platform into the U.K. National Transmission System.

Through this business unit, we are developing cost-effective and efficient plans to transform the terminal and prepare and repurpose the site to progress decarbonization opportunities. We remain the operator of SVT and will continue to support existing users with high levels of operating efficiency while supporting Veri Energy to progress new energy opportunities at the terminal.

The terminal site offers several unique competitive advantages, including a 1,000-acre industrial site with access to existing oil and gas pipeline infrastructure, deep water port and jetties, the highest wind capacity factor across Europe, and a highly skilled workforce and local supply chain.

Sullom Voe Terminal

Overview

SVT is a 1,000 acre brownfield industrial Control of Major Accident Hazards ("**COMAH**") site with 16 crude oil storage tanks (of which eight are currently operational) and four 24 meters deep jetties accepting very large crude carrier ("**VLCC**")-sized vessels (of which two are currently operational). Each jetty at SVT can accommodate different ship types in the range of 30,000 to 350,000 deadweight tons. SVT currently receives oil by pipeline from the oilfields of its customers in the East Shetland Basin and the deep waters West of Shetland, which is then stored in the crude oil storage tanks and later exported via the jetties. SVT was commissioned in 1978 and receives East of Shetland oil via the Brent Pipeline System, servicing Brent and TENCCA, and the NPS, servicing Ninian, Alwyn and Magnus, although the Brent Pipeline System ceased to transport oil to SVT on September 10, 2024. Since 1998, the terminal has also provided services to West of Shetland fields, including Schiehallion, Clair and Foinaven (until Foinaven's suspension of production in 2021 and cessation of production in 2022), whereby gas from these fields is "sweetened" at SVT before being shipped to Magnus for onward export. The terminal also now processes condensate from the Laggan-Tormore development.

On December 1, 2017, we completed the acquisition of an additional 3.0% interest in SVT (bringing our interest to 6.0%) and assumed operatorship of SVT (all as part of the same transaction whereby we obtained our initial 25.0% interest in Magnus). On December 1, 2018, we acquired a further 9.1% interest from bp bringing our total interest to 15.1%. In connection with the transfer of Thistle to bp and Chrysaor (now Harbour Energy) in 2021, we transferred a total of 2.1% to those parties, reducing our total interest to 13.0%. Since taking over operatorship at SVT, we have worked in close collaboration with all our stakeholders to optimize safely and sustainably the size and scale of plant required to ensure the terminal continues to meet existing and future customer needs.

During the second quarter of 2020, a major milestone was achieved in bringing Jetty 3 back into operation after almost seven years, with safe operations maintained throughout project delivery. The reintroduction of operations at the jetty provides us with additional capacity which helps to ensure greater service availability for customers.

SVT provides us with the infrastructure to progress our new energy and decarbonization ambitions, including carbon capture and storage, e-fuels and electrification. In 2024 and 2025, the SVT power station achieved 100% power delivery.

In 2023, we successfully matured and gained owner and regulatory support for two strategic projects, being the connection of SVT to the U.K.'s electricity grid and the construction of new stabilization facilities ("**NSF**"). We are currently working to deliver the NSF, as of the date of these Listing Particulars and this will be sized for current and future production rates and will allow the existing process area and surge tanks to be retired, reducing both operating risks and cost and freeing up a large area that could be re-purposed for new energy opportunities. We believe the completion of the NSF will help us to meet the U.K. Regulator target of zero routine

flaring obligations by 2030. Together with SVT's connection to the electricity grid, the two projects are intended to result in a meaningful reduction in overall emissions from SVT and the EQUANS-operated Sullom Voe power station.

During 2024, we successfully commenced Engineering, Procurement and Construction on two strategic projects: to connect the terminal to the U.K.'s electricity grid and the construction of New Stabilization Facilities ("**NSF**"). The aggregated impact of these two projects is expected to transform the carbon footprint and overall emissions from SVT and the EQUANS-operated Sullom Voe power station. The delivery of these scopes will reduce the Terminal's operating costs and provide resilience for long-term operations through the replacement of obsolete equipment. Together, these projects provide the opportunity to extend production at both East of Shetland and West of Shetland assets.

In 2024, we commenced the phased, partial decommissioning of redundant oil stabilization, processing and storage facilities at SVT. This scope has reduced the risk potential at the site, along with reducing ongoing operating costs. Furthermore, the removal of the facilities creates the opportunity to repurpose areas of SVT for third-party use, including renewable energy projects. 2024 emissions at SVT were elevated due to issues encountered with the site's gas compression system, which resulted in flaring above the routine baseline levels. In September 2024, an engineering solution was deployed effectively, restoring the compression system to full operations. This has resulted in a return to lower process flaring and emissions.

Pipelines

We purchased the associated pipelines when we acquired our operating interests in the producing Magnus asset and SVT in Shetland. These pipelines are of strategic importance.

The NPS, where we have an 18.1% share, the NLGP, where we have a 43.9% share and the EOSPS, where we have a 100.0% share, gather production from approximately 18 fields in the North Sea and deliver oil and gas to onshore terminals at Sullom Voe and St Fergus. During the year ended December 31, 2021, we undertook the planned repair and remediation work on delivery infrastructure relating to Kraken, Magnus and Thistle, in addition to in-line pipeline inspection evaluations at GKA.

During the years ended December 31, 2024 and December 31, 2025, we delivered safe, stable and effective operations for both East of Shetland and West of Shetland oil and gas, delivering 100% uptime for both oil streams.

Veri Energy

Veri Energy is a wholly owned subsidiary of EnQuest, focused on transforming skills and infrastructure to deliver economic decarbonization solutions, initially at the Sullom Voe Terminal ("**SVT**") on Shetland. Veri Energy is supporting the U.K. Government's Clean Power 2030 Action Plan and delivering against the Scottish Government's Energy Strategy and Just Transition Plan. Using the SVT site as a base, Veri Energy is aiming to support further industrial decarbonization and future growth in the energy transition through the execution of phased renewable energy developments.

*Carbon capture and storage ("**CCS**")*

Veri Energy continues to develop a flexible, merchant-market carbon storage solution that can transport and permanently store carbon dioxide ("**CO_2**") from isolated emitters in the UK and Europe. CO_2 captured by emitters will be transported via ship to SVT from where it will be transported, via repurposed pipeline infrastructure, for permanent geological storage in depleted oil and gas reservoirs. In August 2023, we successfully secured four carbon storage licenses as part of the first round of U.K. carbon sequestration licenses issued by the North Sea Transition Authority ("**NSTA**"). Following work to assess the licenses, we took the decision to relinquish the Tern and Eider licenses, effective March 1, 2025. The remaining license areas, CS013 and CS014, are approximately 99 miles northeast of Shetland and incorporate fields currently operated by EnQuest, the Magnus and Thistle fields. These sites are large, well-characterized deep storage formations connected by significant existing infrastructure to the Sullom Voe Terminal on Shetland. During 2025, work included significant engagement with the NSTA to progress the licenses through early risk assessment and site characterization, engaging with strategic partners and refining the project development plan. Veri Energy

continues to be encouraged by the project's potential to be a low-cost merchant-market solution for CO_2 emitters to permanently sequester carbon beginning in the early 2030s.

Veri Energy's merchant model is designed to de-risk the CCS value chain, reducing the burden on government and emitters alike. By aligning commercial success with performance, rather than subsidy, Veri offers a cost-effective, market-led solution to carbon storage. We currently do not expect the U.K. government to make any further investment in carbon storage beyond what was outlined in the most recent Comprehensive Spending Review, which would limit support to carbon capture projects of the 2023 licensing round, with only modest business development funding for carbon capture projects of the 2025 licensing round. The 2025 licensing round opened on December 9, 2025 and ran until March 24, 2026, offering 13 locations in Scottish and English waters for exploration and appraisal, with licenses to be awarded in early 2027. We did not apply for any licenses in the 2025 licensing round.

Veri Energy remains encouraged by the project's potential to provide a low-cost merchant-market solution for CO_2 emitters to permanently sequester carbon. However, it is clear that a delay in government support will impact all UK projects of this type.

Electrification/onshore wind

During 2025, Veri Energy has worked on our behalf to develop an onshore wind farm at the Sullom Voe Terminal. This project will harness Shetland's natural advantage of having one of the world's highest wind capacity factors and will utilize existing terminal infrastructure to assist in decarbonizing and reducing costs at the site. The project underwent technical analysis, environmental impact assessment, and feasibility studies during 2024 and entered front-end engineering and design during 2025, with a final investment decision expected in 2026.

E-Fuels

Veri Energy is advancing its evaluation of a multi-phase green hydrogen and e-fuels program at the Sullom Voe Terminal, targeting scalable production of net-zero derivatives. In early 2025, Veri Energy launched a major initiative to evaluate investable pathways for e-fuel production at Sullom Voe. Working with leading global technology providers, the team assessed and de-risked the full value chain for producing e-fuels from green hydrogen and biogenic CO_2. This work aims to unlock Scotland's potential to produce low-carbon fuels by also harnessing Shetland's exceptional wind resource and the inherent advantages of the terminal site, strengthening long-term energy security and resilience. Support from Aberdeen's Net Zero Technology Centre, through its Energy Hubs project, is enabling the development of an advanced operating model for future e-fuel facilities. The combination of infrastructure, natural resources and skilled labor makes SVT a compelling hub for low-carbon fuel production, and the Veri team continues to evaluate scenarios for end products, scale, partnerships and technology integration for the project.

Competition

The oil industry is competitive, and we compete with a substantial number of other companies, many of which have greater resources than we do. Many of these companies explore for, produce and market oil and natural gas, carry on refining operations and market the resulting products on a worldwide basis. Our competitors include national oil and gas companies, major international oil and gas companies and independent oil and gas companies. The oil and gas business is highly competitive in the search for and acquisition of reserves, in the procurement of rigs and other production equipment, in the production and marketing of oil and gas and in the recruitment and employment of qualified personnel. See "*Risk factors—Risks relating to the oil and gas industry—We carry out business in a highly competitive industry*."

In addition, we compete with oil and gas companies in the bidding for production licenses, farm-ins and other contractual interests in licenses that are made available by governments or are for sale by third parties. Competition for such assets is likely to come from companies already present in the region in which the production licenses are located as well as new entrants. Competition also exists between producers of oil and natural gas and other industries producing alternative energy and fuel, such as solar and wind.

Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation, including taxation, considered from time to time by the governments of the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such legislation and regulations may, however, substantially increase the costs of developing, producing, marketing or exploring for natural gas and oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted. See "*Risk factors—Risks relating to our business—Our business is subject to licensing and other regulatory requirements and fiscal regimes, which are subject to change, in the countries in which we operate, and we are subject to the risks of licenses or other agreements being withheld, suspended, revoked or terminated and of our failing to comply with relevant licenses, agreements or other regulatory requirements*."

Product lifting and distribution

Petroleum from Magnus is transported to SVT through the Ninian Pipeline System. Purchases of third-party gas from West of Shetland fields and produced gas is transported through the Northern Leg Gas Pipeline system and FLAGS to the St Fergus SEGAL gas plant; dry gas is exported to the National Transmission System and natural gas liquids ("**NGLs**") are transported to Mossmorran for processing.

As part of our acquisition of working interests in the Magnus asset in December 2017 and 2018, we acquired an equity interest in SVT bringing our total equity interest to 15.1% by December 2018. In connection with the same transactions, we acquired an additional equity interest of 15.3% in the Ninian Pipeline System, bringing our total equity interest in the Ninian Pipeline System to 18%, including the 2.7% equity interest we had in the Ninian Pipeline System through Heather. Finally, we also acquired 43.9% equity working interests in the Northern Leg Gas Pipeline ("**NLGP**") in connection with the 2017 and 2018 acquisition of Magnus working interests, bringing our total equity in the NLGP to 51.1%. Following the retransfer of Thistle to Britoil and Chrysaor (now Harbour Energy), which included a 7.2% interest in NLGP, our equity interest in the NLGP is 43.9%. Also, in connection with the Thistle retransfer, our equity interest in SVT reduced to 13.1%.

Our participation in these pipeline systems and SVT is regulated by various operating agreements, and we hold working interests in these assets. The costs of maintaining and operating these facilities are shared among the users thereof on a throughput-related basis. We are party to a cross-user liability agreement that provides indemnities between the various groups of owners and between the individual owners for injury or damage caused by the performance or non-performance of their obligations in respect of SVT, the Ninian Pipeline System and the Brent system pipeline. See "*Risk factors—Risks relating to our business—Significant expenditure is required to maintain operability and operations integrity*, *we rely upon infrastructure which is old and/or operated and owned by third parties, and improper maintenance and repair could harm our operations*."

Petroleum from Alba, where we hold a minority interest, is transported by offload tanker from the Alba Northern platform to onshore terminals. With respect to production from the Greater Kittiwake Area and Scolty/Crathes, we hold a working interest in an offshore platform at Kittiwake and a 100% interest in a pipeline linking this platform to the Forties Unity platform. The Greater Kittiwake Area and Scolty/Crathes fields are tied via subsea infrastructure to the offshore platform at Kittiwake. Petroleum from the platform at Kittiwake is transported via pipeline to the Forties Unity platform where it is then transported to shore at Cruden Bay via the Forties Pipeline System. The petroleum is taken from Cruden Bay to Grangemouth for further processing.

Production from PM8/Seligi is transported via the Tapis platform (operated by ExxonMobil) to the Terengganu Crude Oil Terminal (operated by PETRONAS Carigali Sdn. Bhd.) for processing and sale.

Oil production from Block 12W is exported via the Lewek Emas FPSO and gas is exported via pipeline to Vung Tau near Ho Chi Minh City.

For DEWA, initial development concept planning has identified options for produced gas to be transported to the MLNG plant in Bintulu, with technical and economic viability screening ongoing. In Brunei, work has commenced to finalize the resources and evaluate gas development concepts for delivery to the BLNG plant in Lumut, Brunei.

With respect to Kraken, the Kraken FPSO is connected to wells via subsea infrastructure. Offload tankers transport produced oil from the Kraken FPSO to buyers.

Crude oil from the Golden Eagle Area Development is processed on the platform and then transported through the Golden Eagle pipeline to the Claymore line, where it is then routed to the Flotta system and processed into stabilized Flotta Gold blend at the Flotta Terminal.

Sales and customers

Our entitlement to Brent oil (from Magnus) is made available for sale at SVT. Our entitlement to Forties Blend crude oil (from GKA and Scolty/Crathes) is made available for sale at the Kinneil Oil Terminal through the Forties Pipeline System ("**FPS**"). Our entitlement to Flotta Gold blend crude oil is made available for sale at the Flotta Terminal and our Malaysian production is made available for sale at the Terengganu Crude Oil Terminal. Production from Kraken and Alba is lifted by tanker, currently provided by Altera Infrastructure and delivered to the relevant buyer.

Our oil sales for our UKCS assets (excluding Kraken) are primarily priced based on the Platts Dated Brent crude oil benchmark with differentials to the benchmark determined by market conditions and negotiations with customers. Kraken cargo sales continue to be optimized into the shipping fuel market with Kraken oil a key component of IMO 2020 compliant low-sulfur fuel oil. As such, strong pricing associated with the VLSFO market remains robust and we avoid refining-related emissions. Prices for our Malaysian oil sales are set by the Malaysian OSP, which is generally a significant premium to the Platts Dated Brent benchmark. A Tapis differential is then applied to the Malaysian OSP and further differentials are negotiated with customers.

As of December 31, 2023, 2024 and 2025, we had nil trade receivables past due but not impaired.

As of December 31, 2025, we had one customer accounting for 65% of outstanding trade and other receivables (2024: two customers, 91%; 2023: one customer, 58%) and four joint venture partners accounting for over 75% of outstanding joint venture receivables (2024: four joint venture partners, over 70%; 2023: no joint venture partners).

With Kraken's suitability as a component for the production of IMO 2020 compliant shipping fuel, *i.e.*, VLSFO, we have continued to diversify our customer base by selling our production lifted by tanker and delivering to buyers via ports in Northwestern Europe, the United States, the Mediterranean and/or the Far East.

Supplies and third-party contractors

We rely on the services of various contractors in the performance of our activities, including drilling and related operations.

Field and commercial partners

The majority of our assets are owned, explored and developed through commercial partnerships with international, national and private equity-backed oil and gas companies. When we evaluate whether to enter into a commercial partnership or joint venture, we seek prospective commercial partners who will complement our existing strengths. We conduct thorough business and financial diligence on all our prospective commercial partners and strive to ensure they will be able to finance their portion of any development.

During the life cycle of the commercial partnership or joint venture, we often have a very active role in the technical, financial and administrative management of operations including in situations in which we do not take on an official operator role. We typically maintain involvement with many aspects of operations and work closely with our commercial partners to ensure that we continue to comply with the ongoing obligations under the licenses or agreements pursuant to which we operate. For a discussion of certain risks associated with our reliance on commercial partners, see "*Risk factors—Risks relating to our business—We conduct most of our operations with commercial partners which may increase the risk of delays, additional costs and the suspension or termination of the licenses or the agreements that govern our assets*."

Seasonality

Seasonal weather conditions (particularly winter in the UKCS and monsoon season in South East Asia) and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in certain areas. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which can lead to shortages and increase costs or delay our operations. These

seasonal anomalies may also reduce the available weather windows for offloading operations to shuttle tankers from our FPSOs. See "*Risk factors—Risks relating to the oil and gas industry—We face drilling, exploration and production risks and hazards that may affect our ability to produce oil at expected levels, quality and costs and that may result in additional liabilities to us*."

Health, safety, environment and assurance

We are subject to a wide range of laws, regulations, directives and other requirements governing the protection of the environment and health and safety matters. See "*Risk factors—Risks relating to our business—We could incur material costs to comply with, or as a result of liabilities under, health and safety and environmental regulations*." One of our top priorities is to achieve and maintain high health, safety and environmental performance. We believe that we have robust management systems, a culture of positive engagement and a commitment to continuous improvement. We are committed to respecting the people and environments that our business may affect, and we aim to operate our business to achieve safe results, with no harm to people or the environment. To achieve this, we aim to manage our business in compliance with legislation and industry standards, maintain high-quality systems and processes and seek to maintain safe and healthy workplaces. See also "*Management—Code of conduct*."

Health and safety

To help ensure that we maintain safe and healthy workplaces for all our employees and contractors, the group-wide HSE&A system is structured in line with ISO 14001 and covers occupational and process safety. We have a Health & Safety Management System that is aligned with the requirements of the Occupational Health and Safety Assessment Series Standard (OHSAS 18001:2007) while the framework of the management system in Malaysia complies with the Offshore Self-Regulation Management System ("**OSRMS**") and PETRONAS Procedures and Guidelines for Upstream Activities ("**PPGUA**") requirements. See "*Risk factors—Risks relating to our business—We could incur material costs to comply with, or as a result of liabilities under, health and safety and environmental regulations*."

Our HSE policy is fully integrated across our operated sites. There is a strong assurance program in place to ensure we comply with our policy and principles and regulatory commitments. We undertake ongoing improvement activities in support of the 'SAFE' behaviors: (i) standards (following rules and procedures), (ii) awareness (understanding the hazards and controls), (iii) fairness (adopting the correct behaviors) and (iv) engagement (communicating effectively). The goal of our ongoing improvement activities is to ensure that our health and safety culture continues to grow with a focus on the prevention of personal injuries, dangerous occurrences and hydrocarbon releases.

Each of our U.K. assets are inspected periodically by the HSEx. As of the date of these Listing Particulars, there are no open improvement notice on our assets. We recognize the benefits of promoting positive health and wellbeing within the workplace and a Mental Health Policy describing our commitment to protecting and maintaining the health, safety and wellbeing of our workforce was updated and republished in 2025.

In Malaysia, we delivered three years and over seven million man-hours of Lost Time Incident ("**LTI**")-free performance at PM8/Seligi and EnQuest was presented with the 'HSE Excellence Award' at the PETRONAS Emerald Awards in May 2025, evidencing our commitment to health and safety. We have also delivered over four years of LTI-free performance at Kraken and over 20 years of LTI-free performance at GKA. We are also continuously looking for areas of improvement. In 2025, our LTI frequency rate of 0.69 represented a significant year-on-year improvement (2024: 1.55) and a significant outperformance of the U.K. average of 2.23 (according to OEUK 2025 benchmark data). However, we never find it acceptable to incur LTIs and are working closely with the contractors involved to ensure that all parties are aligned with our safety culture, trained on equipment and procedures and empowered to stop a task should a safer method be identified.

Environmental

Environmental protection has been a core feature of our business model since inception, with our priority being safe results with no harm to people and respect for the environment. As integrated energy business, we are focused on safely improving the operating, financial and environmental performance of mature and late-life assets while repurposing existing infrastructure to support delivery of our renewable energy and decarbonization ambitions and managing end of life production and the safe, cost-effective and low carbon decommissioning of operations that have reached the end of their useful lives.

We have in place an Environmental Management System ("**EMS**") to ensure our activities are conducted in such a way that we manage and mitigate our impact on the environment.

Our system is aligned with the requirements of the International Organization for Standardization's environmental management system standard—ISO 14001. Our EMS was verified under The Convention for the Protection of the Marine Environment of the North-East Atlantic OSPAR Recommendation 2003/5 and applicable guidance in September 2024.

We recognize that industry, alongside other key stakeholders such as governments, regulators and consumers, must contribute to reducing the impact on climate change of carbon-related emissions. We are committed to contribute in the achievement of national emission reduction targets having committed to net zero Scope 1 and Scope 2 CO_2 equivalent emissions by 2040.

Within our core Upstream and Decommissioning businesses, the board is focused on a strategy that recognizes that hydrocarbons will remain a key element of the global energy mix for many years and through which we can pursue a business model which helps to fulfil energy demand as part of the transition to a sustainable lower-carbon world, while reducing Scope 1 and Scope 2 CO_2 equivalent emissions from our own business operations where practicable See "*Risk factors—Risks relating to the oil and gas industry—Climate change legislation, the transition to net zero greenhouse gas emissions by 2050 and/or protests and shareholder actions against fossil fuel extraction may have a material adverse effect on our industry*." In 2023, we started reporting Scope 3 CO_2 equivalent emissions against category 5 (waste generated in operations). The expansion of Scope 3 emissions reporting to other categories such as 'Use of sold production' (Category 11) is included in the Group's 'Continuous Improvement Plan' with alignment to the United Nations-adopted Sustainable Development Goal 12 (Responsible Consumption & Production).

During the years ended December 31, 2023, 2024 and 2025, our Scope 1 and 2 emissions in kilo-tons of CO_2 equivalent were 1,041.9, 1,068.4 and 1,068.0, respectively. We have already reduced our U.K. absolute Scope 1 and 2 CO_2 equivalent emissions by 46% since 2018 (measured against the NSTA baseline), driven by the decisions to cease production at a number of our assets and the further reductions achieved in 2024, which is significantly ahead of the U.K. Government's North Sea Transition Deal target of achieving a 10% reduction in Scope 1 and 2 CO_2 equivalent emissions by 2025. We are aiming to significantly reduce the carbon footprint of the Kraken FPSO by replacing diesel fuel with a gas tie-back to Bressay.

In addition to reducing upstream-related emissions, we have also implemented an innovative, economic emissions avoidance opportunity at Kraken by optimizing sales of Kraken cargoes directly to the shipping fuel market. This initiative has two environmental benefits: it avoids emissions related to refining; and it also helps reduce sulfur emissions in accordance with the IMO 2020 regulations. The avoidance of emissions related to Kraken's crude is significant—with refining emissions for a typical North Sea crude estimated to be approximately 32 to 36 $kgCO_2e/bbl$ compared to emissions associated with blending Kraken oil estimated at approximately 1 $kgCO_2e/bbl$. As such, emissions relating to Kraken oil by the time it reaches its end user, compares favorably on a fully-refined basis to even high-performing North Sea fields (based on the University of Calgary 'Petroleum Refinery Life Cycle Model').

In 2023, our Board of Directors approved a net zero commitment in respect of Scope 1 and Scope 2 CO_2 equivalent emissions by 2040. In addition, we are considering a strategic roadmap identifying the steps required to move towards net zero and are reviewing the suitability of a number of Scope 3 emission categories, allowing for further improvement in our emission reduction targets. A baseline has been developed for emissions associated with waste in 2023 under Scope 3 emissions. At SVT, we are working on two projects which, together, aim to reduce terminal emissions by approximately 90%. We also are working to reduce the carbon footprint of the Kraken FPSO by replacing diesel fuel through a gas tie-back from Bressay, which was significantly advanced in 2025, and the Magnus flare gas recovery project, which was sanctioned in 2024.

Since December 2023, Veri Energy has been focused on progressing decarbonization and new energy projects, including carbon capture and storage, e-fuel production and renewable power production at SVT. Veri Energy has identified three discrete and scalable decarbonization opportunities which, we believe, have the potential to help us reach our commitment to reach net zero for Scope 1 and Scope 2 CO_2 equivalent emissions. We believe our carbon capture storage project has the potential to store up to 10 million tons of CO_2 per annum, which represents a multiple of our existing emissions footprint. See also "*Overview of our assets—Veri Energy—Carbon Capture and Storage*." At SVT, we are also progressing the long term power grid connection

which is on track for early 2027 start up and will transform terminal emissions and are also progressing an onshore wind project.

We continue to develop cost-effective and efficient plans to transform SVT and prepare and repurpose the site to progress these opportunities. The terminal site offers several unique competitive advantages, including a 1,000-acre industrial site with access to existing oil and gas pipeline infrastructure, deep water port and jetties, with the highest wind capacity factor across Europe, and a highly skilled workforce and local supply chain. See also "*—Overview of our assets—U.K. Midstream.*"

As other major oil companies and operators continue to shift their focus away from mature basins in a number of geographies, particularly the U.K. given the introduction of the EPL in 2022 and changes to this regime subsequently, we believe that there will be further opportunities for us to access additional oil and gas resources. However, time and careful consideration will be taken to find the right opportunities where we can deliver incremental emission reductions and reduce carbon intensity relative to the carbon footprint in the hands of the seller. We can make a positive contribution towards the future of North Sea oil and gas through doing our part in ensuring that each asset is in the right hands. We also factor in an appropriate associated carbon price into the acquisition economics, even in markets where no carbon trading or pricing mechanism exists.

Emissions management is an important feature during the decommissioning phase of an asset's life cycle. During this phase, wells will need to be plugged and abandoned, while the production and processing facilities and any relevant infrastructure will need to be removed. Given the extent of this work, it will necessarily take place over an extended period of time and require careful project management. Our U.K. Decommissioning directorate will oversee the safe and efficient execution of these work programs and is committed to delivering them in a responsible manner, which includes minimizing emissions and maximizing the recycle and reuse of recovered materials. Our U.K. Decommissioning directorate continues to work with a variety of stakeholders to identify creative ways, such as alternative power generation options, as installed on the Thistle asset, in which emissions associated with decommissioning activities can be kept to a minimum.

We recognize the increasing societal, media and investor focus on climate change, and the desire to understand its potential impacts on the oil and gas industry through improved disclosure, utilizing mechanisms such as those proposed by the Taskforce on Climate-related Financial Disclosures ("**TCFD**"). We provide information relevant to each of the four TCFD recommendations (Governance, Strategy, Risk Management, Metrics and Targets) on our website and annual report and will continue to evolve these disclosures over time.

CDP awarded us a sector-leading score of A- (B in 2024) for our 2025 CDP Climate Change submission, demonstrating that we continue to integrate climate change impacts into the fabric of the business, driven by recognition of our credible transition plan and defined actions to pursue progress towards net zero.

Assurance

We strive for continuous improvement in our HSE performance. Our HSE policy is fully integrated across its operated sites enabling a consistent focus on HSE. We periodically audit and review our HSE management system, to help ensure compliance with all applicable regulations, as well as our policies, principles, processes and procedures, and to identify areas for improvement.

Our risk-based audit and assurance program is designed to measure the conformance and effectiveness of HSE management across all operations, including contractor and supplier organizations as applicable. In conjunction with our core contractors, we maintain a comprehensive program of assurance activities that demonstrate the robustness of the management process and identified opportunities for improvement. We also undertake a series of internal in-depth reviews into the 'Risk Bowties' to ensure the effective management of risk. Our Group-aligned HSE 'Continuous Improvement Plan' promotes a culture of accountability and performance in relation to HSE matters. The purpose of this plan is to ensure that employees have an understanding of their responsibilities and expectations are based on realistic standards, governance, and capabilities to add value and to support the business as a whole. HSE and risk management performance is discussed at each Board meeting and the mitigation of HSE risks continues to be a core responsibility of our Sustainability and Risk Committee. See "*Management—Board* Committees." We continue to focus on the control of major accident hazards and SAFE behaviors.

Insurance

We maintain the types and amounts of insurance coverage that we believe are consistent with customary industry practices in the jurisdictions in which we operate. Our oil and gas properties and liabilities are insured within an operational energy insurance package. Coverage under the terms of this insurance package includes physical damage, operator's extra expense (well control, seepage, pollution clean-up and re-drill) and third-party liabilities. Coverage is placed in respect of scheduled worldwide oil and gas exploration and production activities. We believe limits and deductibles in force for us are in line with applicable oil industry insurance standards.

We currently have a loss of production insurance policy in place which would protect revenues anticipated to be derived from net Kraken forecast production at an oil price of $40.0/bbl (which is capped at a limit of 24 months' production) if there is a loss of production caused by an insured event for a period up to two years, with such cover commencing 60 days after the insured event which caused the loss of production. The loss of production policy was renewed on May 6, 2025 and is due to expire on May 6, 2026. Where applicable, construction all risks insurance coverage is procured in respect of development projects. Such coverage is generally for works executed anywhere in the world in performance of contracts where we are at risk including loss of, or damage to, the pipeline systems, risers, umbilicals, oil wells and completions to be installed and liabilities to third parties arising therefrom.

Our philosophy is to arrange such other insurance from time to time in respect of our other operations as required and in accordance with industry practice and at levels which we feel adequately provide for our needs and the risks that we face. We have not had any material claims under our insurance policies that would either make them void or materially increase their premiums. There can be no assurance, however, that our insurance coverage will adequately protect us from all risks that may arise or in amounts sufficient to prevent any material loss. See "*Risk factors—Risks relating to our business—We do not insure against certain risks and our insurance coverage may not be adequate for covering losses arising from potential operational hazards and unforeseen interruptions*."

Employees

As of December 31, 2023, 2024 and 2025, we employed 736, 731 and 825 full-time employees, respectively.

The following table sets forth our full-time employees as of December 31, 2023, 2024 and 2025.

	As of December 31,		
	2023	**2024**	**2025**
Directors	8	9	8
Operational (onshore)	311	303	360
Operational (offshore)	339	335	328
Corporate	21	21	19
Contractors[(1)]	57	63	110
Total	**736**	**731**	**825**

(1) Excluding contractors who are employed through a third-party service company.

	As of December 31,		
	2023	**2024**	**2025**
United Kingdom	532	524	528
Malaysia	175	179	177
Dubai	29	28	—
Bahrain	—	—	30
Vietnam	—	—	90
Total	**736**	**731**	**825**

We believe that we have satisfactory working relationships with our employees and have not experienced any significant labor disputes. Save in respect of SVT, there is no unionization currently in place for our employees at any of our locations and we have not suffered any labor disputes or stoppages. We may be subject to work stoppages or other labor disturbances, and our employees may become unionized. See "*Risk factors—Risks*

relating to our business—We may be subject to work stoppages or other labor disturbances, *and our employees may become unionized*."

We remain committed to providing an inclusive culture that recognizes and celebrates difference, encourages diversity of thought and embraces new ways of working to create an environment that enables the development of creative solutions to deliver performance and value. In 2024, we updated our diversity and inclusion strategy and policy, introducing our Diversity, Equity and Inclusion ("**DE&I**") policy (the "**DE&I Policy**"). Our 'EnQlusion' committee is promoting a number of initiatives during 2024, including supporting a STEM collaboration session with Dundee University and secondary school pupils and running a transition event with Heriot-Watt University and Association for Black and Ethnic Minority Engineers, offering an opportunity for students to attend a series of seminars, networking and employability sessions run by EnQuest to support their employability in the future.

Targets have also been set for gender and ethnicity representation in leadership.

With DE&I central to ways of working, we continue to challenge our recruitment, employment and training policies and how they attract, retain and develop a wide range of talent in the organization.

Our first published report on the gender pay gap in 2017 highlighted a noticeable pay gap between our male and female employees. Since then, we have worked on addressing and reducing the gap.

We remain committed to narrowing the gender pay gap and striving to provide equal pay for equal jobs and on building on the progress made in the areas of diversity and inclusion within our workforce and this commitment is underpinned by a full review of progress and strategy with the Board during 2025.

We also remain committed to fair treatment of people with disabilities in relation to job applications and, as set out in the DE&I Strategy, we encourage individuals with a disability, or who develop a disability at any time during their employment, to speak to their line manager about their condition. This will enable us to provide support and prevent unfavorable treatment.

Bribery laws

We are committed to behaving fairly and ethically in all of our endeavors and have policies which cover anti-bribery and corruption, including consolidated anti-bribery policies in light of the U.K. Anti-Bribery Act, Malaysian Anti-Corruption Commission Act, Vietnamese Anti-Corruption Law, Indonesian Law on Corruption Eradication and related guidance. We have implemented group-wide training on these policies. The overall anti-bribery and corruption program is reviewed annually by the Board and a corruption risk awareness email is sent out annually by the Chief Executive reminding staff of their obligations and also to prompt them to complete a mandatory online anti-corruption training course. Staff are also regularly reminded of their obligations with regard to anti-bribery and corruption and anti-facilitation of tax evasion through the annual risk awareness email issued by the Chief Executive, our Code of Conduct and the obligatory annual anti-bribery and corruption and anti-facilitation of tax evasion training course.

We also encourage staff to escalate any concerns and, to facilitate this, provide an external "speak-up" reporting line which is available to all staff in the U.K., Malaysia, Vietnam, Bahrain, Indonesia and Brunei. Where concerns are raised, these are investigated by our General Counsel and reported to the Audit Committee.

Legal and arbitration proceedings

We become involved from time to time in various claims and lawsuits arising in the ordinary course of our business.

We are currently engaged in a dispute with PBJV Group Sdn Bhd ("**PBJV**"), a contractor in Malaysia concerning approximately RM70 million (being approximately $17 million of which our partners would be obliged to bear 50% of any such liability) claimed by PBJV which we do not accept is due. The dispute relates to PBJV's charging in 2019 for the blasting material garnet as a separate consumable over and above the blended charge for the paint blasting work they had also performed. In our view, the charge for the service included all consumables, and therefore a separate charge for garnet should not have been made. A contractor adjudication hearing in 2021 found in favor of PBJV, but we have continued to challenge the requirement to pay the claimed sum to PBJV as a result of the adjudication pending the outcome of the arbitration we initiated in January 2022 at

the Asian International Arbitration Center ("**AIAC**"). Two separate arbitration hearings were held in 2024. Arbitrators closed submissions on June 6, 2025 with award anticipated within three months; however, on August 28, 2025, arbitrators requested a further three months extension to submit the award to the AIAC. We had previously paid the disputed funds into an escrow account with AIAC, but in late August 2024 the Malaysian Court of Appeal issued a judgement that the funds, which are reflected in our restricted cash balance at June 30, 2024, should be released to PBJV. The full amount previously held in escrow has been released to PBJV. If the arbitration ruling is in our favor, we will seek recovery of such funds (with our share being approximately $8.6 million) from PBJV. We expect the dispute to be settled in 2026. We do not consider that an adverse outcome in this dispute is likely to be material to our operations or cash flows. See "*Risk factors—Risks relating to our business—Our operations are subject to the risk of litigation*."

On March 1, 2018, hydrocarbon gas was sent to flare on our Heather platform without the flare being lit, which led to an accumulation of gas. No one was injured. On March 28, 2018, the HSEx issued an improvement notice regarding this incident, with which we complied. The Heather platform was shut-in in 2019 following a fire event at the power generation turbines. Formal cessation of production occurred on May 31, 2020. The HSEx referred both the unlit flare and power turbine incidents to the COPFS recommending prosecution of both. The HSEx investigation concluded that both explosions were caused by an ignition source that ignited flammable gases within the lube oil tanks. In June 2025, we pleaded guilty to one charge of failing to take appropriate measures to prevent fire and explosion and the regulator imposed a fine of £300,000.

On April 2, 2026, we received a formal Sanction Notice from the NSTA in respect of alleged non-compliance in relation to the timing of the plugging and abandonment of 33 wells across four licenses. The Sanction Notice includes a fine of £500,000 in respect of each of the wells. We prioritize our P&A work on the basis of asset integrity to minimize risk to human life and the environment, an approach which differs from the date-driven and more mechanistic approach taken by the NSTA's sanction team. We are considering all options with regard to formally appealing the sanction and the fine. See "*Risk factors—Risks relating to our business—We may face unanticipated increased or incremental costs in connection with decommissioning obligations*."

As of the date of these Listing Particulars, there are no open instances of non-compliance with health and safety regulation. However, there can be no assurances that we will not incur material costs in the future, including clean-up costs, civil and criminal fines, penalties and sanctions and third-party claims, including for personal injury, wrongful death and environmental and property damages, and other environmental, health and safety claims under contract, as a result of violations of our obligations under environmental, health and safety requirements. See "*Risk factors—Risks relating to our business—We could incur material costs to comply with, or as a result of liabilities under, health and safety and environmental regulations*."

Material agreements relating to our assets

In this section, where a defined term is used in reference to various contracts, it has the meaning for the relevant sub-section in which it is defined.

U.K. Upstream

Kraken agreements

We acquired our 70.5% interests in the Kraken development through (a) the acquisition of Canamens Energy North Sea Limited ("**CENSL**") (including its 20% working interest in Kraken) and (b) the January 24, 2012 farm-in agreement with Nautical Petroleum Limited ("**Nautical PLC**") and Nautical Petroleum AG (together with Nautical Limited, "**Nautical**") for a 25% working interest; (c) the April 25, 2012 farm-in agreement with First Oil and Gas Limited ("**First Oil**") for a 15% working interest; and (d) the acquisition of a further 10.5% working interest from First Oil on February 22, 2016 following First Oil going into administration. Further to the CENSL acquisition, we are obligated to indemnify Canamens Limited against all decommissioning liabilities.

Additionally, on December 20, 2013, EnQuest Heather Limited (in its capacity as the Kraken operator) entered into a bareboat charter with the Kraken field owners (as charterers) and Armada Kraken PTE. Ltd. ("**Armada**"). Armada agreed, among other things, to construct, and perform the installation, commissioning and hook-up of, the Kraken FPSO at the Kraken field and thereafter charter the Kraken FPSO to the charterers (including, among others, EnQuest Heather Limited and EnQuest ENS Limited). Interest holders in Kraken are also subject to a joint operating agreement dated September 29, 2006. The Kraken joint operating agreement establishes a joint operating committee to prepare and approve programs, budgets and authorizations for

expenditures proposed by the operator. The joint operating committee makes decisions with the affirmative vote of two or more interest holders whose aggregate interests total at least 71%. We have a 70.5% interest in Kraken and therefore cannot exercise unilateral control over operations at Kraken.

Magnus agreements

On January 24, 2017, a special purpose vehicle wholly owned by us (the "**SPV**") and bp Exploration Operating Company ("**BPEOC**") entered into a sale and purchase agreement pursuant to which SPV acquired a 25% interest. Completion of SPV's acquisition of the 25% interests (and transfer of operatorship of the Magnus Assets from BPEOC to SPV) occurred on December 1, 2017. Under the Magnus sale and purchase agreement ("**Magnus SPA**"), BPEOC agreed to be liable for and to indemnify SPV against any decommissioning liabilities arising in respect of any property attributable to the 25% interests in existence before completion under the Magnus SPA and three infill wells which are planned to be drilled as part of the three year work program and budget planned for the Magnus field. SPV agreed to be liable for and to indemnify BPEOC against decommissioning liabilities arising in respect of any property attributable to the 25% interests that comes into existence on or after completion under the Magnus SPA (subject to certain carve-outs which will be treated as existing property). SPV also agreed to be liable for and to indemnify BPEOC against all environmental liabilities relating to the 25% interests (whether arising before, on or after completion under the Magnus SPA) (subject to certain limited carve outs). On completion of the Magnus SPA, SPV entered into the Magnus joint operating agreement and certain security documents in relation to the 25% interests. SPV is the operator under the Magnus joint operating agreement ("**Magnus JOA**"). Joint operations under the Magnus JOA are divided into four phases. The Magnus JOA establishes a joint operating committee which is responsible for, among other things, approving programs and budgets submitted to the joint operating committee by the operator. Save for certain reserved matters which require the unanimous approval of all participants entitled to vote (including authorizing the operator to prosecute or defend litigation outside the United Kingdom, waiving the notice period for calling a meeting of the joint operating committee, any decision to abandon the joint operations and any matter or decision relating to decommissioning), the joint operating committee may approve decisions in accordance with the Magnus JOA, depending on the phase of the Magnus joint operations.

On December 1, 2018, we completed the acquisition from bp of the remaining 75% interest in the Magnus oil field, an additional 9% in the SVT and supply facility and other additional interests in associated infrastructure.

The total consideration for the Magnus Acquisition comprised $100.0 million cash consideration and $200.0 million deferred consideration financed by BP plc. With an effective date of January 1, 2017, the deferred consideration was adjusted for the interim period and working capital adjustments, resulting in contingent consideration of $116.5 million as of December 1, 2018. The outstanding amount of deferred consideration was repaid in full in July 2021. The consideration also included a contingent profit sharing arrangement whereby we and BP plc share the net cash flow generated by the 75% on a 50:50 basis, subject to a cap of $1 billion received by BP plc. Together, the deferred consideration and contingent profit sharing arrangement are known as the "**Magnus Contingent Consideration**." During 2025, management commenced discussions with bp to settle the Magnus Contingent Consideration. On February 26, 2026, we signed an agreement to settle the Magnus Contingent Consideration for $60 million, representing the final settlement of the profit share liability related to Magnus, thereby securing 100% of future Magnus cash flows and removing the associated $433 million liability that was on our balance sheet as of June 30, 2025.

Golden Eagle Area Development agreements

On February 4, 2021, we entered into an agreement with Suncor Energy UK Limited ("**Suncor**") to purchase Suncor's entire 26.69% non-operated equity interest in the Golden Eagle Area Development. The acquisition of Golden Eagle was completed on October 22, 2021.

Interest holders in the Golden Eagle Development Area are subject to a joint operating agreement dated October 31, 2011 and the amendment agreements thereto. The Golden Eagle Development Area joint operating agreement established an operating committee to approve all programs, budgets and expenditures prepared and proposed by the operator. The joint operating committee makes decisions and authorizations for expenditures of at least two parties whose interests total more than 60% (with certain reserved matters with a pass mark of 85%). We have a 26.69% interest in the Golden Eagle Development Area.

Greater Kittiwake Area agreements

On October 21, 2013, we entered into an agreement with Centrica North Sea Oil Limited ("**Centrica**") to acquire its 50% working interest in each of the Kittiwake, Mallard, Goosander, Gadwall and Grouse fields in the Greater Kittiwake Area. The acquisition of the Greater Kittiwake Area assets was closed on March 1, 2014.

Interest holders in the Greater Kittiwake Area are subject to a joint operating agreement dated January 12, 2004 and the amendment agreements thereto. The Greater Kittiwake Area joint operating agreement establishes a joint operating committee to prepare and approve programs, budgets and authorizations for expenditures proposed by the operator. The joint operating committee makes decisions with the affirmative vote of two or more interest holders whose aggregate interests total more than 75%. We have a 50% interest in the Greater Kittiwake Area and therefore cannot exercise unilateral control over operations at the Greater Kittiwake Area. There are separate decommissioning arrangements subject to a decommissioning agreement dated November 25, 2003, which includes Shell as a party.

Scolty and Crathes agreements

EnQuest holds a 50% interest in the Scolty and Crathes fields (JOA for Licenses P.1107 (Block 21/8) and P.1109 (Blocks 21/14 and 21/15b) dated November 2, 2005), with Waldorf as the other equity holder. Under the agreements, at least two parties, representing together 61% of interest, have to vote in favor for decisions to be made.

Alba agreements

Interest holders in Alba are subject to a joint operating agreement dated October 10, 1990. Ithaca is the current operator under the agreement. The agreement establishes an operating committee that approves all production, development, exploratory and decommissioning operations plans. As an interest holder under the agreement, we have the right and obligation to take in kind and separately dispose of our percentage interest share in the total quantities of produced oil. The operator may make monthly cash calls in pounds sterling and dollars. The operator is also not liable to any interest holders for any act or omission in conducting field operations, unless such act or omission was the result of reckless or willful misconduct on the part of the operator.

Bressay Oil Field agreement

On July 30, 2020, EnQuest Heather Limited entered into a sale and purchase agreement with Equinor UK Limited ("**Equinor**") to purchase a 40.81% operating interest in the Bressay oil field, which was completed in January 2021. The initial consideration paid pursuant to the Bressay oil field agreement was: (i) $1 which was deemed paid at the date of the Bressay oil field agreement; (ii) £2.2 million (approximately $3.0 million converted at a rate of $1.3630 to £1.00) payable as a carry against 50.0% of Equinor's net share of costs from completion; and (iii) subject to certain conditions, an additional $30.0 million.

EnQuest Heather Limited has certain obligations to indemnify Equinor including:

- if Equinor incurs any obligations after the date which completion under the Bressay oil field agreement occurs, EnQuest Heather Limited shall reimburse Equinor in respect thereof; and

- if EnQuest Heather Limited accrued any benefits prior to the date which completion under the Bressay oil field agreement occurs, EnQuest Heather Limited shall reimburse Equinor in respect thereof.

In 2022, Equinor and Harbour withdrew from Bressay, leaving EnQuest as the sole owner. In December 2023, EnQuest sold 15% of its equity to RockRose as part of a transaction, and a new joint operating agreement dated December 29, 2023, was executed.

South East Asia

Malaysia

PM8 Extension (PM8/Seligi) agreements

On June 13, 2014, EQPPM entered into a sale and purchase agreement for the purchase of ExxonMobil's 50% interest in the Seligi field and its 80% interest in the PM8 field, offshore Malaysia (although EQPPM's interest in the PM8 field reduced to 50% from July 1, 2014 pursuant to the joint operating agreement). EQPPM also agreed to purchase ExxonMobil's 50% interest in the gas rights available for sale from the PM8 producing fields. Pending completion of the acquisition, ExxonMobil agreed to provide EQPPM with transitional services to continue operating PM8 and Seligi until December 15, 2014, following which EQPPM took over full operatorship from ExxonMobil. EQPPM agreed to pay a consideration of $67.0 million for the interests with only $24.7 million cash consideration ultimately paid upon completion.

EQPPM's interest in the PM8 and Seligi fields is held pursuant to a production sharing contract with PETRONAS Carigali Sdn. Bhd., E&P Malaysia Venture Sdn. Bhd. (as contractors) and PETRONAS dated December 10, 2014 (the "**PM8Extension PSC**"). Under the PM8Extension PSC, EQPPM, as the appointed operator, is required to perform petroleum operations in accordance with an annual work program and budget which is approved by PETRONAS. The PM8Extension PSC establishes an operations committee for the purposes of managing operations and approving the work program and budget. Revenues from production under the PM8Extension PSC are firstly set aside for payments to the Malaysian state and then applied to the contractor's cost recovery, both up to a specified percentage. The additional revenues are divided based on a contractor's profitability. EQPPM's profitability is determined using the R/C index. The R/C index is the ratio of contractor's cumulative revenue over contractor's cumulative costs. Under the PM8Extension PSC, EQPPM, as a contractor, gets a higher share of production when its profitability is low and PETRONAS' share of production increases when EQPPM's contractor's profitability increases.

The contractors are required to pay annual decommissioning fees to PETRONAS based on annual production, estimated cost and estimated remaining production, which is cost recoverable, and also to facilitate the decommissioning of the facilities in accordance with an agreed program and budget approved by PETRONAS. The PM8Extension PSC expires on March 31, 2033.

EQPPM entered into a joint operating agreement on December 10, 2014 in respect of PM8 Extension PSC. From July 1, 2014 onwards, participating interests are held: 50% by EQPPM, 40% by PETRONAS Carigali Sdn. Bhd. and 10% by E&P Malaysia Venture Sdn. Bhd. The role of operator is assigned to EQPPM. The agreement establishes a management committee charged with the supervision and direction of operations and approving work programs and budgets. The management committee makes decisions with the affirmative vote of two or more interest holders (who are not related companies) whose aggregate interests total at least 65%. As EQPPM has a 50% interest, it cannot exercise unilateral control over operations. Pursuant to this agreement, and a subsequent extension, EQPPM agreed to bear all costs of the interest holders (of at least $12 million) between June 26, 2014 and June 26, 2017 in relation to drilling one exploration well or one appraisal well.

On December 17, 2024, in partnership with PETRONAS Carigali Sdn Bhd and E&P Malaysia Venture Sdn Bhd (together, the "**Parties**"), we signed a letter of agreement (the "**PM8 Extension Agreement**") with Petroliam Nasional Berhad (PETRONAS) through Malaysia Petroleum Management, for the annexation of Seligi Field Non-Associated Gas and Condensate to be part of PM8E PSC (Addendum No. 1), effective from January 1, 2025. In addition, the Parties also agreed on the key terms for the PM8E upstream gas sales agreement relating to the supply of natural gas produced from PM8E PSC.

The PM8 Extension Agreement enables the Parties to develop and commercialize the non-associated gas resources in the PM8E PSC contract area and, beginning in December 2025, supply around 70 mmscf per day of sales gas, in line with expected demand in Peninsular Malaysia.

DEWA agreement

Via our wholly owned affiliate, EnQuest Petroleum Production Malaysia Ltd., we hold a 42% interest in the DEWA Complex Cluster Small Field Asset PSC (in partnership with Petroleum Sarawak Exploration & Production Sdn Bhd and Longboat Energy (DEWA) Ltd by Petroliam Nasional Berhad (PETRONAS) through

Malaysia Petroleum Management). Under the terms of the PSC, we are the operator of the block with largest participating interest of 42.0%, effective from October 21, 2024.

The joint operating agreement for DEWA is dated October 18, 2024. The joint operating agreement establishes a management committee to prepare and approve policies, plans, programs, budgets and authorizations for expenditures proposed by the operator. The joint operating committee makes decisions with the affirmative vote of two or more interest holders whose aggregate interests total more than 75%. We have a 42% interest in DEWA and therefore cannot exercise unilateral control over operations at DEWA.

Cendramas agreement

Via our wholly owned affiliate, EnQuest Petroleum Production Malaysia Ltd., we hold a 25% interest in the Cendramas PSC (in partnership with Medco Asia Pacific Limited and DIALOG Resources Sdn Bhd by Petroliam Nasional Berhad (PETRONAS) through Malaysia Petroleum Management). Under the terms of the PSC, Medco Asia Pacific Limited is the operator of the block with largest participating interest of 50%, effective from September 23, 2026.

The joint operating agreement for Cendramas is dated March 31, 2026. The joint operating agreement establishes a committee to prepare and approve work programs and budgets for the PSC. We have a 25% interest in Cendramas and therefore cannot exercise unilateral control over operations at Cendramas.

Vietnam

Block 12W agreements

On January 22, 2025, we entered into a sale and purchase agreement for the purchase of Harbour Energy's 53.125% interest in the equity interest in the Chim Sáo and Dua production fields (together, Block 12W). The transaction has an effective date of January 1, 2024 and was completed on July 9, 2025.

Interest holders in Block 12W are subject to a joint operating agreement originally dated September 3, 2004, as amended from time to time. The Block 12W joint operating agreement established an operating committee to prepare and approve all programs, budgets and expenditures proposed by the operator. The joint operating committee makes decisions and authorizations for expenditures of at least two parties whose interests total more than 65%, other than amendments to the joint operating agreement, development plans, transactions involving proprietary information, borrowings, unitizations and well or data trades, which require unanimous agreement by all parties. We have a 53.125% interest in Block 12W and therefore cannot exercise unilateral control over operations at Block 12W.

Indonesia

Gaea and Gaea II agreements

On August 26, 2025, we, together with our joint venture partners and the Government of Indonesia, signed PSCs for the Gaea and Gaea II exploration blocks, located in Papua Barat, Indonesia. Under the PSC terms, we have a 40% participating interest in the blocks and are the PSC operator, alongside our partners, the Tangguh Joint Venture (40% participating interest, comprising BP Exploration Indonesia Limited, MI Berau B.V. (an INPEX and Mitsubishi joint venture company), CNOOC Southeast Asia Limited, ENEOS Xplora Inc., Indonesia Natural Gas Resources Muturi, Inc. (a subsidiary of LNG Japan Corporation), and KG Wiriagar Petroleum Ltd (a subsidiary of Mitsui & Co., Ltd)) and PT Agra Energi Indonesia (20% participating interest), through their respective newly established entities.

Brunei

Block C agreement

On July 16, 2025, we were awarded a PSC for Block C in Brunei by the Petroleum Authority of Brunei Darussalam. EnQuest EP BV Ltd, a subsidiary of EnQuest, will initially be the sole operator of the PSA with the intention to subsequently, subject to contract, form a 50/50 joint venture company with Brunei Energy Exploration Sdn Bhd. Once established, the joint venture company will assume the role of operator for Block C. In 2025, the key terms of the joint venture were formalized, with incorporation planned by the third quarter of 2026.

U.K. Decommissioning

Heather/Broom agreements

EnQuest Heather Limited's decommissioning liability in respect of the Heather field is 37.5% (correlating to its ownership interest), save that EnQuest Heather Limited has 100.0% decommissioning liability for all material decommissioning costs over and above those which would have been incurred had decommissioning been carried out on October 1, 1999.

On December 22, 2014, a decommissioning security agreement in respect of the Heather field was entered into whereby the decommissioning obligations of the owners of the Heather field are regulated and which includes an obligation on each party thereto to provide security in respect of their respective decommissioning obligations. The cessation of production application for the Heather field was accepted by the regulator in March 2021. EnQuest Heather Limited remains the operator of the Heather Field.

EnQuest Heather Limited's decommissioning liability in respect of the Broom Field is 63.0% (correlating to its ownership interest).

On June 28, 2018, a decommissioning security agreement in respect of the Broom field was entered into whereby the decommissioning obligations of owners of the Broom field are regulated and which includes an obligation on each party thereto to provide security in respect of their respective decommissioning obligations. EnQuest Heather Limited is the operator of both the Heather and the Broom fields, with official cessation of production dates of May 31, 2020.

Thistle/Deveron agreements

On January 1, 2003, Dunlin Thistle Limited (now EnQuest Thistle Limited), acquired from Britoil Public Limited Company ("**Britoil**") and Conoco (U.K.) Limited (now Chrysaor Production (U.K.) Limited) ("**Chrysaor**"), *inter alia* a 99% interest in the Thistle and Deveron fields (the "**Thistle Interests**"). The Thistle Interests were later transferred to EnQuest Heather Limited. On March 25, 2021, the Thistle Interests were re-transferred to Britoil and Chrysaor but EnQuest Heather Limited retained operatorship of both fields and continues to be so.

Pursuant to the terms of the decommissioning liability agreement dated January 1, 2003 (as amended on December 9, 2020 moving the decommissioning obligations to a post-tax basis), EnQuest Heather Limited's decommissioning liability in respect of the Thistle and Deveron Fields is 0% save that EnQuest Heather Limited has 99% decommissioning liability for property installed between January 1, 2003 and March 25, 2021. Each of Britoil and Chrysaor are required to provide security for their respective decommissioning obligations. EnQuest Heather Limited is liable to reimburse Britoil for 7.5% of its share of decommissioning costs relating to the Thistle and Deveron fields, which equates to 6.1% of the gross decommissioning costs.

The cessation of production application for the Thistle and Deveron fields was accepted by the regulator with an official date of May 31, 2020.

Alma/Galia agreements

EnQuest Heather Limited's decommissioning liability in respect of the Alma and Galia fields is 65% (correlating to its ownership interest).

On February 2, 2021, a decommissioning security agreement in respect of the Alma and Galia fields was entered into whereby the decommissioning obligations of the owners of the Alma and Galia fields are regulated and which includes an obligation on each party thereto to provide security in respect of their respective decommissioning obligations. The cessation of production application for the Alma and Galia fields was accepted by the regulator with a cessation of production date of June 30, 2020.

Don fields agreements

EnQuest Heather Limited's decommissioning liability in respect of the Don fields is as follows:

- Ythan field – 60% (correlating to its ownership interest);

- Don Southwest & Conrie fields – 60% (correlating to its ownership interest); and
- West Don field – 78.6% (correlating to its ownership interest).

On September 30, 2020, a decommissioning security agreement in respect of each of the Don fields were entered into whereby the decommissioning obligations of the owners of the Don fields are regulated and includes an obligation on each party thereto to provide security in respect of their respective decommissioning obligations.

The cessation of production application for the Don fields was accepted by the regulator with a cessation of production date of March 8, 2021. EnQuest Heather Limited remains the operator of the Don fields.

U.K. Midstream

Sullom Voe Terminal agreements

EnQuest Heather Limited is a party to the amended SVT operating agreement dated December 17, 2019 (the "**Amended SVTOA**"), which amended and restated the original SVT operating agreement dated April 21, 1999. The Amended SVTOA governs the rights and obligations in relation to the ownership and management of SVT, including the procedure for managing capacity in SVT, the procedures for allocating oil and gas produced at SVT, decommissioning responsibilities and the negotiation of tariff agreements.

The Amended SVTOA establishes a terminal management committee to, among other things, consider and approve programs, budgets and authorizations for expenditure. A majority of the decisions of the terminal management committee are made by an affirmative vote of at least 25% of the total SVT owners whose aggregate equity in SVT amounts to at least 70%. However, there are some decisions which require a higher threshold. Decisions to approve authorization for expenditure in excess of £2 million requires an affirmative vote of 85% of all SVT owners. Decisions relating to decommissioning and the removal of the SVT operator without cause require an affirmative special majority vote of at least 95% of all SVT owners. In addition, decisions including those relating to the disclosure of information outside of the confidentiality provisions, entering into agreements relating to tariffed production (which requires unanimous approval from all participating owners), the amendment of terminal regulations and the amendment of associated agreements requires unanimous approval. EnQuest Heather Limited has a 13.0% interest in SVT and thus cannot exercise unilateral or negative control over operations at SVT, unless the decision requires unanimity.

The SVT operator is EnQuest Heather Limited. Subject to the overall supervision of the terminal management committee, the operator has the exclusive right to carry out all operations and activities relating to the operation, maintenance and decommissioning of SVT and receives a small management fee for providing its services, in addition to amounts received from SVT owners to meet operating costs. The SVT operator is also responsible for the negotiation of all tariff agreements, on behalf of the SVT owners, with non-SVT owner third parties wishing to deliver production to SVT.

The Amended SVTOA was extended alongside a number of ancillary agreements in August 2025.

EnQuest also holds interests in and operates the Northern Leg Gas Pipeline and the Ninian Pipeline Systems.

REGULATION

Like other participants in the industry, we are subject to various laws and regulations administered by local, national, supranational and other government entities, and similar agencies in the United Kingdom and in other countries in which we operate. The oil and gas industry is subject to extensive laws in these jurisdictions that are subject to change. These laws have a significant impact on oil and gas exploration, development, production and marketing activities, and could potentially increase the cost of doing business, and consequently, affect profitability. Some of the legislation and regulation affecting the oil and gas industry in the United Kingdom and in other jurisdictions in which we operate carry significant penalties for failure to comply and can result in other liabilities and claims. While we may for any such liabilities incur fines, penalties or other sanctions, costs or claims, we believe that we are currently in substantial compliance with all material governmental laws and regulations affecting our business and maintain all material permits and licenses relating to our operations. Because the enactment of new laws affecting the oil and gas business is common and because existing laws are often amended or reinterpreted, we are unable to predict with certainty the future cost or impact of complying with such laws. We do not expect that any of these laws would affect us in a materially different manner than any other similarly sized oil company operating in the jurisdictions in which we conduct our business. See "*Risk factors—Risks relating to the oil and gas industry*."

From time to time, we receive notices and inquiries from regulatory authorities and others asserting that we are not in compliance with such laws and regulations. In some instances, litigation or regulatory intervention may ensue. In addition, individuals may initiate litigation against us. See "*Our business—Legal and arbitration proceedings*."

Oil and gas production regulations in the United Kingdom and in other jurisdictions in which we operate include laws related to location of wells, drilling and casing of wells, well production limitations; spill prevention plans; surface use and restoration; platform, facility and equipment removal; the calculation and disbursement of royalties; the plugging and abandonment of wells; bonding; permits for drilling operations; environmental, health and safety matters; and production, severance and ad valorem taxes. Oil and gas companies may encounter delays in drilling as a result of bureaucratic processes and requirements for obtaining relevant permits and other authorizations. Our operations are subject to regulations governing operation restrictions and conservation matters, including provisions for the unitization or pooling of oil and natural gas properties in straddling fields, the establishment of maximum rates of production from oil wells, and limiting flaring or venting of natural gas. These conservation laws have the effect of limiting the amount of oil we can produce from our wells and limiting the number of wells or the locations at which we can drill.

Below is a summary of certain key legal and regulatory regimes that we operate under in the United Kingdom, where the majority of our assets are located. For a discussion of certain risks associated with the legal and regulatory regimes in the countries under which we operate, see "*Risk factors—Risks relating to our business*."

United Kingdom

The Crown possesses all title and rights to petroleum located in the United Kingdom and its territorial waters, which includes the UKCS. Consequently, the legal regime established in the United Kingdom for the exploration for, and exploitation of, oil and gas provides for the transfer of the Crown's rights to explore for and exploit oil and gas to licensees.

The licensing system

Oil and gas exploration and production activities in the UKCS are governed primarily by the Petroleum Act 1998, as amended from time to time (the "**Petroleum Act**"). The Petroleum Act vests ownership of the petroleum resources in the U.K. sectors of the North Sea in the Crown and gives the secretary of state (the "**Secretary of State**") the authority to grant licenses that confer on the licensee for a limited time the right to search for and bore for and get petroleum in the areas governed by the license. Pursuant to the Energy Act 2016 (the "**Energy Act**"), the authority to grant such licenses, together with certain other functions, were transferred from the Secretary of State to the U.K. Regulator.

The Energy Act implements a number of recommendations from Sir Ian Wood's *UKCS Maximizing Recovery Review: Final Report*, including one of its key recommendations which was the creation of a new arm's-length body to regulate UKCS oil and gas recovery, with this body having a remit (and the necessary powers) to deliver its strategy (the "**OGA Strategy**"). The central obligation set out in the OGA Strategy, which has been

updated since it was first introduced, is to maximize the value of economically recoverable petroleum from U.K. waters and, in doing so, take appropriate steps to assist the Secretary of State in meeting the U.K's 2050 net zero target, including by reducing as far as reasonable in the circumstances greenhouse gas emissions from sources such as flaring and venting and power generation, and supporting carbon capture and storage projects. The U.K. Regulator exercises its powers within this context.

Companies are required to obtain a license prior to commencing any exploration or production activities. The current U.K. government is currently not permitting new offshore oil and gas exploration licenses to be issued, and will instead introduce new Transitional Energy Certificates, which will enable limited oil and gas production on or near existing fields. Historically, licenses have been awarded through competitive licensing rounds generally held every other year and conducted by the U.K. Regulator, although in exceptional circumstances licenses may be granted by the U.K. Regulator outside of the ordinary licensing rounds. The U.K. Regulator invites applications for each licensing round, which covers specific acreage. Licenses may be awarded to individual companies or to several companies collectively. "**Out-of-round applications**" may be made by a prospective licensee to the U.K. Regulator with compelling reasons such as urgency, temporary availability of a drilling rig or no prospect of competition. However, certain procedures must still be followed in respect of such applications according to the specified timeframe, including an invitation for applications being published in the London, Edinburgh and Belfast Gazettes at least 90 days in advance of the award of the relevant license.

The U.K. Regulator maintains discretion in the granting of licenses, which is exercised to ensure the maximum economic recovery of the resources and considers other factors as well, such as protection of the environment. Each license carries an annual rental charge due on the anniversary date of the grant of the license (except pre-20th round seaward production licenses, which were only due in their initial year). Rental fees are charged and determined by evaluating the number of square kilometers covered by the license. In addition, yearly levies are applied against UKCS licenses in order to provide the primary funding for the U.K. Regulator's activities. As part of the application process, the U.K. Regulator and the licensee agree a work program of exploration activity for the initial term of the license.

Offshore licenses

The U.K. Regulator awards different types of offshore licenses with the main distinction being seaward exploration licenses and seaward production licenses. Historically, a seaward production license could be a traditional license, a frontier license or a promote license. From the 29th Licensing Round in 2016, all new seaward production licenses have been classified as innovate license ("**Innovate Licenses**"), although previously awarded traditional, frontier and promote licenses may still be in force.

Seaward exploration license

The U.K. Regulator grants seaward exploration licenses to enable seismic surveys, shallow drilling and coring to 350 meters to be carried out in open acreage that is not covered by a production license. These licenses are non-exclusive in that other parties may also hold a seaward exploration license in respect of the same area and typically carry an initial three-year term with the possibility of extension for a further three years.

Seaward production license

A seaward production license is an exclusive license which enables the licensee(s) to search for, bore for and extract petroleum resources in the UKCS within the licensed area for a defined period of time. Separate consents are required prior to drilling and development. Each seaward production license runs for a maximum of three successive terms: the initial term, the second term and the third term. The licensee can only move on to the next term if certain requirements are met during the previous term. A seaward production license usually carries a total term of between 26 and 31 years, although it can be longer for a frontier license. The U.K. Regulator may allow a license to continue if the field is still producing at the end of the original term.

The conditions of seaward production licenses are predominantly contained in "model clauses" applicable at the time of the issue of the license, although additional restrictions or provisions may also be contained in the particular license. The model clauses govern matters such as the grant of the rights, the terms and conditions applicable to each of the three periods of a license and the requirement to relinquish a certain proportion of the license area, the regulation of work programs and development plans, measurement, records and access, working methods, pollution and training. The model clauses also give the U.K. Regulator the power to direct or restrict certain of the licensee's activities, including prohibiting a licensee from carrying out development or

production activities other than with the consent of the U.K. Regulator, or in accordance with a government-approved development plan. A license may be revoked by the U.K. Regulator for a number of reasons set out in the model clauses, including if the licensee fails to comply with the requirements of the license.

Under a seaward license, the U.K. Regulator approves the appointment of an operator. The operator under the license organizes or supervises all the development and production operations associated with the license. Licensees are also subject to the requirements of the Petroleum Act governing the decommissioning of facilities, including the requirement to produce and agree a decommissioning plan at a future date and, if required, to provide financial security for decommissioning costs.

Depending on the type of license, licensees in the UKCS are required to relinquish (or give up) a significant section of their license area after a prescribed period has elapsed. The purpose of this requirement is to ensure that operations conducted in the UKCS are conducted in as efficient and cost-effective manner as possible.

As mentioned above a seaward production license may be either a traditional license, frontier license, promote license or innovative license.

Traditional license

A traditional license has three terms, with the first two terms each lasting four years and the third term lasting 18 years. At the end of the first four-year term, the license will only move into the second four-year term if a specified work program (which may consist of an agreed combination of acquiring seismic data, processing seismic data, committing to drill a well or conducting other exploration or development activities), is completed and at least 50% of the acreage covered by the license has been relinquished. During the second four-year term, a development plan must be approved by the U.K. Regulator and all acreage outside the development area must be relinquished. If the development plan is not approved, the license will expire. The 18-year third term covers the producing life of the field. Applicants must prove their technical, environmental and financial capacity before being awarded a traditional license.

Frontier license

A frontier license usually has a six-year exploration phase and is designed to allow companies to screen large areas that are remote or otherwise difficult to explore. The initial term is split into a two-year period and a four-year period, with a special mandatory relinquishment of 75% of the acreage covered by a frontier license after the first two-year term and a further mandatory relinquishment at the end of the initial term of fifty percent of the remainder (leaving 12.5% of the original license area remaining under license). At the end of the initial term, the licensee must have fully completed the work program agreed for the license. This work program may include a “drill-or-drop” requirement (that is, if a decision to drill an exploration well is not taken, the license area must be relinquished). In exceptional circumstances, the U.K. Regulator may grant an extension to the initial two-year term, for example, in circumstances where uncharacteristically extreme weather conditions delay seismic acquisition during the first year. There is an additional variant to the frontier license designed for the West of Shetland environment providing a nine-year initial term.

Promote license

The promote license is designed to allow smaller companies to obtain a production license before having the necessary operating and financial capacities. Although a promote license is similar to a traditional license, the required financial, technical and environmental capacity and a firm commitment to drill a well to undertake an agreed equivalent substantive activity, need only be in place by the end of the second year of the license. At the end of this two-year period, the licensee faces a “drill-or-drop” decision on the license where the licensee must either submit a further work program to retain the license or relinquish the license. If the further work program is approved, the license continues for the remaining period of the two-year initial term, at which point there is a requirement to relinquish 50% of the acreage, and for a second four-year term on the same terms as a traditional license.

Offshore innovate license

The innovate license replaces several earlier types of seaward production licenses: the traditional, promote and frontier licenses. The innovate license offers greater flexibility in the durations of the initial and

second terms (which was the main difference from the older license types) and an applicant for an innovate license is able to propose the durations of the initial and second terms.

The initial term can now be subdivided into up to three phases, with the work program being correspondingly divided:

- Phase A is a period for carrying out geotechnical studies and geophysical data reprocessing;
- Phase B is a period for undertaking seismic surveys and acquiring other geophysical data; and
- Phase C is for drilling.

Phases A and B are optional and depend on the applicant's plans. Every work program must have at least a Phase C (just as a drilling commitment was the minimum work program before the innovate concept).

It remains the case that a license may only continue from the initial term into the second term if (among other things) the initial term work program has been completed and 50% of the initial acreage has been surrendered. Similarly, an innovate license may only continue from one phase into another if that part of the term work program associated with the earlier phase has been completed and if the licensee has committed to complete that part associated with the next. When continuing into phase C, the licensee must also demonstrate the technical and financial capacity to carry out the phase C part of the work program.

In special cases where an applicant doesn't propose any exploration at all and proposes to develop an existing field discovery or redevelop a field, a License may be awarded with no initial term; this is called a 'straight to second term' license. This option was also available before the innovate concept.

Innovate License term length:

Initial term:	Variable with maximum of nine years
Second term:	Four years
Third term:	18 years
Mandatory relinquishment at end of initial term:	50%

Licensing rounds

Most seaward production licenses are awarded through regular licensing rounds. Licenses are awarded pursuant to a review by the U.K. Regulator of each applicant's technical understanding of the acreage requested and the applicant's proposed work program. The 33rd Round officially opened on October 7, 2022 and closed for applications for licenses on January 12, 2023. This was the first licensing round to utilize the so-called Climate Compatibility Checkpoint, which is intended to ensure licenses awarded are aligned with wider climate objectives, including net zero emissions by 2050 and the UK's diverse energy supply.

On October 30, 2023 the U.K. Regulator announced the offer of 27 new licenses and the merger of 6 blocks into 5 existing licenses, in the first set of awards for the 33rd round. On January 31, 2024 the U.K. Regulator announced the Tranche 2 awards for the 33rd Round, comprising of 24 new licenses made up of 74 blocks/part blocks West of Shetland, the Northern North Sea and the Central North Sea. On May 3, 2024 the U.K. Regulator announced the Tranche 3 awards for the 33rd Round, comprising of 31 new licenses made up of 88 blocks/part blocks in the Central North Sea, East Irish Sea and the Southern North Sea. On May 24, 2024 the U.K. Regulator offered a license to Total Energies. A small number of licenses are still to be awarded pursuant to the 33rd Round and these have not yet been awarded due to a combination of environmental, regulatory and political factors.

Out-of-round licenses

In exceptional circumstances, the U.K. Regulator may formally invite an applicant to apply for a license outside of the regular licensing rounds. The applicant must convince the U.K. Regulator of its case for an out-of-round license. A case for an out-of-round license generally requires that the applicant show that waiting for the next licensing round would cause unnecessary delay to activities under an existing license, and that being awarded an out-of-round license would avoid that delay, or that broad competition for the license is not feasible during a licensing round. The U.K. Regulator will not award out-of-round licenses for pure exploration or where an applicant simply prefers not to wait for the next licensing round. If the U.K. Regulator formally invites an applicant to apply for an out-of-round license, the applicant completes the application in the same manner as applying for a license during a licensing round.

License holders

A license may be held by a single license holder or by a number of entities collectively. We hold our interests under the majority of our license with other parties. However, in such cases, each of these entities' obligations, responsibilities and liabilities under a license will be joint and several.

There are no restrictions imposed under the Petroleum Act regarding the nationality of private sector companies to whom licenses are granted (although certain residency criteria do apply). Also, there is no direct state participation in petroleum operations under license. Licenses are designed so as to ensure the most effective and efficient exploitation and exploration of petroleum by the relevant licensees. One of the primary mechanisms used in a license to focus licensees on efficiently discharging their license obligations is by way of requiring licensees to relinquish a certain percentage of the relevant license area at the end of the exploration period.

License terms

Licenses are valid for a sequence of periods, called terms. Each license will expire automatically at the end of the relevant term unless the licensee has satisfied the requisite conditions to allow it to enter into the next subsequent term under the relevant license. Normally those terms fall into the following categories: the exploration term, the appraisal and development term and the production term.

The exploration term

The exploration period normally lasts between four and six years. A license will expire at the end of the exploration period unless the work program agreed between the U.K. Regulator and the licensee(s) in respect of the exploration period has been completed. At that time, the licensee(s) must also relinquish a prescribed proportion of the relevant license area.

The appraisal and development term

The appraisal and development period normally lasts between four and nine years. The license expires at the end of this period unless a development plan for the relevant license area has been submitted by the licensee and approved by the U.K. Regulator.

The production term

The production period normally lasts 18 years. However, the U.K. Regulator may, acting in its own discretion, extend this term if production is continuing at the date of expiry of the license.

Transfer of a license interest

A licensee may only transfer their interest in a license with the prior written approval of the U.K. Regulator. If a license is transferred without such consent the U.K. Regulator may revoke the relevant license or reverse the assignment.

This requirement also applies to assignments between affiliates and related bodies corporate. In order to obtain such consent, the licensee must apply to the U.K. Regulator using the U.K. Regulator's online e-license administration system (known as "**PEARS**"). The U.K. Regulator will then consider the technical and financial capacity of the proposed new licensee, implications of the prospective assignment or decommissioning of relevant facilities and the relevant company's track record and the parent company's provision of any guarantees. However, the U.K. Regulator will not provide its consent where the relevant assignment would result in the license having no approved operator. Any consent granted will be conditional upon the instrument effecting such assignment being substantially in a form approved by the U.K. Regulator.

In order to hold a license, the licensee must demonstrate its financial capacity to meet its expected commitments, liabilities and obligations and must not be insolvent or a company which appears to be in danger of becoming insolvent. The licensee may be required to furnish the U.K. Regulator with its latest annual report and accounts together with those of its ultimate parent company in order to demonstrate that it can satisfy these requirements. In addition, a licensee must submit a statement of safety and environmental competence and capability, which evidences (inter alia) that a licensee has the appropriate management and control systems in place to deal with environmental or emergency safety issues arising during the course of activities.

The U.K. Regulator may also require trading profit and loss forecasts for the following five years and details, if applicable, of how any deficit may be met by the relevant companies.

Licensees may surrender a license or part of the acreage covered by it. However, surrendering of all or part of a license is not allowed where the surrender would be a "non-standard" surrender, meaning the surrender of irregular shapes or where it leaves a very small licensed area, or, if the surrender would prevent fulfillment of a license obligation.

Indirect transfers of license interests by way of a change of control of the licensee are also regulated. A licensee must apply in writing to the U.K. Regulator for consent to a change of control at least three months before the date on which it intends the change to occur. Any such consent may have conditions attached and a change of control that takes place either without such consent or in breach of the conditions could lead to revocation or partial revocation of the license.

License breach

The U.K. Regulator has the power to issue a sanction notice to any person that is in breach of a term or condition of an offshore license. If a license is held by more than one company, the sanction notice may be issued to only one of the companies, or to some or all of them jointly. It will depend on the nature of the license breach. If the U.K. Regulator proposes to issue a sanction notice as a result of an investigation, it must issue a sanction warning notice before issuing a proposed sanction notice, setting out the alleged breach of the license and allowing the recipient to make representations in relation to those issues within a specified time. In July 2025 the U.K. Regulator introduced its policy on publication of company-specific information which sets out the general approach for information it expects to publish, including naming companies subject to an investigation prior to issue of a formal sanctions notice.

There are four categories of sanction notices, namely:

Enforcement notices

These inform the recipient of the alleged breach and provide a prescribed time within which the recipient must comply, including any specific measures to be taken by the recipient.

Financial penalty notices

These impose a financial penalty payable to the U.K. Regulator of up to £1 million.

Revocation notices

These revoke the license of the recipient following a failure to comply with specified requirements imposed on the licensee in that capacity. If such a notice is only given to one licensee in relation to a license held by several companies, the license is only revoked in relation to the recipient.

Operator removal notices

These require the recipient license holders to remove the operator from its position following a failure to comply with specified petroleum requirements.

Other consents

Activity pursuant to U.K. offshore licenses also requires various other approvals from the U.K. Regulator, DESNZ, the U.K. Offshore Petroleum Regulator for Environment & Decommissioning ("**OPRED**") which forms part of DESNZ and other government departments for a number of license-related activities. Failure to procure such approvals may result in the relevant activity being delayed or prevented altogether.

Decommissioning in the UKCS

The Petroleum Act (as amended by the subsequent Energy Acts) governs decommissioning responsibilities in the UKCS. In addition, the United Kingdom's international obligations on decommissioning are governed principally by the 1992 Oslo and Paris Convention for the Protection of the Marine Environment of the North East Atlantic ("**OSPAR**") and the earlier United Nations Convention on the Law of the Sea 1982

("**UNCLOS**"). The OSPAR regime is a regional convention and is additional to the United Kingdom's obligations under international law. Agreement on the regime to be applied to the decommissioning of offshore installations under OSPAR was reached at a meeting of the OSPAR Commission in July 1998 (the "**OSPAR Decision 98/3**"). The Petroleum Act complies with many of the obligations under the OSPAR regime.

The U.K. Regulator works alongside OPRED and DESNZ in assessing decommissioning programs on the basis of cost, future alternative use and collaboration. OPRED is the competent authority for decommissioning in the UKCS and is the responsible authority for ensuring that the requirements under OSPAR recommendations or actions are applied to decommissioning programs.

Decommissioning obligations under the Petroleum Act

Prior to decommissioning an installation, the Petroleum Act requires that decommissioning programs be approved by OPRED using best-available techniques to achieve best environmental practice.

Under the Petroleum Act, a party will incur liabilities in respect of the decommissioning of installations and pipelines following the service by DESNZ of a section 29 notice on that party under the Petroleum Act. At any time following submission of a field development plan, DESNZ can issue a section 29 notice requiring that a costed decommissioning program be provided by any of the following parties:

- the license holder;
- a parent company or associated companies of a license holder;
- any licensee who transferred an interest in the license to another party without the consent of the U.K. Regulator;
- the field operator;
- the parties to the field joint operating agreement or similar agreement; and
- any person owning an interest in an installation (but generally only where sufficient financial provision has not otherwise been made with regard to decommissioning).

The parties on whom the notice is served are jointly liable to submit a decommissioning program and once a decommissioning program has been approved by OPRED, it becomes a joint and several obligation upon the persons who submitted it to ensure that it is carried out. Where the Secretary of State deems that such a party is unlikely to be able to carry out any decommissioning obligations placed upon it, it is empowered to require the provision of appropriate financial security to cover those decommissioning costs.

In addition to the parties set out above, under section 34 of the Petroleum Act, DESNZ may use a "claw-back" power to impose decommissioning obligations on anyone who, at any time since the issue of the first section 29 notice for the installation, could have been served with such a notice.

The U.K. government's guiding principles on decommissioning

Installations

The underlying presumption on decommissioning is that, in accordance with OSPAR Decision 98/3, all offshore installations will be re-used, recycled or disposed of on land; all topsides of all installations must be returned to shore; all steel installations with a jacket weight of less than 10,000 tons must be completely removed for re-use, recycling or final disposal on land; for steel installations with a jacket weight greater than 10,000 tons, it is possible to consider whether the footings of the installation may remain in place but only with a derogation from the OSPAR requirements; for concrete installations, it is possible to consider whether they should be left wholly or partially in place but only with a derogation from the OSPAR requirements; all installations installed after February 9, 1999 must be completely removed; a decommissioning program is required in respect of all offshore installations; any exceptions or exemptions are individually assessed in accordance with the provisions of OSPAR Decision 98/3; and each decommissioning program is subject to full and open consultation and the section 29 notice will contain a list of organizations to be consulted near the time of decommissioning. Such organizations include fishermen's organizations and other interested bodies.

Pipelines

While OSPAR Decision 98/3 does not apply to pipelines and there are no international guidelines relating to decommissioning of pipelines, the Petroleum Act provides for requirements in this regard. In addition, the United Kingdom's guiding principles on decommissioning provide that:

- decommissioning proposals for pipelines will be considered on an individual basis; and
- all feasible decommissioning options should be assessed including removal, burial or trenching to an adequate depth or just leaving in place.

Residual Liability

The parties who own an installation or pipeline at the time of its decommissioning will normally remain the owners of assets and any residual liability remains with those parties in perpetuity. In addition, parties with a duty to secure that the decommissioning program is carried out will remain liable for any conditions attached to OPRED's approval of the program. Any remains of installations or pipelines will be subject to monitoring at suitable intervals and may require maintenance or remedial action in the longer term. There will also be a need to ensure that fishing and navigation are not disrupted.

*The International Maritime Organization ("**IMO**") Guidelines and Standards for the Removal of Offshore Installations and Structures on the Continental Shelf and in the Exclusive Economic Zone (the "**IMO Guidelines**")*

The IMO is the competent international organization for the purposes of UNCLOS, governing the United Kingdom's international obligations in respect of decommissioning of offshore installations. The IMO Guidelines prescribe the minimum global standards to be applied to decommissioning offshore installations and structures to ensure the safety of navigation. Although the U.K. government accepted OSPAR Decision 98/3, certain aspects of the IMO Guidelines remain relevant, particularly in terms of identification, survey and navigational aids.

Determination of decommissioning timing

The determination of decommissioning timing is influenced by a number of factors such as increased recovery from existing fields, new exploration and tie-back of new fields, the uncertainty about the future fiscal and regulatory regimes, the long-term trends in oil and gas prices as well as the reduction of decommissioning costs and future technical innovations.

If a licensee is successful in bringing further reserves into production from both existing and new fields, decommissioning could be delayed by 10-15 years in many infrastructure systems. Extending the life of infrastructure allows more reserves to be recovered from both existing fields and any developments arising from new exploration drilling (including fields to which the licensee does not have any direct interest in).

Environmental regulations

Our operations in the UKCS are subject to numerous international and national laws, regulations and other requirements relating to HSE, including those governing discharges of pollutants to air and water; the management of produced water and wastes; and the clean-up of contaminated sites. These HSE laws and regulations apply at various stages, including before oil and gas production activities commence, during exploration and production activities and during and after decommissioning and are subject to change.

Before a U.K. licensing round begins, the U.K. Regulator typically consults with public bodies that have responsibility for the environment. Applications for production licenses must include a statement of the general environmental policy of the operator in respect of the contemplated license activities, a summary of the operator's management systems to implement the environmental policy and confirmation as to how those systems will be applied to the proposed work program.

Additionally, the Offshore Petroleum Production and Pipelines (Assessment of Environmental Effects) Regulations 1999 (as amended) require the U.K. Regulator to exercise its licensing powers under the Petroleum Act in such a way to ensure that an environmental assessment is undertaken and considered before consent is given to certain projects.

The following is a non-exhaustive list which includes some of the main legislation and statutory instruments applicable to the disposal and discharge of substances into the U.K. environment:

- Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005;
- Offshore Petroleum Activities (Oil Pollution Prevention and Control) (Amendment) Regulations 2011;
- Offshore Chemicals Regulations 2002;
- Offshore Chemicals (Amendment) Regulations 2011;
- Merchant Shipping (Oil Pollution Preparedness, Response & Co-operation Convention) Regulations 1998;
- Offshore Installations (Emergency Pollution Control) Regulations 2002;
- Food and Environment Protection Act 1985;
- Deposits in the Sea (Exemptions) Order 1985;
- Offshore Combustion Installations (Pollution Prevention and Control) Regulations 2013;
- Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001;
- Environmental Protection (Controls on Ozone Depleting Substances) Regulations 2011;
- Energy Act 1976;
- Fluorinated Greenhouse Gases Regulations 2015;
- Greenhouse Gases Emissions Trading Scheme Regulations 2012;
- Marine and Coastal Access Act 2009;
- Conservation of Offshore Marine Habitats and Species Regulations 2017; and
- Energy Act 2023.

Under these statutes and regulations, an offshore operator may require a permit/consent with respect to discharges into the marine environment, subject to a number of exemptions. Both the permits/consents and, if applicable, exemptions, are subject to conditions that must be met for the permit/consent or exemption to continue to operate. Non-compliance with the requirements of the legislation or conditions of a permit/consent may give rise to criminal offences or civil monetary penalties.

In the European Union, the Directive on Environmental Liability with Regard to the Prevention and Remedying of Environmental Damage (2004/35/EC), or the Environmental Liability Directive, imposes strict liability on an operator for environmental damage or imminent threat of environmental damage caused by activities listed in Annex III thereof, which include most offshore oil and gas operations. The scope of the Environmental Liability Directive, which applies in the U.K., was extended by EU Directive 2013/30/EU on the Safety of Offshore Oil and Gas Operations, or Offshore Directive, to include all marine waters in the EU including the UKCS. The Offshore Directive also requires Member States to ensure that licensees are financially liable for remediation of environmental damage (as defined under the Environmental Liability Directive) caused by offshore oil and gas operations carried out by, or on behalf of, the licensee or operator. In September 2015, the European Commission published a report in furtherance of this directive which analyzed (i) parties' liability types of damage and loss in offshore oil and gas accidents; (ii) how to ensure that liable parties have sufficient financial capacity to provide the requisite compensation for the damage and loss they are liable for; and (iii) how compensation should be disbursed so that it reaches legitimate claimants quickly.

Tax regulations

The following paragraphs are not intended to be exhaustive and are intended as a general guide only. They are based on current U.K. tax law and HMRC published practice (which is subject to change, possibly with retrospective effect) as at December 31, 2025.

Companies engaged in activities relating to the production of oil and gas in the U.K. and in the UKCS are subject to an oil taxation regime which generally consists of the following elements: ring fence corporation tax ("**RFCT**"), a supplementary charge ("**SCT**"), Petroleum Revenue Tax ("**PRT**") and the Energy Profits Levy ("**EPL**").

Ring fence corporation tax

With some modifications (for example, relating to capital allowances and losses), this is the normal U.K. corporation tax applicable to U.K. companies, but it is subject to a "ring-fence." RFCT is charged at a rate of 30% (rather than the prevailing rate of corporation tax of 25% (from April 1, 2023) applicable to non-oil and gas

businesses). This, however, is balanced by 100% first year allowances which are available for almost all capital expenditure (such allowances are largely equivalent to "full capital expensing" for non-oil and gas businesses introduced April 2023). The ring-fence prevents taxable profits from oil and gas extraction in the U.K. and from the UKCS being reduced by losses from other activities by treating ring-fenced activities as a separate trade. However, losses from a ring-fenced trade can be relieved against profits from a non-ring fenced trade (as well as against ring-fenced income), as long as, but for the existence of the ring-fence, the non-ring fenced and ring-fenced activities would comprise a single trade.

Interest paid by a company is not deductible against ring-fenced profits unless it is payable in respect of a loan the proceeds of which were used in carrying on oil extraction activities or in acquiring oil rights other than from a connected person.

The following activities generally fall within the ring-fence:

- hydrocarbon extraction, namely:
- searching for hydrocarbons in the UKCS;
- extracting hydrocarbons at any place in the UKCS under a license held by the company;
- transporting hydrocarbons to land; and
- effecting the initial treatment or storage of hydrocarbons; and
- the acquisition, enjoyment or exploitation of rights to hydrocarbons to be extracted at any place in a designated area in the UKCS.

Aggregated capital gains and losses on material disposals (*i.e.*, disposals of interests in oil to be won from a field and/or field assets) are also confined within the ring-fence. In certain circumstances where the consideration received for such disposals is reinvested in acquiring ring-fenced assets, a company may be able to claim reinvestment relief (*i.e.*, the capital gain will not be a taxable gain).

A number of capital allowances may be available to companies engaged in activities relating to oil and gas production in the U.K. and the UKCS. These may include research and development allowances, enhanced mineral extraction allowances and enhanced plant and machinery allowances.

Where companies incur ring fence tax losses, ring fence expenditure supplements ("**RFES**") may apply to increase the tax losses at a rate of 10% per annum for up to 10 accounting periods. The original legislation restricted this relief to six accounting periods and there are detailed rules which operate to reduce the quantum of losses which can be increased by RFES in the additional four accounting periods. EnQuest ceased claiming RFES in respect of its ring-fence losses from the end of 2024.

The RFCT regime allows ring-fence companies to carryback losses which arise from decommissioning costs beyond the standard loss carry back periods permitted for non-oil and gas companies. Decommissioning losses can be carried back and relieved against ring fence profits back to April 17, 2002.

Supplementary charge

Since April 2002 there has been an additional charge on a company's adjusted ring-fenced profits. Adjusted ring-fence profits for SCT are a company's ring fence profits chargeable to corporation tax but excluding the costs of debt finance. A company's adjusted ring fence profits may be reduced by investment allowances (see next section). The rate of SCT is currently 10% for accounting periods commencing on or after January 1, 2016.

Investment allowance

The Investment Allowance ("**IA**") was introduced in respect of qualifying investment expenditure incurred on or after April 1, 2015. The allowance was introduced with the intention of simplifying the existing field allowance regime (since repealed).

The allowance is equal to 62.5% of qualifying investment expenditure incurred by a company in relation to a field. IA is only activated by reference to field production income. Qualifying investment expenditure includes both capital and operating expenditure which meets the definition of qualifying expenditure in the legislation. The IA reduces the adjusted profits subject to the supplementary charge.

Petroleum revenue tax

PRT is an additional level of taxation on profits derived from oil and gas production in U.K. and the UKCS. It is a "field-based" tax charged on profits of participants arising from individual oil fields which were given development consent prior to March 16, 1993 (not on aggregate profits arising from the entire business of the relevant participator's company). In addition, oil fields which have been decommissioned and are subsequently redeveloped are now removed from the charge to PRT.

The rate of PRT prior to January 1, 2016 was 50% but effective from January 1, 2016 the rate was reduced to 0%. It is calculated on a statutory basis set out in the Oil Taxation Act 1975 ("**OTA**") by reference to six-month periods beginning on July 1 and January 1 of each year rather than by reference to company accounts.

Energy profits levy

EPL was introduced, from May 26, 2022, as an additional tax on profits derived from UK oil and gas activities. The purpose of EPL was to tax extraordinary profits arising to oil and gas companies operating in the UK during a period of oil price volatility.

EPL is charged at a rate of 38% (previously 35% prior to November 1, 2024). The levy applies to a company's RFCT profits (meaning capital allowances, including 100% first year allowances are taken into account) but with a number of adjustments, such as financing and decommissioning costs, are not deductible and RFCT / SCT losses are not relievable against levy profits (EPL has its own loss regime). The EPL currently provides a decarbonization investment allowance (*i.e.*, a reduction against levy profits) in respect of qualifying decarbonization expenditure. The allowance is equal to 66% of qualifying expenditure. Unlike SCT, there is no requirement to "activate" the allowance before it can be utilized. Prior to November 1, 2024, EPL also provided for an investment allowance of 29% on normal capital expenditure and certain qualifying operating expenditure. This allowance was removed in the 2024 Autumn Statement and subsequent Finance Act.

EPL is a temporary tax and is currently due to expire by March 31, 2030, but will end sooner if average oil and gas prices fall below thresholds set out in the Energy Security Investment Mechanism ("**ESIM**"), introduced in 2023. The ESIM threshold prices are currently $76.12 per barrel for oil and £0.59 per therm for gas. The ESIM thresholds were originally based on a 20-year average to the end of 2022 but have been adjusted annually thereafter (from March 1 of each year, by the preceding December's Consumer Prices Index figure).

The most recent changes to the EPL regime were announced in the 2024 Autumn Statement, being:

- Increase in the rate of EPL from 35% to 38%;
- Removal of standard investment allowances; and
- The extension of EPL to March 31, 2030.

These changes have all since been enacted. In the U.K. Chancellor's 2025 Autumn Statement, it was announced that the EPL would end on March 31, 2030 (or earlier, if oil and gas prices fall below a certain threshold) and would be replaced by a permanent Oil and Gas Price Mechanism, a revenue-based tax of 35% when prices are high.

Malaysia

The licensing system

With regard to our operations in Malaysia, upstream petroleum activities in Malaysia are primarily regulated by PETRONAS, which derives its powers from the Petroleum Development Act 1974 and the Petroleum Regulations 1974. Pursuant to the terms of the PM8 (Extension) PSC, PETRONAS regulates the petroleum operations through its approval of well locations, area and field development plans, production operations, annual work programs and budget, and procurement of goods and services.

Decommissioning Regulations

In Malaysia, PETRONAS regulates decommissioning of oil and gas structures/facilities through PSCs and PETRONAS's Guidelines for Decommissioning of Upstream Installations as part of its Procedure and

Guidelines for Upstream Activities. Our obligation under the PM8 (Extension) PSC includes the decommissioning of all assets as approved by PETRONAS under the PM8 (Extension) PSC as well as an annual contribution of a decommissioning fund for the PM8 (Extension) PSC assets.

Vietnam

The licensing system

With regard to our operations in Vietnam, upstream petroleum activities are primarily regulated by the Ministry of Industry and Trade ("**MOIT**") and Vietnam National Industry – Energy Group (PetroVietnam), which derives their powers mainly from the Law on Petroleum 2022.

Block 12W PSC, signed between PetroVietnam and the Joint Venture partners, sets out all rights & obligations for activities of exploration, appraisal, development, and production of petroleum in Block 12W, and the Joint Venture operator and partners require PetroVietnam/MOIT's endorsement and/or approval on key matters with certain thresholds.

Decommissioning Regulations

In Vietnam, decommissioning of oil and gas structures and facilities is regulated by the Government and through the PSC. Block 12W contractor's obligation set out under PSC includes the decommissioning of all facilities that are presented in the Abandonment Plan prepared by the Block 12W operator and approved by the MOIT. The Joint Venture makes funding contribution to the abandonment account as required under the approved Abandonment Plan and Block 12W Decommissioning and Abandonment funding Agreement.

MANAGEMENT

Board of directors

The persons set forth below are our current members of the board of directors. The address for each of our directors and executive officers is EnQuest PLC, 2nd Floor, Charles House, 5-11 Regent Street, London SW1Y 4LR, United Kingdom.

Following shareholder approval at the 2024 Annual General Meeting, Jonathan Copus joined the Board as an Executive Director, with Rosalind Kainyah MBE and Marianne Daryabegui joining the Board as Non-Executive Directors. As previously announced, Salman Malik, Rani Koya and Liv Monica Stubholt stepped down as Directors at the 2024 Annual General Meeting.

Name	Age	Position	Type of director	Date appointed to the Board
Amjad Bseisu	62	Chief Executive Officer	Executive Director	February 22, 2010
Gareth Penny	63	Non-Executive Chair	Non-Executive Director	December 6, 2022
Jonathan Copus	53	Chief Financial Officer	Executive Director	February 1, 2024
Farina Khan	54	Senior Independent Director	Non-Executive Director	November 1, 2020
Michael Borrell	63	Non-Executive Director	Non-Executive Director	September 5, 2023
Rosalind Kainyah	68	Non-Executive Director	Non-Executive Director	May 30, 2024
Marianne Daryabegui	61	Non-Executive Director	Non-Executive Director	May 30, 2024

Mr. Amjad Bseisu holds a Bachelor of Science Honors degree in Mechanical Engineering and a Master of Science and Doctor of Engineering degree in Aeronautical Engineering. From 1984 to 1998, Mr. Bseisu worked for the Atlantic Richfield Company ("**ARCO**"), eventually becoming president of ARCO Petroleum Ventures and ARCO Crude Trading Inc. In 1998, Mr. Bseisu founded and was the Chief Executive of Petrofac Energy Developments International Limited, the operations and investment business for Petrofac Limited, which organically grew an upstream and midstream oil and gas business in South East Asia, the United Kingdom and North America. Mr. Bseisu was also chairman of Enviromena Ltd., a solar power engineering company in the Middle East and Northern Africa region, until the entity's sale in 2017. In 2010, Mr. Bseisu formed EnQuest plc, having previously been a founding non-executive chairman of Serica Energy plc and director of Stratic Energy Corporation. Mr. Bseisu was British Business Ambassador for Energy from 2013 to 2015. Other principal external appointments include chairman of the World Economic Forum Independent Oil and Gas Community since 2016 and chairman of The Amjad and Suha Bseisu Foundation. Mr. Bseisu is a member of the Governance and Nomination Committee.

Mr. Gareth Penny holds a Master of Philosophy, Politics & Economics degree from the University of Oxford. Mr. Penny joined EnQuest in December 2022, having previously chaired a number of public and private boards. He is currently the chairman of Ninety One plc and Ninety One Ltd and was previously chairman of Norilsk Nickel, a Russian diversified mining and metals company. Mr. Penny also served on the board of Julius Baer Group for 12 years. He has extensive experience in extractive industries, having spent 22 years with De Beers and Anglo American, the last five of which he was group Chief Executive Officer of De Beers. Mr. Penny is also chair of the Governance and Nomination Committee and a member of the Remuneration and Social Responsibility Committee.

Dr. Jonathan Copus holds a PhD in Deepwater channel and slope systems from the University of Cambridge. Mr. Copus joined EnQuest in December 2023 as Chief Financial Officer Designate, becoming Chief Financial Officer on February 1, 2024. Mr. Copus has a technical background in geology and geoscience alongside ten years' capital markets experience. He has been an energy analyst and co-authored an industry handbook, "Oil and Gas for Beginners." Previously, Mr. Copus spent four years as Chief Financial Officer of Salamander Energy plc, a production and development business focused in South East Asia. He was also Chief Executive Officer of Getech Group plc for seven years, where he repositioned and recapitalized the business as a data and analytics specialist.

Ms. Farina Khan holds a Bachelor of Commerce degree from the University of New South Wales, Sydney, Australia and completed the Advanced Management Program at Harvard Business School, USA. Ms. Khan joined EnQuest in 2020. She is a Fellow of the Institute of Chartered Accountants Australia and New Zealand. Ms. Khan started her career in 1994 with Coopers & Lybrand, Australia, before returning to Malaysia in 1997 to join PETRONAS where she held various senior positions. Ms. Khan was Chief Financial Officer of PETRONAS Carigali Sdn. Bhd., one of the largest subsidiaries of PETRONAS with operations in over 20

countries and has also been Chief Financial Officer at PETRONAS Exploration and Production. From 2013, Ms. Khan was the Chief Financial Officer of PETRONAS Chemical Group Berhad, the largest listed entity of PETRONAS. Ms. Khan left PETRONAS in 2015 to pursue non-executive opportunities. Ms. Khan currently sits on the Boards of the following Malaysian listed companies: KLCC Property Holdings Berhad, Lianson Fleet Group Bhd (formerly known as Icon Offshore Bhd) and PETRONAS Gas Bhd. Ms. Khan also currently sits on the boards of YAPEIM Holdings Sdn Bhd and KLCC REIT Management Sdn. Bhd. Ms. Khan is chair of the Audit Committee and a member of the Remuneration and Social Responsibility Committee and Governance and Nomination Committee.

Mr. Michael Borrell joined EnQuest in September 2023 and holds a BA, MA and MSc in Chemical Engineering from Emmanuel College Cambridge. Mr. Borrell is an experienced operator of large-scale Exploration and Production assets, having worked with TotalEnergies for over 35 years, including managing the integration of the Maersk Oil business. His international career with TotalEnergies spanned Europe, Asia, North and South America, culminating in his appointment as Senior Vice President of North Sea and Russia and as Denmark country chair in 2020. Between 2015 and 2021, Mr. Borrell was a non-executive director of Novatek OAO, which was listed on the London Stock Exchange and Moscow Stock Exchange. Mr. Borrell is chair of the Sustainability and Risk Committee and a member of the Audit Committee and Governance and Nomination Committee.

Ms. Rosalind Kainyah holds a Master of Law degree from University College, University of London. Ms. Kainyah joined EnQuest in May 2024. Ms. Kainyah has over 30 years of international, legal, operational, executive and board experience in a variety of sectors, including energy, oil and gas, mining, infrastructure, private equity, financial services and manufacturing. She has worked across Africa, Europe, the Americas, Asia and the South Pacific for companies and organizations, including Linklaters, Anglo American, De Beers, Tullow Oil plc, the United Nations Environment Programme, University of Oxford's Environmental Change Unit and ERM. She is the founder and director of Kina Advisory Limited and a non-executive director of discoverIE plc, Gem Diamonds Limited, Flamingo Group (Chair of Sustainability Committee) and WE Soda, a private company. Ms. Kainyah is chair of the Remuneration and Social Responsibility Committee and a member of the Sustainability and Risk Committee.

Ms. Marianne Daryabegui joined EnQuest in May 2024 and holds a Master of Corporate Finance and Capital markets degree from Sciences Po, Paris and a Master of Business and Tax Law degree from Panthéon-Assas University Paris. She is a seasoned capital markets adviser who has focused on oil and gas throughout her career, firstly in-house at Total, then as an adviser at BNP Paribas. Backed by her experience in corporate transactions, capital markets and structured finance, Ms. Daryabegui joined the banking sector and has since advised multiple oil and gas companies. She co-led the M&A Energy and Natural Resources practice at Natixis and was also formerly Head of Natural Resources at BNP Paribas. She was appointed as Chief Financial Officer of Lithium de France in 2021 and led the €44 million Series B financing of the company. Her experience includes the listing of Arverne Group on Euronext through its merger with Transition SPAC. She is currently the Head of Financing, Capital Markets and M&A of the Arverne Group. Ms. Daryabegui is a member of the Audit Committee and the Sustainability and Risk Committee.

Executive Committee

The persons set forth below are our current members of the executive committee or persons who regularly participate in Board Committees.

Name	Age	Position
Amjad Bseisu	62	Chief Executive Officer
Jonathan Copus	53	Chief Financial Officer
Radzif Ahmed	59	General Manager, South East Asia
Paul Massie	44	Legal and Commercial Director
Claire Scrimgeour	43	Human Resources Director, North Sea
Ian McKimmie	53	Interim General Manager, North Sea
Kate Christ	47	Company Secretary

Mr. Radzif Ahmed joined EnQuest in 2015 as Head of Commercial and Strategy for EnQuest Petroleum Developments Malaysia Sdn Bhd, and in 2022 became the General Manager and Country Head for Malaysia, before assuming the role of General Manager, South East Asia in 2025. Mr. Ahmed has a Diploma in Civil Engineering from the Institute Technology Mara, Malaysia and a B.Eng. with Honours in Civil Engineering from

the University of Liverpool. He also holds a Post-Graduate Diploma in business administration from Strathclyde Graduate Business School.

Mr. Paul Massie joined EnQuest in October 2011 as Senior Legal Advisor, and has served as Legal Manager, Corporate Development Manager and Corporate Development & New Energy Director, before assuming the role of Legal and Commercial Director in December 2024. Mr. Massie has an LLB in law with accounts (first class) and a Diploma in legal practice from the University of Aberdeen. He has responsibility for the commercial, legal, risk and compliance affairs of the company and holds the office of Chief Risk Officer. He is also a member of the Excom.

Mrs. Claire Scrimgeour joined EnQuest PLC in 2012. progressing through various roles within the Human Resources team before becoming Human Resources Director, North Sea in July 2024. Prior to joining EnQuest, Claire completed a graduate program within the retail industry, focusing on Commercial Management and Human Resources and has worked as a management consultant within the recruitment industry. She has an MA in International Business and Languages and is a member of the Chartered Institute of Personnel Development.

Mr. Ian McKimmie joined EnQuest in September 2012 as a Senior Completion Engineer. Over the years, he advanced through various roles, becoming the Well Delivery Manager in 2018. In 2023, he was appointed Corporate Head of HSE, and in 2024, he took on the role of Director of HSE and Wells. Mr. McKimmie holds a First-Class Honours degree in Mechanical Engineering and is a Chartered Member of the Institution of Mechanical Engineers.

Ms. Kate Christ joined EnQuest in 2016 and became Company Secretary in 2024. She has a MSc in Corporate Governance and is a Fellow of the Chartered Governance Institute and over the past 17 years has worked in governance roles in a variety of industries. She started her career in the charitable sector, has worked within government departments and, prior to joining EnQuest, worked for FTSE 100 and FTSE 250 financial service companies.

Board committees

Sustainability and Risk Committee

In the year ended December 31, 2023, the Safety, Sustainability and Risk Committee merged with the Technical and Reserves Committee and became the Sustainability Committee. In May 2024, it was renamed the Sustainability and Risk Committee. The Sustainability and Risk Committee undertakes in-depth analysis of specific risks in relation to the company and supports the implementation and progression of the Group's Risk Management Framework. It conducts reviews of key non-financial risks not reviewed within the Audit Committee and undertakes such other actions as the Board may require in relation to technical, reserves, business development, HSE, risk and sustainability issues.

The following table sets forth the current members of the Sustainability and Risk Committee.

Name	Position	Type
Michael Borrell	Chair	Non-Executive Director
Rosalind Kainyah	Member	Non-Executive Director
Marianne Daryabegui	Member	Non-Executive Director

Audit Committee

The purpose of the Audit Committee is to assist the board of directors in fulfilling its responsibilities of oversight and supervision of, among other things, the company's financial reporting, the Company's internal control procedures and risk management systems and the effectiveness of the external and internal audit activities. The Audit Committee meets at least three times a year at appropriate times in our reporting and audit cycle and more frequently if required.

The following table sets forth the current members of the Audit Committee.

Name	Position	Type
Farina Khan	Chair	Non-Executive Director
Michael Borrell	Member	Non-Executive Director

Marianne Daryabegui.....	Member	Non-Executive Director

Governance and Nomination Committee

The Governance and Nomination Committee reviews the size, structure and composition (including the skills, experience, independence, knowledge and diversity) of the Board and its Committees in order to recommend changes to the Board and to ensure the orderly succession of executive, non-executive directors and senior management. It also considers the governance of the Company and adherence to the Corporate Governance Code.

The following table sets forth the current members of the Governance and Nomination Committee.

Name	Position	Type
Gareth Penny.....	Chair	Non-Executive Director
Amjad Bseisu.....	Member	Executive Director
Farina Khan	Member	Non-Executive Director
Michael Borrell.....	Member	Non-Executive Director

Remuneration and Social Responsibility Committee

The main responsibilities of the Remuneration and Social Responsibility Committee are to set the compensation and benefits for the Chairman and the company's executives; make recommendations to the Board, and that of shareholders, on the design of long-term share incentive plans and the grant of awards to executives under such plans; make recommendations to the Board on social responsibility matters and determine the policy and scope for pension rights and any compensation payments and ensuring compliance with the Corporate Governance Code.

The remuneration of the non-executive directors is determined by the chair and the other executive directors outside the framework of the Remuneration and Social Responsibility Committee.

The following table sets forth the current members of the Remuneration and Social Responsibility Committee.

Name	Position	Type
Rosalind Kainyah.....	Chair	Non-Executive Director
Gareth Penny.....	Member	Non-Executive Director
Farina Khan	Member	Non-Executive Director

Code of conduct

The EnQuest Code of Conduct (the "**Code**") sets out the behavior which EnQuest expects of its directors, managers and employees and of its suppliers, contractors, agents and partners. EnQuest is committed to complying with all applicable legal requirements, to upholding the highest ethical standards and to acting with complete integrity at all times.

The Code provides policies and guidance as to the following topics:

- Whistle-blowing and a "speak up" reporting hotline;
- Compliance with anti-corruption rules and prohibitions on facilitation payments by us and those associated with us;
- Limitations on business gifts, entertainment expenses, charitable donations and political contributions and activities;
- Restrictions on anti-competitive behavior;
- Record keeping and financial integrity;
- Compliance with anti-money laundering rules and anti-facilitation of tax evasions;
- Compliance with insider trading and conflict of interest rules;

- Compliance with export and import controls;
- Workplace conduct, including anti-harassment rules;
- Health, safety, security and the environment; and
- Privacy protection.

The Code applies to the Board of Directors, all managers and employees of EnQuest, affiliated companies, controlled joint ventures, and to other individuals and companies when they are working for us—including contractors and consultants who will contractually be obliged to act consistently with the Code.

Governance issues

The directors support high standards of corporate governance. As a U.K. listed company, we are required to state whether we have complied with the relevant provisions of the revised U.K. Corporate Governance Code (the "**U.K. Governance Code**") published in January 2024.

The chief executive pay P50 median ratio for 2025 was 10:1. In line with the U.K. Governance Code, we are tracking changes in the CEO pay ratio on an annual basis. The Remuneration and Social Responsibility Committee considers the ratio to be reasonable considering our relative position against our benchmark peers.

Save as otherwise disclosed, the directors consider that we complied with the relevant provisions set out in Section 1 of the U.K. Corporate Governance Code during the financial years ended December 31, 2023, 2024 and 2025. The directors expect that we will comply with the relevant provisions of the U.K. Corporate Governance Code in respect of our current financial year.

No group of individuals dominates the Board's decision-making process and none of the directors has any conflict of interest between their duties to the Company and their private interests. The division of responsibilities between the Chairman and the Chief Executive has been clearly established, set out in writing and agreed by the Board.

The Board has a formal schedule of matters specifically reserved to it for decision. Its reserved matters include determination of our overall strategy, to review business plans, trading performance and overhead costs, to approve major capital investment projects, examine acquisition opportunities and divestment possibilities, review significant financial and operational issues, and review and approve our financial statements and control and risk management systems.

The Board delegates the execution of its strategic objectives and day to day management to executive management.

The Board has full and timely access to all relevant information to enable it to perform its duties. The Company Secretary is responsible for advising the Board, through the Chairman, on all governance matters. In addition, each director has access to the advice and services of the Company Secretary. There is also a procedure agreed by the Board, in furtherance of the duties, to take independent professional advice if necessary, at the Company's expense, up to a pre-determined limit.

Compensation paid to our board of directors and committee members

We paid aggregate remuneration, including salaries, bonuses and other amounts, to key management personnel, including executive and non-executive directors and other senior personnel, of $6.1 million, $6.4 million and $5.6 million in 2023, 2024 and 2025, respectively.

Share-based payment plans

We have two primary share schemes for the benefit of our directors and employees a Performance Share Plan and a Sharesave Plan.

Performance share plan

The Performance Share Plan is the primary long-term incentive awarded to executive directors, senior management and other key talent in the Group. The three-year performance period for the Performance Share Plan awarded in 2025 will end on December 31, 2027 and for which is based 40% on our total shareholder return performance relative to a group of sector comparators, 40% on absolute total shareholder return and 20% on reduction of emissions over the performance period.

The fair value of the awards granted under the plan at various grant dates during the year are based on quoted market prices adjusted for an assumed vesting rate over the relevant vesting period.

We recognized charges of $2.1 million, $0.5 million and $0.8 million in our statement of comprehensive income in relation to our Performance Share Plan for the years ended December 31, 2023, 2024 and 2025, respectively.

Sharesave Plan

We also operate an approved savings-related share option scheme. The plan is based on eligible employees being granted options and their agreement to opening a Sharesave Plan account with a nominated savings carrier and to save over a specified period, either three or five years. The right to exercise the option is at the employee's discretion at the end of the period previously chosen, for a period of six months.

The credit/(charge) recognized in our statement of comprehensive income in relation to our savings-related share option scheme for the years ended December 31, 2023, 2024 and 2025 were a charge of $1.0 million, a charge of $0.4 million and a credit of $0.1 million, respectively.

PRINCIPAL SHAREHOLDERS

As of December 31, 2025, EnQuest had an issued share capital of 1,885,029,503 allotted and fully paid ordinary shares of 5 pence each, of which 20,000,000 ordinary shares were held in Treasury. The following table sets forth certain information concerning the significant shareholders with a notifiable interest of EnQuest ordinary shares as of December 31, 2025.

Name of shareholder	Number of shares	Total percentage of shares owned
Bseisu consolidated interests[1]	234,732,857	12.63
Aberforth Partners LLP	207,954,847	11.19
Cobas Asset Mgmt	171,281,386	9.21
Hargreaves Lansdown Asset Management	105,700,431	5.69
Schroder Investment Management Ltd	95,347,363	5.13
Interactive Brokers Group, Inc.	78,317,159	4.21
Avanza Bank AB	62,490,362	3.36
Baillie Gifford & Co Ltd	53,112,983	2.86
Swedbank Robur Fonder AB	50,776,634	2.73

(1) 201,881,058 shares are held by Double A Limited, a company beneficially owned by the extended family of Amjad Bseisu. 32,674,840 shares are also held by The Amjad & Suha Bseisu Foundation and 176,959 shares are held directly by Amjad Bseisu.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

In the course of our ordinary business activities, we may from time to time enter into agreements with or render services to related parties. In turn, such related parties may render services or deliver goods to us as part of their business. Purchase and supply agreements between subsidiaries and affiliated companies and with associated companies or shareholders of such associated companies are entered into from time to time within the ordinary course of business.

DESCRIPTION OF CERTAIN FINANCING ARRANGEMENTS

RBL Facility

Overview

On November 9, 2025, we entered into a secured multicurrency revolving borrowing base facilities agreement, between, among others, the Company, as an obligor, and DNB Bank ASA, London Branch, as agent and security agent (the "**RBL Facility Agreement**"). The RBL Facility Agreement comprises a $400.0 million secured multicurrency revolving loan facility ("**Facility A**") and a $400.0 million secured multicurrency revolving letter of credit facility ("**Facility B**").

On November 20, 2025 (i) all loan drawings under the 2021 RBL Facility Agreement were repaid with cash from balance sheet and (ii) the letters of credit outstanding under the 2021 RBL Facility Agreement and the existing surety bonds and cash which support our decommissioning security agreement obligations were cancelled and returned and replaced by new letters of credit issued under Facility B. The 2021 RBL Facility was then cancelled. As of December 31, 2025, Facility B had $381.5 million utilized, with $18.5 million residual availability thereunder and Facility A remained undrawn. The amount of letters of credit utilized under the RBL Facility Agreement corresponds to the security in place supporting our decommissioning security agreement obligations as of December 31, 2025.

The RBL Facility will mature on the earliest of (i) the reserve tail date (as set out in the RBL Facility Agreement), (ii) December 31, 2031, (iii) if the 2027 Notes have not been repaid in full by the date falling six months before its maturity date, six months before such maturity date or (iv) if an obligor has incurred capital market indebtedness with a maturity or any scheduled principal repayment date on or before December 31, 2031 (including the indebtedness under the Notes but excluding indebtedness under the 9% Retail Notes), six months before the earliest maturity date (or scheduled principal repayment date).

The RBL Facility may be utilized in US dollars or pounds sterling by drawing of cash advances or by issuances of letters of credit for, among other things, the Group's general corporate purposes.

DNB Bank ASA, London Branch is the facility agent, security agent and fronting bank for letters of credit.

Borrowers and guarantors

Each of the following companies are both a borrower under the RBL Facility (a "**RBL Borrower**") and guarantor under the RBL Facility (a "**RBL Guarantor**"): the Company, EnQuest Heather Limited, EnQuest Heather Leasing Limited, EnQuest Britain Limited, EnQuest Global Limited and EnQuest Petroleum Production Malaysia Ltd.

Each of the following companies are a RBL Guarantor but not a RBL Borrower: EnQuest Marketing and Trading Limited, EnQuest Progress Limited, Premier Oil Vietnam Offshore B.V. and Premier Oil (Vietnam) Limited.

The RBL Borrowers and the RBL Guarantors are, taken together, referred to in this section as "**RBL Obligors**".

A mechanism is included in the RBL Facility Agreement to enable certain of the Company's subsidiaries to accede as additional RBL Borrowers or additional RBL Guarantors with respect to the RBL Facility, subject to certain conditions.

Security

The RBL Facility is secured by way of:

- an English law composite debenture incorporating: (i) certain floating charges, (ii) a share charge over the shares of EnQuest Marketing and Trading Limited, EnQuest Britain Limited, EnQuest Global Limited, EnQuest Heather Limited, EnQuest Heather Leasing Limited, EnQuest Progress Limited and EnQuest Petroleum Production Malaysia Ltd; and (iii) security over hedging agreements and intra-group loans and proceeds accounts;

- a separate Scots law floating charge over the assets of EnQuest Heather Limited;
- a separate Dutch law share charge over the shares in Premier Oil Vietnam Offshore B.V; and
- a separate British Virgin Islands equitable share mortgage over the shares in Premier Oil (Vietnam) Limited.

Guarantees

Subject to the terms of the RBL Facility Agreement, each of the RBL Guarantors (among other things) provides a guarantee of all amounts payable to the Finance Parties (as defined in the RBL Facility Agreement) by any RBL Borrower in connection with the RBL Facility Agreement.

Commitments and additional commitments

The initial committed amount of Facility A is $400 million and the initial committed amount of Facility B is $400 million, each of which reduces in accordance with an amortization schedule. There is an accordion option, such that EnQuest Heather Limited can increase the Facility A commitments to up to $800.0 million and the Facility B commitments to up to $800.0 million on no more than four occasions (a request to increase Facility A commitments and Facility B commitments at the same time constituting a single occasion) (and subject to finding existing and/or new lenders willing to assume the additional commitments). In addition, aggregate utilizations under the two facilities are limited by reference to the Borrowing Base Amount but for this purpose "**Eligible L/Cs**" (being letters of credit or any portion thereof which have been issued in respect of obligations the outgoings in respect of which have been taken into account in calculating the Borrowing Base Amount) and any other letters of credit to the extent the same have been cash covered do not count towards aggregate utilizations.

"**Borrowing Base Amount**" means in relation to any calculation period or any day falling within that period:

the lower of:

(i) the net present value (the "**NPV**") of cash flow available for debt service ("**CFADS**") from the borrowing base assets over the field life, divided by a field life cover ratio of 1.45x;

(ii) NPV of CFADS from borrowing base assets over the remaining loan life, divided by a loan life cover ratio of 1.30x,

plus: a capex add back amount (being the lower of (y) the forecast capital expenditure on the borrowing base assets for the next 12 months and (z) the aggregate of any undrawn available commitment under the Facilities (excluding the relevant expenditure to be added back), the amount standing to the credit of any bank account of a RBL Obligor which is available for capex add back under (y) and certain other committed sources), which amount is added back to the NPV of CFADS prior to applying both ratios; and

minus: an amount which, if not deducted, would result in the proportion of the field life NPV attributable to the development assets exceeding 40%; or the proportion of operating profits of the RBL Obligors attributable to a single borrowing base asset on or before the field life end date for such borrowing base asset exceeding 70%, which amount is deducted from the NPV of CFADS prior to applying both ratios.

Conditions to drawdown

The lenders under the RBL Facility are only obliged to advance loans and the fronting bank is only obliged to issue letters of credit if (i) no Event of Default (as defined in the RBL Facility Agreement) in the case of a rollover loan or letter of credit, or default in the case of any other utilization is continuing or would result from the utilization; (ii) the repeating representations are true in all material respects on the date of the utilization request and proposed utilization date; (iii) the projection which is due to be adopted by the most recent redetermination date has been so adopted (other than where non adoption is due to a failure on the part of one of the Finance Parties (as defined in the RBL Facility Agreement)); and (iv) the aggregate amount of the proposed utilization will not exceed the applicable limits.

Reduction, repayment and letter of credit cash collateralization

Facility A will reduce on a straight-line semi-annual reducing basis to a final balloon repayment of 25% in accordance with an amortization schedule, with no reduction prior December 31, 2028.

Facility B will reduce on a straight-line annual reducing basis on to a final balloon repayment of $250 million in accordance with an amortization schedule, with no reduction prior to January 1, 2030. The RBL Borrowers are required to maintain cash cover in respect of outstanding letters of credit as follows:

- on and from the date falling 24 months before the final maturity date to but excluding the date falling 18 months before the final maturity date 40% of the L/C Excess Amount;
- on and from the date falling 18 months before the final maturity date to but excluding the date falling 12 months before the final maturity date, 60% of the L/C Excess Amount ;
- on and from the date falling 12 months before the final maturity date to but excluding the date falling 6 months before the final maturity date 80% of the L/C Excess Amount ; and
- on and from 6 months before the final maturity date, 100% of the nominal amount of all letters of credit issued under Facility B.

Where, for the purposes of the above, the "**L/C Excess Amount**" means the aggregate amount by which loans and letters of credit taken together exceed the Borrowing Base Amount and the "**final maturity date**" means the earlier of the (i) the reserve tail date (as set out in the RBL Facility Agreement) and (ii) December 31, 2031.

Mandatory Prepayment

Illegality

If it becomes unlawful in any applicable jurisdiction for a lender or for an affiliate of a lender for that lender to perform its obligations under the RBL Facility Agreement or to fund, issue or maintain its participation in a utilization (other than as a result of that lender or fronting bank being a sanctioned lender or sanctioned fronting banks, respectively), the available commitment of that lender would be cancelled and, if applicable, all obligations under such commitment would be payable on the last day(s) of the relevant interest period(s) or earlier if required by the lender (such date being no earlier than the last day of any applicable grace period permitted by law).

Change of Control

If we experience certain change of control events, any lender may, by notice to us and the agent, to cancel its commitments immediately and each borrower must repay any such lender's participation in all outstanding loans, together with accrued interest and all other amounts due to that lender under the finance documents.

Other

The RBL Facility Agreement includes customary prepayment events and rights related to defaulting lenders, taxes and increased costs.

Voluntary prepayment and cancellation

Subject to payment of break costs (if any) (and of an administration fee due to the facility agent in the case of more than four prepayments in a calendar year), an RBL Borrower may voluntarily cancel the available commitments or prepay amounts outstanding under the RBL Facility Agreement without penalty or premium, at any time in whole or in part, subject to a minimum cancellation or repayment of $1.0 million, on not less than five business days' (or such shorter period as the Majority Lenders (as defined in the RBL Facility Agreement) may agree) prior notice to the facility agent.

Interest and fees

The rate of interest payable on the loans under the RBL Facility Agreement is the benchmark rate plus the agreed margin.

Margin is calculated as follows:

- on and from the RBL Effective Date to but excluding the second anniversary of the RBL Effective Date, 4.00% per annum;
- on and from the second anniversary of the RBL Effective Date to but excluding the fourth anniversary of the RBL Effective Date, 4.25% per annum; and
- on and from the fourth anniversary of the RBL Effective Date up to and including the final maturity date, 4.50% per annum.

EnQuest Heather Limited is required to pay a commitment fee to the RBL lenders as follows:

- Facility A:
  - 40% per annum of the applicable margin on the "**Available Undrawn Amount (Facility A)**", being the daily amount (if any) by which the lower of (i) the total Facility A commitments and (ii) the Borrowings Base Amount less the amount of any letters of credit then outstanding which are not Eligible L/Cs, exceeds the aggregate principal amount of the loans then outstanding; and
  - 20% per annum of the applicable margin on the daily amount (if any) by which the total Facility A commitments exceeds the aggregate of (i) the aggregate principal amount of the loans then outstanding and (ii) the Available Undrawn Amount (Facility A).
- Facility B: 20% per annum of the applicable margin on the daily amount (if any) by which the total Facility B commitments exceed the aggregate amount of letters of credit then outstanding.

Representations and warranties

The RBL Facility Agreement includes representations and warranties customary for reserve-based lending facilities, subject to customary exceptions and appropriate materiality qualifications.

Negative covenants

The RBL Facility Agreement includes restrictive covenants customary for reserve-based lending facilities, subject to certain agreed exceptions, including, but not limited to, covenants restricting the ability of each RBL Borrower and RBL Guarantor (and in certain cases other subsidiaries), among other things to:

- create security;
- dispose of petroleum assets;
- merge or consolidate with other companies or make acquisitions;
- make a substantial change to the general nature of its business;
- incur indebtedness or provide guarantees;
- allow its rights under certain project documents to be terminated, suspended or limited;
- make loans or extend credit to third parties;
- make distributions unless, *inter alia*, it is a distribution to an existing RBL Obligor or included in the latest EnQuest Group Liquidity Test (as defined below); and
- violate sanctions and anti-corruption law.

Affirmative covenants

The RBL Facility Agreement requires each RBL Borrower and RBL Guarantor to (and, in certain cases, to procure other subsidiaries to) observe affirmative covenants customary for reserve-based lending facilities, subject to customary exceptions.

Financial covenant

The RBL Facility Agreement contains the following financial covenant: the ratio of consolidated net financial indebtedness to adjusted EBITDAX is not greater than 3.5x, which is tested on each June 30 and December 31.

The RBL Facility Agreement requires us to demonstrate twice yearly that the Group (as defined in the RBL Facility Agreement) has sufficient funds available to meet all liabilities in each three-month period over the next 12 months (the "**EnQuest Group Liquidity Test**").

The RBL Facility Agreement requires EnQuest Heather Limited to maintain a minimum level of liquidity in the amount of $25.0 million which may comprise, amongst others, cash and authorized investments of the RBL Obligors, taken together with any available undrawn amount under any committed credit facility by an RBL Obligor.

These financial terms are defined in the RBL Facility Agreement and may not correspond to similarly titled metrics in our Group Financial Statements or this document.

Events of Default

The RBL Facility Agreement sets out certain events of default, the occurrence of which would allow the agent at its discretion or, if so directed by the Majority Lenders (as defined in the RBL Facility Agreement) to, among other things, cancel their commitments and/or declare that all or part of the loans, together with accrued interest and other amounts outstanding are immediately due and payable and/or payable immediately on demand and/or declare that full cash cover in respect of each letter of credit is immediately due and payable. The events of default are customary for reserve-based lending facilities and are subject to customary grace periods, thresholds and other qualifications.

Hedging

Under the RBL Facility Agreement we are required, subject to certain grace periods where increased hedged volumes are required, to hedge as follows, where references below to "**total relevant outstandings**" means the aggregate amount of all utilizations under the RBL Facility disregarding Eligible L/Cs and other letters of credit to the extent the same are subject to cash cover:

- From the RBL Effective Date to but excluding June 30, 2029:
    - where the total relevant outstandings are 10% or less of the then current Borrowing Base Amount: a minimum of 10% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the (i) 12 months following the relevant quarter date and (ii) from the date 12 months after the relevant quarter date to the date 24 months after that date.
    - where the total relevant outstandings are more than 10% but less than 50% of the then current Borrowing Base Amount: a minimum of (i) 30% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months following the relevant quarter date and (ii) 15% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months after the relevant quarter date to the date 24 months after that date.
    - where the total relevant outstandings are 50% or more of the then current Borrowing Base Amount: a minimum of (i) 45% of forecast volumes of net crude oil and natural

gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months following the relevant quarter date and (ii) 30% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months after the relevant quarter date to the date 24 months after that date.

- On and from June 30, 2029:

    - where the total relevant outstandings are less than 50% of the then current Borrowing Base Amount: a minimum of (i) 30% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months following the relevant quarter date and (ii) 15% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months after the relevant quarter date to the date 24 months after that date.

    - where the total relevant outstandings are 50% or more of the then current Borrowing Base Amount: a minimum of (i) 45% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months following the relevant quarter date and (ii) 30% of forecast volumes of net crude oil and natural gas entitlement production related to borrowing base assets which are not development assets expected to be produced in the 12 months after the relevant quarter date to the date 24 months after that date.

In all cases, minimum floor protection will be equal to or above the lower of 90% of the economic assumption as to hydrocarbon prices included in the then-current projection and 90% of the forward price curve at the time the hedging transaction was entered into.

Governing law

The RBL Facility Agreement is governed by English law.

SVT Working Capital Facility

Overview

EnQuest Heather Limited is the borrower under a revolving loan facility originally entered into with BNP Paribas and since transferred to Deutsche Bank AG, Amsterdam Branch in, among others, its capacity as lender for an aggregate amount of £42.0 million dated December 1, 2017, as novated and amended on December 1, 2018 and further amended on November 25, 2020 and January 3, 2022 and further amended pursuant to an amendment and restatement agreement with Deutsche Bank AG, Amsterdam Branch dated April 22, 2024 (the "**SVT Working Capital Facility**") in connection with its assumption of the role of operator of SVT. BP International Limited (the "**BP SVT Guarantor**") separately provided a guarantee capped at £42 million dated December 1, 2017, as amended and restated on December 1, 2018 and further amended and restated on March 26, 2024 in relation to the SVT Working Capital Facility, such guarantee given directly to Deutsche Bank AG, Amsterdam Branch. The operating agreement for SVT (under which EnQuest Heather Limited is operator) currently operates on an invoicing basis (whereby the operator must pay out amounts and then subsequently invoice the joint venture parties for their percentage interest share of costs) as opposed to a cash calling basis (whereby an operator can call amounts in advance from the joint venture parties).

The proceeds of the SVT Working Capital Facility are used for project expenditure in respect of SVT and the loan is repayable on the last day of each interest period. The representations, mandatory prepayment provisions, undertakings and events of default are customary for a facility of this nature. Interest is calculated at the rate per annum equal to the aggregate of the margin of 2.05% per annum, the compounded reference rate for that day and mandatory costs (if any).

The remuneration due to the BP SVT Guarantor for providing the BP guarantee is equal to 90% of the difference between the sum of all SVT/NLGP/NPS operator fees received by SPV less the interest paid and any other fees paid by SPV to the bank on the overdraft balance (to the extent not recovered from relevant joint venture partners/users). This remuneration is payable by SPV to the BP SVT Guarantor on a monthly basis. To the extent that the fees paid to the operator under the operating agreement for SVT are insufficient to cover the fees payable to the bank, the shortfall shall be met by the BP SVT Guarantor and recoverable through a separate waterfall mechanism.

The BP SVT Guarantor agreed to continue to provide its guarantee of such a working capital facility for EnQuest Heather Limited until the earlier to occur of:

a) the date on which production from Magnus permanently ceases; and

b) if the operating agreements for both SVT and the NPS are amended to allow for cash calling, the effective date of such amendment.

Guarantee Subordination Agreement

In the following summary of the subordination agreement dated April 9, 2014 between, among others, the Company and BNP Paribas (as facility agent and security trustee under the 2021 RBL Facility) as amended, novated, supplemented, extended and/or restated from time to time (the "**Guarantee Subordination Agreement**") the terms set out below shall have the meanings set out against them. On the RBL Effective Date, DNB Bank ASA, London Branch, as agent and security agent under the RBL Facility, acceded to the Guarantee Subordination Agreement. The Trustee will also accede to the Guarantee Subordination Agreement as trustee under the Indenture, prior to or substantially concurrent with the issue of the Notes.

- "**Debt Documents**" refers to (among others) each of the Senior Finance Documents and the Notes Documents;

- each member of our Group (excluding any Notes Issuer) that is a borrower or guarantor under the Debt Documents is referred to as a "**Debtor**" and are collectively referred to as the "**Debtors**";

- "**Group**" refers to all of the Company's subsidiaries for the time being but, for the avoidance of doubt, not the Company itself;

- "**Liabilities**" refers to (among others) all present and future liabilities and obligations at any time of a Debtor to a creditor under the Debt Documents, both actual and contingent and whether incurred solely or jointly or as principal or surety or in any capacity, together with any of the following matters relating to or arising in respect of those liabilities and obligations:

    - any refinancing, novation, deferral or extension;

    - any claim for breach of representation, warranty or undertaking or an event of default or under any indemnity given under or in connection with any document or agreement evidencing or constituting any other liability or obligation falling within the definition of "**Liabilities**";

    - any claim for damages or restitution; and

    - any claim as a result of any recovery of any Debtor of a payment to a creditor on the grounds or preference or otherwise,

and any amounts which would be included in any of the above but for any discharge, non-provability, unenforceability or non-allowance of those amounts in any insolvency or other proceedings;

- "**Notes Creditors**" refers to (i) the Notes Trustee and the holders, from time to time, of the Notes; and (ii) U.S. Bank Trustees Limited as trustee under the 9% Retail Notes Trust Deed (as defined below) ("**9% Retail Notes Trustee**") and the holders, from time to time, of the 9% Retail Notes;

- "**Notes Documents**" refers to, as applicable, each of (i) the Guarantee Subordination Agreement, (ii) the 9% Retail Notes, the 9% Retail Notes Guarantees, the trustee deed dated January 24, 2013

constituting the 9% Retail Notes (as amended, novated, supplemented, extended and/or restated from time to time, including pursuant to the first supplemental trust deed to the 9% Retail Notes Trustee Deed) (the "**9% Retail Notes Trust Deed**") and (iii) the Notes, the Note Guarantees and the Indenture;

- "**Notes Issuer**" refers to the Company (in its capacity as issuer of the Notes and the 9% Retail Notes) and any of its wholly owned subsidiaries which may in the future issue bonds or notes and on-lend the proceeds of such issuance to the Company;

- "**Notes Trustees**" refers to the 9% Retail Notes Trustee, the Trustee or any other trustee under any indenture which has acceded to the Guarantee and Subordination Agreement as a trustee; and

- "**Senior Finance Documents**" refers to (among others) the Guarantee Subordination Agreement and the RBL Facility Agreement and certain hedging agreements and other documents evidencing the Senior Liabilities (as defined below).

Ranking and Priority

The Guarantee Subordination Agreement provides that the Liabilities owed by the Debtors to the Senior Creditors under the Senior Finance Documents (the "**Senior Liabilities**") and the Liabilities owed by the Guarantors to the Notes Creditors under the Notes Documents (the "**Note Guarantee Liabilities**") will rank in right and priority of payment in the following order:

- first, the Senior Liabilities *pari passu* and without any preference between them; and

- second, the Note Guarantee Liabilities, *pari passu* and without preference between them.

The parties to the Guarantee Subordination Agreement have agreed that the Liabilities owed by any Notes Issuer to the Notes Creditors under the Notes Documents, certain amounts owed to the Notes Trustees under the Notes Documents and certain security enforcement and preservation costs relating to the Notes and the 9% Retail Notes (if any) are senior obligations (and are therefore not Note Guarantee Liabilities) and the Guarantee Subordination Agreement does not purport to rank, postpone and/or subordinate any of them in relation to any other liability.

Permitted Payments

Until the Senior Discharge Date (as defined below), the Guarantee Subordination Agreement only permits Debtors to pay any amounts due to the Notes Creditors with respect to the Note Guarantee Liabilities if:

- no Stop Notice (as defined below) is outstanding and no Senior Payment Default (as defined below) has occurred and is continuing;

- the requisite consent of the lenders under the RBL Facility Agreement has been obtained; or

- the payment is of:

    - costs, commissions, taxes, fees payable to administrative service providers in connection with any consent process (provided that no portion of such fees may be payable to, or received by, the holders of the Notes and 9% Retail Notes) and expenses incurred in respect of (or reasonably incidental to) the Notes Documents (or any of them);

    - additional amounts payable as a result of the tax gross-up provisions relating to the Note Guarantee Liabilities and amounts in respect of currency indemnities in the Notes Documents;

    - any amount not exceeding $2,250,000 (or its equivalent in other currencies) in aggregate in any twelve-month period; or

    - the principal amount of the liabilities in respect of the Notes or the 9% Retail Notes on or after the final maturity date thereof; *provided* that such maturity date is the date so stated in the relevant Notes Document in its original form.

The "**Senior Discharge Date**" means the date on which all Senior Liabilities have been fully and finally discharged to the satisfaction of the relevant Representative (as defined below) and the Senior Creditors are under no further obligations to provide financial accommodation to any Debtor under any Senior Finance Document.

A "**Senior Payment Default**" refers to a payment default under the Senior Finance Documents other than in respect of an amount not exceeding $1.0 million (or its equivalent in any currency).

The agent representative (the "**Representative**") of the creditors under the RBL Facility Agreement may serve a notice (a "**Stop Notice**") to a Notes Trustee specifying that an event of default (other than a Senior Payment Default) under such facility is outstanding and suspend the payment of any Note Guarantee Liabilities (subject to the exceptions described above) until the earliest of:

- the date on which such relevant event of default is waived, remedied or cured in accordance with the relevant document, is no longer continuing or otherwise ceases to exist;
- the date falling 179 days after the date of receipt by a Notes Trustee of the Stop Notice;
- the date on which the Senior Liabilities owed to the relevant Senior Creditors under the Senior Finance Documents under which such event of default occurred have been fully and finally discharged and the relevant Senior Creditors are under no further obligation to provide financial accommodation to any Debtor under any Senior Finance Document;
- the date on which the Representative that served the Stop Notice cancels such Stop Notice;
- if a Standstill Period (as defined below) is already in effect, the date on which the aforementioned Standstill Period expires; and
- the date on which that Notes Trustee takes any enforcement action that is permitted under the Guarantee Subordination Agreement.

Each Stop Notice is to be issued within 60 days of receipt of notice of such default, only one notice may be served within any 360 day period, not more than one such notice may be served in respect of the same event or set of circumstances and no such notice may be served in respect of an event of default which has been notified to the relevant Representative at the time at which an earlier Stop Notice was issued.

Notwithstanding the foregoing, the Notes Issuer is not prevented from making a payment from its own assets if such payment is in respect of any of its obligations under the Notes or the 9% Retail Notes in respect of which such Stop Notice has been delivered and such payment is not financed by a payment to such Notes Issuer by a member of our Group which is prohibited as described in the paragraph entitled "**Permitted payments**."

Turnover – by the Notes Creditors

The Guarantee Subordination Agreement provides that if, at any time prior to the Senior Discharge Date, a Notes Creditor (subject to certain limited exceptions, including in respect of a Notes Trustee) receives or recovers a payment or distribution of, on account of or in relation to any Note Guarantee Liabilities which is not a permitted payment under the Guarantee Subordination Agreement, it will, in relation to receipts and recoveries from a Notes Guarantor:

- hold the received or recovered amount on trust for the Representative;
- promptly notify the Representative of such receipt or recovery and request that the Representative confirm the amount of Senior Liabilities outstanding under the relevant Senior Finance Document; and
- pay or distribute such amounts to the Representatives for application in accordance with the terms of the Senior Finance Documents.

Turnover – by the Representatives

The Guarantee Subordination Agreement provides that after the occurrence of certain insolvency, liquidation or other similar enforcement events in relation to any Note Guarantor and until the Senior Discharge Date, a Representative may (i) demand, sue, prove and give receipt for any Guarantors' Note Guarantee Liabilities; (ii) collect and receive all distributions on, or on account of, any Guarantors' Note Guarantee Liabilities; and (iii) file claims, take proceedings and do other things to recover any Guarantors' Note Guarantee Liabilities.

If the Representative collects, receives or recovers any amounts following the exercise of any of the foregoing rights and after the Senior Discharge Date, the Representative continues to hold any such amounts so collected, received or recovered, the Representative shall promptly pay all such amounts to the relevant trustee *pro rata* to the amounts outstanding under each Notes Document to which the Notes Trustees are a party for application in accordance with the terms of the Notes Documents.

General

The Guarantee Subordination Agreement contains provisions dealing with:

- the incurrence of future debt that will allow (i) certain agents with respect to the creditors of senior debt to accede to the Guarantee Subordination Agreement and benefit from, and be subject to, the provisions described above (including, for the avoidance of doubt, as creditors in respect of Senior Liabilities); and (ii) certain trustees with respect to the creditors of debt ranking *pari passu* with the Notes and the 9% Retail Notes to accede to the Guarantee Subordination Agreement and have the same rights and obligations as the Notes Trustees;

- the circumstances in which any Notes Trustee may by giving at least 10 business days' notice to the Representative, at any time when a Stop Notice is outstanding and any enforcement action has been taken by or on behalf of a Senior Creditor, require the transfer to it of all (and not part) of the rights and obligations in respect of the Senior Liabilities (subject to certain conditions);

- when a Notes Trustee will be required, pursuant to any enforcement action taken in relation to the Senior Finance Documents, to release any guarantees given by the Guarantors;

- notwithstanding any other provision of the Guarantee Subordination Agreement, no Notes Trustee shall have any obligation to take any action under the Guarantee Subordination Agreement unless it is indemnified and/or secured to its satisfaction in respect of all costs, expenses and liabilities which it would in its opinion thereby incur (together with any associated VAT); and

- customary protections, entitlements and exemptions from liability for Notes Trustees all as further set out in the Guarantee Subordination Agreement.

Governing Law

The Guarantee Subordination Agreement is governed by and construed in accordance with English law.

9% Retail Notes

On April 27, 2022, in connection with an exchange offer (the "**Exchange Offer**") to holders of the 7% Retail Notes, pursuant to which some holders exchanged their 7% Retail Notes for new sterling-denominated 9.00% notes due October 27, 2027 and an accompanying cash offer, the Company issued £133.3 million 9.00% notes due October 27, 2027. The following description of the 9% Retail Notes is based on their terms and conditions in effect as at the date of these Listing Particulars.

Overview

The 9% Retail Notes are guaranteed on a joint and several basis (the "**9% Retail Notes Guarantee**") by EnQuest Heather Limited, EnQuest Britain Limited, EnQuest ENS Limited, EnQuest Global Limited, EnQuest Heather Leasing Limited, EnQuest NWO Limited, EnQuest Production Limited, EnQuest Petroleum Production Malaysia Ltd, NSIP (GKA) Limited, EnQuest Marketing and Trading Limited, EnQuest Petroleum Developments

Malaysia Sdn. Bhd., EnQuest Advance Limited, EnQuest Advance Holdings Limited, EQ Petroleum Sabah Ltd and North Sea (Golden Eagle) Resources Ltd. (the "**9% Retail Notes Guarantors**").

The 9% Retail Notes are listed on the Financial Conduct Authority's Official List and admitted to trading on the London Stock Exchange's regulated market and through the electronic Order Book for Retail Bonds (ORB) market.

Interest

The 9% Retail Notes bear a fixed rate of 9.00% per annum payable semi-annually in arrears on April 27 and October 27 in each year.

Form

The 9% Retail Notes were issued in registered form.

Currency

The 9% Retail Notes are denominated in pounds sterling.

Maturity

The 9% Retail Notes will mature on October 27, 2027.

Ranking of 9% Retail Notes

The 9% Retail Notes rank *pari passu* without preference or priority among themselves.

Ranking of the 9% Retail Notes Guarantees

Each 9% Retail Note Guarantee is a subordinated obligation of the respective 9% Retail Note Guarantor; subordinated in right of payment to all existing and future senior obligations of that 9% Retail Note Guarantor, including, where applicable, such 9% Retail Note Guarantor's obligations under the RBL Facility Agreement; *pari passu* in right of payment with all existing and future senior subordinated obligations of that 9% Retail Note Guarantor, including the Notes; senior in right of payment to all future obligations of that 9% Retail Note Guarantor that are expressly contractually subordinated to that 9% Retail Note Guarantee; and effectively subordinated to all existing and future secured obligations of that 9% Retail Note Guarantor (including under the RBL Facility Agreement), to the extent of the value of the property and assets securing such obligations, unless such assets also secure the 9% Retail Note Guarantee on an equal and rateable or senior basis. The 9% Retail Note Guarantee will be subject to release under certain circumstances.

Negative Pledge

So long as any 9% Retail Notes are outstanding, neither the Company nor any of its subsidiaries will create or have outstanding any security interest upon the whole or any part of its present or future undertakings, assets or revenues to secure any indebtedness which is in the form of, or represented or evidenced by, bonds, notes, debentures, loan stock, or other securities which for the time being are, quoted, listed or dealt in or traded on any stock exchange or over the counter or other securities market, without at the same time or prior thereto according the same security to the holders of the 9% Retail Notes.

Events of Default

The 9% Retail Notes contain customary events of default, including those relating to (a) non-payment of interest or principal; (b) breach of other obligations under the 9% Retail Notes or the 9% Retail Notes Trust Deed; (c) cross acceleration; (d) enforcement proceedings; (e) security enforcement; (f) insolvency; (g) winding up; (h) lack of authorizations and consents; (i) illegality; and (j) Guarantee not in full force and effect. The provisions include certain minimum thresholds and grace periods. In addition, in certain cases, a certification in writing that a particular event is materially prejudicial to the interests of the holders of the 9% Retail Notes is required from the 9% Retail Notes Trustee before the 9% Retail Notes can be accelerated.

Final redemption

Unless previously redeemed, purchased or cancelled, the 9% Retail Notes are due to be redeemed on October 27, 2027 at their nominal amount.

Optional redemption

The 9% Retail Notes may be redeemed prior to their maturity date in certain circumstances at the Company's discretion at an optional redemption price calculated as a specified percentage of the principal amount of the 9% Retail Notes, being 104% if the redemption falls on or after April 27, 2024 but before April 27, 2025, 102% if the redemption falls on or after April 27, 2025 but before April 27, 2026 and 100% if the redemption falls on or after April 27, 2026. The Company may also (prior to the expected maturity date) redeem the 9% Retail Notes as a result of changes in taxation such that the Company would be required to pay additional amounts to the holders of the 9% Retail Notes.

Taxation

All payments in respect of 9% Retail Notes are made without withholding or deduction for, or on account of, any present or future taxes imposed by the United Kingdom unless and save to the extent that the withholding or deduction of such taxes is required by law. In that event, the Company or, as the case may be, the relevant Guarantor(s) shall pay such additional amounts as shall result in receipt by the holders of the 9% Retail Notes of such amounts as would have been received by them had no such withholding or deduction been required, subject to certain exceptions.

Covenants

The 9% Retail Notes Trust Deed contains customary covenants for the type of issuance, which are subject to caveats and limitations, including covenants to notify the 9% Retail Notes Trustee in the event of an event of default and to deliver to the 9% Retail Notes Trustee the Company's audited financial statements.

Financial covenants

The 9% Retail Notes do not contain any financial covenants.

Governing law

The 9% Retail Notes are governed by English law.

Letters of credit, surety bonds and restricted cash

We use letters of credit, surety bonds and cash deposits to provide security for our decommissioning security agreement obligations. As of December 31, 2025, we did not hold any surety bonds or cash. On January 1, 2026, certain of the letters of credit under Facility B were replaced by surety bonds resulting in our decommissioning security obligations being covered by £225.7 million utilization of Facility B and £90.0 million of surety bonds.

As of December 31, 2025 we held a residual $1.2 million in accounts relating to 2025 decommissioning security agreement obligations and $1.8 million related to the deposit of a performance bond in Indonesia.

As of December 31, 2025, letter of credit utilization under Facility B of the RBL Facility was $381.5 million, with $18.5 million residual availability thereunder. As of December 31, 2025, there were no drawdowns under Facility A of the RBL Facility.

Facilities for the issuance of surety bonds

Each of Euler Hermes SA (NV), HCC International Insurance Company Plc, Liberty Mutual Insurance Europe SE, Markel International Insurance Company Limited and QBE UK Limited have issued unsecured surety bonds in respect of our decommissioning liabilities and the Company as lead indemnitor together with other members of the Group as indemnitors have entered into unsecured uncommitted surety bond facilities as follows:

- dated November 28, 2025 with Euler Hermes SA (NV);

- dated November 28, 2025 with HCC International Insurance Company Plc;
- dated November 28, 2025 with Liberty Mutual Insurance Europe SE;
- dated November 28, 2025 with Markel International Insurance Company Limited and
- dated November 28, 2025 with QBE UK Limited (as subsequently confirmed by a deed of confirmation between, among others, the Company and QBE UK Limited).

Hedging arrangements

We maintain certain commodity hedges to manage our exposure to movements in oil and gas prices. In addition, we hold a small portfolio of foreign exchange derivatives. In connection with these activities, we have entered into International Swaps and Derivatives Association master agreements with several hedging partners.

Vendor Loan Facilities

From time to time, we enter into vendor loans or deferred payment facility agreements to support our operations.

For example, in August 2024, EnQuest Heather Limited ("**EnQuest Heather**") and Baker Hughes UK Funding Limited ("**Baker Hughes**") entered into a deferred payment facility agreement (the "**Vendor Loan Facility Agreement**") pursuant to which Baker Hughes agreed to provide EnQuest Heather a deferred payment facility (the "**Vendor Loan Facility**") for the purposes of refinancing the payment of invoices under certain "eligible contracts" in relation to certain "eligible services" in an amount of up to £23.7 million. As of December 31, 2025, this facility was drawn in the amount of $22.1 million.

DESCRIPTION OF NOTES

EnQuest PLC (the "**Company**") will issue the Notes under an indenture (the "**Indenture**") among, *inter alios,* the Company, the Guarantors, Deutsche Bank Trust Company Americas, as trustee (the "**Trustee**") and Deutsche Bank Trust Company Americas, as Principal Paying Agent, Transfer Agent and Registrar in a private transaction that is not subject to the registration requirements of the U.S. Securities Act. The terms of the Notes include those set forth in the Indenture. The Indenture will not incorporate or include or be subject to any of the provisions of the U.S. Trust Indenture Act of 1939, as amended.

The following description is a summary of the material provisions of the Indenture and the Notes and refers to the Guarantee Subordination Agreement and certain other agreements relating to the Notes. This description does not restate those agreements in their entirety. We urge you to read the Indenture, the Notes and the Guarantee Subordination Agreement because they, and not this description, define your rights as holders of the Notes. Copies of the Indenture, the form of Note and the Guarantee Subordination Agreement are available as set forth below under "*—Additional information*." The Indenture, the Notes and the Note Guarantees (as defined herein) will be subject to the terms of the Guarantee Subordination Agreement and any additional subordination agreements entered into in the future. The terms of the Guarantee Subordination Agreement are important to understand the terms and ranking of the Note Guarantees. See "*Description of certain financing arrangements—Guarantee Subordination Agreement*" for a description of the material terms of the Guarantee Subordination Agreement.

You can find the definitions of certain terms used in this "*Description of Notes*" under the subheading "*—Certain definitions*." Certain defined terms used in this "*Description of Notes*" but not defined below under "*—Certain definitions*" or elsewhere in this description have the meanings assigned to them in the Indenture. For purposes of this "*Description of Notes*," the term "**Company**" refers only to EnQuest PLC and not to any of its subsidiaries, and unless the context requires otherwise, references in this "*Description of Notes*" to the Notes include the Notes and any additional Notes that are issued.

The registered holder of a Note will be treated as the owner of it for all purposes. Only registered holders will have rights under the Indenture.

Brief description of the Notes and the Note Guarantees

The Notes

The Notes will be:

- senior obligations of the Company;
- *pari passu* in right of payment with all existing and future obligations of the Company that are not expressly contractually subordinated in right of payment to the Notes, including obligations under the 9% Retail Notes and the RBL Facility;
- senior in right of payment to all future obligations of the Company that are subordinated in right of payment to the Notes;
- effectively subordinated to all existing and future secured obligations of the Company, including obligations under the RBL Facility, to the extent of the value of the property and assets securing such obligations, unless such assets also secure the Notes on an equal and ratable or senior basis;
- structurally subordinated to all existing and future obligations of the Company's Subsidiaries that do not guarantee the Notes, including any non-Guarantor Subsidiaries of the Company that guarantee the RBL Facility; and
- guaranteed on a senior subordinated basis by the Guarantors, subject to limitations under applicable law as set forth below under the caption *"—Note Guarantees*."

The Note Guarantees

The Notes will be guaranteed by the Guarantors. Each Note Guarantee will be:

- a senior subordinated obligation of the respective Guarantor;
- contractually subordinated in right of payment to all existing and future senior obligations of that Guarantor, including such Guarantor's obligations under the RBL Facility;
- *pari passu* in right of payment with all existing and future senior subordinated obligations of that Guarantor;
- senior in right of payment to all future obligations of that Guarantor that are expressly contractually subordinated to that Guarantor's Note Guarantee;
- structurally subordinated to all existing and future obligations of such Guarantor's Subsidiaries that do not guarantee the Notes; and
- effectively subordinated to all existing and future secured obligations of that Guarantor (including under the RBL Facility), to the extent of the value of the property and assets securing such obligations, unless such assets also secure the Note Guarantees on an equal and ratable or senior basis.

Not all of the Company's Subsidiaries will guarantee the Notes on the Issue Date and the Company will not have any obligation to cause any of its Subsidiaries to guarantee the Notes in the future (except as required under the circumstances described below under the caption "*—Certain covenants—Limitation on guarantees of indebtedness by restricted subsidiaries*"). In the event of a bankruptcy, liquidation or reorganization of any Subsidiary that is not a Guarantor, such Subsidiary will pay the holders of its debt and its trade creditors before it will be able to distribute any of its assets to the Company or a Guarantor. As of and for the year ended December 31, 2025, our subsidiaries that are not Guarantors collectively represented 16% of our consolidated total assets. As of December 31, 2025, on a *pro forma* basis after giving effect to the Offering, such non-Guarantors had no third-party debt. See "*Risk factors—Risks relating to the Notes and our structure—The Notes and Note Guarantees will be structurally subordinated to the liabilities and preference shares (if any) of our non-Guarantor subsidiaries*."

As of the Issue Date, all of the Company's Subsidiaries will be "Restricted Subsidiaries." However, under the circumstances described below under the caption "*—Certain covenants—Designation of restricted and unrestricted subsidiaries*," the Company will be permitted to designate certain of its Subsidiaries as "Unrestricted Subsidiaries." The Company's Unrestricted Subsidiaries will not be subject to any of the restrictive covenants in the Indenture.

Principal, maturity and interest

The Company will issue $675.0 million in aggregate principal amount of Notes in this offering. The Company will issue Notes in minimum denominations of $200,000 and integral multiples of $1,000 in excess thereof. The Notes will mature on April 30, 2031. The Company may issue additional Notes (the "**Additional Notes**") under the Indenture from time to time after this offering. Any issuance of Additional Notes is subject to all of the covenants in the Indenture, including the covenant described below under the caption "*—Certain covenants—Incurrence of indebtedness and issuance of preferred stock*." The Notes and any Additional Notes subsequently issued under the Indenture will be treated as a single class for all purposes under the Indenture, including, without limitation, waivers, amendments, redemptions and offers to purchase. Any Additional Notes shall have terms substantially identical to the Notes except in respect of any of the following terms:

(1) the title of such Additional Notes;

(2) the aggregate principal amount of such Additional Notes;

(3) the date or dates on which such Additional Notes will be issued;

(4) the rate or rates (which may be fixed or floating) at which such Additional Notes shall bear interest and, if applicable, the interest rate basis, formula or other method of determining such interest payment dates on which such interest shall be payable or the method by which such dates will be determined, the record dates for the determination of holders thereof to whom such interest is payable and the basis upon which such interest will be calculated;

(5) the currency or currencies in which such Additional Notes shall be denominated and the currency in which cash or government obligations in connection with such series of Additional Notes may be payable;

(6) the date or dates and price or prices at which, the period or periods within which, and the terms and conditions upon which, such Additional Notes may be redeemed, in whole or in part;

(7) if other than denominations of $200,000 and in integral multiples of $1,000 in excess thereof, the denominations in which such Additional Notes shall be issued and redeemed; and

(8) the ISIN, Common Code, CUSIP or other securities identification numbers with respect to such Additional Notes.

The initial Notes and any Additional Notes denominated in U.S. dollars shall be deemed to form one series and references to the "Notes" shall be deemed to include the Notes initially issued on the Issue Date as well as any Additional Notes denominated in U.S. dollars.

In the event any Additional Notes are not fungible with the Notes for U.S. federal income tax purposes, such nonfungible Additional Notes will be issued with a separate CUSIP number or common code and ISIN, as applicable, so that they are distinguishable from the Notes.

Interest on the Notes will accrue at the rate of 9⅞% per annum and will be payable semi-annually in arrears on April 30 and October 30, commencing on October 30, 2026. Interest on overdue principal and interest, if any, will accrue at a rate that is 1.0% higher than the then applicable interest rate on the Notes. The Company will make each interest payment to the holders of record on the Business Day immediately preceding the applicable interest payment date.

Interest on the Notes will accrue from the date of original issuance or, if interest has already been paid, from the date it was most recently paid. Interest will be computed on the basis of a 360-day year comprised of twelve 30-day months.

Transfer and exchange

Notes sold within the United States to qualified institutional buyers pursuant to Rule 144A under the U.S. Securities Act will initially be represented by one or more global notes in registered form without interest coupons attached (the "**144A Global Note**"). Notes sold outside the United States pursuant to Regulation S under the U.S. Securities Act will initially be represented by one or more global notes in registered form without interest coupons attached (the "**Reg S Global Note**" and, together with the 144A Global Note, the "**Global Notes**").

Ownership of interests in the Global Notes ("**Book-Entry Interests**") will be limited to persons that have accounts with The Depository Trust Company ("**DTC**") or persons that may hold interests through such participants, including through Euroclear and Clearstream. Ownership of interests in the Book-Entry Interests and transfers thereof will be subject to the restrictions on transfer and certification requirements summarized below and described more fully under "*Notice to investors*." In addition, transfers of Book-Entry Interests between participants in DTC, participants in Euroclear or participants in Clearstream will be effected by DTC, Euroclear or Clearstream pursuant to customary procedures and subject to the applicable rules and procedures established by DTC, Euroclear or Clearstream and their respective participants.

Book-Entry Interests in a 144A Global Note, or the "144A Book-Entry Interests," may be transferred to a person who takes delivery in the form of Book-Entry Interests in a Reg S Global Note, or the "Reg S Book-Entry Interests," only upon delivery by the transferor of a written certification (in the form provided in the Indenture) to the effect that such transfer is being made in accordance with Regulation S under the U.S. Securities Act. During the 40-Day Period (as defined in "*Book-entry, delivery and form*"), Reg S Book-Entry Interests may be transferred to a person who takes delivery in the form of 144A Book-Entry Interests only upon delivery by the transferor of a written certification (in the form provided in the Indenture) to the effect that such transfer is being made to a person who the transferor reasonably believes is a "qualified institutional buyer" within the meaning of Rule 144A in a transaction meeting the requirements of Rule 144A or otherwise in accordance with applicable transfer restrictions and any applicable securities laws of any state of the United States or any other jurisdiction.

Any Book-Entry Interest that is transferred will, upon transfer, cease to be a Book-Entry Interest in the Global Note from which it was transferred and will become a Book-Entry Interest in the Global Note to which it was transferred. Accordingly, from and after such transfer, it will become subject to all transfer restrictions, if any, and other procedures applicable to Book-Entry Interests in the Global Note to which it was transferred.

If definitive Notes in registered form ("**Definitive Registered Notes**") are issued, they will be issued only in denominations of $200,000 and integral multiples of $1,000 in excess thereof upon receipt by the Registrar of instructions relating thereto and any certificates, opinions and other documentation required by the Indenture. It is expected that such instructions will be based upon directions received by DTC from the participant which owns the relevant Book-Entry Interest. Definitive Registered Notes issued in exchange for a Book-Entry Interest will, except as set forth in the Indenture or as otherwise determined by the Company in compliance with applicable law, be subject to, and will have a legend with respect to, the restrictions on transfer summarized below and described more fully under "*Notice to investors*."

Subject to the restrictions on transfer referred to above, Notes issued as Definitive Registered Notes may be transferred or exchanged, in whole or in part, in denominations of $200,000 in principal amount or integral multiples of $1,000 in excess thereof. In connection with any such transfer or exchange, the Indenture will require the transferring or exchanging holder, among other things, to furnish appropriate endorsements and transfer documents, to furnish information regarding the account of the transferee at DTC, Euroclear or Clearstream, where appropriate, to furnish certain certificates and opinions, and to pay any taxes, duties and governmental charges in connection with such transfer or exchange. Any such transfer or exchange will be made without charge to the holder of the Notes, other than any transfer taxes or similar governmental charges payable in connection with such transfer or exchange.

Notwithstanding the foregoing, the Company is not required to register the transfer of any Definitive Registered Notes:

(1) for a period of 15 calendar days prior to any date fixed for the redemption of the Notes;

(2) for a period of 15 calendar days immediately prior to the date fixed for selection of Notes to be redeemed in part;

(3) for a period of 15 calendar days prior to the record date with respect to any interest payment date; or

(4) which the holder of the Notes has tendered (and not withdrawn) for repurchase in connection with a Change of Control Offer or an Asset Sale Offer.

The Company, the Trustee, the Paying Agents, the Transfer Agent and the Registrar will be entitled to treat the registered Holder of a Global Note as the owner thereof for all purposes.

Paying agent and registrar for the Notes

The Company will maintain one or more paying agents (each, a "**Paying Agent**") for the Notes in the Borough of Manhattan, City of New York. Deutsche Bank Trust Company Americas in New York will act as the initial principal Paying Agent (the "**Principal Paying Agent**").

The Company will also maintain both a registrar (the "**Registrar**") and a transfer agent (the "**Transfer Agent**") in the Borough of Manhattan, City of New York. The initial Registrar will be Deutsche Bank Trust Company Americas, and the initial Transfer Agent will be Deutsche Bank Trust Company Americas. The Registrar will maintain a register reflecting record ownership of the Global Notes and any Definitive Registered Notes outstanding from time to time, and the Transfer Agent will facilitate transfers of any Definitive Registered Notes on behalf of the Company.

The Company may change the Paying Agent, the Registrar or the Transfer Agent without prior notice to the holders of the Notes. For so long as the Notes are listing on the Official List of the Luxembourg Stock Exchange and if and to the extent the rules of the Authority so require the Company will notify the Authority of any change of Paying Agent, Registrar or Transfer Agent in respect of the Notes.

Note Guarantees

The Notes will be guaranteed by the Guarantors, which comprise certain of the Company's current Subsidiaries that are borrowers and guarantors under the RBL Facility. The Note Guarantees will be joint and several obligations of the Guarantors. The obligations of the Guarantors under the Note Guarantees will be subordinated in right of payment to the Guarantors' obligations under the RBL Facility, and may be subordinated in right of payment to the Guarantors' future senior obligations. See "*—Subordination of the Note Guarantees*." The obligations of the Guarantors will be contractually limited under the applicable Note Guarantees to reflect limitations under applicable law with respect to maintenance of share capital, corporate benefit, fraudulent conveyance and other legal restrictions applicable to the Guarantors and their respective shareholders, directors and general partners. See "*Risk factors—Risks relating to the Notes and our structure—Each Note Guarantee will be subject to certain limitations on enforcement and may be limited by applicable laws or subject to certain defenses that may limit its validity and enforceability*."

Note Guarantees release

The Note Guarantee of a Guarantor will be automatically and unconditionally released and discharged without any further action by the Company, the relevant Guarantor or the Trustee, and such Guarantor's obligations under the Note Guarantee, the Indenture, the Guarantee Subordination Agreement and any Additional Guarantee Subordination Agreement will terminate and be of no further force and effect:

(1) in connection with any sale or other disposition of all or substantially all of the properties or assets of that Guarantor (including by way of merger, amalgamation or consolidation) to a Person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, if the sale or other disposition does not violate the provisions set forth below under "*—Repurchase at the option of holders—Asset sales*";

(2) in connection with any sale or other disposition of the Capital Stock of that Guarantor (whether by direct sale or through a holding company) to a Person that is not (either before or after giving effect to such transaction) the Company or a Restricted Subsidiary of the Company, if the sale or other disposition does not violate the provisions set forth below under "*—Repurchase at the option of holders—Asset sales*" and as a result of such disposition such Guarantor no longer qualifies as a Subsidiary of the Company;

(3) if the Company designates such Guarantor (or any parent entity thereof) as an Unrestricted Subsidiary in accordance with the applicable provisions of the Indenture;

(4) as a result of a transaction permitted by "*—Certain covenants—Merger, consolidation or sale of assets*;"

(5) upon repayment in full of the Notes or upon Legal Defeasance or Covenant Defeasance as described below under the caption "*—Legal defeasance and covenant defeasance*" or upon satisfaction and discharge of the Indenture as described under the caption "*—Satisfaction and discharge*";

(6) upon the liquidation, winding up, dissolution or corporate reorganization of such Guarantor on a solvent basis or in case of a Dormant Guarantor; *provided* that no Default or Event of Default has occurred and is continuing or would be caused thereby;

(7) as described under "*—Amendment, supplement and waiver*";

(8) in connection with the implementation of a Permitted Reorganization;

(9) upon such Guarantor consolidating or amalgamating with, merging into or transferring all of its properties or assets to the Company or another Guarantor, and as a result of, or in connection with, such transaction such Guarantor dissolving or otherwise ceasing to exist;

(10) as described in the fourth paragraph of the covenant described below under "*—Certain covenants—Limitation on guarantees of indebtedness by restricted subsidiaries*"; or

(11) in connection with certain enforcement actions taken by the creditors under the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement.

The Indenture will provide that any release of a Guarantee may be evidenced, at the Company's option and expense, by the delivery by the Company to the Trustee of an Officer's Certificate of the Company. The Trustee shall take all necessary actions reasonably requested by the Company, including the granting of releases or waivers, to effectuate any release in accordance with these provisions, subject to customary protections and indemnifications.

Subordination of the Note Guarantees

On the Issue Date, the Trustee shall accede to the Guarantee Subordination Agreement entered into on April 9, 2014, among others, the Company, the agents and security trustee under the senior facility, as described under "*Description of certain financing arrangements—Guarantee subordination agreement*." The Note Guarantees will be subordinated in right of payment to outstanding claims under the Senior Debt of the Guarantors, including obligations under the RBL Facility. In addition, the payment on each Note Guarantee will be subject to provisions in the Guarantee Subordination Agreement relating to payment blockage, restrictions on enforcement, turnover, release and other customary senior debt protections. See "*Description of certain financing arrangements—Guarantee subordination agreement*."

Additional amounts

All payments made by or on behalf of the Company under or with respect to the Notes or any of the Guarantors with respect to any Note Guarantee will be made free and clear of and without withholding or deduction for, or on account of, any present or future Taxes unless the withholding or deduction for, or on account of, such Taxes is then required by law. If any deduction or withholding for, or on account of, any Taxes imposed or levied by or on behalf of (1) any jurisdiction in which the Company or any Guarantor is then incorporated, organized or resident for tax purposes or any political subdivision thereof or therein or (2) any jurisdiction from or through which payment is made by or on behalf of the Company or any Guarantor (including the jurisdiction of any Paying Agent) or any political subdivision thereof or therein (each of clause (1) and (2), a "**Tax Jurisdiction**") will at any time be required to be made from any payments made by the Company under or with respect to the Notes or any of the Guarantors with respect to any Note Guarantee, including payments of principal, redemption price, purchase price, interest or premium, the Company or the relevant Guarantor, as applicable, will pay such additional amounts (the "**Additional Amounts**") as may be necessary in order that the net amounts received in respect of such payments by each holder of Notes (including payments of the Additional Amounts) after such withholding or deduction will equal the respective amounts that would have been received in respect of such payments in the absence of such withholding or deduction; *provided, however,* that no Additional Amounts will be payable with respect to:

(1) any Taxes, to the extent such Taxes would not have been imposed but for the existence of any present or former connection between the holder (or between a fiduciary, settlor, beneficiary, member or shareholder of, or possessor of a power over, the relevant holder, if the relevant holder is an estate, nominee, trust, partnership, limited liability company or corporation) or the beneficial owner of the Notes and the relevant Tax Jurisdiction (including, without limitation, being a resident of such jurisdiction for tax purposes), other than the mere holding of such Note, the enforcement of rights under such Note or under a Note Guarantee or the receipt of any payments in respect of such Note or a Note Guarantee;

(2) any Taxes, to the extent such Taxes were imposed as a result of the presentation of a Note for payment (where presentation is required) more than 30 days after the relevant payment is first made available for payment to the holder (except to the extent that the holder would have been entitled to Additional Amounts had the Note been presented on the last day of such 30-day period);

(3) any estate, inheritance, gift, sales, transfer, personal property or similar Taxes;

(4) Taxes imposed on or with respect to a payment made to a holder or beneficial owner of Notes who would have been able to avoid such withholding or deduction by presenting the relevant Notes to another Paying Agent;

(5) any Taxes not payable by deduction or withholding from payments under, or with respect to, the Notes or with respect to any Note Guarantee;

(6) any Taxes, to the extent such Taxes are imposed, withheld or deducted by reason of the failure of the holder or beneficial owner of Notes to comply with any reasonable written request of the Company or the relevant Guarantor, addressed to the holder and made at least 30 days before any such withholding or deduction is to be made, to satisfy any certification, identification, information or other reporting requirements, whether required by statute, treaty, regulation or administrative practice of a Tax Jurisdiction, as a precondition to exemption from, or reduction in the rate of deduction or withholding of, Taxes imposed by the Tax Jurisdiction (including, without limitation, a certification that the holder or beneficial owner is not resident in the Tax Jurisdiction), but in each case, only to the extent the holder or beneficial owner is legally entitled to satisfy such requirement;

(7) any Taxes imposed or withheld pursuant to Sections 1471 through 1474 of the United States Internal Revenue Code of 1986, as amended (the "**Code**") as of the Issue Date (or any amended or successor version of such sections), any current or future regulations promulgated thereunder, any official interpretations thereof, any similar law or regulation adopted pursuant to an intergovernmental agreement between a non-U.S. jurisdiction and the United States with respect to the foregoing or any agreements entered into pursuant to section 1471(b)(1) of the Code;

(8) any Tax that is imposed on or with respect to any payment with respect to the Notes and Note Guarantee made to any holder who is a fiduciary or partnership or an entity that is not the sole beneficial owner of such payment, to the extent that a beneficiary or settlor (for tax purposes) with respect to such fiduciary, a member of such partnership or the beneficial owner of such payment would not have been entitled to the Additional Amounts had such beneficiary, settlor, member or beneficial owner been the actual holder of the applicable Note; or

(9) any combination of items (1) through (8) above.

In addition to the foregoing, the Company and the Guarantors will also pay and indemnify the Trustee, Paying Agents and holders for any present or future stamp, issue, registration, court or documentary taxes, or any other excise or property taxes, charges or similar levies (including penalties, interest and any other reasonable expenses related thereto), which are levied by any Tax Jurisdiction on the execution, delivery, issuance, enforcement or registration of any of the Notes, the Indenture or any Note Guarantee or any other document referred to therein, except for any such taxes imposed or levied as a result of a transfer after the Issue Date.

If the Company or any Guarantor, as the case may be, becomes aware that it will be obligated to pay Additional Amounts with respect to any payment under or with respect to the Notes or any Note Guarantee, the Company or the relevant Guarantor, as the case may be, will deliver to the Trustee and Paying Agents on a date that is at least 30 days prior to the date of that payment (unless the obligation to pay Additional Amounts arises less than 30 days prior to that payment date, in which case the Company or the relevant Guarantor shall notify the Trustee promptly thereafter) an Officers' Certificate stating the fact that Additional Amounts will be payable and the amount estimated to be so payable. The Officers' Certificate must also set forth any other information reasonably necessary to enable any Paying Agent to pay Additional Amounts to holders on the relevant payment date. The Trustee and Paying Agents shall be entitled to rely solely on such Officers' Certificate as conclusive proof that such payments are necessary.

The Company or the relevant Guarantor will make all withholdings and deductions for, or on account of, Taxes required by law and will remit the full amount deducted or withheld to the relevant Tax authority in accordance with applicable law. The Company or the relevant Guarantor will use its reasonable efforts to obtain Tax receipts from each Tax authority evidencing the payment of any Taxes so deducted or withheld. The Company or the relevant Guarantor will furnish to the Trustee (or to a holder upon written request), within a reasonable time after the date the payment of any Taxes so deducted or withheld is made to the relevant Tax authority, certified copies of Tax receipts evidencing payment by the Company or the Guarantor, as the case may be, or if, notwithstanding such entity's efforts to obtain receipts, receipts are not obtained, other evidence of such payments (reasonably satisfactory to the Trustee) by such entity.

Whenever in the Indenture or in this "*Description of Notes*" there is mentioned, in any context, the payment of amounts based upon the principal amount of the Notes or of principal, interest or any other amount payable under, or with respect to, any of the Notes or any Note Guarantee, such mention shall be deemed to include mention of the payment of Additional Amounts to the extent that, in such context, Additional Amounts are, were or would be payable in respect thereof.

The above obligations will survive any termination, defeasance or discharge of the Indenture or any transfer by a holder or beneficial owner of its Notes, and will apply, *mutatis mutandis*, to any jurisdiction in which any successor Person to the Company or any Guarantor is incorporated, organized or resident for tax purposes or any political subdivision thereof or therein or any jurisdiction from or through which such Person makes any payment on the Notes (or any Note Guarantee) or any political subdivision thereof or therein.

Optional redemption

Except as otherwise described below, the Notes will not be redeemable at the Company's option prior to maturity. The Company and any Restricted Subsidiary may, however, acquire, or cause to be acquired, the Notes by means other than a redemption, whether pursuant to a tender offer, open market purchase or otherwise, so long as the acquisition does not violate the terms of the Indenture.

Prior to April 30, 2028 the Company may, at its option, on any one or more occasions, redeem up to 40% of the aggregate principal amount of the Notes (including any Additional Notes issued after the Issue Date) at a redemption price equal to 109.875% of the principal amount thereof, plus accrued and unpaid interest thereon to the redemption date, subject to the right of the holders on the relevant record date to receive interest due on the relevant interest payment date, with all or a portion of the net proceeds of one or more Equity Offerings; *provided* that at least 50% of the aggregate principal amount of the Notes (including any Additional Notes) issued under the Indenture remains outstanding immediately after the occurrence of such redemption; and *provided, further,* that such redemption shall occur within 180 days of the date of the closing of any such Equity Offering.

In addition, at any time prior to April 30, 2028 the Company may also redeem, in whole or in part, the Notes at a redemption price equal to 100% of the principal amount of Notes to be redeemed, plus the Applicable Premium in respect of, and accrued and unpaid interest to the redemption date, subject to the rights of the holders on the relevant record date to receive interest due on the relevant interest payment date.

Except pursuant to the preceding two paragraphs and except pursuant to "*—Redemption for changes in taxes*," the Notes will not be redeemable at the Company's option prior to April 30, 2028.

On or after April 30, 2028, the Company may on any one or more occasions redeem all or a part of the Notes at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest, if any, on the Notes redeemed, to the applicable date of redemption, if redeemed during the twelve-month period beginning on April 30 of the years indicated below, subject to the rights of holders of Notes on the relevant record date to receive interest on the relevant interest payment date:

Year	Redemption Price
2028	104.9375%
2029	102.4688%
2030 and thereafter	100.0000%

Prior to April 30, 2028, the Company may redeem during each twelve-month period commencing with the Issue Date up to 10% of the original principal amount of the Notes at its option at a redemption price equal to 103% of the principal amount of the Notes so redeemed, plus accrued and unpaid interest, if any, to the applicable redemption date.

All redemptions of the Notes will be made upon not less than 10 days' nor more than 60 days' prior notice, except that a redemption notice may be made more than 60 days prior to a redemption date if the notice is issued in connection with a defeasance of the Notes or a satisfaction and discharge of the Indenture. Unless the Company defaults in the payment of the redemption price, interest will cease to accrue on the Notes or portions thereof called for redemption on the applicable redemption date. If a redemption date is not a Business Day, payment may be made on the next succeeding day that is a Business Day, and no interest shall accrue on any

amount that would not have been otherwise payable on such redemption date if it were a Business Day for the intervening period.

Any redemption including, without limitation, upon an Equity Offering may, at the Company's discretion, be subject to one or more conditions precedent, including, but not limited to, completion of the related Equity Offering.

In addition, if such redemption is subject to the satisfaction of one or more conditions precedent, the notice of redemption shall describe each such condition and, in the Company's discretion, the redemption date may be delayed until such time as any or all such conditions shall be satisfied or waived, or such redemption may not occur and the notice of redemption may be rescinded in the event that any or all such conditions shall not have been satisfied or waived by the redemption date, or by the redemption date so delayed.

Subject to the applicable procedures of DTC, the Company may redeem Notes pursuant to one or more of the relevant provisions of the Indenture, and a single notice of redemption may be delivered with respect to redemptions made pursuant to different provisions. Any such notice may provide that redemptions made pursuant to different provisions will have different redemption dates.

Optional redemption upon certain tender offers

In connection with any tender offer or other offer to purchase for all of the Notes, including a Change of Control Offer or Asset Sale Offer, if holders of not less than 90% of the aggregate principal amount of the then outstanding Notes validly tender and do not validly withdraw such Notes in such tender offer or other offer and the Company, or any third party making such tender offer or other offer in lieu of the Company, purchases all of the Notes validly tendered and not validly withdrawn by such holders, all of the holders of the Notes will be deemed to have consented to such tender offer or other offer and, accordingly, the Company or such third party will have the right upon not less than 10 nor more than 60 days' notice following such purchase date, to redeem all Notes that remain outstanding following such purchase at a price equal to the price paid (excluding any early tender premium or similar payment) to each other holder in such tender offer or other offer, plus, to the extent not included in the tender offer payment or other offer payment, accrued and unpaid interest, if any, thereon, to, but excluding, the date of such redemption.

Redemption for changes in taxes

The Company may redeem the Notes, in whole but not in part, at its discretion at any time upon giving not less than 10 nor more than 60 days' prior notice to the holders of the Notes (with a copy to the Trustee and Paying Agent) (which notice will be irrevocable and given in accordance with the procedures described in "— *Selection and notice*"), at a redemption price equal to 100% of the aggregate principal amount thereof, together with accrued and unpaid interest, if any, to the date fixed by the Company for redemption (a "**Tax Redemption Date**") and all Additional Amounts (if any) then due and which will become due on the Tax Redemption Date as a result of the redemption or otherwise (subject to the right of holders of the Notes on the relevant record date to receive interest due on an interest payment date that is on or prior to the Tax Redemption Date and Additional Amounts (if any) in respect thereof), if on the next date on which any amount would be payable in respect of the Notes, the Company or a Guarantor is or would be required to pay Additional Amounts, and the Company or Guarantor cannot avoid any such payment obligation by taking reasonable measures available to it, including, for the avoidance of doubt, the appointment of a new Paying Agent where this would be reasonable (provided that changing the jurisdiction of the Company or any Guarantor is not a reasonable measure for the purposes of this section), and the requirement arises as a result of:

(1) any amendment to, or change in, the laws or treaties (or any protocols, regulations or rulings promulgated thereunder) of a relevant Tax Jurisdiction which change or amendment is announced and becomes effective on or after the Issue Date (or, if the applicable Tax Jurisdiction became a Tax Jurisdiction on a date after the Issue Date, such later date); or

(2) any amendment to, or change in, an official position, or the introduction of an official position, regarding the interpretation, administration or application of such protocols, laws, regulations, treaties or rulings (including by virtue of a holding, judgment or order by a court of competent jurisdiction or a change in published administrative practice) which amendment, change or introduction is announced and becomes

effective on or after the Issue Date (or, if the applicable Tax Jurisdiction became a Tax Jurisdiction on a date after the Issue Date, such later date) (each of clause (1) and (2) a "**Change in Tax Law**").

The Company will not give any such notice of redemption earlier than 60 days prior to the earliest date on which the Company or Guarantor would be obligated to make such payment or withholding if a payment in respect of the Notes or Note Guarantees was then due, and the obligation to pay Additional Amounts must be in effect at the time such notice is given. Prior to the publication or provision of any notice of redemption of the Notes pursuant to the foregoing, the Company will deliver to the Trustee an opinion of independent tax counsel of recognized standing, to the effect that there has been such Change in Tax Law. In addition, before the Company publishes or provides notice of redemption of the Notes as described above, it will deliver to the Trustee an Officers' Certificate to the effect that the obligation to pay Additional Amounts cannot be avoided by the Company or Guarantor taking reasonable measures available to it.

The Trustee will accept and shall be entitled to rely on such Officers' Certificate and opinion of counsel as sufficient evidence, without further inquiry, of the existence and satisfaction of the conditions precedent as described above, in which event it will be conclusive and binding on the holders of the Notes.

Mandatory redemption

The Company is not required to make mandatory redemption or sinking fund payments with respect to the Notes. However, under certain circumstances, the Company may be required to offer to purchase the Notes as described under the captions "*—Repurchase at the option of holders—Change of control*" and "*—Asset sales*."

Repurchase at the option of holders

Change of control

If a Change of Control occurs, each holder of Notes will have the right to require the Company to repurchase all or any part (equal to $200,000 or an integral multiple of $1,000 in excess thereof) of that holder's Notes pursuant to an offer (the "**Change of Control Offer**") on the terms set forth in the Indenture. In the Change of Control Offer, the Company will offer a payment in cash (the "**Change of Control Payment**") equal to 101% of the aggregate principal amount of Notes repurchased plus accrued and unpaid interest on the Notes repurchased to the date of purchase (the "**Change of Control Payment Date**"), subject to the rights of holders of Notes on the relevant record date to receive interest due on the relevant interest payment date. Within 30 days following any Change of Control, the Company will provide a notice to each holder (with a copy to the Trustee) or otherwise deliver a notice (with a copy to the Trustee) in accordance with the procedures described under "*—Selection and notice*," describing the transaction or transactions that constitute the Change of Control and offering to repurchase Notes on the Change of Control Payment Date specified in the notice, which date will be no earlier than 10 days and no later than 60 days from the date such notice is provided, pursuant to the procedures required by the Indenture and described in such notice.

On the Change of Control Payment Date, the Company will, to the extent lawful:

(1) accept for payment all Notes or portions of Notes properly tendered pursuant to the Change of Control Offer;

(2) deposit with the Principal Paying Agent an amount equal to the Change of Control Payment in respect of all Notes or portions of Notes properly tendered; and

(3) deliver or cause to be delivered to the Principal Paying Agent the Notes properly accepted.

The Principal Paying Agent will promptly provide to each holder of Notes properly tendered the Change of Control Payment for such Notes, and the Trustee (or its authentication agent) will promptly authenticate and provide (or cause to be transferred by book entry) to each holder a new Note equal in principal amount to any unpurchased portion of the Notes surrendered, if any; *provided* that each such new Note will be in a principal amount of $200,000 or an integral multiple of $1,000 in excess thereof. Any Note so accepted for payment will cease to accrue interest on and after the Change of Control Payment Date unless the Company defaults in making the Change of Control Payment. The Company will publicly announce the results of the Change of Control Offer on or as soon as practicable after the Change of Control Payment Date.

The provisions described herein that require the Company to make a Change of Control Offer following a Change of Control will be applicable whether or not any other provisions of the Indenture are applicable. Except as described above with respect to a Change of Control, the Indenture will not contain provisions that permit the holders of the Notes to require that the Company repurchase or redeem the Notes in the event of a takeover, recapitalization or similar transaction.

The Company will not be required to make a Change of Control Offer upon a Change of Control if (1) a third party makes the Change of Control Offer in the manner, at the time and otherwise in compliance with the requirements set forth in the Indenture applicable to a Change of Control Offer made by the Company and purchases all Notes properly tendered and not withdrawn under the Change of Control Offer, or (2) notice of redemption of all outstanding Notes has been given pursuant to the Indenture as described above under the caption "*—Optional redemption*," unless and until there is a default in payment of the applicable redemption price.

The occurrence of certain events that would constitute a Change of Control could constitute a default under the RBL Facility and could also allow holders of the 9% Retail Notes to exercise a put option in respect of the 9% Retail Notes. Future debt of the Company or its Subsidiaries may also contain descriptions of certain change of control events that, if they occurred, would constitute a default under such debt or require such debt to be repurchased. In addition, the exercise by the holders of the Notes of their right to require the Company to purchase the Notes could cause a default under, or require a repurchase of, other debt, even if the Change of Control itself does not, due to the financial effect of the purchase on the Company. If a Change of Control Offer is made, there can be no assurance that the Company will have sufficient funds or other resources to pay the Change of Control Payment for all the Notes that might be delivered by holders thereof seeking to accept the Change of Control Offer and to repurchase any other debt that may be required to be repaid following a change of control. See "*Risk factors—Risks relating to the Notes and our structure—We may not be able to obtain the funds required to repurchase the Notes upon a change of control*."

Notwithstanding anything to the contrary contained herein, a Change of Control Offer may be made in advance of a Change of Control, and conditioned upon the occurrence of such Change of Control, if a definitive agreement is in place for the Change of Control at the time of making the Change of Control Offer.

The definition of Change of Control includes a phrase relating to the direct or indirect sale, lease, transfer, conveyance or other disposition of "all or substantially all" of the properties or assets of the Company and its Restricted Subsidiaries taken as a whole. Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, the ability of a holder of the Notes to require the Company to repurchase its Notes as a result of a sale, lease, transfer, conveyance or other disposition of less than all of the properties or assets of the Company and its Restricted Subsidiaries may be uncertain.

The provisions under the Indenture relating to the Company's obligation to make an offer to repurchase the Notes as a result of a Change of Control may be waived or modified with the consent of the holders of a majority in aggregate principal amount of the Notes.

If and for so long as the Notes are listed on the Official List of the Luxembourg Stock Exchange and admitted for trading on the Euro MTF Market and the rules of the Luxembourg Stock Exchange so require, the Company will notify the Authority of such Change of Control Offer.

Asset sales

The Company will not, and will not permit any of its Restricted Subsidiaries to, consummate an Asset Sale unless:

(1) the Company (or a Restricted Subsidiary, as the case may be) receives consideration at the time of the Asset Sale at least equal to the Fair Market Value of the assets or Equity Interests issued or sold or otherwise disposed of; and

(2) at least 75% of the consideration received in the Asset Sale by the Company or such Restricted Subsidiary is in the form of cash or Cash Equivalents. For purposes of this provision, each of the following will be deemed to be cash:

(a) any liabilities, as shown on the most recent consolidated balance sheet, of the Company or any Restricted Subsidiary (other than contingent liabilities and liabilities that are by their terms subordinated to the Notes or any Note Guarantee) that are assumed by the transferee of any such assets pursuant to an agreement that releases the Company or such Restricted Subsidiary from further liability or indemnifies the Company or such Restricted Subsidiary against further liabilities;

(b) any securities, notes or other obligations received by the Company or any Restricted Subsidiary from such transferee that are converted by the Company or such Restricted Subsidiary into cash or Cash Equivalents within 180 days following the closing of the Asset Sale, to the extent of the cash or Cash Equivalents received in that conversion;

(c) with respect to any Asset Sale of oil and gas properties by the Company or any of its Restricted Subsidiaries, the costs and expenses related to the exploration, development, completion or production of such oil and gas properties and activities related thereto agreed to be assumed by the transferee (or an Affiliate thereof);

(d) any Capital Stock or other assets of the kind referred to in clauses (3) or (4) of the next paragraph of this covenant;

(e) Indebtedness (other than Subordinated Obligations) of any Restricted Subsidiary that is no longer a Restricted Subsidiary as a result of such Asset Sale, to the extent that the Company and each other Restricted Subsidiary are released from any Guarantee of such Indebtedness in connection with such Asset Sale;

(f) consideration consisting of Indebtedness of the Company or any Guarantor received from Persons who are not the Company or any Restricted Subsidiary;

(g) accounts receivable of a business retained by the Company or any Restricted Subsidiary, as the case may be, following the sale of such business; and

(h) any Designated Non-Cash Consideration received by the Company or any Restricted Subsidiary in such Asset Sales having an aggregate Fair Market Value, taken together with all other Designated Non-Cash Consideration received pursuant to this clause (h) that is at that time outstanding, not to exceed the greater of (x) $250.0 million and (y) 7.0% of Consolidated Total Assets at the time of the receipt of such Designated Non-Cash Consideration (with the Fair Market Value of each item of Designated Non- Cash Consideration being measured at the time received and without giving effect to subsequent changes in value).

Within 365 days after the receipt of any Net Proceeds from an Asset Sale, the Company or one of its Restricted Subsidiaries may apply such Net Proceeds (at the option of the Company or such Restricted Subsidiary):

(1) to purchase the Notes pursuant to an offer to all holders of Notes at a purchase price equal to at least 100% of the principal amount thereof, plus accrued and unpaid interest to the date of purchase (a "**Notes Offer**");

(2) to repay Senior Debt;

(3) to invest in Additional Assets;

(4) to make a capital expenditure; or

(5) to enter into a binding commitment to apply the Net Proceeds pursuant to clauses (2), (3) or (4) of this paragraph; *provided* that such binding commitment shall be treated as a permitted application of the Net Proceeds from the date of such commitment until the earlier of (x) the date on which such repayment, investment or expenditure is consummated, and (y) the 180th day following the expiration of the aforementioned 365-day period.

Pending the final application of any Net Proceeds, the Company or any Restricted Subsidiary may temporarily reduce revolving credit borrowings or otherwise invest the Net Proceeds in any manner that is not prohibited by the Indenture. Any Net Proceeds from Asset Sales that are not applied or invested pursuant to the second paragraph of this covenant will constitute "**Excess Proceeds**."

When the aggregate amount of Excess Proceeds exceeds $75.0 million, within ten Business Days thereof, the Company will make an offer (an "**Asset Sale Offer**") to all holders of Notes and may make an offer to all holders of other Indebtedness that is *pari passu* with the Notes or any Note Guarantees to purchase, prepay or redeem with the proceeds of sales of assets the maximum principal amount of Notes and such other *pari passu* Indebtedness (plus all accrued interest on the Indebtedness and the amount of all fees and expenses, including premiums, incurred in connection therewith) that may be purchased, prepaid or redeemed out of the Excess Proceeds. The offer price for the Notes in any Asset Sale Offer will be equal to 100% of the principal amount, plus accrued and unpaid interest, if any, to the date of purchase, prepayment or redemption, subject to the rights of holders of Notes on the relevant record date to receive interest due on the relevant interest payment date, and will be payable in cash. If any Excess Proceeds remain after consummation of an Asset Sale Offer, the Company or any of its Restricted Subsidiaries may use those Excess Proceeds for any purpose not otherwise prohibited by the Indenture. If the aggregate principal amount of Notes and other *pari passu* Indebtedness tendered into (or to be prepaid or redeemed in connection with) such Asset Sale Offer exceeds the amount of Excess Proceeds or if the aggregate amount of Notes tendered pursuant to a Notes Offer exceeds the amount of the Net Proceeds so applied, the Company will select the Notes and such other *pari passu* Indebtedness, if applicable, to be purchased on a *pro rata* basis or, in the case of Notes issued in global form as discussed under "*Book-entry, delivery and form*," based on a method that most nearly approximates a *pro rata* selection as the Company deems fair and appropriate unless otherwise required by applicable law or applicable stock exchange or depositary requirements, based on the amounts tendered or required to be prepaid or redeemed. Upon completion of each Asset Sale Offer, the amount of Excess Proceeds will be reset at zero.

The Company will comply with the requirements of Rule 14e-1 under the U.S. Exchange Act and any other applicable securities laws and regulations to the extent those laws and regulations are applicable in connection with each repurchase of Notes pursuant to a Change of Control Offer, an Asset Sale Offer or a Notes Offer. To the extent that the provisions of any securities laws or regulations conflict with the Change of Control, Asset Sale or Notes Offer provisions of the Indenture, the Company will comply with the applicable securities laws and regulations and will not be deemed to have breached its obligations under the Change of Control, Asset Sale or Notes Offer provisions of the Indenture by virtue of such compliance.

Selection and notice

If less than all of the Notes are to be redeemed at any time, the Trustee, a Paying Agent or the Registrar (as applicable) will select Notes for redemption on a *pro rata* pass-through distribution basis or in accordance with the procedures of DTC (or, in the case of Notes issued in global form as discussed under "*Book-Entry, Delivery and Form*," based on a method that most nearly approximates a *pro rata* selection) unless otherwise required by law or applicable stock exchange or depository requirements.

No Notes of $200,000 or less can be redeemed in part and only Notes in integral multiples of $1,000 will be redeemed. Notices of redemption will be provided at least 10 days but not more than 60 days before the redemption date to each holder of Notes to be redeemed at its registered address, except that redemption notices may be provided more than 60 days prior to a redemption date if the notice is issued in connection with a defeasance of the Notes or a satisfaction and discharge of the Indenture.

If the Company elects to redeem the Notes or portions thereof and requests the Trustee (or such other entity directed, designated or appointed by the Trustee in accordance with the provisions set forth under "*Satisfaction and Discharge*") to distribute to the holders any amounts deposited in trust (which, for the avoidance of doubt, will include accrued and unpaid interest to the date fixed for redemption) prior to the date fixed for redemption in accordance with the provisions set forth under "*Satisfaction and Discharge*," the applicable redemption notice will state that holders will receive such amounts deposited in trust prior to the date fixed for redemption and state the payment date.

If any Note is to be redeemed in part only, the notice of redemption that relates to that Note will state the portion of the principal amount of that Note that is to be redeemed. A new Note in principal amount equal to the unredeemed portion of the original Note will be issued in the name of the holder of Notes upon cancellation of

the original Note. A notice of redemption shall state whether the redemption is conditioned on any events and, if so, a detailed explanation of such conditions. Subject to the satisfaction of any conditions precedent set forth in a notice of redemption, Notes called for redemption become due on the date fixed for redemption. On or after the redemption date, interest ceases to accrue on Notes or portions of Notes called for redemption.

None of the Trustee, any Paying Agent or the Registrar shall be liable for any such selections made by them in accordance with the provisions described in the four preceding paragraphs.

For Notes which are represented by global certificates held on behalf of DTC, notices may be given by delivery of the relevant notices to DTC in accordance with its applicable procedures for communication to entitled account holders in substitution for any required mailing. So long as any Notes are listed on the Official List of the Luxembourg Stock Exchange and admitted to trading on the Euro MTF Market and the rules of the Luxembourg Stock Exchange so require, any such notice to the holders of the Notes shall also be published with an appropriate internationally recognized wire service (including, without limitation, through the newswire service of Bloomberg, or if Bloomberg does not then operate, any similar agency) or, to the extent and in the manner permitted by such rules, posted on the official website of the Exchange and, in connection with any redemption, the Company will notify the Authority of any change in the principal amount of Notes outstanding.

Certain covenants

Restricted payments

The Company will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly:

(1) declare or pay any dividend or make any other payment or distribution on account of the Company's or any of its Restricted Subsidiaries' Equity Interests (including, without limitation, any such payment or distribution made in connection with any merger, amalgamation or consolidation involving the Company or any of its Restricted Subsidiaries) or to the direct or indirect holders of the Company's or any of its Restricted Subsidiaries' Equity Interests in their capacity as such (other than dividends or distributions payable in Equity Interests (other than Disqualified Stock) of the Company and other than dividends or distributions payable to the Company or a Restricted Subsidiary of the Company);

(2) repurchase, redeem or otherwise acquire or retire for value (including, without limitation, any such purchase, redemption, acquisition or retirement made in connection with any merger, amalgamation or consolidation involving the Company) any Equity Interests of the Company or any direct or indirect parent of the Company;

(3) make any principal payment on or with respect to, or repurchase, redeem, defease or otherwise acquire or retire for value, prior to the Stated Maturity thereof, any Indebtedness of the Company or any Guarantor that is expressly contractually subordinated in right of payment to the Notes or to any Note Guarantee (excluding any intercompany Indebtedness between or among the Company and/or any of its Restricted Subsidiaries), except (i) a payment of principal at the Stated Maturity thereof or (ii) the repurchase, redemption or other acquisition of Indebtedness in anticipation of satisfying a sinking fund obligation, principal installment or scheduled maturity, in each case due within one year of the date of such repurchase, redemption or other acquisition; or

(4) make any Restricted Investment;

(all such payments and other actions set forth in clauses (1) through (4) above being collectively referred to as "**Restricted Payments**"), unless, at the time of and after giving effect to such Restricted Payment:

(1) no Default or Event of Default has occurred and is continuing or would occur as a consequence of such Restricted Payment;

(2) at the time of such Restricted Payment and after giving *pro forma* effect thereto as if such Restricted Payment had been made at the beginning of the applicable two half-year reference period, the Company would have been permitted to incur at least $1.00 of additional Indebtedness pursuant to the Fixed Charge Coverage Ratio test set forth in the first paragraph of the covenant described below under the caption "— *Incurrence of indebtedness and issuance of preferred stock*"; and

(3) such Restricted Payment, together with the aggregate amount of all other Restricted Payments made by the Company and its Restricted Subsidiaries since the Issue Date (including Restricted Payments permitted below by clauses (1) and (13) of the next succeeding paragraph, but excluding all other Restricted Payments permitted by the next succeeding paragraph), is equal to or less than the sum, without duplication, of:

(a) 50% of the Consolidated Net Income of the Company for the period (taken as one accounting period) from the beginning of the half-year period commencing immediately prior to the Issue Date to the end of the Company's most recently ended fiscal half-year for which internal financial statements are available at the time of such Restricted Payment (or, if such Consolidated Net Income for such period is a deficit, less 100% of such deficit) provided that the amount taken into account pursuant to this sub-clause (a) shall not be less than zero; *plus*

(b) 100% of the aggregate net cash proceeds received, the Fair Market Value of marketable securities received and the Fair Market Value of other property or assets received by the Company subsequent to the Issue Date as a contribution to its common capital or from the issue or sale of Equity Interests of the Company (other than Disqualified Stock) or from the issue or sale of convertible or exchangeable Disqualified Stock or convertible or exchangeable debt securities of the Company that have been converted into or exchanged for such Equity Interests (other than Equity Interests (or Disqualified Stock or debt securities) sold to a Subsidiary of the Company); *plus*

(c)

(i) to the extent that any Restricted Investment that was made subsequent to the Issue Date is (x) sold, disposed of or otherwise cancelled, liquidated or repaid, 100% of the aggregate amount received in cash and the Fair Market Value of the marketable securities and other property received by the Company or any Restricted Subsidiary, or (y) made in an entity that subsequently becomes a Restricted Subsidiary, 100% of the Fair Market Value of the Restricted Investment of the Company and its Restricted Subsidiaries as of the date such entity becomes a Restricted Subsidiary; *plus*

(ii) to the extent that any Unrestricted Subsidiary of the Company designated as such subsequent to the Issue Date is redesignated as a Restricted Subsidiary or is merged, amalgamated or consolidated with or into the Company or a Restricted Subsidiary, or all or substantially all of the properties or assets of such Unrestricted Subsidiary are transferred to the Company or a Restricted Subsidiary, the Fair Market Value of the property received by the Company or Restricted Subsidiary or the Company's Restricted Investment in such Subsidiary as of the date of such redesignation, merger, amalgamation, consolidation or transfer of properties or assets, to the extent such Investments reduced the Restricted Payments capacity under this clause (c) and were not previously repaid or otherwise reduced; *plus*

(d) 100% of any dividends or distributions received in cash by the Company or a Restricted Subsidiary after the Issue Date from an Unrestricted Subsidiary, to the extent that such dividends or distributions were not otherwise included in the Consolidated Net Income of the Company for such period.

The preceding provisions will not prohibit:

(1) the payment of any dividend or the consummation of any irrevocable redemption within 60 days after the date of declaration of the dividend or giving of the redemption notice, as the case may be, if at the date of declaration or notice, the dividend or redemption payment would have complied with the provisions of the Indenture;

(2) the making of any Restricted Payment in exchange for, or out of the net cash proceeds of the substantially concurrent sale (other than to a Subsidiary of the Company) of, Equity Interests of the Company (other than Disqualified Stock) or from the substantially concurrent contribution of common equity capital to the Company; *provided* that the amount of any such net cash proceeds that are utilized for any such Restricted Payment will be excluded from clause (3)(b) of the preceding paragraph;

(3) the repurchase, redemption, defeasance or other acquisition or retirement for value of Indebtedness of the Company or any Guarantor that is contractually subordinated to the Notes or to any Note Guarantee with the net cash proceeds from a substantially concurrent incurrence of Permitted Refinancing Indebtedness for the purpose of such repurchase, redemption, defeasance or other acquisition or retirement for value;

(4) the payment of any dividend (or, in the case of any partnership or limited liability company, any similar distribution) by a Restricted Subsidiary of the Company to the holders of its Equity Interests (other than the Company or any Restricted Subsidiary) on no more than a *pro rata* basis;

(5) so long as no Default or Event of Default has occurred and is continuing or would be caused thereby, the repurchase, redemption or other acquisition or retirement for value of any Equity Interests of the Company or any Restricted Subsidiary of the Company held by any of the Company's (or any of its Restricted Subsidiaries') current or former officers, directors, employees or consultants pursuant to any equity subscription agreement, stock option agreement, restricted stock grant, shareholders' agreement or similar agreement; *provided* that the aggregate price paid for all such repurchased, redeemed, acquired or retired Equity Interests may not exceed $30.0 million in any calendar year and *provided*, *further*, that such amount in any calendar year may be increased by an amount not to exceed (A) the cash proceeds from the sale of Equity Interests of the Company or a Restricted Subsidiary received by the Company or a Restricted Subsidiary during such calendar year, in each case to members of management, directors or consultants of the Company, any of its Restricted Subsidiaries or any of its direct or indirect parent companies, to the extent the cash proceeds from the sale of Equity Interests have not otherwise been applied to the making of Restricted Payments pursuant to clause (3)(b) of the preceding paragraph or clause (2) of this paragraph and (B) the cash proceeds of key man life insurance policies;

(6) the repurchase, redemption or other acquisition or retirement for value of any Equity Interests of the Company or any Restricted Subsidiary of the Company held by any of the Company's (or any of its Restricted Subsidiaries') current or former directors or employees in connection with the exercise or vesting of any equity compensation (including, without limitation, stock options, restricted stock and phantom stock) in order to satisfy the Company's or such Restricted Subsidiary's tax withholding obligation with respect to such exercise or vesting;

(7) repurchases of Subordinated Obligations at a purchase price not greater than (i) 101% of the principal amount of such Subordinated Obligations and accrued and unpaid interest thereon in the event of a Change of Control or (ii) 100% of the principal amount of such Subordinated Obligations and accrued and unpaid interest thereon in the event of an Asset Sale, in each case plus accrued interest, in connection with any change of control offer or asset sale offer required by the terms of such Indebtedness, but only if:

(a) in the case of a Change of Control, the Company has first complied with and fully satisfied its obligations under the provisions described under "*—Repurchase at the option of holders—Change of control*"; or

(b) in the case of an Asset Sale, the Company has complied with and fully satisfied its obligations in accordance with the covenant under the heading, "*—Repurchase at the option of holders—Asset sales*";

(8) the repurchase, redemption or other acquisition for value of Capital Stock of the Company representing fractional shares of such Capital Stock in connection with a merger, consolidation, amalgamation or other combination involving the Company or any other transaction permitted by the Indenture;

(9) the repurchase of Equity Interests deemed to occur upon the exercise of stock options or warrants to the extent such Equity Interests represent a portion of the exercise price of those stock options or warrants;

(10) so long as no Default or Event of Default has occurred and is continuing or would be caused thereby, the declaration and payment of regularly scheduled or accrued dividends to holders of any class or series of Disqualified Stock of the Company or any Restricted Subsidiary of the Company issued on or after the Issue Date in accordance with the Fixed Charge Coverage Ratio test described below under the caption "*—Incurrence of indebtedness and issuance of preferred stock*";

(11) payments of cash, dividends, distributions, advances or other Restricted Payments by the Company or any of its Restricted Subsidiaries to allow the payment of cash in lieu of the issuance of fractional shares upon (x) the exercise of options or warrants or (y) the conversion or exchange of Capital Stock of any such Person;

(12) so long as no Default or Event of Default has occurred and is continuing or would be caused thereby, (a) advances or loans to any future, present or former officer, director, employee or consultant of the Company or a Restricted Subsidiary to pay for the purchase or other acquisition for value of Equity Interests of the Company (other than Disqualified Stock), or any obligation under a forward sale agreement, deferred purchase agreement or deferred payment arrangement pursuant to any management equity plan or stock option plan or any other management or employee benefit or incentive plan or other agreement or arrangement; *provided* that the total aggregate amount of Restricted Payments made under this subclause (a) does not exceed $5.0 million in any calendar year or (b) advances, grants or loans in relation to any management equity plan or stock option plan or any other management or employee benefit or incentive plan or unit trust, whether made directly to any such plan or trust or to the trustees of any such plan or trust, to pay for the purchase or other acquisition for value of Equity Interests of the Company (other than Disqualified Stock); *provided* that the total aggregate amount of Restricted Payments made under this subclause (b) does not exceed $75.0 million in any 12-month period;

(13) so long as no Default or Event of Default has occurred and is continuing or would be caused thereby, the repurchase of Equity Interests of the Company to be held as treasury stock; *provided* that the total aggregate amount of Restricted Payments made under this clause (13) does not exceed $150.0 million plus the cash proceeds from the sale of such Equity Interests of the Company from treasury stock since the Issue Date;

(14) so long as no Default has occurred and is continuing or would be caused thereby, the declaration or payment of dividends or distributions, or the making of any cash payments, advances, loans or expense reimbursements on the common stock or common equity interests of the Company or any direct or indirect parent company; *provided* that the aggregate amount of all such dividends or distributions under this clause (14) shall not exceed in any fiscal year the greater of (a) 7.0% per annum of the net cash proceeds received by the Company in any Public Equity Offering or contributed to the equity of the Company and (b) an amount equal to 7.0% of the Market Capitalization;

(15) so long as no Default or Event of Default has occurred and is continuing or would be caused thereby, other Restricted Payments in an aggregate amount not to exceed the greater of (a) $200.0 million and (b) 5.5% of Consolidated Total Assets since the Issue Date; and

(16) so long as no Default or Event of Default has occurred and is continuing or would be caused thereby, Restricted Payments aggregating up to an amount equivalent to 50% of the net cash proceeds received by the Company or any of its Restricted Subsidiaries from all dispositions (including, without limitation, any farm-out or lease) of oil and gas properties subsequent to the Issue Date; *provided* that, after giving *pro forma* effect to any such Restricted Payment (and any related transactions), the Consolidated Leverage Ratio of the Company does not exceed 2.0 to 1.0.

The amount of all Restricted Payments (other than cash) will be the Fair Market Value on the date of the Restricted Payment (or, in the case of a dividend, on the date of declaration) of the asset(s) or securities proposed to be transferred or issued by the Company or such Restricted Subsidiary, as the case may be, pursuant to the Restricted Payment. The Fair Market Value of any cash Restricted Payment shall be its face amount. The Company, in its sole discretion, may classify any Investment or other Restricted Payment as being made in part under one of the provisions of this covenant (or, in the case of any Investment, the clauses of the definition of Permitted Investments) and in part under one or more other such provisions (or, as applicable, clauses). Unsecured Indebtedness shall not be deemed to be subordinate or junior to secured Indebtedness solely by virtue of its nature as unsecured Indebtedness.

Incurrence of indebtedness and issuance of preferred stock

The Company will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly, create, incur, issue, assume, guarantee or otherwise become directly or indirectly liable, contingently or otherwise, with respect to (collectively, "**incur**") any Indebtedness (including Acquired Debt), and the Company will not issue any Disqualified Stock and will not permit any of its Restricted Subsidiaries to issue any shares of preferred

stock; *provided, however,* that the Company may incur Indebtedness (including Acquired Debt) or issue Disqualified Stock and any Restricted Subsidiary of the Company may incur Indebtedness (including Acquired Debt) or issue preferred stock, if the Fixed Charge Coverage Ratio for the Company's most recently ended two full fiscal half-years for which internal financial statements are available immediately preceding the date on which such additional Indebtedness is incurred or such Disqualified Stock or preferred stock is issued, as the case may be, would have been at least 2.25 to 1.0, determined on a *pro forma* basis (including a *pro forma* application of the net proceeds therefrom), as if the additional Indebtedness had been incurred or the Disqualified Stock or the preferred stock had been issued, as the case may be, at the beginning of such two half-year reference period.

The first paragraph of this covenant will not prohibit the incurrence of any of the following items of Indebtedness or issuances of Disqualified Stock or preferred stock (collectively, "**Permitted Debt**"):

(1) the incurrence by the Company and any Restricted Subsidiary of additional Indebtedness under Credit Facilities in an aggregate principal amount at any one time outstanding under this clause (1) not to exceed the greatest of (x) $675.0 million, (y) an amount equal to the sum of $100.0 million *plus* any amounts under all Borrowing Base Facilities of the Company and its Restricted Subsidiaries and (z) 20% of Consolidated Total Assets determined as of the date of such incurrence, *plus* in the case of any refinancing of any Indebtedness permitted under this clause (1) or any portion thereof, the aggregate amount of fees, accrued and unpaid interest, costs (including defeasance costs), premiums and expenses (including underwriting commissions paid as discounts) incurred in connection with such refinancing;

(2) the incurrence by the Company and its Restricted Subsidiaries of Indebtedness (other than Indebtedness incurred under clause (1) of this paragraph) outstanding on the Issue Date which remains outstanding on the Issue Date after giving effect to the Transactions including, for the avoidance of doubt, the 9% Retail Notes;

(3) [*Reserved*.];

(4) the incurrence by the Company of Indebtedness represented by the Notes to be issued on the date of the Indenture and the incurrence by any Guarantor of a Note Guarantee at any time;

(5) the incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness:

(a) incurred for the purpose of financing all or any part of the purchase price, lease expense, charter expense, rental payments or cost of design, development, construction, transportation, installation, migration or improvement of any FPSO, rig or production facility, transport or pipeline, in each case, used or useful in the Energy Business; or

(b) represented by Capital Lease Obligations, mortgage financings or purchase money obligations or other Indebtedness, in each case, incurred for the purpose of financing all or any part of the purchase price, lease expense, charter expense, rental payments or cost of design, development, construction, transportation, installation, migration, drydocking or improvement of property, plant or equipment or other assets used in the business of the Company or any of its Restricted Subsidiaries and any other capital expenses or operating expenses in relation thereto (including any reasonably related fees or expenses incurred in connection therewith), in an aggregate principal amount, including all Permitted Refinancing Indebtedness incurred to extend, renew, refund, refinance, replace, exchange, defease or discharge any Indebtedness incurred pursuant to this clause (5)(b), not to exceed the greater of (x) $130.0 million and (y) 3.5% of Consolidated Total Assets at any time outstanding,

in each case, whether such Indebtedness is incurred for the charter of, leasing of or direct purchase of or the purchase of the Capital Stock of any Person owning such property, plant or equipment or other assets (including any Indebtedness deemed to be incurred in connection with such purchase) (it being understood that any such Indebtedness may be incurred after the acquisition or purchase or the design, development, construction, transportation, installation, migration, drydocking or the making of any improvement with respect to any such property, plant or equipment or other assets);

(6) the incurrence by the Company or any of its Restricted Subsidiaries of Permitted Refinancing Indebtedness in exchange for, or the net proceeds of which are used to extend, renew, refund, refinance, replace, exchange, defease or discharge any Indebtedness (other than intercompany Indebtedness) that was permitted by the Indenture to be incurred under the first paragraph of this covenant or clauses (2), (4), (5) or (15) of this paragraph or this clause (6);

(7) the incurrence by the Company or any of its Restricted Subsidiaries of intercompany Indebtedness between or among the Company and any of its Restricted Subsidiaries; *provided*, *however*, that:

(a) if the Company or any Guarantor is the obligor on such Indebtedness and the payee is not the Company or a Guarantor, such Indebtedness must be ((i) except in respect of the intercompany current liabilities incurred in the ordinary course of business or consistent with past practice or industry practice in connection with the cash management operations of the Company and its Restricted Subsidiaries and (ii) only to the extent legally permitted) expressly subordinated to the prior payment in full in cash of all Obligations then due with respect to the Notes, in the case of the Company, or the Note Guarantee, in the case of a Guarantor; and

(b) (i) any subsequent issuance or transfer of Equity Interests that results in any such Indebtedness being held by a Person other than the Company or a Restricted Subsidiary of the Company and (ii) any sale or other transfer of any such Indebtedness to a Person that is not either the Company or a Restricted Subsidiary of the Company will be deemed, in each case, to constitute an incurrence of such Indebtedness by the Company or such Restricted Subsidiary, as the case may be, that was not permitted by this clause (7);

(8) the issuance by any of the Company's Restricted Subsidiaries to the Company or to any of its Restricted Subsidiaries of shares of preferred stock; *provided, however,* that:

(a) any subsequent issuance or transfer of Equity Interests that results in any such preferred stock being held by a Person other than the Company or a Restricted Subsidiary of the Company; and

(b) any sale or other transfer of any such preferred stock to a Person that is not either the Company or a Restricted Subsidiary of the Company,

will be deemed, in each case, to constitute an issuance of such preferred stock by such Restricted Subsidiary that was not permitted by this clause (8);

(9) the incurrence by the Company or any of its Restricted Subsidiaries of Hedging Obligations in the ordinary course of business or consistent with past practice or industry practice, including in connection with any commodities marketing activities or any permitted Energy Business activities;

(10) the Guarantee by the Company or any Restricted Subsidiary of Indebtedness of the Company or a Restricted Subsidiary that was permitted to be incurred by another provision of this covenant; *provided* that if the Indebtedness being Guaranteed is subordinated to or *pari passu* with the Notes or a Note Guarantee, as applicable, then the Guarantee shall be subordinated or *pari passu*, as applicable, to the same extent as the Indebtedness Guaranteed;

(11) the incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness arising from the honoring by a bank or other financial institution of a check, draft or similar instrument inadvertently drawn against insufficient funds, so long as such Indebtedness is covered within 30 Business Days;

(12) the incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness in respect of self-insurance obligations or captive insurance companies or consisting of the financing of insurance premiums in the ordinary course of business or consistent with past practice or industry practice;

(13) the incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness arising from agreements of the Company or any of its Restricted Subsidiaries providing for indemnification, obligations in respect of earnouts or other adjustment of purchase price or, in each case, similar obligations, in each case, incurred or assumed in connection with the disposition of any business, assets or Capital Stock of a

Subsidiary; *provided* that the maximum aggregate liability in respect of all such Indebtedness shall at no time exceed the gross proceeds, including the Fair Market Value of non-cash proceeds (measured at the time received and without giving effect to any subsequent changes in value), actually received by the Company and its Restricted Subsidiaries in connection with such disposition;

(14) the incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness in respect of (A) letters of credit, bankers' acceptances, guarantees, bid, performance, appeal, surety and similar bonds, completion guarantees, judgment, advance payment, customs, VAT or similar instruments issued for the account of the Company and any of its Restricted Subsidiaries in the ordinary course of business or consistent with past practice or industry practice, including Guarantees and obligations of the Company or any of its Restricted Subsidiaries with respect to letters of credit, bankers' acceptances, guarantees or similar instruments supporting trade payables or issued or relating to other liabilities or obligations incurred in the ordinary course of business or consistent with past practice or industry practice (including, without limitation, in connection with leases, or self-insurance and workers compensation obligations) or (B) any customary cash management, cash pooling or netting or setting off arrangements with banks or other financial institutions;

(15) Indebtedness or preferred stock of a Person outstanding on the date on which such Person becomes a Restricted Subsidiary or is acquired by the Company or a Restricted Subsidiary or merged, consolidated, amalgamated or otherwise combined with (including pursuant to any acquisition of assets and assumption of related liabilities) the Company or any Restricted Subsidiary in accordance with the Indenture (including Indebtedness incurred (a) to provide all or any portion of the funds utilized to consummate the transaction or series of related transactions pursuant to which such Person became a Restricted Subsidiary or was otherwise acquired by or was merged into the Company or a Restricted Subsidiary or (b) otherwise in connection with, or in contemplation of, such acquisition); *provided, however*, with respect to this clause (15) that at the time of the acquisition or other transaction pursuant to which such Indebtedness was deemed to be incurred, (x)(A) the Company would have been able to incur $1.00 of additional Indebtedness pursuant to the first paragraph of this covenant after giving effect to the incurrence of such Indebtedness or issuance of such preferred stock pursuant to this clause (15) or (B) the Fixed Charge Coverage Ratio would not be less than it was immediately prior to giving effect to such acquisition or other transaction or (y) in the case of Acquired Debt, such Indebtedness is discharged in full within six months of such Person becoming a Restricted Subsidiary or otherwise being merged, consolidated, amalgamated or combined with the Company or a Restricted Subsidiary;

(16) Guarantees by the Company or any of its Restricted Subsidiaries of any Management Advances;

(17) Guarantees by the Company or any Restricted Subsidiary granted to any trustee of any management equity plan or stock option plan or any other management or employee benefit or incentive plan or unit trust scheme approved by the Board of Directors of the Company, so long as the proceeds of the Indebtedness so Guaranteed are used to purchase Equity Interests of the Company (other than Disqualified Stock); *provided* that the amount of any net cash proceeds from the sale of such Equity Interests of the Company will be excluded from clause (3)(b) of the first paragraph of the covenant described above under the caption "*—Certain covenants—Restricted payments*" and will not be considered to be net cash proceeds from an Equity Offering for purposes of the "*Optional redemption*" provisions of the Indenture;

(18) Guarantees by the Company or any of its Restricted Subsidiaries of pension fund obligations of the Company or any Restricted Subsidiary required by law or regulation;

(19) the incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness in connection with one or more standby letters of credit, Guarantees, performance bonds or other reimbursement obligations, in each case, issued in the ordinary course of business or consistent with past practice or industry practice and not in connection with the borrowing of money or the obtaining of an advance or credit (other than advances or credit for goods and services in the ordinary course of business or consistent with past practice or industry practice and on terms and conditions that are customary in the Energy Business, and other than the extension of credit represented by such letter of credit, Guarantee or performance bond itself);

(20) Indebtedness of the Company and any Guarantor in an aggregate principal amount that, when taken together with any Permitted Refinancing Indebtedness in respect thereof and the principal amount of all

other Indebtedness incurred pursuant to this clause (20) and then outstanding, will not exceed 100% of the net cash proceeds received by the Company from the issuance or sale (other than to a Restricted Subsidiary) of its Capital Stock of the Company, in each case, subsequent to the Issue Date *provided*, *however*, that (i) any such net cash proceeds that are so received or contributed shall be excluded for the purposes of making Restricted Payments under the first paragraph or clauses (2) or (5) of the second paragraph of the covenant described above under "*—Restricted Payments*" to the extent the Company and its Restricted Subsidiaries can incur Indebtedness in reliance thereon and (ii) any net cash proceeds that are so received or contributed shall be excluded for the purposes of incurring Indebtedness pursuant to this clause (20) to the extent the Company or any of its Restricted Subsidiaries makes a Restricted Payment under the first paragraph or clauses (2) and (5) of the second paragraph of the covenant described under "*—Restricted Payments*" in reliance thereon;

(21) the incurrence by the Company or any Restricted Subsidiary of Indebtedness through the provision of bonds, Guarantees, letters of credit or similar instruments required by any national or international maritime commission or authority or other governmental or regulatory agencies, including, without limitation, customs authorities; in each case, for vessels owned or chartered by, and in the ordinary course of business or consistent with past practice or industry practice of, the Company or any of its Restricted Subsidiaries at any time outstanding not to exceed the amount required by such governmental or regulatory authority;

(22) the incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness in the form of customer deposits and advance payments received in the ordinary course of business or consistent with past practice or industry practice from customers for purchases in the ordinary course of business or consistent with past practice or industry practice;

(23) the incurrence by the Company or any of its Restricted Subsidiaries of additional Indebtedness or the issuance of Disqualified Stock by the Company or preferred stock by any Restricted Subsidiary in an aggregate principal amount (or accreted value, as applicable) at any time outstanding, including all Permitted Refinancing Indebtedness incurred to extend, renew, refund, replace, exchange, defease or discharge any Indebtedness incurred pursuant to this clause (22), not to exceed the greater of (x) $125.0 million and (y) 3.5% of Consolidated Total Assets determined as of the date of such incurrence or issuance; and

(24) the incurrence by the Company or any of its Restricted Subsidiaries of Indebtedness and Guarantees of joint ventures or Indebtedness to finance the purchase of such joint venture interest in an aggregate amount which, when taken together with any Permitted Refinancing Indebtedness in respect thereof, not to exceed the greater of (x) $140.0 million and (y) 4.0% of Consolidated Total Assets.

For purposes of determining compliance with, and the outstanding principal amount of, any particular Indebtedness incurred pursuant to and in compliance with this covenant:

(1) in the event that an item or portion of an item of proposed Indebtedness meets the criteria of more than one of the categories of Permitted Debt described in clauses (1) through (22) above, or is entitled to be incurred pursuant to the first paragraph of this covenant, the Company, in its sole discretion, will be permitted to classify such item or portion of an item of Indebtedness on the date of its incurrence and only be required to include the amount and type of such Indebtedness in one of such clauses and from time to time to reclassify all or a portion of such item of Indebtedness, in any manner that complies with this covenant;

(2) Guarantees of, or obligations in respect of letters of credit relating to, Indebtedness which is otherwise included in the determination of a particular amount of Indebtedness shall not be included;

(3) subject to the provisions set forth under "*Financial Calculations*," for the purposes of determining "Consolidated Total Assets" in relation to the second paragraph of this covenant, Consolidated Total Assets shall be measured (in the case of revolving facilities or Borrowing Base Facilities) at the option of the Company on the most recent date on which the commitments are obtained or the date on which new Indebtedness is incurred (in the case of other term facilities) on the date on which the new indebtedness is incurred, in each case by reference to the balance sheet of the most recent month end for which internal consolidated financial statements of the Company are available; and

(4) Indebtedness permitted by this covenant need not be permitted solely by reference to one provision permitting such Indebtedness but may be permitted in part by one such provision and in part by one or more other provisions of this covenant permitting such Indebtedness.

The amount of any Indebtedness outstanding as of any date will be:

(1) in the case of any Indebtedness issued with original issue discount, the amount of the liability in respect thereof determined in accordance with IFRS;

(2) in respect of Hedging Obligations, either (a) zero if such Hedging Obligation is incurred pursuant to clause (9) of the second paragraph of this covenant or (b) the notional amount of such Hedging Obligation if not incurred pursuant to such clause;

(3) the principal amount of the Indebtedness, in the case of any other Indebtedness; and

(4) in respect of Indebtedness of another Person secured by a Lien on the assets of the specified Person, the lesser of:

(i) the Fair Market Value of such assets at the date of determination; and

(ii) the amount of the Indebtedness of the other Person.

Accrual of interest, accrual of dividends, the accretion or amortization of original issue discount, the payment of interest on any Indebtedness in the form of additional Indebtedness, the reclassification of preferred stock as Indebtedness due to a change in accounting principles and the payment of dividends in the form of additional shares of preferred stock or Disqualified Stock will not be deemed to be an incurrence of Indebtedness or an issuance of preferred stock or Disqualified Stock for purposes of this covenant. The amount of any Indebtedness outstanding as of any date shall be the principal amount or liquidation preference thereof, together with any interest thereon that is more than 30 days past due, in the case of any other Indebtedness.

If at any time an Unrestricted Subsidiary becomes a Restricted Subsidiary, any Indebtedness of such Subsidiary shall be deemed to be incurred by a Restricted Subsidiary of the Company as of such date (and, if such Indebtedness is not permitted to be incurred as of such date under this "*—Incurrence of indebtedness and issuance of preferred stock*" covenant, the Company shall be in Default of this covenant).

For purposes of determining compliance with any U.S. dollar-denominated restriction on the incurrence of Indebtedness, the U.S. dollar-equivalent principal amount of Indebtedness denominated in a different currency shall be utilized, calculated based on the relevant currency exchange rate in effect on the date such Indebtedness was incurred in the case of term Indebtedness, or, at the option of the Company, first committed, in the case of Indebtedness incurred under a revolving credit facility; *provided, however*, that (i) if such Indebtedness denominated in non-U.S. dollar currency is subject to a Currency Exchange Protection Agreement with respect to U.S. dollars, the amount of such Indebtedness expressed in U.S. dollars will be calculated so as to take account of the effects of such Currency Exchange Protection Agreement; and (ii) the U.S. dollar-equivalent of the principal amount of any such Indebtedness outstanding on the Issue Date shall be calculated based on the relevant currency exchange rate in effect on the Issue Date. The principal amount of any refinancing Indebtedness incurred in the same currency as the Indebtedness being refinanced will be the U.S. dollar-equivalent of the Indebtedness refinanced determined on the date such Indebtedness was originally incurred, except that to the extent that:

(1) such U.S. dollar-equivalent was determined based on a Currency Exchange Protection Agreement, in which case the refinancing Indebtedness will be determined in accordance with the preceding sentence; and

(2) the principal amount of the refinancing Indebtedness exceeds the principal amount of the Indebtedness being refinanced, in which case the U.S. dollar-equivalent of such excess will be determined on the date such refinancing Indebtedness is being incurred.

The principal amount of any Indebtedness incurred to refinance other Indebtedness, if incurred in a different currency from the Indebtedness being refinanced, shall be calculated based on the currency exchange

rate applicable to the currencies in which such Permitted Refinancing Indebtedness is denominated that is in effect on the date of such refinancing. Notwithstanding any other provision of this covenant, the maximum amount of Indebtedness that the Company or any Restricted Subsidiary may incur pursuant to this covenant shall not be deemed to be exceeded solely as a result of fluctuations in exchange rates or currency values.

Liens

The Company will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly, create, incur, assume or suffer to exist any Lien of any kind securing Indebtedness upon any of its property or assets (whether now owned or hereafter acquired), except (x) Permitted Liens or (y) Liens on property or assets that are not Permitted Liens (the "**Initial Lien**") if payment due under the Notes or Note Guarantees, as applicable, are secured by a Lien on such property or assets on at least an equal and ratable basis with the Indebtedness so secured.

Any Lien created for the benefit of holders pursuant to this covenant will provide by its terms that such Lien will be automatically and unconditionally released and discharged upon the release and discharge of the Initial Lien other than as a consequence of an enforcement action with respect to the assets subject to such Lien.

Dividend and other payment restrictions affecting subsidiaries

The Company will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly, create or permit to exist or become effective any consensual encumbrance or restriction on the ability of any Restricted Subsidiary to:

(1) pay dividends or make any other distributions on its Capital Stock to the Company or any of its Restricted Subsidiaries, or with respect to any other interest or participation in, or measured by, its profits, or pay any Indebtedness owed to the Company or any of its Restricted Subsidiaries;

(2) make loans or advances to the Company or any of its Restricted Subsidiaries; or

(3) sell, lease or transfer any of its properties or assets to the Company or any of its Restricted Subsidiaries,

provided that (x) the priority of any preferred stock in receiving dividends or liquidating distributions prior to dividends or liquidating distributions being paid on common stock and (y) the subordination of (including the application of any standstill period to) loans or advances made to the Company or any Restricted Subsidiary to other Indebtedness incurred by the Company or any Restricted Subsidiary, shall not be deemed to constitute such an encumbrance or restriction.

However, the preceding restrictions will not apply to encumbrances or restrictions existing under or by reason of:

(1) agreements governing the Company's Indebtedness and Credit Facilities as in effect on the Issue Date and any amendments, restatements, modifications, renewals, supplements, increases, refundings, replacements or refinancings of those agreements; *provided* that the amendments, restatements, modifications, renewals, supplements, increases, refundings, replacements or refinancings are not materially more restrictive, taken as a whole, with respect to such dividend and other payment restrictions than those contained in those agreements on the Issue Date or will not adversely affect in any material respect the Company's ability to make principal or interest payments on the Notes as they become due (in each case, as determined in good faith by a responsible accounting or financial officer of the Company);

(2) the Indenture, the Notes (including Additional Notes), the Note Guarantees and Guarantee Subordination Agreement and any Additional Guarantee Subordination Agreement;

(3) applicable law, rule, regulation or order or the terms of any license, authorization, approval, concession or permit or similar restriction;

(4) any instrument governing Indebtedness or Capital Stock of a Person acquired by the Company or any of its Restricted Subsidiaries as in effect at the time of such acquisition (except to the extent such Indebtedness

or Capital Stock was incurred in connection with or in contemplation of such acquisition), which encumbrance or restriction is not applicable to any Person, or the properties or assets of any Person, other than the Person, or the property or assets of the Person, so acquired; *provided* that, in the case of Indebtedness, such Indebtedness was permitted by the terms of the Indenture to be incurred;

(5) customary non-assignment and similar provisions in contracts, leases and licenses (including, without limitation, licenses of intellectual property) entered into in the ordinary course of business or consistent with past practice or industry practice;

(6) purchase money obligations for property (including Capital Stock) acquired in the ordinary course of business or consistent with past practice or industry practice, Capital Lease Obligations and mortgage financings that impose restrictions on the property purchased or leased for the financing of all or any part of the purchase price, lease expense, charter expense, rental payments or cost of design, development, construction, transportation, installation, migration, drydocking or improvement of any FPSO, rig, production facility, transport or pipeline, in each case, used or useful in the Energy Business;

(7) any agreement for the sale or other disposition of assets, including without limitation an agreement for the sale or other disposition of the Capital Stock or assets of a Restricted Subsidiary, that restricts distributions by the applicable Restricted Subsidiary pending the sale or other disposition;

(8) Permitted Refinancing Indebtedness; *provided* that the restrictions contained in the agreements governing such Permitted Refinancing Indebtedness are not materially more restrictive, taken as a whole, than those contained in the agreements governing the Indebtedness being refinanced or will not adversely affect in any material respect the Company's ability to make principal or interest payments on the Notes as they become due (in each case, as determined in good faith by a responsible accounting or financial officer of the Company);

(9) Liens permitted to be incurred under the provisions of the covenant described above under the caption "—*Liens*" that limit the right of the debtor to dispose of the assets subject to such Liens;

(10) provisions limiting the disposition or distribution of assets or property in, or transfer of Capital Stock of, joint venture agreements, asset sale agreements, sale-leaseback agreements, stock sale agreements and other similar agreements (including agreements entered into in connection with a Restricted Investment), which limitations are applicable only to the assets, property or Capital Stock that are the subject of such agreements;

(11) agreements governing other Indebtedness of the Company or any of its Restricted Subsidiaries permitted to be incurred in accordance with the covenant described under the caption "*—Incurrence of indebtedness and issuance of preferred stock*," and any amendments, restatements, modifications, renewals, supplements, increases, refundings, replacements or refinancings of those agreements; *provided* that any such encumbrance or restriction contained in such Indebtedness are not materially more restrictive taken as a whole than customary in comparable financings in such jurisdictions as such Indebtedness is being incurred or will not adversely affect in any material respect the Company's ability to make principal or interest payments on the Notes as they become due (in each case, as determined in good faith by a responsible accounting or financial officer of the Company);

(12) supermajority voting requirements existing under corporate charters, bylaws, stockholders agreements, joint venture agreements and similar documents and agreements;

(13) customary provisions restricting subletting or assignment of any lease governing a leasehold interest;

(14) encumbrances or restrictions contained in Hedging Obligations permitted from time to time under the Indenture;

(15) restrictions on cash or other deposits or net worth imposed by customers or suppliers or required by insurance, surety or bonding companies, in each case under contracts entered into in the ordinary course of business or consistent with past practice or industry practice;

(16) encumbrances or restrictions contained in agreements for the financing of all or any part of the purchase price, lease expense, charter expense, rental payments or cost of design, development, construction, transportation, installation, migration, drydocking or improvement of any FPSO, rig, production facility, transport or pipeline, in each case, used or useful in the Energy Business, provided that such encumbrance or restriction contained in such agreements will not adversely affect in any material respect the Company's ability to make principal or interest payments on the Notes as they become due (in each case, as determined in good faith by a responsible accounting or financial officer of the Company); and

(17) any encumbrance or restriction existing under any agreement that extends, renews, refinances or replaces the agreements containing the encumbrances or restrictions in the foregoing clauses (1) through (15), or in this clause (16); *provided* that the terms and conditions of any such encumbrances or restrictions are not materially more restrictive taken as a whole with respect to such dividend and other payment restrictions than those under or pursuant to the agreement so extended, renewed, refinanced or replaced or will not adversely affect in any material respect the Company's ability to make principal or interest payments on the Notes as they become due (in each case, as determined in good faith by a responsible accounting or financial officer of the Company).

Merger, consolidation or sale of assets

The Company

The Company will not, directly or indirectly (i) consolidate, amalgamate or merge with or into another Person (whether or not the Company is the surviving corporation) or (ii) sell, assign, transfer, lease, convey or otherwise dispose of all or substantially all of the properties or assets of the Company and its Restricted Subsidiaries, taken as a whole, in one or more related transactions, to another Person, unless:

(1) either: (a) the Company is the surviving corporation; or (b) the Person formed by or surviving any such consolidation, amalgamation or merger (if other than the Company) or to which such sale, assignment, transfer, lease, conveyance or other disposition has been made is an entity organized or existing under the laws of any member state of the European Union as in effect on the Issue Date, the United Kingdom, Jersey, Switzerland, Norway, Canada, Australia, Japan, any state of the United States or the District of Columbia;

(2) the Person formed by or surviving any such consolidation, amalgamation or merger (if other than the Company) or the Person to which such sale, assignment, transfer, conveyance, lease or other disposition has been made assumes all the obligations of the Company under the Notes and the Indenture pursuant to a supplemental indenture in a form reasonably acceptable to the Trustee;

(3) immediately after such transaction or transactions, no Default or Event of Default exists;

(4) the Company or the Person formed by or surviving any such consolidation, amalgamation or merger (if other than the Company), or to which such sale, assignment, transfer, conveyance, lease or other disposition has been made would, on the date of such transaction after giving *pro forma* effect thereto and any related financing transactions as if the same had occurred at the beginning of the applicable two half-year reference period (i) be permitted to incur at least $1.00 of additional Indebtedness pursuant to the Fixed Charge Coverage Ratio test set forth in the first paragraph of the covenant described above under the caption "— *Incurrence of indebtedness and issuance of preferred stock*" or (ii) have a Fixed Charge Coverage Ratio not less than it was immediately prior to giving effect to such transaction;

(5) each Guarantor (unless it is the other party to the transactions above, in which case clause (2) shall apply) shall have by supplemental indenture confirmed that its Guarantee shall apply to such Person's obligations in respect of the Indenture and the Notes and shall continue to be in effect; and

(6) the Company shall have delivered to the Trustee an Officers' Certificate and an opinion of counsel, each stating that such consolidation, amalgamation, merger or disposition and such supplemental indenture (if any) comply with this covenant; *provided* that in giving an opinion of counsel, counsel may rely on an Officers' Certificate as to any matters of fact.

The surviving entity will succeed to, and be substituted for, and may exercise every right and power of, the Company under the Indenture, but, in the case of a lease of all or substantially all of its properties or assets, the Company will not be released from the obligation to pay the principal of and interest and premium, if any, on the Notes.

The Guarantors

A Guarantor (other than any Guarantor whose Note Guarantee is to be released in accordance with the terms of the Note Guarantee and the Indenture as described under "*—Note Guarantees release*") may not sell or otherwise dispose of all or substantially all of its properties or assets to, or consolidate with or merge with or into (whether or not such Guarantor is the surviving Person), another Person, other than the Company or another Guarantor, unless:

(1) immediately after giving effect to that transaction, no Default or Event of Default exists; and

(2) either:

(a) such Guarantor is the surviving entity;

(b) the Person acquiring the property in any such sale or other disposition or the Person formed by or surviving any such consolidation, amalgamation or merger (if other than the Company or another Guarantor) unconditionally assumes, pursuant to a supplemental indenture substantially in the form specified in the Indenture, all the obligations of such Guarantor under such Indenture, its Note Guarantee, the Guarantee Subordination Agreement and any Additional Guarantee Subordination Agreement on the terms set forth therein; or

(c) the Net Proceeds of such sale or other disposition are applied in accordance with the provisions of the Indenture described under the caption "*—Repurchase at the option of holders—Asset sales*."

Although there is a limited body of case law interpreting the phrase "substantially all," there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve "all or substantially all" of the properties or assets of a Person.

Clauses (3) and (4) of the first paragraph of this covenant and clause (1) of the third paragraph of this covenant will not apply to any merger, consolidation or amalgamation of the Company or any Restricted Subsidiary with or into an Affiliate solely for the purpose of reincorporating the Company or such Restricted Subsidiary in another jurisdiction. Nothing in the Indenture will prevent and this covenant will not apply to (i) any Restricted Subsidiary consolidating or amalgamating with, merging or liquidating into or disposing of all or part of its properties or assets to the Company or any Guarantor, (ii) the Company or such Guarantor consolidating or amalgamating with, or merging or liquidating into a Restricted Subsidiary for the purpose of reincorporating the Company or such Guarantor in another jurisdiction, (iii) any Restricted Subsidiary consolidating or amalgamating with, merging with or into or disposing of all or part of its properties or assets to another Restricted Subsidiary and (iv) any liquidation, winding up, dissolution or corporate reorganization of any Restricted Subsidiary of the Company on a solvent basis.

Transactions with affiliates

The Company will not, and will not permit any of its Restricted Subsidiaries to, make any payment to, or sell, lease, transfer or otherwise dispose of any of its properties or assets to, or purchase any property or assets from, or enter into or make or amend any transaction, contract, agreement, understanding, loan, advance or guarantee with, or for the benefit of, any Affiliate of the Company (each, an "Affiliate Transaction") involving aggregate payments or consideration in excess of $30.0 million, unless:

(1) the Affiliate Transaction is on terms that are no less favorable to the Company or the relevant Restricted Subsidiary than those that would have been obtained in a comparable transaction by the Company or such Restricted Subsidiary with an unrelated Person (as determined in good faith by a responsible accounting or financial officer of the Company); and

(2) with respect to any Affiliate Transaction or series of related Affiliate Transactions involving aggregate consideration in excess of the greater of $50.0 million and 1.5% of Consolidated Total Assets, the Company delivers to the Trustee a resolution of the Board of Directors of the Company set forth in an Officers' Certificate certifying that such Affiliate Transaction complies with this covenant and that such Affiliate Transaction has been approved by a majority of the disinterested members of the Board of Directors of the Company.

The following items will not be deemed to be Affiliate Transactions and, therefore, will not be subject to the provisions of the prior paragraph:

(1) transactions between or among the Company and/or its Restricted Subsidiaries;

(2) Restricted Payments not prohibited by the provisions of the Indenture described above under the caption "*—Restricted payments*" and Permitted Investments;

(3) transactions with a Person (other than an Unrestricted Subsidiary of the Company) that is an Affiliate of the Company or any Restricted Subsidiary solely because the Company owns, directly or through a Restricted Subsidiary, an Equity Interest in, or controls, such Person;

(4) any customary directors' fees, indemnification and similar arrangements (including the payment of directors' and officers' insurance premiums), consultant agreements, employment agreements, collective bargaining agreements, severance agreements, any other compensation or employee benefit plans or arrangements (including stock option, stock appreciation, stock incentive or stock ownership or similar plans) or legal fees (as determined in good faith by a majority of the disinterested members of the Board of Directors of the Company or, so long as the Company remains listed on the London Stock Exchange, otherwise in compliance with the Company's code of corporate governance) and payments, awards, grants or issuances of securities pursuant thereto;

(5) any issuance of Equity Interests (other than Disqualified Stock) of the Company to Affiliates of the Company;

(6) transactions with a joint venture or similar entity which would constitute an Affiliate Transaction solely because the Company owns, directly or through a Restricted Subsidiary, an Equity Interest in, can designate one or more members of the board of, or otherwise controls, such joint venture or similar entity;

(7) transactions pursuant to, or contemplated by any agreement or arrangement in effect on the Issue Date and as described in these Listing Particulars under the caption "*Certain relationships and related party transactions*," and transactions pursuant to any amendment, modification, supplement or extension thereto; *provided* that any such amendment, modification, supplement or extension to the terms thereof, taken as a whole, is not materially more disadvantageous to the holders of the Notes than the original agreement or arrangement as in effect on the Issue Date;

(8) (i) the Transactions; (ii) the Offering; (iii) transactions with customers, clients, suppliers, purchasers or sellers of goods or services, providers of employees or other labor, oil field service companies, construction companies, engineering companies, other energy exploration and development companies or other suppliers or service providers which are in the ordinary course of business or consistent with past practice or industry practice and otherwise in compliance with the terms of the Indenture, and which are fair to the Company or the Restricted Subsidiaries, in the reasonable determination of the senior management of the Company, or are on terms at least as favorable as might reasonably have been obtained at such time from an unaffiliated Person; and (iv) to the extent constituting Affiliate Transactions, transactions with any governmental or regulatory agency or entity in connection with the Energy Business;

(9) payments or other transactions pursuant to any tax sharing agreement or arrangement among the Company or any of its Restricted Subsidiaries and any other Person with which the Company or any of its Restricted Subsidiaries files or filed a consolidated tax return or with which the Company or any of its Restricted Subsidiaries is or was part of a consolidated group for tax purposes or any tax advantageous group contribution made pursuant to applicable legislation; *provided, however*, that such payments, and the value

of such transactions, shall not exceed the amount of tax that the Company or such Restricted Subsidiaries would owe if such Person was not a member of such consolidated or tax advantageous group;

(10) transactions between the Company or any Restricted Subsidiary and any Person, a director of which is also a director of the Company or any direct or indirect parent of the Company and such director is the primary cause for such Person to be deemed an Affiliate of the Company or any Restricted Subsidiary; *provided, however,* that such director shall abstain from voting as a director of the Company or such direct or indirect parent company, as the case may be, on any matter involving such other Person;

(11) any transactions for which the Company or a Restricted Subsidiary delivers a written letter or opinion to the Trustee from an Independent Financial Advisor stating that such transaction is (a) fair to the Company or such Restricted Subsidiary from a financial point of view or (b) on terms not less favorable than might have been obtained in a comparable transaction at such time on an arm's length basis from a Person who is not an Affiliate;

(12) any participation in a public tender or exchange offer for securities or debt instruments issued by the Company or any of its Subsidiaries that are conducted on arm's length terms and provide for the same price or exchange ratio, as the case may be, to all holders accepting such tender or exchange offer;

(13) the contribution of net cash proceeds received, the Fair Market Value of marketable securities received and the Fair Market Value of other property or assets (excluding oil and gas properties or interests therein) received by the Company as a contribution to its common capital or from the issue or sale of Equity Interests of the Company (other than Disqualified Stock) or from the issue or sale of convertible or exchangeable Disqualified Stock or convertible or exchangeable debt securities of the Company that have been converted into or exchanged for such Equity Interests;

(14) the transfer, pledge or other disposition of all or any portion of Equity Interests of Unrestricted Subsidiaries;

(15) any lease entered into between the Company or any Restricted Subsidiary, as lessee, and any Affiliate of the Company that is not a Restricted Subsidiary, as lessor, which is approved by a majority of the members of the Board of Directors of the Company;

(16) payments to or from, and transactions with, any joint venture or Unrestricted Subsidiary, including the entry into, and performance of obligations and related services under, any management services agreement or any licensing agreement with regards to any existing or future joint venture, in the ordinary course of business or consistent with past practice or industry practice; and

(17) any Management Advances and any waiver or transaction with respect thereto

Limitation on lines of business

The Company will not, and will not permit any Restricted Subsidiary to, engage in any business other than the Energy Business, except to the extent as would not be material to the Company and its Restricted Subsidiaries taken as a whole.

Limitation on guarantees of indebtedness by Restricted Subsidiaries

The Company will not permit any Restricted Subsidiary that is not a Guarantor, directly or indirectly, to Guarantee, assume or in any other manner become liable for the payment of any Public Indebtedness of the Company (other than the Notes) or a Guarantor (other than a Guarantee of the Notes), unless such Restricted Subsidiary simultaneously executes and delivers a supplemental indenture to the Indenture providing for a Guarantee of payment of the Notes by such Restricted Subsidiary which Note Guarantee will be senior in right of payment to or *pari passu* in right of payment with such Restricted Subsidiary's Guarantee of such other Indebtedness unless such other Indebtedness is Senior Debt, in which case the Note Guarantee may be subordinated in right of payment to the Senior Debt of such additional Guarantor.

The foregoing paragraph will not be applicable to any Guarantees of any Restricted Subsidiary:

(1) existing on the date of the Indenture;

(2) that existed at the time such Person became a Restricted Subsidiary if the Guarantee was not incurred in connection with, or in contemplation of, such Person becoming a Restricted Subsidiary;

(3) arising due to the granting of a Permitted Lien; or

(4) given to a bank or trust company having combined capital and surplus and undivided profits of not less than $250.0 million, whose debt has a rating, at the time such Guarantee was given, of at least "A" or the equivalent thereof by S&P and at least "A2" or the equivalent thereof by Moody's, in connection with the operation of cash management programs established for the Company's benefit or that of any Restricted Subsidiary.

In addition, notwithstanding anything to the contrary herein:

(1) no Guarantee shall be required if such Guarantee could reasonably be expected to give rise to or result in (A) personal liability for the officers, directors or shareholders of such Restricted Subsidiary, (B) any violation of applicable law that cannot be avoided or otherwise prevented through measures reasonably available to the Company or such Restricted Subsidiary or (C) any significant cost, expense, liability or obligation (including with respect to any Taxes) other than reasonable out of pocket expenses and other than reasonable expenses incurred in connection with any governmental or regulatory filings required as a result of, or any measures pursuant to clause (B) undertaken in connection with, such Guarantee, which cannot be avoided through measures reasonably available to the Company or the Restricted Subsidiary; and

(2) each such Guarantee will be limited as necessary to recognize certain defenses generally available to guarantors (including those that relate to fraudulent conveyance or transfer, voidable preference, financial assistance, corporate purpose, capital maintenance or similar laws, regulations or defenses affecting the rights of creditors generally) or other considerations under applicable law.

Future Guarantees granted pursuant to this provision will be released as set forth under "*—Note Guarantees release*." A Guarantee of a future Guarantor will be deemed to provide by its terms that it shall be automatically and unconditionally released and discharged if at the date of such release either (i) there is no Indebtedness of such Guarantor outstanding which was incurred after the Issue Date and which could not have been incurred in compliance with the Indenture if such Guarantor had not been designated as a Guarantor, or (ii) there is no Indebtedness of such Guarantor outstanding which was incurred after the Issue Date and which could not have been incurred in compliance with the Indenture as at the date of such release if such Guarantor were not designated as a Guarantor as at that date. The Trustee shall take all necessary actions, including the granting of releases or waivers under the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement, to effectuate any release of a Note Guarantee in accordance with these provisions, subject to customary protections and indemnifications.

Designation of Restricted and Unrestricted Subsidiaries

The Board of Directors of the Company may designate any Restricted Subsidiary to be an Unrestricted Subsidiary if that designation would not cause a Default. If a Restricted Subsidiary is designated as an Unrestricted Subsidiary, the aggregate Fair Market Value of all outstanding Investments owned by the Company and its Restricted Subsidiaries in the Subsidiary designated as an Unrestricted Subsidiary will be deemed to be either (1) a Restricted Investment made as of the time of the designation that will reduce the amount available for Restricted Payments under the covenant described above under the caption "*—Restricted payments*" and/or (2) a Permitted Investment under one or more clauses of the definition of Permitted Investments, as determined in good faith by a responsible accounting or financial officer of the Company. That designation will only be permitted if the Investment would be permitted at that time and if the Restricted Subsidiary otherwise meets the definition of an Unrestricted Subsidiary.

Any designation of a Subsidiary of the Company as an Unrestricted Subsidiary will be evidenced to the Trustee by filing with the Trustee a copy of a resolution of the Board of Directors of the Company giving effect to such designation and an Officers' Certificate certifying that such designation complied with the preceding

conditions and was permitted by the covenant described above under the caption "—*Restricted payments*." If, at any time, any Unrestricted Subsidiary would fail to meet the preceding requirements as an Unrestricted Subsidiary, it will thereafter cease to be an Unrestricted Subsidiary for purposes of the Indenture and any Indebtedness of such Subsidiary will be deemed to be incurred by a Restricted Subsidiary of the Company as of such date and, if such Indebtedness is not permitted to be incurred as of such date under the covenant described under the caption "—*Incurrence of indebtedness and issuance of preferred stock*," the Company will be in default of such covenant.

The Board of Directors of the Company may at any time designate any Unrestricted Subsidiary to be a Restricted Subsidiary of the Company; *provided* that such designation will be deemed to be an incurrence of Indebtedness by a Restricted Subsidiary of the Company of any outstanding Indebtedness of such Unrestricted Subsidiary, and such designation will only be permitted if (1) such Indebtedness is permitted under the covenant described under the caption "—*Incurrence of indebtedness and issuance of preferred stock*," calculated on a *pro forma* basis as if such designation had occurred at the beginning of the two half-year reference period; and (2) no Default or Event of Default would be in existence following such designation.

Reports

(1) The Company will make available, upon request, to any holder of Notes or prospective purchaser of Notes in the United States, in connection with any sale thereof, the information specified in Rule 144A(d)(4) under the U.S. Securities Act, unless the Company is subject to Section 13 or 15(d) of the U.S. Exchange Act at or prior to the time of such request.

(2) So long as any Notes are outstanding, the Company shall furnish to the Trustee (which shall distribute the same to a holder of Notes upon such holder's written request):

(i) within 120 days after the end of each of the Company's fiscal years beginning with the first fiscal year end after the Issue Date, annual reports containing the following information with respect to the Company with a level of detail that is substantially comparable and similar in scope to these Listing Particulars: (a) audited consolidated balance sheet of the Company as of the end of the two most recent fiscal years and audited consolidated income statements and statements of cash flow of the Company for the two most recent fiscal years (and comparative information for the end of the prior fiscal year), including complete notes to such financial statements and the report of the independent auditors on the financial statements; (b) *pro forma* income statement and balance sheet information, together with any explanatory footnotes, for any material acquisitions, dispositions or recapitalizations that have occurred since the beginning of the most recently completed fiscal year as to which such annual report relates (other than the Transactions), unless the *pro forma* information has been previously provided; *provided* that such *pro forma* financial information will be provided only to the extent required to be disclosed by the U.K. Listing Authority and London Stock Exchange or, in the event the Company is no longer listed on the London Stock Exchange, to the extent available without unreasonable expense; (c) an operating and financial review of the audited financial statements, including a discussion of the results of operations including a discussion of financial condition and liquidity and capital resources, and a discussion of material commitments and contingencies and critical accounting policies; (d) a description of the business, all material affiliate transactions, Indebtedness and material financing arrangements and all material debt instruments; and (e) material risk factors and material recent developments; *provided that* (for so long as the U.K. Listing Authority and London Stock Exchange require annual reports and the Company is subject to such requirements) any item of disclosure that complies in all material respects with the requirements of the U.K. Listing Authority and London Stock Exchange for annual reports with respect to such item will be deemed to satisfy the Company's obligations under this clause (i) with respect to such item; *provided further*, that the information described in clauses (d) and (e) may be provided in the footnotes to the audited consolidated financial statements;

(ii) within 90 days after the end of the Company's first fiscal half-year in each fiscal year beginning with the half-year ending after the Issue Date, semi-annual reports containing the following information: (a) an unaudited condensed consolidated balance sheet as of the end of such six-month period and unaudited condensed statements of income and cash flow for the year-to-date period ending on the unaudited condensed balance sheet date, and the comparable prior year period for the Company, together with condensed note disclosure; (b) *pro forma* income statement and balance sheet information of the Company, together with explanatory footnotes, for any material

acquisitions, dispositions or recapitalizations that have occurred since the beginning of the period as to which such report relates (other than the Transactions); *provided* that such *pro forma* financial information will be provided only to the extent required to be disclosed by the U.K. Listing Authority and London Stock Exchange or, in the event the Company is no longer listed on the London Stock Exchange, to the extent available without unreasonable expense; (c) an operating and financial review of the unaudited financial statements including a discussion of the consolidated financial condition and results of operations of the Company and any material change between the current half-year period and the corresponding period of the prior year; and (d) material recent developments; *provided that* (for so long as the U.K. Listing Authority and London Stock Exchange require interim reports and the Company is subject to such requirements) any item of disclosure that complies in all material respects with the requirements of the U.K. Listing Authority and London Stock Exchange for interim reports with respect to such item will be deemed to satisfy the Company's obligations under this clause (ii) with respect to such item; *provided further*, that the information described in clause (d) may be provided in the footnotes to the unaudited financial statements; and

(iii) promptly after the occurrence of any material acquisition, disposition or restructuring of the Company and its Restricted Subsidiaries, taken as a whole, or any senior executive officer changes at the Company or changes in auditors of the Company or other material event that the Company announces publicly, a report containing a description of such event (but only to the extent that such acquisition, disposition, restructuring, change or event has been required to be publicly announced or disclosed by the U.K. Listing Authority and London Stock Exchange for so long as the Company is subject to such requirements);

provided, however, that any reports set out in this paragraph delivered to the Trustee via e-mail or other electronic means shall be deemed to have been "furnished" to the Trustee in accordance with the terms of this paragraph.

All financial statements, other than any *pro forma* financial information provided pursuant to clauses (i) and (ii) of the second paragraph of this covenant, shall be prepared in accordance with IFRS on a consistent basis for the periods presented; provided, however, that the reports set forth in clauses (i) and (ii) above may, in the event of a change to IFRS, present earlier periods on a basis applied to such periods. Except as provided for above, no report need include separate financial statements for the Company or Subsidiaries of the Company or any disclosure with respect to the results of operations or any other financial or statistical disclosure not of a type included in these Listing Particulars. In addition, the reports set forth above will not be required to contain any reconciliation to US GAAP.

If the Company has designated any of its Subsidiaries as Unrestricted Subsidiaries and such Subsidiaries are Significant Subsidiaries, then the semi-annual and annual financial information required pursuant to clauses (i) and (ii) of the second paragraph of this covenant will include a reasonably detailed presentation, either on the face of the financial statements or in the footnotes thereto, of the financial condition and results of operations of the Company and its Restricted Subsidiaries separate from the financial condition and results of operations of the Unrestricted Subsidiaries of the Company.

The Company will also make available copies of all reports required by clauses (i)-(iii) of the second paragraph of this covenant either (i) on the Company's website or (ii) publicly available through substantially comparable means (as determined by an Officer of the Company in good faith) (it being understood that, without limitation, making such reports available on Bloomberg or another private electronic information service will constitute substantially comparable public availability). In addition, in the case of furnishing the information pursuant to clauses (i) and (ii) of the second paragraph of this covenant, the Company will promptly thereafter hold a conference call or provide live streaming access to a presentation in which holders of the Notes are given an opportunity to participate hosted by an Officer of the Company to discuss the operations of the Company and its Subsidiaries in respect of the relevant period. The Company will also make available copies of all reports required by clauses (i) and (ii) of the second paragraph of this covenant, if and so long as the Notes are listed on the Official List of the Luxembourg Stock Exchange and the rules of the Luxembourg Stock Exchange so require, at the specified office of the Principal Paying Agent in New York.

Notwithstanding the foregoing, the Company will be deemed to have provided such information to the Trustee, the holders of the Notes and prospective holders of the Notes if such information referenced in clauses

(1) and (2) has been posted to the Company's website; provided that such information is not password protected and remains posted on the Company's website until the earlier of (i) the full redemption of the Notes and (ii) final maturity of the Notes.

Delivery of information, documents and reports to the Trustee is for informational purposes only. The Trustee's receipt of such shall not constitute actual or constructive notice of any information contained therein, including the Company's compliance with any of its covenants under the Indenture or documents related therein.

Suspension of covenants when Notes rated investment grade

If on any date following the Issue Date:

(1) the Notes have achieved Investment Grade Status; and

(2) no Default or Event of Default shall have occurred and be continuing on such date,

then, beginning on that day and continuing until such time, if any, at which the Notes cease to have Investment Grade Status (such period, the "**Suspension Period**"), the covenants specifically listed under the following captions in these Listing Particulars will no longer be applicable to the Notes and any related default provisions of the Indenture will cease to be effective and will not be applicable to the Company and its Restricted Subsidiaries:

(1) "*—Repurchase at the option of holders—Asset sales*";

(2) "*—Certain covenants—Restricted payments*";

(3) "*—Certain covenants—Incurrence of indebtedness and issuance of preferred stock*";

(4) "*—Certain covenants—Dividend and other payment restrictions affecting subsidiaries*";

(5) "*—Certain covenants—Designation of restricted and unrestricted subsidiaries*";

(6) "*—Certain covenants—Transactions with affiliates*";

(7) "*—Certain covenants—Limitation on guarantees of indebtedness by restricted subsidiaries*";

(8) clause (4) of the first paragraph of the covenant described under "*—Certain covenants—Merger, consolidation or sale of assets*"; and

(9) "*—Certain covenants—Limitation on lines of business*."

Such covenants will not, however, be of any effect with regard to the actions of the Company and the Restricted Subsidiaries properly taken during the continuance of the Suspension Period; *provided* that (1) with respect to the Restricted Payments made after any such reinstatement (a "**Reversion Date**"), the amount of Restricted Payments will be calculated as though the covenant described under the caption "*—Restricted payments*" had been in effect prior to, but not during, the Suspension Period and (2) all Indebtedness incurred, or Disqualified Stock or preferred stock issued, during the Suspension Period will be classified to have been incurred or issued pursuant to clause (2) of the second paragraph of the caption "*—Incurrence of indebtedness and issuance of preferred stock*." Upon the occurrence of a Suspension Period, the amount of Excess Proceeds shall be reset at zero.

The Company and any Subsidiary will be permitted, without causing a Default or Event of Default or breach of any kind under the Indenture, to honor, comply with or otherwise perform any contractual commitments or obligations entered into during a Suspension Period following a Reversion Date and to consummate the transactions contemplated thereby; provided, however, that (a) the Company and its Subsidiaries did not incur or otherwise enter into such contractual commitments or obligations in contemplation of the Reversion Date and (b) the Company reasonably believed that such incurrence or actions would not cause or result in a Reversion Date. For purposes of clauses (a) and (b) in the preceding sentence, anticipation and reasonable belief may be determined

by the Company and shall be conclusively evidenced by a board resolution to such effect adopted in good faith by the Board of Directors of the Company. In reaching its determination, the Board of Directors may, but need not, consult with the Rating Agencies.

The Company shall notify the Trustee and the holders that the two conditions set forth in the first paragraph under this heading have been satisfied, *provided* that such notification shall not be a condition for the suspension of the covenants set forth above to be effective. The Trustee shall not be obligated to notify holders that the two conditions set forth in the first paragraph under this heading have been satisfied.

There can be no assurance that the Notes will ever achieve or maintain an Investment Grade Status.

Maintenance of listing

The Company will use its commercially reasonable efforts to maintain the listing of the Notes on the Euro MTF Market for so long as such Notes are outstanding; *provided* that if the Company is unable to obtain admission to listing of the Notes on the Luxembourg Stock Exchange or if at any time the Company determines that it will not so list or maintain such listing, it will use its commercially reasonable efforts to obtain and maintain a listing of such Notes on another "recognized stock exchange" (as defined under section 1005 of the UK Income Tax Act 2007) in which case, references in this covenant to the Exchange will be deemed to refer to such other "recognized stock exchange".

Events of default and remedies

Each of the following is an "Event of Default":

(1) default for 30 days in the payment when due of interest or Additional Amounts, if any, with respect to the Notes (whether or not prohibited by the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement);

(2) default in the payment when due (at final maturity, upon redemption or otherwise) of the principal of, or premium, if any, on, the Notes (whether or not prohibited by the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement);

(3) [*Reserved.*]

(4) failure by the Company for 30 days after written notice to the Company by the Trustee or the holders of at least 25% in aggregate principal amount of the Notes then outstanding to comply with any of the provisions described under the caption "*—Repurchase at the option of holders—Change of control*" above;

(5) failure by the Company or relevant Guarantor for 60 days after written notice to the Company by the Trustee or the holders of at least 25% in aggregate principal amount of the Notes then outstanding to comply with any of the other agreements in the Indenture (other than a default in performance, or breach, of a covenant or agreement which is specifically dealt with in clauses (1), (2) or (4)), or the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement;

(6) default under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any Indebtedness for money borrowed by the Company or any of its Restricted Subsidiaries (or the payment of which is Guaranteed by the Company or any of its Restricted Subsidiaries) (other than inter-company Indebtedness), whether such Indebtedness or Guarantee now exists, or is created, after the Issue Date, if that default:

   (a) is caused by a failure to pay principal of such Indebtedness at final maturity thereof after giving effect to any applicable grace periods provided in such Indebtedness and such failure to make any payment has not been waived or the maturity of such Indebtedness has not been extended (a "**Payment Default**"); or

   (b) results in the acceleration of such Indebtedness prior to its express maturity,

and, in each case, the principal amount of any such Indebtedness, together with the principal amount of any other such Indebtedness under which there has been a Payment Default or the maturity of which has been so accelerated, aggregates $100.0 million or more;

(7) failure by the Company or any Significant Subsidiary or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary, to pay final judgments entered by a court or courts of competent jurisdiction aggregating in excess of $100.0 million (net of any amount with respect to which a reputable and solvent insurance company has acknowledged liability in writing), which judgments are not paid, discharged, stayed or fully bonded for a period of 60 days (or, if later, the date when payment is due pursuant to such judgment);

(8) except as permitted by the Indenture (including with respect to any limitations), any Note Guarantee of the Company or a Guarantor that is a Significant Subsidiary is held in any judicial proceeding to be unenforceable or invalid or ceases for any reason to be in full force and effect, or any Guarantor that is a Significant Subsidiary or any Person acting on behalf of any such Guarantor that is a Significant Subsidiary, denies or disaffirms its obligations under its Note Guarantee; and

(9) certain events of bankruptcy or insolvency (excluding (i) Chapter 15 of the US Bankruptcy Code of 1978 in each case of any proceedings in respect of the recognition of foreign proceedings and (ii) schemes of arrangement, restructuring plans and similar procedures in the United Kingdom) described in the Indenture with respect to the Company or any Significant Subsidiary or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary, except as a result of, or in connection with, any liquidation, winding up, dissolution or corporate reorganization on a solvent basis.

In the case of an Event of Default arising from certain events of bankruptcy or insolvency, with respect to the Company, all then outstanding Notes will become due and payable immediately without further action or notice. If any other Event of Default occurs and is continuing, the Trustee or the holders of at least 25% in aggregate principal amount of the then outstanding Notes may declare all of the then outstanding Notes to be due and payable immediately by notice in writing to the Company and, in case of a notice by holders, also to the Trustee specifying the respective Event of Default and that it is a notice of acceleration.

In the event of any Event of Default specified in clause (6) of the first paragraph above, such Event of Default and all consequences thereof (including, without limitation, the declaration of acceleration of the Notes) will be annulled, waived and rescinded, automatically and without any action by the Trustee or the holders of the notes, if within 30 days after such Event of Default arose the Issuer delivers an Officer's Certificate to the Trustee stating that (x) the Indebtedness or guarantee that is the basis for such Event of Default has been discharged or (y) the holders thereof have rescinded or waived the acceleration, default, notice or action (as the case may be) giving rise to such Event of Default or (z) the default or acceleration that is the basis for such Event of Default has been cured or waived.

Subject to certain limitations, holders of a majority in aggregate principal amount of the then outstanding Notes may direct the Trustee in its exercise of any trust or power. The Trustee may withhold from holders of the Notes notice of any continuing Default or Event of Default if it determines that withholding notice is in their interest, except a Default or Event of Default relating to the payment of principal, interest or Additional Amounts or premium, if any.

Subject to the provisions of the Indenture relating to the duties of the Trustee in case an Event of Default occurs and is continuing, the Trustee will be under no obligation to exercise any of the rights or powers under the Indenture at the request or direction of any holders of Notes unless such holders have offered to the Trustee and, if requested, the Trustee has received indemnity and/or security satisfactory to it against any loss, cost liability or expense. Except (subject to the provisions described under "*—Amendment, supplement and waiver*") to enforce the right to receive payment of principal, premium, if any, or interest or Additional Amounts when due, no holder of a Note may pursue any remedy with respect to the Indenture or the Notes unless:

(1) such holder has previously given the Trustee notice that an Event of Default is continuing;

(2) holders of at least 25% in aggregate principal amount of the then outstanding Notes have requested the Trustee to pursue the remedy;

(3) such holders have offered the Trustee and, if requested, the Trustee has received security and/or indemnity satisfactory to it against any loss, liability or expense;

(4) the Trustee has not complied with such request within 60 days after the receipt of the request and the offer of security or indemnity; and

(5) holders of a majority in aggregate principal amount of the then outstanding Notes have not given the Trustee a direction inconsistent with such request within such 60-day period.

The holders of a majority in aggregate principal amount of the Notes then outstanding by notice to the Trustee may, on behalf of the holders of all of the Notes, rescind an acceleration or waive any existing Default or Event of Default and its consequences under the Indenture, if the rescission would not conflict with any judgment or decree, except a continuing Default or Event of Default in the payment of interest or Additional Amounts or premium on, or the principal of, the Notes held by a non-consenting holder (which may be waived with the consent of holders of at least 90% of the aggregate principal amount of the then outstanding Notes).

The Indenture will provide that (i) if a Default occurs for a failure to deliver a report or required certificate in connection with another default (an "**Initial Default**") then at the time such Initial Default is cured, such Default for failure to deliver a report or required certificate in connection with the Initial Default will also be cured without any further action and (ii) any Default or Event of Default for failure to comply with the time periods prescribed in the covenant entitled "*—Certain Covenants—Reports*" or otherwise to deliver any notice or certificate pursuant to any other provision of the Indenture shall be deemed to be cured upon delivery of (prior to acceleration in respect to the relevant breach) any such report, notice or certificate, even though such delivery is not within the prescribed period specified in the Indenture.

The Company is required to deliver to the Trustee annually a statement regarding compliance with the Indenture.

The Trustee may assume without inquiry, in the absence of written notice, that the Company is duly complying with its obligations contained in the Indenture required to be observed and performed by it, and that no Default or Event of Default or other event that would require repayment of the Notes has occurred.

Additional guarantee subordination agreements

The Indenture will provide that, subject to the covenants contained therein, at the request of the Company, at or prior to any time that the Company or any of the Company's Restricted Subsidiaries Guarantees or otherwise incurs any Senior Debt that is permitted to be incurred pursuant to the covenants described under the heading "*—Certain covenants—Incurrence of indebtedness and issuance of preferred stock*" and "*—Certain covenants—Liens*," the Company, any relevant Guarantor and the Trustee may (without the consent of the holders of the Notes), either amend and/or restate the Guarantee Subordination Agreement or enter into with the creditors and/or representatives of creditors with respect to such Senior Debt a subordination agreement or deed (each, an "**Additional Guarantee Subordination Agreement**"), in either such case on substantially similar terms to the terms of the Guarantee Subordination Agreement (where applicable) with respect to the subordination in right of payment, payment blockage, restrictions on enforcement, turnover, release and other customary senior debt protections (or, in the case of any such terms, terms more favorable to the holders of the Notes).

Such amendment and/or restatement of the Guarantee Subordination Agreement or such entry into an Additional Guarantee Subordination Agreement, as the case may be, will not impose any personal obligations on the Trustee or adversely affect the rights, duties, liabilities or immunities of the Trustee or the holders of Notes under the Indenture, the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement or result in the Trustee or the holders of the Notes being in breach, or otherwise in violation, of the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement.

The Indenture will also provide that, at the direction of the Company and without the consent of the holders of the Notes, the Trustee will, upon the direction of the Company, from time to time enter into one or more amendments to the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement to: (i) cure any ambiguity, omission, defect or inconsistency therein; (ii) increase the amount of Indebtedness of the types covered by the Guarantee Subordination Agreement or any Additional Guarantee

Subordination Agreement in a manner not prohibited by the Indenture and in a manner substantially consistent with the ranking and terms of such Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement; (iii) add Guarantors or other parties (such as representatives of new issuances of Indebtedness) thereto; (iv) make any change necessary or desirable, in the good faith determination of an Officer of the Company, in order to implement any transactions permitted under the caption "*—Certain covenants—Merger, consolidation or sale of assets*"; *provided* that any such change does not adversely affect the rights of the holders of the Notes in any material respect; or (v) make any other such change thereto that does not adversely affect the rights of the holders of the Notes in any material respect; *provided* that the Trustee shall not be obligated to enter into any amendment to the extent such amendment imposes any personal obligations on the Trustee or, in the reasonable opinion of the Trustee, adversely affects the Trustee's rights, duties, liabilities or immunities under the Indenture, the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement.

The Company shall not otherwise direct the Trustee to enter into any amendment or restatement of the Guarantee Subordination Agreement or enter into any Additional Guarantee Subordination Agreement without the consent of the holders of a majority in aggregate principal amount of the Notes then outstanding, except as otherwise permitted as described below under "*—Amendment, supplement and waiver*."

The Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement may be discharged at the option of the Company if at the date of such discharge the Indebtedness of the Company or a Restricted Subsidiary in respect of Senior Liabilities (as defined in the Guarantee Subordination Agreement or any relevant Additional Guarantee Subordination Agreement) has been discharged or refinanced. The Trustee shall take all necessary actions to effectuate the discharge of the Guarantee Subordination Agreement or any relevant Additional Guarantee Subordination Agreement in accordance with these provisions, subject to customary protections and indemnifications.

Each holder of a Note, by accepting such Note, will be deemed to have:

(1) irrevocably appointed and authorized the Trustee to give effect to such provisions;

(2) authorized the Trustee to become a party to the Guarantee Subordination Agreement and any Additional Guarantee Subordination Agreements and perform the duties and exercise the rights, powers and discretions that are specifically given to it under the Guarantee Subordination Agreement and any Additional Guarantee Subordination Agreements, together with any other incidental rights, power and discretions;

(3) agreed to be bound by such provisions and the provisions of the Guarantee Subordination Agreement and any Additional Guarantee Subordination Agreements; and

(4) irrevocably appointed the Trustee to act on its behalf to enter into and comply with such provisions and the provisions of the Guarantee Subordination Agreement and any Additional Guarantee Subordination Agreements.

No personal liability of directors, officers, employees and stockholders

No director, officer, employee, incorporator or stockholder of the Company or any Guarantor, as such, will have any liability for any obligations of the Company or the Guarantors under the Notes, the Indenture or the Note Guarantees or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each holder of Notes by accepting a Note waives and releases all such liability. The waiver and release are part of the consideration for the issuance of the Notes. The waiver may not be effective to waive liabilities under U.S. federal securities laws.

Legal defeasance and covenant defeasance

The Company may at any time, at its option, elect to have all of its obligations discharged with respect to the outstanding Notes and all obligations of the Guarantors discharged with respect to their Note Guarantees ("**Legal Defeasance**") except for:

(1) the rights of holders of outstanding Notes to receive payments in respect of the principal of, or interest (including Additional Amounts) or premium, if any, on, such Notes when such payments are due from the trust referred to below;

(2) the Company's obligations with respect to the Notes concerning registration of Notes, mutilated, destroyed, lost or stolen Notes and the maintenance of an office or agency for payment and money for security payments held in trust;

(3) the rights, powers, trusts, duties and immunities of the Trustee, and the Company's and the Guarantors' obligations in connection therewith; and

(4) the Legal Defeasance and Covenant Defeasance provisions of the Indenture.

In addition, the Company may, at its option and at any time, elect to have the obligations of the Company and the Guarantors released with respect to certain covenants (including the Company's obligation to make Change of Control Offers and Asset Sale Offers) that are described in the Indenture ("**Covenant Defeasance**") and thereafter any omission to comply with those covenants will not constitute a Default or Event of Default with respect to the Notes. In the event Covenant Defeasance occurs, certain events (not including non-payment or, solely with respect to the Company, bankruptcy, receivership, rehabilitation and insolvency events) described under "*—Events of default and remedies*" will no longer constitute an Event of Default with respect to the Notes. If the Company exercises either its Legal Defeasance or Covenant Defeasance option, each Guarantor will be released and relieved of any obligations under its Note Guarantee.

In order to exercise either Legal Defeasance or Covenant Defeasance:

(1) the Company must irrevocably deposit with the Trustee (or such other entity directed, designated or appointed as agent by the Trustee for this purpose), in trust, for the benefit of the holders of the Notes, cash in U.S. dollars, non-callable U.S. Government Obligations or a combination of cash in U.S. dollars and non-callable U.S. Government Obligations (or in the case of Additional Notes denominated in a currency other than U.S. dollars, cash in such currency, non-callable government obligations (including European Government Obligations, as applicable) of such currency or a combination thereof), in amounts as will be sufficient to pay the principal of, or interest (including Additional Amounts) and premium, if any, on, the outstanding Notes on the stated date for payment thereof or on the applicable redemption date, as the case may be, and the Company must specify whether the Notes are being defeased to such stated date for payment or to a particular redemption date;

(2) in the case of Legal Defeasance, the Company must deliver to the Trustee an opinion of United States counsel reasonably acceptable to the Trustee confirming that (a) the Company has received from, or there has been published by, the U.S. Internal Revenue Service a ruling or (b) since the Issue Date, there has been a change in the applicable U.S. federal income tax law, in either case to the effect that, and based thereon such opinion of counsel will confirm that, the holders of the outstanding Notes will not recognize income, gain or loss for U.S. federal income tax purposes as a result of such Legal Defeasance and will be subject to U.S. federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Legal Defeasance had not occurred;

(3) in the case of Covenant Defeasance, the Company must deliver to the Trustee an opinion of United States counsel reasonably acceptable to the Trustee confirming that the holders of the outstanding Notes will not recognize income, gain or loss for U.S. federal income tax purposes as a result of such Covenant Defeasance and will be subject to U.S. federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Covenant Defeasance had not occurred;

(4) such Legal Defeasance or Covenant Defeasance will not result in a breach or violation of, or constitute a default under, any material agreement or instrument (other than the Indenture) to which the Company or any of its Subsidiaries is a party or by which the Company or any of its Subsidiaries is bound;

(5) the Company must deliver to the Trustee an Officers' Certificate stating that the deposit was not made by the Company with the intent of preferring the holders of Notes over the other creditors of the Company with the intent of defeating, hindering, delaying or defrauding any creditors of the Company or others; and

(6) the Company must deliver to the Trustee an Officers' Certificate and an opinion of counsel, subject to customary assumptions and qualifications, each stating that all conditions precedent relating to the Legal Defeasance or the Covenant Defeasance have been complied with.

For the avoidance of doubt, all cash and securities deposited with the Trustee (or such other entity directed, designated or appointed as agent by the Trustee for this purpose) to hold in trust pursuant to this section or "—*Satisfaction and discharge*" shall not be subject to subordination pursuant to the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement.

Amendment, supplement and waiver

Except as provided in the next two succeeding paragraphs, the Indenture, the Notes, the Note Guarantees, the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement may be amended or supplemented with the consent of the Company and the holders of a majority in aggregate principal amount of the Notes then outstanding (including, without limitation, consents obtained in connection with a purchase of, or tender offer or exchange offer for, Notes), and any existing Default or Event of Default or compliance with any provision of the Indenture, the Notes, the Note Guarantees, the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement may be waived with the consent of the holders of a majority in aggregate principal amount of the then outstanding Notes (including, without limitation, consents obtained in connection with a purchase of, or tender offer or exchange offer for, Notes).

Unless consented to by the holders of at least 90% of the aggregate principal amount of then outstanding Notes (including, without limitation, consents obtained in connection with a purchase of, or tender offer or exchange offer for, Notes), without the consent of the Company and each holder of Notes affected, an amendment, supplement or waiver may not (with respect to any Notes held by a non-consenting holder):

(1) reduce the principal amount of Notes whose holders must consent to an amendment, supplement or waiver;

(2) reduce the principal of or change the fixed maturity of any Note or alter the provisions with respect to the redemption or repurchase of the Notes (other than provisions relating to the covenants described above under the caption "—*Repurchase at the option of holders*");

(3) reduce the rate of or change the time for payment of interest, including default interest, on any Note;

(4) waive a Default or Event of Default in the payment of principal of, or interest, Additional Amounts or premium, if any, on, the Notes (except a rescission of acceleration of the Notes by the holders of a majority in aggregate principal amount of the then outstanding Notes and a waiver of the payment default that resulted from such acceleration);

(5) make any Note payable in money other than that stated in the Notes;

(6) make any change in the provisions of the Indenture relating to waivers of past Defaults or the rights of holders of Notes to receive payments of principal of, or interest, Additional Amounts or premium, if any, on, the Notes (other than as permitted in clause (7) below);

(7) waive a redemption or repurchase payment with respect to any Note (other than a payment required by one of the covenants described above under the caption "—*Repurchase at the option of holders*");

(8) modify or release any of the Note Guarantees in any manner adverse to the holders of the Notes, other than in accordance with the terms of the Indenture and the Guarantee Subordination Agreement (or any Additional Guarantee Subordination Agreement);

(9) impair the right of any holder of Notes to institute suit for the enforcement of any payment on or with respect to such holder's Notes or any Note Guarantee in respect thereof;

(10) make any change to the ranking of the Notes or Note Guarantees, in each case in a manner that adversely affects the rights of the holders of the Notes; or

(11) make any change in the preceding amendment, supplement and waiver provisions.

Notwithstanding the preceding, without the consent of any holder of Notes, the Company, the Guarantors and the Trustee may amend or supplement the Indenture, the Notes, the Note Guarantees, the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement for the purposes described under "*—Additional guarantee subordination agreements*" or:

(1) to cure any ambiguity, defect or inconsistency;

(2) to provide for uncertificated Notes in addition to or in place of certificated Notes (provided that the uncertificated Notes are issued in registered form for purposes of Section 163(f) of the Code);

(3) to provide for the assumption of the Company's or a Guarantor's obligations to holders of Notes and Note Guarantees in the case of a transaction described under "*—Certain covenants—Merger, consolidation or sale of assets*";

(4) to make any change that would provide any additional rights or benefits to the holders of Notes or that does not adversely affect the legal rights under the Indenture of any such holder in any material respect;

(5) to conform the text of the Indenture, the Notes or the Note Guarantees to any provision of this "*Description of Notes*" to the extent that such provision in this "*Description of Notes*" was intended to be a verbatim recitation of a provision of the Indenture, the Notes or the Note Guarantees;

(6) to provide for the issuance of Additional Notes in accordance with the limitations set forth in the Indenture as of the Issue Date;

(7) to allow any Guarantor to Guarantee the Notes or to evidence the release of Note Guarantees pursuant to the terms of the Indenture;

(8) to the extent necessary to provide for the granting of a security interest for the benefit of any Person; *provided* that the granting of such security interest is not prohibited under the Indenture; or

(9) to evidence and provide for the acceptance and appointment of a successor trustee under the Indenture, the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement or to provide for the accession by the Trustee to the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement.

In formulating its opinion on such matters, the Trustee shall be entitled to rely absolutely on such evidence as it deems appropriate, including opinions of counsel and Officers' Certificates.

The consent of the holders of Notes is not necessary under the Indenture to approve the particular form of any proposed amendment. It is sufficient if such consent approves the substance of the proposed amendment.

For the avoidance of doubt, no amendment to, or deletion of any of the covenants described under "*—Certain covenants*," shall be deemed to impair or affect any rights of the holders of the Notes to receive payment of principal of, or premium, if any, or interest on, the Notes.

Satisfaction and discharge

The Indenture and the Note Guarantees will be discharged and will cease to be of further effect as to all Notes issued thereunder (except as to surviving rights to transfer or exchange Notes and as otherwise specified in the Indenture), when:

(1) either:

(a) all Notes that have been authenticated, except lost, stolen or destroyed Notes that have been replaced or paid and Notes for whose payment money has been deposited in trust and thereafter repaid to the Company, have been delivered to the Registrar for cancellation; or

(b) all Notes that have not been delivered to the Registrar for cancellation have become due and payable by reason of the providing of a notice of redemption or otherwise or will become due and payable within one year, and the Company or any Guarantor has irrevocably deposited or caused to be deposited with the Trustee (or such other entity directed, designated or appointed as agent by the Trustee for this purpose) as trust funds in trust solely for the benefit of the holders, cash in U.S. dollars, non-callable U.S. Government Obligations or a combination of cash in U.S. dollars and non-callable U.S. Government Obligations (or in the case of Additional Notes denominated in a currency other than U.S. dollars, cash in such currency (including European Government Obligations), non-callable government obligations of such currency or a combination thereof), in amounts as will be sufficient, without consideration of any reinvestment of any interest, to pay and discharge the entire Indebtedness on the Notes not delivered to the Registrar for cancellation for principal, premium, Additional Amounts, if any, and accrued interest to the date of final maturity or redemption;

(2) in the case of clause (1)(b), no Default or Event of Default has occurred and is continuing on the date of the deposit (other than a Default or Event of Default resulting from the borrowing of funds to be applied to such deposit) and the deposit will not result in a breach or violation of, or constitute a default under, any other instrument to which the Company or any Guarantor is a party or by which the Company or any Guarantor is bound;

(3) the Company or any Guarantor has paid or caused to be paid all sums payable by it under the Indenture; and

(4) the Company has delivered irrevocable instructions to the Trustee to apply the deposited money toward the payment of the Notes at final maturity or on the redemption date, as the case may be.

In addition, the Company must deliver an Officers' Certificate and an opinion of counsel to the Trustee stating that all conditions precedent to satisfaction and discharge have been satisfied; *provided* that any such counsel may rely on any Officers' Certificate as to matters of fact (including as to compliance with the foregoing clauses (1), (2), (3) and (4)).

If requested by the Company in writing the Trustee (or such other entity directed, designated or appointed as agent by the Trustee for this purpose) may distribute any amounts deposited in trust to the Holders prior to the final maturity or redemption date, as the case may be; provided, however, that the Trustee, the Principal Paying Agent and the Holders have received at least three Business Days' prior written notice from the Company of such earlier repayment date (which request may be included in the applicable notice of redemption pursuant to the above referenced Officer's Certificate); provided that the Notes shall be marked down on the date of early repayment and such early repayment will not occur prior to the record date set for redemption and the Trustee, such other entity directed, designated or appointed as agent by the Trustee for this purpose (if applicable) and the Paying Agent shall not be required to incur any losses, fees, costs or penalties in relation to such early distribution. For the avoidance of doubt, the distribution and payment to the Holders prior to the maturity or redemption date as set forth above shall not include any negative interest, present value adjustment, break cost or any additional premium on such amounts. To the extent the Notes are represented by a Global Note deposited with a depositary for the clearing system, any payment to the beneficial holders holding interests as a participant of such clearing system shall be subject to the then applicable procedures of the clearing system.

Listing

Application has been made to list the Notes on the Official List of the Luxemburg Stock Exchange and for admission to trading on the Euro MTF Market.

Financial calculations

When calculating the availability or permission under any basket or ratio under the Indenture, in each case, in connection with any acquisition, disposition, merger, joint venture, Investment or any other similar transaction (the "**Applicable Transaction**") where there is a time difference between commitment and closing or incurrence (including in respect of incurrence of Indebtedness, Restricted Payments and Permitted Investments), the date of determination of such basket or ratio and of any Default or Event of Default shall, at the option of the Company be (A) the date of the definitive agreements for such Applicable Transaction and the other transactions

to be entered into in connection therewith (including any incurrence of Indebtedness and the use of proceeds thereof, and including any pro forma adjustments as are appropriate and consistent with the pro forma adjustments set forth in the definition of "**Fixed Charge Coverage Ratio**") as if they occurred at the beginning of the applicable reference period for purposes of determining the ability to consummate any such Applicable Transaction (and not for the purposes of any subsequent availability of any basket or ratio), (B) the date of consummation of any Applicable Transaction or (C) any other date relevant to the Applicable Transaction determined by the Company in good faith, in which case such baskets or ratios shall likewise be calculated on a pro forma basis after giving effect to the Applicable Transaction and the other transactions to be entered into in connection therewith (including any incurrence of Indebtedness and the use of proceeds thereof) as if they occurred at the beginning of the applicable reference period for purposes of determining the ability to consummate any such transaction. For the avoidance of doubt, (1) if any of such baskets or ratios are determined to be in compliance with (A) or (C) above and are exceeded as a result of fluctuations in such basket or ratio (including due to fluctuations in Consolidated Cash Flow or Consolidated Total Assets of the Company or the target company) subsequent to such date of determination and at or prior to the consummation of the relevant Applicable Transactions, such baskets or ratios will not be deemed to have been exceeded as a result of such fluctuations solely for the purposes of determining whether the transactions are permitted under the Indenture and (2) if the Company elects to have such determinations occur at the Acquisition Agreement Date or on another date as contemplated by (C) above, and in each case to be outstanding thereafter for purposes of calculating any baskets and ratios under the Indenture (except to the extent such Applicable Transaction is subsequently abandoned).

Unless otherwise specified in the Indenture, in the event that any amount or transaction meets the criteria of more than one of the baskets and exceptions set out in a particular provision of the Indenture (subject to the limitations imposed under clause (1) of the third paragraph under "*—Certain Covenants—Incurrence of Indebtedness and issuance of preferred stock*"), the Company may classify (and may from time to time reclassify) that amount or transaction to a particular basket or exception in respect of the same provision and will only be required to include that amount or transaction in one of those baskets or exceptions (and, for the avoidance of doubt, an amount or transaction may at the option of the Company be split between different baskets and exceptions).

Subject to the limitations imposed under clause (1) of the third paragraph under "*—Certain covenants—Incurrence of Indebtedness and issuance of preferred stock*," if a proposed action, matter, transaction or amount (or a portion thereof) is Incurred or entered into pursuant to a fixed permission and at a later time would subsequently be permitted under a ratio-based permission, unless otherwise elected by the Company, such action, matter, transaction or amount (or a portion thereof) shall automatically be reclassified to such ratio-based permission.

In the event any fixed permissions are intended to be utilized together with any ratio-based permissions in a single transaction or series of related transactions, (i) compliance with or satisfaction of any ratio-based permission for the portion of such indebtedness or other applicable transaction or action to be incurred under such ratio-based permission shall first be calculated without giving effect to amounts being utilized pursuant to any fixed permission but giving full *pro forma* effect to all applicable and related transactions (including, subject to the foregoing with respect to fixed baskets, any incurrence and repayments of indebtedness) and all other permitted *pro forma* adjustments, and (ii) thereafter, incurrence of the portion of such indebtedness or other applicable transaction or action to be incurred under any fixed permissions shall be calculated.

For any relevant Applicable Metric set by reference to a fiscal year, a calendar year, a four-quarter period, a twelve-month period or any other similar annual period (each, an "**Annual Period**"):

(a) at the option of the Issuer, the maximum amount so permitted under such Applicable Metric during such Annual Period may be increased by:

(i) an amount equal to 100% of the difference (if positive) between the permitted amount in the preceding Annual Periods and the amounts thereof actually used or applied by the Group during such preceding Annual Periods (the "**Carry Forward Amount**"); and/or

(ii) an amount equal to 100% of the permitted amount in the following Annual Periods and the permitted amount in such following Annual Periods shall be reduced by such corresponding amount (the "**Carry Back Amount**"); and

(b) to the extent that the maximum amount so permitted under such Applicable Metric during such Annual Periods is increased in accordance with sub-clause (a)(i) of this paragraph, any usage of such Applicable Metric during such Annual Periods shall be deemed to be applied in the following order:

(i) firstly, against the Carry Forward Amount;

(ii) secondly, against the maximum amount so permitted during such Annual Periods prior to any increase in accordance with sub-clause (a)(i) of this paragraph; and

(iii) thirdly, against the Carry Back Amount.

Judgment currency

Any payment on account of an amount that is payable in U.S. dollars which is made to or for the account of any holder or the Trustee in lawful currency of any other jurisdiction (the "**Judgment Currency**"), whether as a result of any judgment or order or the enforcement thereof or the liquidation of the Company or any Guarantor, shall constitute a discharge of the Company or the Guarantor's obligation under the Indenture and the Notes or Note Guarantee, as the case may be, only to the extent of the amount of U.S. dollars with such holder or the Trustee, as the case may be, could purchase in the London foreign exchange markets with the amount of the Judgment Currency in accordance with normal banking procedures at the rate of exchange prevailing on the first Business Day following receipt of the payment in the Judgment Currency. If the amount of U.S. dollars that could be so purchased is less than the amount of U.S. dollars originally due to such holder or the Trustee, as the case may be, the Company and the Guarantors shall indemnify and hold harmless the holder or the Trustee, as the case may be, from and against all loss or damage arising out of, or as a result of, such deficiency. This indemnity shall constitute an obligation separate and independent from the other obligations contained in the Indenture or the Notes, shall give rise to a separate and independent cause of action, shall apply irrespective of any indulgence granted by any holder or the Trustee from time to time and shall continue in full force and effect notwithstanding any judgment or order for a liquidated sum in respect of an amount due hereunder or under any judgment or order.

Concerning the Trustee

The Company shall deliver written notice to the Trustee within 30 days of becoming aware of the occurrence of a Default or an Event of Default. The Trustee will be permitted to engage in other transactions with the Company and its subsidiaries, If the Trustee becomes a creditor of the Company or any Guarantor, the Indenture will limit the right of the Trustee to obtain payment of claims in certain cases, or to realize on certain property received in respect of any such claims as security or otherwise.

The holders of a majority in aggregate principal amount of the then outstanding Notes will have the right to direct the time, method and place of conducting any proceeding for exercising any remedy available to the Trustee, subject to certain exceptions. In case an Event of Default occurs and is continuing of which a responsible officer of the Trustee has received written notice, the Trustee will be required, in the exercise of its rights or powers, to use the degree of care of a prudent person in the conduct of its own affairs. Subject to such provisions, the Trustee will be under no obligation to exercise any of its rights or powers under the Indenture at the request of any holder of Notes, unless such holder has offered to the Trustee security and/or indemnity satisfactory to the Trustee against any loss, cost, liability or expense.

The Company and the Guarantors jointly and severally will indemnify the Trustee for certain claims, liabilities and expenses incurred without gross negligence, fraud or willful misconduct on the Trustee's part, arising out of or in connection with its duties and the administration of the Indenture.

Additional information

Anyone who receives these Listing Particulars may, following the Issue Date, obtain a copy of the Indenture, the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement without charge by writing to EnQuest PLC, Cunard House, 15 Regent Street, London, SW1Y 4LR, United Kingdom, care of Stefan Ricketts.

So long as the Notes are listed on the Official List of the Luxembourg Stock Exchange and admitted for trading on the Euro MTF Market and the rules of the Luxembourg Stock Exchange shall so require, copies, current and future, of all of the Company's annual audited consolidated financial statements and the Company's unaudited consolidated interim financial statements may be obtained, free of charge, during normal business hours at the offices of the Paying Agents in New York and London.

Consent to jurisdiction and service of process

The Indenture will provide that each of the Company and the Guarantors will appoint CT Corporation System as its agent for service of process in any suit, action or proceeding with respect to the Indenture, the Notes and the Note Guarantees brought in any U.S. federal or New York state court located in the City of New York and will submit to such non-exclusive jurisdiction.

Enforceability of judgments

Since substantially all of the assets of the Company and the Guarantors are outside the United States, any judgment obtained in the United States against the Company or any Guarantor may not be collectable within the United States. See "*Service of process and enforcement of civil liabilities*."

Prescription

Claims against the Company or any Guarantor for the payment of principal or Additional Amounts, if any, on the Notes will not be permitted ten years after the applicable due date for payment thereof. Claims against the Company or any Guarantor for the payment of interest on the Notes will not be permitted five years after the applicable due date for payment of interest.

Governing law

The Indenture and the Notes, and the rights and duties of the parties thereunder, shall be governed by and construed in accordance with the laws of the State of New York. The Guarantee Subordination Agreement will be governed by the laws of England and Wales.

Certain definitions

Set forth below are certain defined terms used in the Indenture. Reference is made to the Indenture for a full disclosure of all defined terms used therein, as well as any other capitalized terms used herein for which no definition is provided.

"*2027 Notes*" means, collectively, the Company's $305.0 million aggregate principal amount of 11⅝% senior notes due 2027 and the additional $160.0 million aggregate principal amount of the Company's 11⅝% senior notes due 2027, issued under a New York law governed indenture dated October 25, 2022.

"*9% Retail Notes*" means the Company's £133.3 million 9.0% notes due October 27, 2027 issued under a trust deed dated April 27, 2022.

"*Acquired Debt*" means, with respect to any specified Person:

(1) Indebtedness of any other Person existing at the time such other Person is merged with or into or became a Subsidiary of such specified Person, whether or not such Indebtedness is incurred in connection with, or in contemplation of, such other Person merging with or into, or becoming a Restricted Subsidiary of, such specified Person; and

(2) Indebtedness secured by a Lien encumbering any asset acquired by such specified Person.

"*Additional Assets*" means:

(1) any property or assets used or useful in the Energy Business;

(2) the Capital Stock of a Person that becomes a Restricted Subsidiary as a result of the acquisition of such Capital Stock by the Company or any of its Restricted Subsidiaries; or

(3) Capital Stock constituting a Minority Interest in any Person that at such time is a Restricted Subsidiary;

provided, however, that any such Restricted Subsidiary described in clauses (2) or (3) is primarily engaged in the Energy Business.

"*Affiliate*" of any specified Person means any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with such specified Person. For purposes of this definition, "control," as used with respect to any Person, means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of such Person, whether through the ownership of voting securities, by agreement or otherwise. For purposes of this definition, the terms "controlling," "controlled by" and "under common control with" have correlative meanings.

"*Applicable Metric*" means any financial covenant or financial ratio or Incurrence-based permission, test, basket or threshold in the Indenture (including any financial definition or component thereof and any financial ratio, test, basket or threshold or permission based on the calculation of Consolidated Leverage Ratio or the Fixed Charge Coverage Ratio), any Default, Event of Default or other relevant breach of the Indenture.

"*Applicable Premium*" means, with respect to any Note at any time, the greater of (a) 1.0% of the principal amount of such Note and (b) the excess of:

(1) the present value at such time of (i) the redemption price of the Note on April 30, 2028 (such redemption price being set forth in the table appearing under the caption "*—Optional Redemption*"), plus (ii) all required interest payments due on the Note through April 30, 2028 (excluding accrued but unpaid interest to the redemption date) discounted back to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at a rate equal to the Treasury Rate as of such time plus 50 basis points; over

(2) the then-outstanding principal amount of the Note,

as calculated by the Company or on behalf of the Company by such Person as the Company may engage. For the avoidance of doubt, calculation of the Applicable Premium shall not be the duty or obligation of the Trustee, Registrar, Transfer Agent or any Paying Agent.

"*Asset Sale*" means:

(1) the sale, lease, conveyance or other disposition of any assets or rights (including by way of a Production Payment but excluding an operating lease entered into in the ordinary course of the Energy Business); *provided* that the sale, lease, conveyance or other disposition of all or substantially all of the properties or assets of the Company and its Restricted Subsidiaries taken as a whole will be governed by the provisions of the Indenture described above under the caption "*—Repurchase at the option of holders—Change of control*" and/or the provisions described above under the caption "*—Certain covenants—Merger, consolidation or sale of assets*" and not by the provisions described under the caption "*—Repurchase at the option of holders—asset sales*"; and

(2) the issuance of Equity Interests in any of the Company's Restricted Subsidiaries or the sale by the Company or its Restricted Subsidiaries of Equity Interests in any of the Company's Subsidiaries.

Notwithstanding the preceding, none of the following items will be deemed to be an Asset Sale:

(1) any single transaction or series of related transactions that involves assets having a Fair Market Value of less than the greater of $50.0 million and 1.5% of Consolidated Total Assets;

(2) a transfer or other disposition of assets or Equity Interests between or among the Company and/or its Restricted Subsidiaries;

(3) an issuance or sale of Equity Interests by a Restricted Subsidiary of the Company to the Company or to a Restricted Subsidiary of the Company;

(4) the sale, lease or other disposition of products, services, Hydrocarbons or mineral products inventory or accounts receivable or other assets in the ordinary course of business or consistent with past practice or industry practice;

(5) the abandonment, decommissioning, farm-out transfer in exchange for carry, lease or sublease of any oil and gas properties or the forfeiture or other disposition of such properties, in each case in the ordinary course of business or consistent with past practice or industry practice;

(6) the disposition of assets to a Person who is providing services (the provision of which have been or are to be outsourced by the Company or any Restricted Subsidiary to such Person) related to such assets;

(7) any sale or other disposition of damaged, unserviceable, worn-out or obsolete assets in the ordinary course of business or consistent with past practice or industry practice;

(8) the sale or other disposition of cash or Cash Equivalents or other financial assets in the ordinary course of business or consistent with past practice or industry practice;

(9) for purposes of the covenant described above under the heading "*—Repurchase at the option of holders—Asset sales*" only, the making of a Permitted Investment or a disposition subject to the covenant described above under the caption "*—Certain covenants—Restricted payments*";

(10) the sale or other disposition (whether or not in the ordinary course of business or consistent with past practice or industry practice) of crude oil, natural gas and clean energy (including carbon capture storage) properties (for the avoidance of doubt, whether by direct sale or disposition or through a sale or disposition of shares); *provided*, that at the time of such sale or other disposition such properties do not have associated with them any proved and probable reserves;

(11) any Asset Swap;

(12) granting of Liens not prohibited by the covenant described under the caption "*—Certain covenants—Liens*";

(13) the licensing or sublicensing of intellectual property, including, without limitation, licenses for seismic data or other general intangibles and licenses, leases or subleases of other property, in the ordinary course of business or consistent with past practice or industry practice and which do not materially interfere with the business of the Company and its Restricted Subsidiaries taken as a whole;

(14) a surrender or waiver of contract rights, oil and gas leases or the settlement, release or surrender of contract, tort or other claims of any kind;

(15) dispositions of receivables in connection with the compromise, settlement or collection thereof in the ordinary course of business or consistent with past practice or industry practice or in bankruptcy or similar proceedings and exclusive of factoring or similar arrangements;

(16) any sale or other disposition of any oil and gas properties or interests therein to any governmental authority that is (i) a result of a relinquishment to, or a compulsory or involuntary acquisition by, such authority or (ii) made in connection with acquiring, renewing or retaining, as applicable, any other oil and gas properties or interests awarded by such governmental authority; *provided* that any cash or Cash Equivalents received in connection with any such sale or other disposition must be applied in accordance with the covenant described under "*—Repurchase at the option of holders—Asset sales*";

(17) foreclosure, condemnation or any similar action with respect to any property or other assets;

(18) any Production Payments and Reserve Sales; *provided* that any such Production Payments and Reserve Sales, other than incentive compensation programs on terms that are reasonably customary in the Energy

Business for geologists, geophysicists and other providers of technical services to the Company or a Restricted Subsidiary, shall have been created, incurred, issued, assumed or Guaranteed in connection with the financing of, and within 60 days after the acquisition of, the property that is subject thereto;

(19) any issuance, sale or transfer of Capital Stock in, or Indebtedness or other securities of, an Unrestricted Subsidiary or any other disposition of Capital Stock, Indebtedness or other securities of an Unrestricted Subsidiary; and

(20) the disposition of any assets (i) made in connection with the approval of any applicable antitrust authority, (ii) to comply with an order of any agency of state, court, authority or other regulatory body, (iii) to comply with any applicable law or regulation or (iv) otherwise necessary or advisable in the good faith determination of the Company to consummate any acquisition.

"*Asset Swap*" means any substantially contemporaneous (and in any event occurring within 180 days of each other) purchase and sale or exchange (including, without limitation, by way of any farm-out, farm-in, lease or sublease or any other contractual transfer of rights) of any assets or properties or interests therein (including, for the avoidance of doubt, shares in companies owning such assets or properties or interests therein or otherwise primarily engaged, directly or indirectly, in the Energy Business) used or useful in the Energy Business between the Company or any of its Restricted Subsidiaries and another Person; *provided* that the Fair Market Value of the properties or assets or interests therein traded or exchanged (including, without limitation, by way of any farm-out, farm-in, lease, sublease or any other contractual transfer of rights) by the Company or such Restricted Subsidiary (together with any cash) is reasonably equivalent (as determined in good faith by a responsible accounting or financial officer of the Company) to the Fair Market Value of the properties or assets or interests therein (including, without limitation, by way of any farm-out, farm-in, lease, sublease or any other contractual transfer of rights) (together with any cash) to be received by the Company or such Restricted Subsidiary, and *provided further* that any net cash received must be applied in accordance with the provisions described above under the caption "*—Repurchase at the option of holders—asset sales*" if then in effect.

"*Authority*" means the Luxembourg Stock Exchange or any other Recognized Stock Exchange, as applicable.

"*Bank Credit Facilities*" means any Credit Facility that does not constitute Public Indebtedness.

"*Beneficial Owner*" has the meaning assigned to such term in Rule 13d-3 and Rule 13d-5 under the U.S. Exchange Act, except that in calculating the beneficial ownership of any particular "person" (as that term is used in Section 13(d)(3) of the U.S. Exchange Act), such "person" will be deemed to have beneficial ownership of all securities that such "person" has the right to acquire by conversion or exercise of other securities, whether such right is currently exercisable or is exercisable only after the passage of time. The terms "Beneficial Ownership," "Beneficially Owns" and "Beneficially Owned" have a corresponding meaning.

"*Board of Directors*" means:

(1) with respect to a corporation, the board of directors of the corporation or any committee thereof duly authorized to act on behalf of such board;

(2) with respect to a partnership, the board of directors of the general partner of the partnership;

(3) with respect to a limited liability company, the managing member or members or any controlling committee of managing members thereof; and

(4) with respect to any other Person, the board or committee of such Person serving a similar function.

"*Borrowing Base Facilities*" means one or more debt facilities, instruments or arrangements incurred by the Company, any Restricted Subsidiary or any Finance Subsidiary with one or more commercial banks, funds or other institutions or investors providing for revolving credit loans, term loans or letters of credit, or other Indebtedness, pursuant to a reserves and/or resources-based borrowing base or other asset-backed base and/or calculation based on the present value of estimated future oil and gas revenues and/or development financing, in each case, as amended, restated, modified, renewed, refunded, replaced, restructured, refinanced, repaid, increased or extended in whole or in part from time to time and in each case including all agreements, instruments and

documents executed and delivered pursuant to or in connection with the foregoing (including any promissory notes and letters of credit issued pursuant thereto and any Guarantee and collateral agreement and other Guarantees, pledges, agreements, security agreements and collateral documents). Without limiting the generality of the foregoing, the term "Borrowing Base Facilities" shall include any agreement or instrument (1) changing the maturity of any Indebtedness incurred thereunder or contemplated thereby, (2) adding Subsidiaries of the Company as additional borrowers, issuers or guarantors thereunder, (3) increasing the amount of Indebtedness incurred thereunder or available to be borrowed thereunder or (4) otherwise altering the terms and conditions thereof.

"*Business Day*" means each day that is not a Saturday, Sunday or other day on which banking institutions in London, Luxembourg or New York or another place of payment under the Indenture are authorized or required by law to close.

"*Calculation Date*" has the meaning given in the definition of "Fixed Charge Coverage Ratio."

"*Capital Lease Obligation*" means, at the time any determination is to be made, the amount of the liability in respect of a capital lease that would at that time be required to be capitalized on a balance sheet prepared in accordance with IFRS, and the Stated Maturity thereof shall be the date of the last payment of rent or any other amount due under such lease prior to the first date upon which such lease may be prepaid by the lessee without payment of a penalty.

"*Capital Stock*" means:

(1) in the case of a corporation, corporate stock;

(2) in the case of an association or business entity, any and all shares, interests, participations, rights or other equivalents (however designated) of corporate stock;

(3) in the case of a partnership or limited liability company, partnership interests (whether general or limited) or, membership interests; and

(4) any other interest or participation that confers on a Person the right to receive a share of the profits and losses of, or distributions of assets of, the issuing Person,

but excluding from all of the foregoing any debt securities convertible into Capital Stock, whether or not such debt securities include any right of participation with Capital Stock.

"*Cash Equivalents*" means:

(1) Australian Dollars, Canadian dollars, euros, Japanese Yen, Swiss Francs, U.K. pounds, U.S. Dollars or any national currency of any member state of the European Union or any other foreign currency held by the Company and the Restricted Subsidiaries in the ordinary course of business or consistent with past practice or by any future Restricted Subsidiary of the Company, the official currency of its country of organization;

(2) securities issued or other direct obligations directly and fully guaranteed or insured by the government of the United States of America, a member state of the European Union on the Issue Date, the United Kingdom, Switzerland, Norway, Canada, Australia or Japan (including, in each case, any agency or instrumentality thereof), as the case may be, the payment of which is backed by the full faith and credit of the United States, the relevant member state of the European Union, the United Kingdom, Switzerland, Norway, Canada, Australia or Japan, as the case may be, having maturities of not more than 24 months from the date of acquisition;

(3) certificates of deposit, time deposits, eurodollar time deposits, money market deposits, overnight bank deposits or bankers' acceptances (and similar instruments) having maturities of not more than fifteen months from the date of acquisition thereof issued by any lender or by any bank or trust company:

(i) whose commercial paper is rated at least "A-1" or the equivalent thereof by S&P or at least "F1" or the equivalent thereof by Fitch or at least "P-1" or the equivalent thereof by Moody's (or if at the time neither

is issuing comparable ratings, then a comparable rating of another by an internationally recognized rating agency selected by the Company); or

(ii) (in the event that the bank or trust company does not have commercial paper which is rated) having combined capital and surplus in excess of $250.0 million or, in the case of a bank or trust company organized outside the United States, Canada, the United Kingdom or the European Economic Area, $100.0 million;

(4) repurchase obligations for underlying securities of the types described in clauses (2), (3) and (9) of this definition entered into with any financial institution meeting the qualifications specified in clause (3) above;

(5) Securities with maturities of one year or less from the date of acquisition backed by standby letters of credit issued by any person referenced in clause (3) above

(6) commercial paper rated at the time of acquisition thereof at least "A-2" or the equivalent thereof by S&P or "P-2" or the equivalent thereof by Moody's, or carrying an equivalent rating by an internationally recognized rating agency, if both of the two named rating agencies cease publishing ratings of investments, and in any case maturing within one year after the date of acquisition thereof;

(7) in the case of any Restricted Subsidiary of the Company located outside the United States, Canada, the United Kingdom and the European Union, any substantially similar investment to the kinds described in clauses (2) and (3) of this definition obtained in the ordinary course of business or consistent with past practice or industry practice and (i) with the highest ranking obtainable in the applicable jurisdiction or (ii) with any bank, trust company or similar entity, that is nationally recognized in the jurisdiction of incorporation or organization of such Restricted Subsidiary;

(8) bills of exchange issued in the United States of America, a member state of the European Union on the Issue Date, the United Kingdom, Switzerland, Norway, Canada, Australia or Japan eligible for rediscount at the relevant central bank and accepted by a bank (or any dematerialized equivalent); and

(9) interests in any investment company, money market fund, enhanced high yield fund or other investment fund which invests 90% or more of its assets in instruments of the type specified in clauses (1) through (8) above.

"*Change of Control*" means the occurrence of any of the following:

(1) the direct or indirect sale, lease, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions, of all or substantially all of the properties or assets of the Company and its Restricted Subsidiaries taken as a whole to any "person" (as that term is used in Section 13(d) of the U.S. Exchange Act);

(2) the adoption of a plan relating to the liquidation or dissolution of the Company; or

(3) the consummation of any transaction (including, without limitation, any merger or consolidation), the result of which is that any "person" (as defined above) other than one or more Permitted Holders becomes the Beneficial Owner, directly or indirectly, of more than 50% of the Voting Stock of the Company, measured by voting power rather than number of shares.

Notwithstanding the foregoing, (a) a transaction will not be deemed to involve a Change of Control solely as a result of the Company becoming a direct or indirect Wholly Owned Subsidiary of a holding company if (1) the direct or indirect holders of the Voting Stock of such holding company immediately following that transaction are substantially the same as the holders of the Company's Voting Stock immediately prior to that transaction or (2) immediately following that transaction no Person (other than a holding company satisfying the requirements of this sentence) is the beneficial owner, directly or indirectly, of more than 50% of the Voting Stock of such holding company, (b) the right to acquire Voting Stock (so long as such person does not have the right to direct the voting of the Voting Stock subject to such right) will not cause a party to be a beneficial owner and (c) any Voting Stock beneficially owned by any Permitted Holder shall not be included in any Voting Stock of which any other person

or group is the beneficial owner so long as such other person does not have greater voting power with respect to such Permitted Holder's Voting Stock.

"*Clearstream*" means Clearstream Banking, *société anonyme* and its successors.

"*Consolidated Cash Flow*" means, with respect to any specified Person for any period, the Consolidated Net Income of such Person for such period *plus* the following, without duplication:

(1) an amount equal to any extraordinary loss plus any net loss realized by such Person or any of its Restricted Subsidiaries in connection with a sale of assets (together with any related provision for taxes and any related non-recurring charges relating to any premium or penalty paid, write-off of deferred financing costs or other financial recapitalization charges in connection with redeeming or retiring any Indebtedness prior to its Stated Maturity) to the extent deducted in calculating such Consolidated Net Income; *plus*

(2) taxes based on income or profits of such Person and its Restricted Subsidiaries for such period to the extent deducted in calculating such Consolidated Net Income; *plus*

(3) the Fixed Charges of such Person and its Restricted Subsidiaries for such period to the extent deducted in calculating such Consolidated Net Income; *plus*

(4) depreciation, depletion, amortization (including, without limitation, amortization of intangibles and deferred financing fees but excluding amortization of prepaid cash expenses that were paid in a prior period), impairment and other non-cash charges and expenses (including, without limitation, write downs and impairment of property, plant, equipment and intangible and other long lived assets and the impact of purchase accounting on the Company and its Restricted Subsidiaries for such period), of such Person and its Restricted Subsidiaries (excluding any such non-cash expense to the extent that it represents an accrual of or reserve for cash expenses in any future period or amortization of a prepaid cash expense that was paid in a prior period) for such period to the extent deducted in calculating such Consolidated Net Income; *plus*

(5) (x) any expenses, charges or other costs related to the issuance of any Capital Stock, or any Permitted Investment, acquisition (including amounts paid in connection with the acquisition or retention of one or more individuals comprising part of a management team retained to manage an acquired business and any expenses, charges or other costs related to deferred or contingent payments), disposition, recapitalization or listing or the incurrence of Indebtedness permitted to be incurred under the covenant described above under the caption "*—Certain covenants—incurrence of indebtedness and issuance of preferred stock*" (including any refinancing thereof) whether or not successful, including (i) such fees, expenses or charges related to any incurrence of Indebtedness issuance, (ii) such fees, expenses or charges related to the Transactions, (iii) any amendment or other modification of any incurrence, in each case to the extent deducted in calculating such Consolidated Net Income and (iv) the amount of Pro Forma Cost Savings; *plus*

(6) any foreign currency translation losses (including losses related to currency remeasurements of Indebtedness); *plus*

(7) the amount of any minority interest expense (whether paid or not) consisting of subsidiary income attributable to Minority Interests of third parties in any non-wholly owned Restricted Subsidiary in such period or any prior period, except to the extent of dividends declared or paid on, or other cash payments in respect of, Equity Interests held by such parties; *plus*

(8) if such Person accounts for its oil and natural gas or clean energy operations using successful efforts or a similar method of accounting, consolidated exploration and abandonment expense and write-offs of the Company and its Restricted Subsidiaries; *plus*

(9) any income or charge attributable to a post-employment benefit scheme other than the current service costs and any past service costs and curtailments and settlements attributable to the scheme; *plus*

(10) the proceeds of any business interruption insurance received or that become receivable during such period to the extent the associated losses arising out of the event that resulted in the payment of such business interruption insurance proceeds were included in computing Consolidated Net Income; *plus*

(11) the amount of management, monitoring, consulting and advisory fees and related expenses paid in such period to the Permitted Holders to the extent permitted by the covenant described under "*—Certain Covenants—Limitations on Affiliate Transactions*;" *plus*

(12) payments received or that become receivable with respect to expenses that are covered by the indemnification provisions in any agreement entered into by such Person in connection with an acquisition to the extent such expenses were included in computing Consolidated Net Income; *minus*

(13) non-cash items increasing such Consolidated Net Income for such period (other than any non-cash items increasing such Consolidated Net Income pursuant to clauses (1) through (10) of the definition of Consolidated Net Income), other than items that were accrued in the ordinary course of business or consistent with past practice or industry practice; and *minus*

(14) the sum of (a) the amount of deferred revenues that are amortized during such period and are attributable to reserves that are subject to Volumetric Production Payments and (b) amounts recorded in accordance with IFRS as repayments of principal and interest pursuant to Dollar-Denominated Production Payments,

in each case, on a consolidated basis and determined in accordance with IFRS.

"*Consolidated Leverage*" means, as of any date of determination, with respect to any specified Person, the total amount of Indebtedness under Credit Facilities of such Person and its Restricted Subsidiaries on a consolidated basis (excluding Hedging Obligations and excluding letters of credit), *less* cash and Cash Equivalents held by such specified Person on that date of determination.

"*Consolidated Leverage Ratio*" means, as of any date of determination, with respect to any specified Person, the ratio of (a) the Consolidated Leverage of such Person on such date to (b) the Consolidated Cash Flow of the Person for the two most recent half-year periods ending immediately prior to such date for which internal financial statements are available. For purposes of calculating the Consolidated Cash Flow for such period:

(1) acquisitions that have been made by the specified Person or any of its Restricted Subsidiaries, including through mergers or consolidations, or any Person or any of its Restricted Subsidiaries acquired by the specified Person or any of its Restricted Subsidiaries, and including all related financing transactions and including increases in ownership of Restricted Subsidiaries, during the two half-year reference period or subsequent to such reference period, and on or prior to the date of determination, or that are to be made on the date of determination, will be given *pro forma* effect (including Pro Forma Cost Savings) as if they had occurred on the first day of the two half-year reference period;

(2) the Consolidated Cash Flow attributable to discontinued operations, as determined in accordance with IFRS, and operations or businesses (and ownership interests therein) disposed of on or prior to the date of determination (including transactions giving rise to the need to calculate such Consolidated Leverage Ratio) will be excluded;

(3) any Person that is a Restricted Subsidiary on the date of determination will be deemed to have been a Restricted Subsidiary at all times during such two half-year reference period;

(4) any Person that is not a Restricted Subsidiary on the date of determination will be deemed not to have been a Restricted Subsidiary at any time during such two half-year reference period; and

(5) if any Indebtedness bears a floating rate of interest, the interest expense on such Indebtedness will be calculated as if the rate in effect on the Calculation Date had been the applicable rate for the entire period (taking into account any Interest Rate Agreement applicable to such Indebtedness, and if any Indebtedness is not denominated in the Company's functional currency, that Indebtedness for purposes of this calculation of Consolidated Leverage shall be treated in accordance with IFRS).

For purposes of this definition, whenever *pro forma* effect is to be given to a transaction or cost optimization initiative, the *pro forma* calculation shall be determined in good faith by a responsible accounting or financial officer of the Company and may include Pro Forma Cost Savings. In determining the amount of Indebtedness in respect of borrowed money outstanding on any date of determination, *pro forma* effect will be given to any incurrence, repayment, repurchase, defeasance or other acquisition, retirement or discharge of Indebtedness in respect of borrowed money on such date. Any undrawn amounts under revolving credit Indebtedness shall be deemed not to be outstanding.

"*Consolidated Net Income*" means, with respect to any specified Person for any period, the aggregate of the net income (loss) of such Person and its Restricted Subsidiaries for such period, on a consolidated basis (excluding the net income (loss) of any Unrestricted Subsidiaries), determined in accordance with IFRS; *provided* that:

(1) the net income (but not loss) of any Person that is not a Restricted Subsidiary or that is accounted for by the equity method of accounting will be included only to the extent of the aggregate amount of cash or Cash Equivalents actually distributed by such Person during such period to the specified Person or a Restricted Subsidiary of the Person, as a dividend or other distribution or return on investment or could have been distributed, as reasonably determined by an Officer;

(2) solely for the purpose of determining the amount available for Restricted Payments under clause (c)(i) of the first paragraph under the caption "*—Certain covenants—Restricted payments*," any net income (but not loss) of any Restricted Subsidiary (other than any Guarantor) will be excluded if such Subsidiary is subject to restrictions, directly or indirectly, on the payment of dividends or the making of distributions by such Restricted Subsidiary, directly or indirectly, to such Person (or any Guarantor that holds the Equity Interests of such Restricted Subsidiary, as applicable) by operation of the terms of such Restricted Subsidiary's charter or any agreement, instrument, judgment, decree, order, statute or governmental rule or regulation applicable to such Restricted Subsidiary or its shareholders (other than (a) restrictions that have been waived or otherwise released, (b) restrictions pursuant to the Notes (including Additional Notes), the Note Guarantees, the Indenture or the Guarantee Subordination Agreement or any Additional Guarantee Subordination Agreement, (c) contractual restrictions in effect on the Issue Date with respect to the Restricted Subsidiary and other restrictions with respect to such Restricted Subsidiary that taken as a whole, are not materially less favorable to the holders of the Notes than such restrictions in effect on the Issue Date and (d) any restriction listed under clauses (1), (2), (3), (4) or (11) of the second paragraph of the covenant described above under the caption "*—Certain covenants—Dividend and other payment restrictions affecting subsidiaries*") except that such Person's equity in the net income of any such Restricted Subsidiary for such period will be included in such Consolidated Net Income up to the aggregate amount of cash or Cash Equivalents actually distributed or that could have been distributed by such Restricted Subsidiary during such period to such Person or another Restricted Subsidiary as a dividend or other distribution (subject, in the case of a dividend to another Restricted Subsidiary (other than any Guarantor), to the limitation contained in this clause);

(3) the cumulative effect of a change in accounting principles will be excluded;

(4) income resulting from transfers of assets (other than cash) between such Person or any of its Restricted Subsidiaries, on the one hand, and an Unrestricted Subsidiary, on the other hand, will be excluded;

(5) any gain (loss) realized upon the sale or other disposition of any property, plant or equipment of such Person or its consolidated Restricted Subsidiaries (including pursuant to any sale or leaseback transaction) which is not sold or otherwise disposed of in the ordinary course of business or consistent with past practice or industry practice (as determined in good faith by a responsible accounting or financial officer of such Person) and any gain (loss) realized upon the sale or other disposition of any Capital Stock of any Person will be excluded;

(6) any "ceiling limitation" or other asset impairment write-downs on oil and gas properties will be excluded;

(7) all deferred financing costs written off and premiums paid or other expenses incurred directly in connection with any early extinguishment of Indebtedness or Hedging Obligations and any net gain (loss) from any write-off or forgiveness of Indebtedness will be excluded;

(8) any unrealized non-cash gains or losses in respect of Hedging Obligations or any ineffectiveness recognized in earnings related to qualifying hedge transactions or the fair value or changes therein recognized in earnings for derivatives that do not qualify as hedge transactions, in each case, in respect of Hedging Obligations will be excluded;

(9) any non-cash compensation charge or expense arising from any grant of stock, stock option or other equity-based award will be excluded;

(10) any non-cash expenses, accruals or reserves to adjustments to historical tax exposures or the release of any valuation allowances related to such item.

(11) any unrealized foreign currency translation or transaction gains or losses in respect of Indebtedness or other obligations of any Person denominated in a currency other than the functional currency of such Person and any unrealized foreign exchange gains or losses resulting from remeasuring assets and liabilities denominated in foreign currencies will be excluded;

(12) to the extent deducted in the calculation of net income, any non- cash or non-recurring charges associated with any premium or penalty paid, write-off of deferred financing costs or other financial recapitalization charges in connection with redeeming or retiring any Indebtedness prior to its Stated Maturity will be excluded;

(13) any one-time non-cash charges or amortization or depreciation, or any acquisition of another Person or business or resulting from any reorganization or restructuring will be excluded;

(14) any goodwill or other intangible asset amortization charge, impairment charge or write-off or write-down will be excluded; and

(15) (a) extraordinary, exceptional, unusual or non-recurring gains, losses or charges, (b) any asset impairment charges or the financial impacts of natural disasters (including fire, flood and storm and related events) or (c) any non-cash charges or reserves in respect of any restructurings, redundancy, integration or severance, or other post-employment arrangements, signing, retention or completion bonuses, transaction costs, acquisition costs, business optimization initiatives, system establishment, software or information technology implementation or development, costs related to governmental investigations and curtailments or modifications to pension or post-retirement benefits schemes, litigation or any asset impairment charges, in each case will be excluded.

"*Consolidated Total Assets*" means the total assets of the Company and its Subsidiaries on a consolidated basis, as shown on the most recent consolidated balance sheet of the Company prepared in accordance with IFRS, as adjusted to give *pro forma* effect to acquisitions and dispositions made prior to or that are made on the date of determination.

"*Contingent Obligations*" means, with respect to any Person, any obligation of such Person Guaranteeing in any manner, whether directly or indirectly, any operating lease, dividend or other obligation that, in each case, does not constitute Indebtedness ("primary obligations") of any other Person (the "primary obligor"), including any obligation of such Person, whether or not contingent:

(1) to purchase any such primary obligation or any property constituting direct or indirect security therefor;

(2) to advance or supply funds:

(a) for the purchase or payment of any such primary obligation; or

(b) to maintain the working capital or equity capital of the primary obligor or otherwise to maintain the net worth or solvency of the primary obligor; or

(3) to purchase property, securities or services primarily for the purpose of assuring the owner of any such primary obligation of the ability of the primary obligor to make payment of such primary obligation against loss in respect thereof; or

(4) for the avoidance of doubt, any contingent obligations in respect of workers' compensation claims, early retirement or termination obligations, pension fund obligations or contributions, or similar claims, obligations or contributions or social security or wage taxes.

"*continuing*" means, with respect to any Default or Event of Default, that such Default or Event of Default has not been cured or waived.

"*Credit Facilities*" means, one or more debt facilities, capital markets indentures, instruments or arrangements incurred by the Company, any Restricted Subsidiary or any Finance Subsidiary (including, without limitation the RBL Facility, Borrowing Base Facilities, commercial paper facilities, letters of credit facilities, banks' acceptances and overdraft facilities) with banks, funds or other institutions or investors, providing for revolving credit loans, term loans, receivables financing (including through the sale of receivables to such institutions or to special purpose entities formed to borrow from such institutions against such receivables) or letters of credit, notes or other Indebtedness, in each case, as amended, restated, modified, renewed, refunded, replaced, restructured, refinanced, repaid, increased or extended in whole or in part from time to time (and whether in whole or in part and whether or not with the original administrative agent and lenders or another administrative agent or agents or trustees or other banks, funds, institutions or investors and whether provided under the 2021 RBL Facility, the RBL Facility, Borrowing Base Facilities or one or more other credit or other agreements, indentures, financing agreements or otherwise) and in each case including all agreements, instruments and documents executed and delivered pursuant to or in connection with the foregoing (including any promissory notes and letters of credit issued pursuant thereto and any Guarantee and collateral agreement, patent and trademark security agreement, mortgages or letter of credit applications and other Guarantees, pledges, agreements, security agreements and collateral documents). Without limiting the generality of the foregoing, the term "Credit Facilities" shall include any agreement or instrument (1) changing the maturity of any Indebtedness incurred thereunder or contemplated thereby, (2) adding Subsidiaries of the Company as additional borrowers, issuers or guarantors thereunder, (3) increasing the amount of Indebtedness incurred thereunder or available to be borrowed thereunder or (4) otherwise altering the terms and conditions thereof.

"*Currency Exchange Protection Agreement*" means, in respect of any Person, any foreign exchange contract, currency swap agreement, currency option, cap, floor, ceiling or collar agreement or other similar agreement or arrangement designed to protect such Person against fluctuations in currency exchange rates as to which such Person is a party.

"*Default*" means any event that is, or with the passage of time or the giving of notice or both would be, an Event of Default.

"*Designated Non-Cash Consideration*" means the Fair Market Value of non-cash consideration received by the Company or one of its Restricted Subsidiaries in connection with an Asset Sale that is so designated as "Designated Non-Cash Consideration" pursuant to an Officers' Certificate, setting forth the basis of such valuation, *less* the amount of cash or Cash Equivalents received in connection with a subsequent sale of such Designated Non-Cash Consideration.

"*Disqualified Stock*" means any Capital Stock that, by its terms (or by the terms of any security into which it is convertible, or for which it is exchangeable, in each case, at the option of the holder of the Capital Stock), or upon the happening of any event, matures or is mandatorily redeemable, pursuant to a sinking fund obligation or otherwise, or redeemable at the option of the holder of the Capital Stock, in whole or in part, on or prior to the date that is 91 days after the date on which the Notes mature; *provided*, that only the portion of Capital Stock which so matures or is mandatorily redeemable, or is so redeemable at the option of the holder thereof prior to such date, will be deemed to be Disqualified Stock. Notwithstanding the preceding sentence, any Capital Stock that would constitute Disqualified Stock solely because the holders of the Capital Stock have the right to require the Company to repurchase or redeem such Capital Stock upon the occurrence of a change of control or an asset sale will not constitute Disqualified Stock if the terms of such Capital Stock provide that the Company may not repurchase or redeem any such Capital Stock pursuant to such provisions unless such repurchase or redemption complies with the covenant described above under the caption "*—Certain covenants—Restricted payments*." For purposes hereof, the amount of Disqualified Stock which does not have a fixed repurchase price shall be calculated in accordance with the terms of such Disqualified Stock as if such Disqualified Stock were purchased on any date on which Indebtedness shall be required to be determined pursuant to the Indenture, and if such price is based

upon, or measured by, the Fair Market Value of such Disqualified Stock, such Fair Market Value to be determined as set forth herein.

"*Dollar-Denominated Production Payments*" means production payment obligations recorded as liabilities in accordance with IFRS, together with all undertakings and obligations in connection therewith.

"*Dormant Guarantor*" means a Guarantor that is not engaging in any material financial transactions or business activities.

"*Eligible JV Transaction*" means a transaction by which a Guarantor becomes a non-Wholly Owned Subsidiary whether as a result of the issuance, sale, transfer, contribution or other disposition, directly or indirectly, of Capital Stock of such Guarantor, the entry into a joint venture or farm-out arrangement, or otherwise; provided that (i) such transaction or series of related transactions (a) is not entered into for the primary purpose of releasing such Note Guarantee and (b) is entered into for bona fide business purposes and involves a counterparty that is not an Affiliate of the Company and (ii) at the time of, and after giving effect to, such transaction or series of related transactions, the Capital Stock which is the subject of such transaction or series of related transactions (directly or indirectly) comprises no less than 25% of the total outstanding Capital Stock of such Guarantor.

"*Energy Business*" means:

(1) the acquisition, exploration, exploitation, development, production, operation and disposition of interests in oil, natural gas, natural gas liquids, liquefied natural gas, biofuels and other Hydrocarbon, mineral and renewable energy properties or products produced in association with the foregoing;

(2) the gathering, marketing, distributing, compressing, handling, developing, treating, refining, processing, storing, terminalling, selling and transporting of any production from oil, natural gas, natural gas liquids, liquefied natural gas, biofuels and other Hydrocarbon, mineral and renewable energy properties or assets (whether or not such properties are owned by the Company and/or its Subsidiaries) and products produced in association therewith, or in constructing or contracting with third parties for the construction of infrastructure in support of the same and the marketing of oil, natural gas, biofuels, renewable energy and other hydrocarbons, minerals and renewable energy obtained from unrelated Persons;

(3) any other related energy business, including, without limitation, (i) power generation, carbon capture and storage and electrical transmission business, from oil, natural gas, biofuels and other Hydrocarbons, minerals and clean energy sources produced substantially from properties in which the Company or its Restricted Subsidiaries, directly or indirectly, participates and the generation of electricity from other sources primarily to power its own facilities, (ii) the purchase and sale of carbon credits, offsets and renewable energy certificates and (iii) providing or sourcing front end studies or other engineering solutions, subsea production equipment or offshore field design for oil and gas or renewable energy companies;

(4) any business relating to renewable energy, oil and gas field seismic mapping, sales, service provision and technology development; and

(5) any business or activity relating to, arising from, or necessary, appropriate, complementary, related or incidental to the businesses, services and activities described in clauses (1), (2), (3) and (4) of this definition.

"*Equity Interests*" means Capital Stock and all warrants, options or other rights to acquire Capital Stock (but excluding any debt security that is convertible into, or exchangeable for, Capital Stock).

"*Equity Offering*" means any public or private sale of Capital Stock (other than Disqualified Stock and other than to a Subsidiary of the Company) by the Company after the Issue Date.

"*Euroclear*" means Euroclear Bank SA/NV and its successors, as operator of the Euroclear System.

"*European Government Obligations*" means (A) any security that is (1) a direct and unconditional obligation of the European Union, (2) backed by the European Union's budgetary and cash resources and by the European

Commission's right to call for additional resources from member states, (3) a direct obligation of any member state of the European Union, for the payment of which the full-faith-and-credit of such country is pledged or (4) an obligation of a person controlled or supervised by and acting as an agency or instrumentality of any such country, the payment of which is unconditionally guaranteed as a full-faith-and-credit obligation by such country, which, in any case under the preceding clauses (1) through (4), is not callable or redeemable at the option of the issuer thereof and (B) certificates, depositary receipts or other instruments which evidence a direct ownership interest in obligations described in clause (A) above or in any specific principal or interest payments due in respect thereof.

"*Exchange*" means the Luxembourg Stock Exchange or any other Recognized Stock Exchange, as applicable.

"*Existing Indebtedness*" means Indebtedness of the Company and its Restricted Subsidiaries (other than Indebtedness under the RBL Facility) in existence on the date of the Indenture, including, for the avoidance of doubt, the 9% Retail Notes.

"*2021 RBL Facility*" means the secured revolving borrowing base facility agreement dated as of June 10, 2021, and amended and restated on November 29, 2021 and October 3, 2022, entered into between, among others, the Company, as obligor, and BNP Paribas, as agent and security agent, which was cancelled on November 20, 2025.

"*Fair Market Value*" means the value that would be paid by a willing buyer to an unaffiliated willing seller in a transaction not involving distress or necessity of either party, as determined in good faith by a responsible accounting or financial officer of the Company.

"*Finance Subsidiary*" means a Wholly Owned Subsidiary of the Company that is formed for the purpose of borrowing funds or issuing securities and lending the proceeds to the Company or a Guarantor and that conducts no business other than as may be reasonably incidental to, or related to, the foregoing.

"*Fitch*" means Fitch, Inc. or any successor to its ratings business.

"*Fixed Charge Coverage Ratio*" means, with respect to any specified Person for any period, the ratio of the Consolidated Cash Flow of such Person for such period to the Fixed Charges of such Person for such period. In the event that the specified Person or any of its Restricted Subsidiaries incurs, assumes, Guarantees, repays, repurchases, redeems, defeases or otherwise discharges any Indebtedness (other than ordinary course working capital borrowings) or issues, repurchases or redeems preferred stock subsequent to the commencement of the period for which the Fixed Charge Coverage Ratio is being calculated and on or prior to the date on which the event for which the calculation of the Fixed Charge Coverage Ratio is made (the "**Calculation Date**"), then the Fixed Charge Coverage Ratio will be calculated giving *pro forma* effect (as determined in good faith by a responsible accounting or financial officer of the Company) to such incurrence, assumption, Guarantee, repayment, repurchase, redemption, defeasance or other discharge of Indebtedness, or such issuance, repurchase or redemption of preferred stock, and the use of the proceeds therefrom, as if the same had occurred at the beginning of the applicable two full half-year reference period; *provided*, *however*, that the *pro forma* calculation of Fixed Charges shall not give effect to (i) any Indebtedness incurred on the Calculation Date (and, for the avoidance of doubt, not reclassified on such Calculation Date) pursuant to the provisions described in the second paragraph under "*—Certain covenants—Incurrence of indebtedness and issuance of preferred stock*" or (ii) the discharge on the Calculation Date of any Indebtedness to the extent that such discharge results from the application of the proceeds of any Indebtedness incurred pursuant to the provisions described in the second paragraph under "*—Certain covenants—Incurrence of indebtedness and issuance of preferred stock*."

In addition, for purposes of calculating the Fixed Charge Coverage Ratio:

(1) acquisitions that have been made by the specified Person or any of its Restricted Subsidiaries, including through mergers, consolidations or otherwise (including acquisitions of assets used or useful in the Energy Business), or any Person or any of its Restricted Subsidiaries acquired by the specified Person or any of its Restricted Subsidiaries, and including any related financing transactions and including increases in ownership of Restricted Subsidiaries, during the two half-year reference period or subsequent to such reference period and on or prior to the Calculation Date or that are to be made on the Calculation Date, will be given *pro forma* effect (including Pro Forma Cost Savings) as if they had occurred on the first day of the two half-year reference period;

(2) the Consolidated Cash Flow attributable to discontinued operations, as determined in accordance with IFRS, and operations or businesses (and ownership interests therein) disposed of prior to the Calculation Date, will be excluded;

(3) the Fixed Charges attributable to discontinued operations, as determined in accordance with IFRS, and operations or businesses (and ownership interests therein) disposed of prior to the Calculation Date, will be excluded, but only to the extent that the obligations giving rise to such Fixed Charges will not be obligations of the specified Person or any of its Restricted Subsidiaries following the Calculation Date;

(4) any Person that is a Restricted Subsidiary on the Calculation Date will be deemed to have been a Restricted Subsidiary at all times during such two half-year reference period; and

(5) any Person that is not a Restricted Subsidiary on the Calculation Date will be deemed not to have been a Restricted Subsidiary at any time during such two half-year reference period.

"*Fixed Charges*" means, with respect to any specified Person for any period, the sum, without duplication, of:

(1) the consolidated interest expense (net of interest income) of such Person and its Restricted Subsidiaries for such period, whether paid or accrued (excluding any interest attributable to Dollar-Denominated Production Payments) including, without limitation, amortization of discount (but not debt issuance costs, commissions, fees and expenses), non-cash interest payments (but excluding any non-cash interest expense attributable to the movement in the mark to market valuation of Hedging Obligations or other derivative instruments), the interest component of any deferred payment obligations (but not with respect to any decommissioning obligations), the interest component of all payments associated with Capital Lease Obligations, commissions, discounts and other fees and charges incurred in respect of letter of credit or bankers' acceptance financings, and net of the effect of all payments made or received pursuant to Hedging Obligations (excluding amortization of fees) in respect of interest rates; *plus*

(2) the consolidated interest expense of such Person and its Restricted Subsidiaries that was capitalized during such period; *plus*

(3) any interest on Indebtedness of another Person that is Guaranteed by such Person or one of its Restricted Subsidiaries or secured by a Lien on assets of such Person or one of its Restricted Subsidiaries, to the extent paid in cash by such Person or any of its Restricted Subsidiaries; *plus*

(4) the product of (a) all dividends, whether paid or accrued and whether or not in cash, on any series of Disqualified Stock of such Person or any series of preferred stock of its Restricted Subsidiaries, other than dividends on Equity Interests payable solely in Equity Interests of such Person (other than Disqualified Stock) or to the Person or a Restricted Subsidiary of such Person, *times* (b) a fraction, the numerator of which is one and the denominator of which is one minus the then current statutory tax rate of such Person, expressed as a decimal.

"*FPSO*" means any floating storage and offloading unit, floating storage and production unit, floating production, storage and offloading unit or similar moveable infrastructure (including vessels used or useful in connection with performing seismic surveys) and any related infrastructure in connection with the foregoing.

"*Guarantee*" means a guarantee other than by endorsement of negotiable instruments for collection in the ordinary course of business, direct or indirect, in any manner including, without limitation, by way of a pledge of assets or through letters of credit or reimbursement agreements in respect thereof, of all or any part of any Indebtedness (whether arising by virtue of partnership arrangements, or by agreements to keep-well, to maintain financial statement conditions or otherwise), or entered into for purposes of assuring in any other manner the obligee of such Indebtedness of the payment thereof or to protect such obligee against loss in respect thereof (in whole or in part); *provided, however*, that the term "Guarantee" will not include the endorsements for collection or deposit in the ordinary course of business or any obligation to the extent it is payable only in Capital Stock of the guarantor that is not Disqualified Stock. The term "Guarantee" used as a verb has a corresponding meaning.

"*Guarantee Subordination Agreement*" means the subordination agreement dated on April 9, 2014 between, among others, the Company, the Trustee and the facility agent and security trustee under the senior facility, and to which the Trustee will accede on the Issue Date, as amended, restated or otherwise modified or varied from time to time.

"*Guarantors*" means, collectively, EnQuest Heather Limited, EnQuest Britain Limited, EnQuest Heather Leasing Limited, EnQuest Global Limited, EnQuest Petroleum Production Malaysia Ltd and EnQuest Marketing and Trading Limited and any other Person that Guarantees the Notes in accordance with the provisions of the Indenture, and their respective successors and assigns, in each case, until the Note Guarantee of such Person has been released in accordance with the Indenture.

"*Hedging Obligations*" means, with respect to any specified Person, the obligations of such Person under:

(1) interest rate swap agreements (whether from fixed to floating or from floating to fixed), interest rate cap agreements and interest rate collar agreements, other agreements or arrangements designed to manage interest rates or interest rate risk;

(2) any foreign exchange contract, currency swap agreement, currency option, cap, floor, ceiling or collar agreement or other similar agreement or arrangement designed to protect such Person against fluctuations in currency exchange rates;

(3) any forward contract, commodity futures contract, commodity option agreement, commodity swap agreement, cap, floor, ceiling or collar agreement or other similar agreement or arrangement designed to protect against fluctuations in the price of commodities used, produced, processed or sold by that Person or any of its Restricted Subsidiaries at the time; and

(4) other agreements or arrangements designed to protect such Person against fluctuations in interest rates, commodity prices, weather conditions or currency exchange rates, including Currency Exchange Protection Agreements.

"*Hydrocarbons*" means oil, gas, casing head gas, drip gasoline, natural gasoline, condensate, distillate, liquid hydrocarbons, gaseous hydrocarbons and all constituents, elements or compounds thereof and products refined or processed therefrom.

"*IFRS*" means International Financial Reporting Standards as issued by the International Accounting Standards Board and in effect on the Issue Date or, with respect to the covenant entitled "*—Certain Covenants—Reports*," as in effect from time to time.

"*Indebtedness*" means, with respect to any specified Person, any indebtedness of such Person (excluding accrued expenses and trade payables):

(1) in respect of borrowed money;

(2) evidenced by bonds, notes, debentures or similar instruments or letters of credit (or reimbursement agreements in respect thereof);

(3) in respect of bankers' acceptances (or reimbursement obligations in respect thereof except to the extent any such reimbursement obligations relate to trade payables and such obligations are satisfied within 30 days of incurrence);

(4) representing Capital Lease Obligations;

(5) representing the balance deferred and unpaid of the purchase price of any property due more than one year after such property is acquired;

(6) representing any Hedging Obligations;

(7) the principal component of all Indebtedness of other Persons secured by a Lien on any asset of such Person, whether or not such Indebtedness is assumed by such Person; *provided, however,* that the amount of such Indebtedness will be the lesser of (a) the Fair Market Value of such asset at such date of determination and (b) the amount of such Indebtedness of such other Persons; and

(8) the principal component of Indebtedness of other Persons to the extent Guaranteed by such Person (including, with respect to any Production Payment, any warranties or guarantees of production or payment by such Person with respect to such Production Payment, but excluding other contractual obligations of such Person with respect to such Production Payment);

provided that the foregoing indebtedness (other than letters of credit and Hedging Obligations) shall be included in this definition of Indebtedness only if, and to the extent that, the indebtedness would appear as a liability upon a balance sheet of such Person prepared in accordance with IFRS; provided that, notwithstanding any consolidation under IFRS, the preceding items shall not constitute "Indebtedness" for the purposes hereof if (i) such Indebtedness is incurred by an orphan vehicle whose shares are not owned by such specified Person or any of its Subsidiaries and (ii) such Indebtedness is neither guaranteed by, nor secured by the assets of, such specified Person or any of its Subsidiaries. Notwithstanding the foregoing, indebtedness shall be included in the definition of Indebtedness after deducting any receivable due from another Person (other than the Company and its

Restricted Subsidiaries) who has an interest in an asset financed with such indebtedness to the Company or any Restricted Subsidiary in respect of such other Person's interest in the relevant asset. Subject to clause (8) of the preceding sentence, neither Dollar-Denominated Production Payments nor Volumetric Production Payments shall be deemed to be Indebtedness.

The term "*Indebtedness*" shall not include:

(1) any lease of property which would have been considered an operating lease under IAS 17 prior to January 1, 2019;

(2) for the avoidance of doubt, Contingent Obligations;

(3) any obligation of a Person in respect of a farm-in agreement, an agreement with an operator (the "Operator") of an oil or gas property where the Company or any of its Restricted Subsidiaries owns a working interest, or any similar arrangement whereby such Person (i) agrees to pay all or a share of the drilling, completion, development costs or other expenses of an exploratory or development well, field or other oil or gas property (which agreement may be subject to a maximum payment obligation, after which expenses are shared in accordance with the working or participation interest therein or in accordance with the agreement of the parties) or perform the drilling, completion or other operation on such oil or gas property in exchange for an ownership interest in an oil or gas property; and/or (ii) agrees to have the Operator pay or carry such Person's share of the drilling, completion, development costs or other expenses of an exploratory or development well, field or other oil or gas property or perform the drilling, completion or other operation on such oil or gas property, in each case, in exchange for deferred repayments following a specified first oil, development milestone or backstop date;

(4) in-kind obligations relating to net oil or natural gas balancing positions arising in the ordinary course of business or consistent with past practice or industry practice; or

(5) in connection with the purchase by the Company or any Restricted Subsidiary of any business, any post-closing payment adjustments to which the seller may become entitled to the extent such payment is determined by a final closing balance sheet or such payment depends on the performance of such business after the closing or other contingencies (including commodity prices) after closing such transaction.

"*Investment Grade Status*" shall occur when the Notes are rated as follows by two of the following three Rating Agencies: Baa3 or better by Moody's, BBB− or better by S&P and/or BBB− or better by Fitch (or, if any such entity ceases to rate the Notes, the equivalent investment grade credit rating from any other "nationally recognized statistical rating organization," as that term is defined for purposes of Section 3(a)(62) of the U.S. Exchange Act, selected by the Company as a replacement agency).

"*Investments*" means, with respect to any Person, all direct or indirect investments by such Person in other Persons (including Affiliates) in the forms of loans (including Guarantees or other obligations, but excluding advances or extensions of credit to customers or suppliers made in the ordinary course of business or consistent with past practice or industry practice), advances or capital contributions (excluding endorsements of negotiable instruments and documents in the ordinary course of business or consistent with past practice or industry practice, and commission, travel and similar advances to officers, employees and consultants made in the ordinary course of business or consistent with past practice or industry practice), purchases or other acquisitions for consideration of Indebtedness, Equity Interests or other securities, together with all items that are or would be classified as investments on a balance sheet prepared in accordance with IFRS. If the Company or any Restricted Subsidiary of the Company sells or otherwise disposes of any Equity Interests of any direct or indirect Subsidiary of the Company such that, after giving effect to any such sale or disposition, such Person is no longer a Restricted Subsidiary of the Company, the Company will be deemed to have made an Investment on the date of any such sale or disposition equal to the Fair Market Value of the Company's Investments in such Restricted Subsidiary that were not sold or disposed of in an amount determined as provided in the final paragraph of the covenant described above under the caption "*—Certain covenants—Restricted payments*." The acquisition by the Company or any Subsidiary of the Company of a Person that holds an Investment in a third Person will be deemed to be an Investment by the Company or such Subsidiary in such third Person in an amount equal to the Fair Market Value of the Investments held by the acquired Person in such third Person in an amount determined as provided in the final paragraph of the covenant described above under the caption "*—Certain covenants—Restricted payments*."

Except as otherwise provided in the Indenture, the amount of an Investment will be determined at the time the Investment is made and without giving effect to subsequent changes in value and, to the extent applicable, shall be determined based on the equity value of such Investment.

"*Issue Date*" means April 30, 2026.

"*Lien*" means, with respect to any asset, any mortgage, lien, pledge, charge, security interest or encumbrance of any kind in respect of such asset, whether or not filed, recorded or otherwise perfected under applicable law, including any conditional sale or other title retention agreement, any lease in the nature thereof.

"*Listing Authority*" means any nationally recognized listing authority in the United States, Jersey, Guernsey, the United Kingdom or any member state of the European Union.

"*Management Advances*" means loans or advances made to, or Guarantees with respect to loans or advances made to, directors, officers or employees of the Company or any Restricted Subsidiary:

(1) in respect of travel, entertainment or moving and housing-related and similar expense incurred in the ordinary course of business or consistent with past practice or industry practice;

(2) in respect of moving related expenses incurred in connection with any closing or consolidation of any facility or office; or

(3) in the ordinary course of business or consistent with past practice or industry practice and (in the case of this clause (3)) not exceeding $10.0 million in the aggregate outstanding at any time.

"*Market Capitalization*" means an amount equal to the greater of (a) (i) the total number of issued and outstanding shares of share capital or common equity interests of the Company on the date of the declaration of the relevant dividend multiplied by (ii) the arithmetic mean of the closing prices per share of such share capital or common equity interests for the 30 consecutive trading days immediately preceding the date of declaration of such dividend and (b) £75.0 million, being the market capitalization at the time of the initial public offering of EnQuest PLC.

"*Minority Interest*" means the percentage interest represented by any shares of stock of any class of Capital Stock of a Restricted Subsidiary of the Company that are not owned by the Company or a Restricted Subsidiary of the Company.

"*Moody's*" means Moody's Investors Service, Inc. or any successor to its ratings business.

"*Net Proceeds*" means the aggregate cash proceeds received by the Company or any of its Restricted Subsidiaries in respect of any Asset Sale (including, without limitation, any cash received upon the sale or other disposition of any non-cash consideration or Cash Equivalents received in any Asset Sale), net of the direct costs relating to such Asset Sale, including, without limitation:

(1) all legal, accounting, investment banking, commissions and other fees and expenses incurred, title and recording tax expenses, and all Taxes required to be paid or accrued as a liability under IFRS, as a consequence of such Asset Sale;

(2) all payments made on any Indebtedness which is secured by any assets subject to such Asset Sale, in accordance with the terms of any Lien upon such assets, or which must by its terms, or in order to obtain a necessary consent to such Asset Sale, or by applicable law be repaid out of the proceeds from such Asset Sale;

(3) all distributions and other payments required to be made to holders of Minority Interests in Subsidiaries or joint ventures as a result of such Asset Sale; and

(4) the deduction of appropriate amounts to be provided by the seller as a reserve, in accordance with IFRS, or held in escrow, in either case for adjustment in respect of the sale price or for any liabilities associated with the assets disposed of in such Asset Sale and retained by the Company or any Restricted Subsidiary after such Asset Sale.

"*Non-Recourse Debt*" means Indebtedness:

(1) as to which neither the Company nor any of its Restricted Subsidiaries (a) provides credit support of any kind (including any undertaking, agreement or instrument that would constitute Indebtedness), (b) is directly or indirectly liable as a guarantor or otherwise, or (c) constitutes the lender;

(2) no default with respect to which (including any rights that the holders of the Indebtedness may have to take enforcement action against an Unrestricted Subsidiary) would permit upon notice, lapse of time or both any holder of any other Indebtedness of the Company or any of its Restricted Subsidiaries to declare a default on such other Indebtedness or cause the payment of the Indebtedness to be accelerated or payable prior to its Stated Maturity; and

(3) the explicit terms of which provide there is no recourse to the stock or assets of the Company or any of its Restricted Subsidiaries, except as contemplated by clause (26) of the definition of Permitted Liens.

"*Note Guarantee*" means the Guarantee by each Guarantor of the Company's Obligations under the Indenture and the Notes pursuant to the Indenture.

"*Obligations*" means any principal, interest, penalties, fees, indemnifications, reimbursements, damages and other liabilities payable under the documentation governing any Indebtedness.

"*Offering*" has the meaning set forth in these Listing Particulars under "*Definitions*."

"*Listing Particulars*" means these listing particulars dated April 30, 2026.

"*Officer*" means, with respect to any Person, a member of the Board of Directors, the chief executive officer, the president, the chief financial officer, any vice president, the treasurer, any managing director, any responsible accounting or financial officer, the secretary or the equivalent position of any of the foregoing or any other Person that the Board of Directors of such Person shall designate for such purpose.

"*Officers' Certificate*" means a certificate signed on behalf of any Person by one or more Officers of such Person.

"*Permitted Business Investments*" means Investments and/or expenditures made in the ordinary course of, and of a nature that is or has become customary in, or is ancillary, complimentary, related or appropriate to the conduct of, the Energy Business, as a means of actively exploiting, exploring for, acquiring, developing, producing, processing, gathering, marketing, distributing, storing or transporting oil, natural gas, biofuels or other Hydrocarbons, minerals and/or renewable energy (including with respect to plugging, decommissioning and abandonment), or in constructing or contracting with third parties for the construction of infrastructure in support of the same through agreements, transactions, interests or arrangements that permit one to share risks or costs, comply with regulatory requirements regarding local ownership or satisfy other objectives customarily achieved through the conduct of the Energy Business jointly with third parties, including without limitation:

(1) direct or indirect ownership of crude oil, natural gas biofuels, other Hydrocarbon and minerals properties or assets or any interest therein or liquefied natural gas facilities, carbon capture storage facilities, gathering systems, transportation systems, processing facilities, pipelines, storage facilities, properties or property interests relating to power generation and electrical transmission infrastructure, solar, wind and other clean energy sources or related systems or ancillary real property interests;

(2) Investments in the form of or pursuant to operating agreements, joint ventures, processing agreements, farm-in agreements, farm-out agreements, development agreements, production sharing agreements, area of mutual interest agreements, unitization agreements contracts for the sale, transportation or exchange of crude oil and natural gas, biofuels and other Hydrocarbons, minerals and/or renewable energy, participation agreements, unitization agreements, pooling arrangements, joint bidding agreements, service contracts, partnership agreements (whether general or limited), subscription agreements, stock purchase agreements, stockholder agreements and other similar agreements (including for limited liability companies), carbon credit agreements, offset and renewable energy certificates or other similar or customary agreements, in each case made or entered into with third parties (including Unrestricted Subsidiaries); and

(3) direct or indirect ownership interests in drilling rigs, FPSOs, drill ships, jack-up rigs or tender rigs or other drilling vessels, and common processing facilities, power generation and electrical transmission infrastructure (including from solar, wind and other clean energy sources) and in each case related equipment, including, without limitation, transportation equipment.

"*Permitted Holders*" means, collectively,

(1) Amjad Bseisu and any of his Affiliates;

(2) any person having a relationship with Amjad Bseisu by blood, marriage or adoption not more remote than first cousin;

(3) any heir of Amjad Bseisu and any beneficiary of his estate;

(4) any trust or similar arrangement established solely for the benefit of Amjad Bseisu or any Person mentioned in clause (2) or (3) of this definition; provided that Amjad Bseisu or any such Person retains sole control over the voting rights of the Capital Stock held by such trust or arrangement;

(5) any Person that is directly or indirectly owned solely by any other Permitted Holder described under clause (1), (2), (3) or (4) of this definition;

(6) for the avoidance of doubt, any Person or group, together with their Affiliates, whose acquisition of beneficial ownership constitutes a Change of Control in respect of which a Change of Control Offer is made in accordance with the requirements of the Indenture.

"*Permitted Investments*" means:

(1) any Investment in the Company or in a Restricted Subsidiary of the Company;

(2) any Investment in cash and Cash Equivalents;

(3) any Investment by the Company or any Restricted Subsidiary of the Company in any Person whose primary business is the Energy Business, if as a result of such Investment:

  (a) such Person becomes a Restricted Subsidiary of the Company; or

  (b) such Person is merged, consolidated or amalgamated with or into, or transfers or conveys substantially all of its properties or assets to, or is liquidated into, the Company or a Restricted Subsidiary of the Company;

(4) any Investment made as a result of the receipt of non-cash consideration from an Asset Sale that was made pursuant to and in compliance with the covenant described above under the caption "*—Repurchase at the option of holders—Asset sales*";

(5) any acquisition of assets or Capital Stock solely in exchange for the issuance of Equity Interests (other than Disqualified Stock) of the Company;

(6) any Investments received in compromise or resolution of (A) obligations of trade creditors or customers that were incurred in the ordinary course of business or consistent with past practice or industry practice of the Company or any of its Restricted Subsidiaries, including pursuant to any plan of reorganization or similar arrangement upon the bankruptcy or insolvency of any trade creditor or customer; or (B) litigation, arbitration or other disputes with Persons who are not Affiliates;

(7) Investments represented by Hedging Obligations;

(8) receivables owing to the Company or any Restricted Subsidiary created or acquired in the ordinary course of business or consistent with past practice or industry practice and payable or dischargeable in accordance

with customary trade terms; *provided, however,* that such trade terms may include such concessionary trade terms as the Company or any such Restricted Subsidiary deems reasonable under the circumstances;

(9) surety and performance bonds and workers' compensation, utility, lease, tax, performance and similar deposits and prepaid expenses in the ordinary course of business or consistent with past practice; or industry practice

(10) Guarantees of Indebtedness permitted under the covenant contained under the caption "*—Certain covenants—Incurrence of indebtedness and issuance of preferred stock*";

(11) guarantees by the Company or any of its Restricted Subsidiaries of operating leases (other than Capital Lease Obligations) or of other obligations that do not constitute Indebtedness, in each case entered into by any Restricted Subsidiary in the ordinary course of business or consistent with past practice or industry practice;

(12) Investments of a Restricted Subsidiary acquired after the Issue Date or of any entity merged into the Company or merged into or consolidated or amalgamated with a Restricted Subsidiary in accordance with the covenant described under "*—Certain covenants—Merger, consolidation or sale of assets*" to the extent that such Investments were not made in contemplation of or in connection with such acquisition, merger, consolidation or amalgamation and were in existence on the date of such acquisition, merger or consolidation;

(13) Permitted Business Investments;

(14) Investments received as a result of a foreclosure by the Company or any of its Restricted Subsidiaries with respect to any secured Investment in default;

(15) any Investment existing on, or made pursuant to binding commitments existing on, the Issue Date and any Investment consisting of an extension, modification or renewal of any Investment existing on, or made pursuant to a binding commitment existing on, the Issue Date; *provided* that the amount of any such Investment may be increased (a) as required by the terms of such Investment as in existence on the Issue Date or (b) as otherwise permitted under the Indenture;

(16) Guarantees of performance or other obligations (other than Indebtedness) arising in the ordinary course in the Energy Business, including obligations under oil and natural gas exploration, development, joint operating, and related agreements and licenses, concessions or operating leases related to the Energy Business;

(17) Investments in the Notes and any other Indebtedness of the Company or any Restricted Subsidiary;

(18) Management Advances;

(19) payroll, commission, travel, relocation and similar advances to cover matters that are expected at the time of such advances ultimately to be treated as expenses for accounting purposes and that are made in the ordinary course of business or consistent with past practice or industry practice, in each case to the extent the same constitutes an Investment;

(20) Investments in any Person to the extent such Investments consist of prepaid expenses, negotiable instruments held for collection and lease, utility and workers' compensation, performance and similar deposits made in the ordinary course of business or consistent with past practice or industry practice by the Company or any Restricted Subsidiary;

(21) receivables or working capital loans or other such similar forms of credit support owing to the Company or any Restricted Subsidiary of the Company and advances to suppliers, contractors or builders, in each case payable or dischargeable in accordance with such trade terms as the Company or such Restricted Subsidiary deems reasonable under the circumstances;

(22) (a) loans or grants customary or advisable in the Energy Business in respect of community development projects or economic development activities appropriate for the Company's regions of operation and in regions other than the United Kingdom and consistent with past practice or industry practice or counterparty requirements and (b) Investments made with funds received by the Company and its Restricted Subsidiaries from grants or donations from third parties;

(23) other Investments in any Person having an aggregate Fair Market Value (measured on the date each such Investment was made and without giving effect to subsequent changes in value), when taken together with all other Investments made pursuant to this clause (23) that are at the time outstanding, not to exceed the greater of (x) $130 million and (y) 3.5% of Consolidated Total Assets; *provided* that if an Investment is made pursuant to this clause in a Person that is not a Restricted Subsidiary and such Person subsequently becomes a Restricted Subsidiary or is subsequently designated a Restricted Subsidiary pursuant to the covenant described above under the caption "*—Certain covenants—Restricted payments*," such Investment shall thereafter be deemed to have been made pursuant to clauses (1) or (3) of the definition of "Permitted Investments" and not this clause

"*Permitted Liens*" means, with respect to any Person:

(1) Liens securing Indebtedness incurred under (i) Bank Credit Facilities pursuant to the first paragraph of the covenant entitled "*—Certain covenants—Incurrence of indebtedness and issuance of preferred stock*" and (ii) Credit Facilities pursuant to clause (1) of the second paragraph of the covenant entitled "*—Certain covenants—Incurrence of indebtedness and issuance of preferred stock*;"

(2) Liens in favor of the Company or any Restricted Subsidiary;

(3) Liens on property of a Person existing at the time such Person is merged with or into or consolidated or amalgamated with the Company or any Subsidiary of the Company; *provided* that such Liens were in existence prior to the contemplation of such merger, consolidation or amalgamation and do not extend to any assets other than those of the Person merged into or consolidated or amalgamated with the Company or the Subsidiary;

(4) Liens on property (including Capital Stock) existing at the time of acquisition of the property by the Company or any Subsidiary of the Company; *provided* that such Liens were in existence prior to such acquisition, and not incurred in contemplation of, such acquisition;

(5) Liens existing on the Issue Date;

(6) Liens on Capital Stock of and assets of any Restricted Subsidiary that is not a Guarantor that secures Indebtedness of such Restricted Subsidiary or any other Restricted Subsidiary that is not a Guarantor;

(7) Liens for taxes, assessments or governmental charges or claims that (x) are not yet due and payable or (y) that are being contested in good faith by appropriate proceedings;

(8) survey exceptions, easements or reservations of, or rights of others for, licenses, rights of way, gas and oil pipelines, sewers, electric lines, telegraph and telephone lines and other similar purposes, or zoning or other restrictions as to the use of real property that were not incurred in connection with Indebtedness and that do not in the aggregate materially adversely affect the value of said properties or materially impair their use in the operation of the business of such Person;

(9) Liens encumbering property or assets under construction arising from progress or partial payments by a customer of the Company or its Restricted Subsidiaries relating to such property or assets;

(10) Liens in favor of customs and revenue authorities arising as a matter of law to secure payments of customs duties in connection with the importation of goods;

(11) any attachment, prejudgment or judgment Lien that does not constitute an Event of Default and notices of *lis pendens* and associated rights related to litigation being contested in good faith by appropriate proceedings and for which adequate reserves have been made;

(12) Liens created for the benefit of (or to secure) the Notes (or the Note Guarantees);

(13) Liens to secure any Permitted Refinancing Indebtedness permitted to be incurred under the Indenture; *provided, however,* that:

(a) the new Lien shall be limited to all or part of the same property and assets that secured or, under the written agreements pursuant to which the original Lien arose, could secure the original Lien (plus improvements and accessions to, such property or proceeds or distributions thereof); and

(b) the Indebtedness secured by the new Lien is not increased to any amount greater than the sum of (x) the outstanding principal amount, or, if greater, committed amount, of the Indebtedness extended, renewed, refunded, refinanced, replaced, exchanged, defeased or discharged with such Permitted Refinancing Indebtedness and (y) an amount necessary to pay any costs, fees and expenses, including premiums and defeasance costs, related to such extension, renewal, refunding, refinancing, replacement, exchange, defeasance or discharge;

(14) Liens for the purpose of securing (a) all or any part of the purchase price, lease expense, rental payments or cost of design, construction, installation or improvement of, or any other capital expenses in relation to, any FPSO, rig, production or storage facility (including for carbon capture), transport or pipeline, in each case, used or useful in the Energy Business and any Permitted Refinancing Indebtedness in respect thereof permitted to be incurred under the Indenture and (b) the payment of all or a part of the purchase price or lease expense of, or Capital Lease Obligations with respect to, or the repair, improvement or construction cost of, assets or property acquired or repaired, improved or constructed in the ordinary course of business or consistent with past practice or industry practice;

(15) Liens arising solely by virtue of any statutory or common law provisions relating to banker's Liens, rights of set-off or similar rights and remedies as to deposit accounts or other funds maintained or deposited with a depositary institution;

(16) Liens on cash, Cash Equivalents or other property arising in connection with the defeasance, discharge or redemption of Indebtedness;

(17) Liens in respect of Production Payments and Reserve Sales, *provided* such Liens are limited to the property that is the subject of such Production Payment and Reserve Sale;

(18) Liens on pipelines and pipeline facilities that arise by operation of law;

(19) Liens arising under oil and gas leases or subleases, assignments, farm-out agreements, farm-in agreements, division orders, contracts for the sale, purchase, exchange, transportation, gathering or processing of Hydrocarbons, unitizations and pooling designations, declarations, orders and agreements, development agreements, partnership agreements, operating agreements, royalties, royalty trusts, working interests, carried working interests, net profit interests, joint interest billing arrangements, joint venture agreements, participation agreements, production sales contracts, area of mutual interest agreements, gas balancing or deferred production agreements, injection, repressuring and recycling agreements, salt water or other disposal agreements, seismic or geophysical permits or agreements, licenses, sublicenses and other agreements which are customary in the Energy Business; *provided, however*, in all instances that such Liens are limited to the assets that are subject to the relevant agreement, program, order or contract;

(20) any (a) interest or title of a lessor or sublessor under any lease, Liens reserved in oil, gas or other Hydrocarbons, mineral leases for bonus, royalty or rental payments and for compliance with the terms of such leases; (b) restriction or encumbrance that the interest or title of such lessor or sublessor may be subject to (including without limitation, ground leases or other prior leases of the demised premises, mortgages, mechanics' liens, tax liens, and easements); or (c) subordination of the interest of the lessee or sublessee under such lease to any restrictions or encumbrance referred to in the preceding subclause (b);

(21) Liens arising under the Indenture in favor of the Trustee for its own benefit and similar Liens in favor of other trustees, agents and representatives arising under instruments governing Indebtedness permitted to be incurred under the Indenture, *provided, however,* that such Liens are solely for the benefit of the trustees,

agents or representatives in their capacities as such and not for the benefit of the holders of the Indebtedness;

(22) Liens securing Hedging Obligations, which obligations are permitted by clause (9) of the second paragraph of the covenant described under "*—Certain covenants—Incurrence of indebtedness and issuance of preferred stock";*

(23) Liens upon specific items of inventory, receivables or other goods (or the proceeds thereof) of any Person securing such Person's obligations in respect of bankers' acceptances or receivables securitizations issued or created for the account of such Person to facilitate the purchase, shipment or storage of such inventory, receivables or other goods (or the proceeds thereof);

(24) Liens arising out of conditional sale, title retention, consignment or similar arrangements for the sale of assets entered into in the ordinary course of business or consistent with past practice or industry practice;

(25) (i) mortgages, liens, security interests, restrictions, encumbrances or any other matters of record that have been placed by any developer, landlord, contractor or other third party on property over which the Company or any Restricted Subsidiary has easement rights or on any real property leased by the Company or any Restricted Subsidiary (including those arising from progress or partial payments by a third party relating to such property or assets) and subordination or similar agreements relating thereto and (ii) any condemnation or eminent domain proceedings or compulsory purchase order affecting real property;

(26) Liens (including put and call arrangements) on Capital Stock or other securities of any Unrestricted Subsidiary or joint venture that secure Indebtedness of such Unrestricted Subsidiary or joint venture (but only to the extent that such Indebtedness is not Indebtedness of the Company or a Guarantor);

(27) pledges of goods, the related documents of title and/or other related documents arising or created in the ordinary course of the Company or any Restricted Subsidiary's business or operations as Liens only for Indebtedness to a bank or financial institution directly relating to the goods or documents on or over which the pledge exists;

(28) limited recourse Liens in respect of the ownership interests in, or assets owned by, any joint ventures which are not Restricted Subsidiaries securing obligations of such joint ventures;

(29) Liens on any proceeds loan made by the Company or any Restricted Subsidiary in connection with any future incurrence of Indebtedness permitted under the Indenture and securing that Indebtedness;

(30) Liens created on any asset of the Company or a Restricted Subsidiary established to hold assets of any stock option plan or any other management or employee benefit or incentive plan or unit trust of the Company or a Restricted Subsidiary securing any loan to finance the acquisition of such assets;

(31) Liens over treasury stock of the Company or a Restricted Subsidiary purchased or otherwise acquired for value by the Company or such Restricted Subsidiary pursuant to a stock buy-back scheme or other similar plan or arrangement;

(32) Liens with respect to Indebtedness of the Company or any Subsidiary of the Company with respect to Indebtedness at any one time outstanding that does not exceed the greater of (x) $80 million and (y) 2.25% of Consolidated Total Assets as determined on the date of incurrence of such Indebtedness after giving *pro forma* effect to such incurrence and the application of the proceeds therefrom;

(33) grants of software and other technology licenses in the ordinary course of business or consistent with past practice or industry practice;

(34) the following ordinary course items:

(a) leases or subleases granted to others that do not materially interfere with the ordinary course of business or consistent with past practice or industry practice of the Company and its Restricted Subsidiaries, taken as a whole;

(b) landlords', carriers', warehousemen's, mechanics', materialmen's, repairmen's or the like Liens arising by contract or statute in the ordinary course of business or consistent with past practice or industry practice;

(c) pledges or deposits made in the ordinary course of business or consistent with past practice or industry practice (A) in connection with leases, tenders, bids, statutory obligations, surety or appeal bonds, government contracts, performance bonds and similar obligations, (B) in connection with workers' compensation, unemployment insurance and other social security legislation (including, in each case, Liens to secure letters of credit issued to assure payment of such obligations) or (C) to secure plugging, abandonment and decommissioning obligations;

(d) Liens arising from Uniform Commercial Code financing statement filings under U.S. state law (or similar filings under applicable jurisdictions) regarding operating leases entered into by the Company and its Restricted Subsidiaries in the ordinary course of business or consistent with past practice or industry practice;

(e) Liens on insurance policies and proceeds thereof, or other deposits, to secure insurance premium financings in the ordinary course of business or consistent with past practice or industry practice;

(f) leases, licenses, subleases and sublicenses of assets in the ordinary course of business or consistent with past practice or industry practice; and

(g) Liens securing or arising by reason of any netting or set-off arrangement entered into in the ordinary course of banking or other trading activities; and

(35) any extension, renewal, refinancing or replacement, in whole or in part, of any Lien described in the foregoing clauses (2) through (34) (but excluding clauses (14) and (32)); *provided* that any such Lien is limited to all or part of the same property or assets (plus improvements, accessions, proceeds or dividends or distributions in respect thereof) that secured (or, under the written arrangements under which the original Lien arose, could secure) the Indebtedness being refinanced.

"*Permitted Refinancing Indebtedness*" means any Indebtedness of the Company or any of its Restricted Subsidiaries issued in exchange for, or the net proceeds of which are used to extend, renew, refund, refinance, replace, exchange, defease or discharge other Indebtedness of the Company or any of its Restricted Subsidiaries (other than intercompany Indebtedness); *provided* that:

(1) the aggregate principal amount (or accreted value, if applicable, or if issued with original issue discount, aggregate issue price) of such Permitted Refinancing Indebtedness does not exceed the principal amount (or accreted value, if applicable, or if issued with original issue discount, aggregate issue price) of the Indebtedness being extended, renewed, refunded, refinanced, replaced, exchanged, defeased or discharged (plus all accrued interest on the Indebtedness and the amount of all fees and expenses, including premiums, incurred in connection therewith);

(2) such Permitted Refinancing Indebtedness has (a) a final maturity date that is either (i) no earlier than the final maturity date of the Indebtedness being extended, renewed, refunded, refinanced, replaced, exchanged, defeased or discharged or (ii) after the final maturity date of the Notes and (b) has a Weighted Average Life to Maturity that is equal to or greater than the Weighted Average Life to Maturity of the Indebtedness being extended, renewed, refunded, refinanced, replaced, exchanged, defeased or discharged;

(3) if the Indebtedness being extended, renewed, refunded, refinanced, replaced, exchanged defeased or discharged is expressly contractually subordinated in right of payment to the Notes or the Note Guarantees, as the case may be, such Permitted Refinancing Indebtedness is subordinated in right of payment to the Notes or the Note Guarantees, as the case may be, on terms at least as favorable to the holders of Notes or the Note Guarantees, as the case may be, as those contained in the documentation governing the Indebtedness being extended, renewed, refunded, refinanced, replaced, exchanged, defeased or discharged; and

(4) if the Company or any Guarantor was the obligor on the Indebtedness being extended, renewed, refunded, refinanced, replaced, defeased or discharged, such Indebtedness is incurred either by the Company, a Finance Subsidiary or by a Guarantor.

Permitted Refinancing Indebtedness in respect of any Credit Facility or any other Indebtedness may be incurred from time to time after the termination, discharge or repayment of all or any part of such Credit Facility or other Indebtedness.

"*Permitted Reorganization*" means (i) an Eligible JV Transaction or (ii) any amalgamation, demerger, merger, voluntary liquidation, consolidation, reorganization, redomiciliation, winding up or corporate restriction involving the Company or any of its Restricted Subsidiaries and the assignment, transfer or assumption of intragroup receivables and payables among the Company and its Restricted Subsidiaries in connection therewith (a "**Reorganization**") that is made on a solvent basis; provided that after giving effect to such Permitted Reorganization: (a) all of the business and assets distributed in connection with such Reorganization remain owned by the Company and its Restricted Subsidiaries, (b) any payments or assets distributed in connection with such Reorganization remain within the Company and its Restricted Subsidiaries, (c) the Company will provide to the Trustee an Officer's Certificate confirming that no Default is continuing or would arise as a result of such Reorganization and (d) in the case of a Reorganization involving the Company, such Person formed by or surviving any such Reorganization (if other than the Company) shall (x) be an entity organized or existing under the laws of any member state of the European Union as in effect on the Issue Date, the United Kingdom, Jersey, Switzerland, Norway, Canada, Australia, Japan, any state in the United States or the District of Columbia and (y) expressly assume by supplemental indenture, executed and delivered to the Trustee, all the obligations of the Company under the Guarantee Subordination Agreement and any Additional Guarantee Subordination Agreement to which the Company is a party, as applicable.

"*Person*" means any individual, corporation, partnership, joint venture, association, joint-stock company, trust, unincorporated organization, limited liability company or government or other entity.

"*Production Payments*" means, collectively, Dollar-Denominated Production Payments and Volumetric Production Payments.

"*Production Payments and Reserve Sales*" means the grant or transfer by the Company or a Restricted Subsidiary of the Company to any Person of a royalty, overriding royalty, net profits interest, Production Payment, partnership or other interest in oil and gas properties, reserves or the right to receive all or a portion of the production or the proceeds from the sale of production attributable to such properties where the holder of such interest has recourse solely to such production or proceeds of production, subject to the obligation of the grantor or transferor to operate and maintain, or cause the subject interests to be operated and maintained, in a reasonably prudent manner or other customary standard or subject to the obligation of the grantor or transferor to indemnify for environmental, title or other matters customary in the Energy Business, including any such grants or transfers pursuant to incentive compensation programs on terms that are reasonably customary in the Energy Business for geologists, geophysicists and other providers of technical services to the Company or a Subsidiary of the Company.

"*Pro Forma Cost Savings*" means, without duplication, with respect to any period, (a) cost savings, operating expense reductions and related adjustments that have been actually realized or are projected in good faith by a responsible accounting or financial officer of the Company to result from reasonably identifiable and factually supportable actions (including cost optimization or other initiatives) or events, but only if such reductions in costs, other operating improvements or synergies and related adjustments are so projected by the Company to be realized during the consecutive six-quarter reference period commencing after the transaction or initiative giving rise to such calculation; *plus* (b) the "run-rate" synergies (including, without limitation, revenue synergies) that are expected (in the good faith determination of the Company) to be realized within 18 months of the determination date as a result of actions relating to any acquisition, disposition, divestiture, restructuring, cost savings initiative, operational improvements, procurement rationalization, establishment of information and technology systems, modernization or modification of business procedures, execution of new contracts, modification or renegotiation of contracts (including the effect of increased pricing in customer contracts or the renegotiations of contracts or other arrangements) or any other similar initiative (calculated on a pro forma basis as though such synergies had been realized from the first day of such period and during the entirety of such period), net of the amount of actual benefits realized during such period from such transaction or initiative; provided that the aggregate amount added

pursuant to this clause (b) for the period for which Consolidated Cash Flow is being determined shall not exceed 20% of the Consolidated Cash Flow for such period (calculated after giving full effect to the pro forma adjustments set forth in this paragraph).

"*Public Equity Offering*" means, with respect to any Person, a *bona fide* underwritten primary public offering of the ordinary shares or common equity of such Person, either:

(1) pursuant to a flotation on the London Stock Exchange or any other nationally recognized stock exchange or listing authority in a member state of the European Union; or

(2) pursuant to an effective registration statement under the U.S. Securities Act (other than a registration statement on Form S-8 or otherwise relating to Equity Interests issued or issuable under any employee benefit plan).

"Public Indebtedness" means any Indebtedness consisting of bonds, debentures, notes or other similar debt securities issued in (x) a public offering or (y) a private placement to institutional investors that is underwritten for resale in accordance with Rule 144A under the U.S. Securities Act (or Rule 144A and Regulation S under the U.S. Securities Act) whether or not it includes registration rights entitling the holders of such debt securities to registration thereof with the SEC for public resale. For the avoidance of doubt, the term "Public Indebtedness" shall not be construed to include any Indebtedness issued to institutional investors in a direct placement of such Indebtedness that is not underwritten by an intermediary (it being understood that, without limiting the foregoing, a financing that is distributed to not more than fifteen Persons (provided that multiple managed accounts and affiliates of any such Persons shall be treated as one Person for the purposes of this definition) shall be deemed not underwritten), or any commercial bank or similar Indebtedness, receivables financing, Capital Lease Obligation or recourse transfer of any financial asset or any other type of Indebtedness incurred in a manner not customarily viewed as a "securities offering."

"*Rating Agencies*" means (1) S&P, (2) Moody's, (3) Fitch and (4) if S&P, Moody's, Fitch or any of these shall not make a rating of the Notes available, an internationally-recognized securities rating agency or agencies, as the case may be, selected by the Company, which shall be substituted for S&P, Moody's, Fitch or any of these, as the case may be.

"*RBL Facility*" means the secured multicurrency revolving borrowing base facilities agreement dated November 9, 2025 between, among others, the Company, as obligor, and DNB Bank ASA, London Branch, as agent and security agent.

"*Recognized Stock Exchange*" means any nationally recognized stock exchange in the United States, Jersey, Guernsey, Luxembourg, the United Kingdom or any member of the European Union.

"*Restricted Investment*" means an Investment other than a Permitted Investment.

"*Restricted Subsidiary*" of a Person means any Subsidiary of the referent Person that is not an Unrestricted Subsidiary. Unless the context requires otherwise, each reference to a Restricted Subsidiary herein is to a Restricted Subsidiary of the Company.

"*S&P*" means Standard & Poor's Ratings Services and any successor to its ratings business.

"*SEC*" means the U.S. Securities and Exchange Commission.

"*Senior Debt*" means, whether outstanding on the Issue Date or thereafter incurred, all amounts payable by, under or in respect of all other Indebtedness of the Company or any Guarantor, including premiums and accrued and unpaid interest (including interest accruing on or after the filing of any petition in bankruptcy or for reorganization relating to the Company or such Guarantor at the rate specified in the documentation with respect thereto whether or not a claim for post-filing interest is allowed in such proceeding) and fees relating thereto; *provided*, *however*, that Senior Debt will not include:

(a) any Indebtedness incurred in violation of the Indenture;

(b) any obligation of (i) the Company to any Restricted Subsidiary or (ii) any Guarantor to the Company or any Restricted Subsidiary;

(c) any liability for taxes owed or owing by the Company or any Restricted Subsidiary;

(d) any accounts payable or other liability to trade creditors arising in the ordinary course of business or consistent with past practice or industry practice (including guarantees thereof or instruments evidencing such liabilities);

(e) any Indebtedness, guarantee or obligation of the Company or any Guarantor that is evidenced by an instrument that expressly provides, in the case of the Company, that it is subordinate in right of payment to the Notes, or in the case of any Guarantor, that it is subordinate or *pari passu* in right of payment with the Note Guarantee of such Guarantor; or

(f) any Capital Stock.

"*Significant Subsidiary*" means, at the date of determination, any Restricted Subsidiary that, together with its Subsidiaries which are Restricted Subsidiaries, (i) for the most recent fiscal year, accounted for more than 10% of the consolidated revenues of the Company or (ii) as of the end of the most recent fiscal year, was the owner of more than 10% of the consolidated assets of the Company.

"*Stated Maturity*" means, with respect to any installment of interest or principal on any series of Indebtedness, the date on which the payment of interest or principal was scheduled to be paid in the original documentation governing such Indebtedness, and will not include any contingent obligations to repay, redeem or repurchase any such interest or principal prior to the date originally scheduled for the payment thereof.

"*Subordinated Obligation*" means any Indebtedness of the Company (whether outstanding on the Issue Date or thereafter incurred) which is subordinate or junior in right of payment to the Notes pursuant to a written agreement or any Indebtedness of a Guarantor (whether outstanding on the Issue Date or thereafter incurred) which is subordinate or junior in right of payment to the Note Guarantee of such Guarantor pursuant to a written agreement, as the case may be.

"*Subsidiary*" means, with respect to any specified Person:

(1) any corporation, association or other business entity (other than a partnership, joint venture, limited liability company or similar entity) of which more than 50% of the total ordinary voting power of its Voting Stock is at the time owned or controlled, directly or indirectly, by that Person or one or more of the other Subsidiaries of that Person (or a combination thereof);

(2) any corporation, association or other business entity of which that Person or one or more of the other Subsidiaries of that Person (or any combination thereof), directly or indirectly, has the right to appoint a majority of the directors, managers or trustees, as applicable, or has the operational control of the corporation, association or other business entity and the financial results of such corporation, association or other business entity are consolidated with the financial results of such Person or one or more of the other Subsidiaries of that Person (or any combination thereof); and

(3) any partnership, joint venture, limited liability company or similar entity of which (a) more than 50% of the capital accounts, distribution rights, total equity and voting interests or general and limited partnership interests, as applicable, are owned or controlled, directly or indirectly, by such Person or one or more of the other Subsidiaries of that Person or a combination thereof, whether in the form of membership, general, special or limited partnership interests or otherwise, and (b) such Person or any Subsidiary of such Person is a controlling general partner or otherwise controls such entity.

"*Tax*" means any tax, duty, levy, impost, assessment or other governmental charge in the nature of a tax (including penalties, interest and any other additions thereto). "Taxes" and "Taxation" shall be construed to have corresponding meanings.

"*Tax Sharing Agreement*" means any payments or other transactions pursuant to any tax sharing agreement or arrangement among the Company or any of its Restricted Subsidiaries and any other Person with which the Company or its Restricted Subsidiaries files or filed a consolidated tax return or with which the Company or any of its Restricted Subsidiaries is or was part of a consolidated group for tax purposes or any tax advantageous group contribution made pursuant to applicable legislation.

"*Transactions*" means collectively, the Offering and the use of proceeds thereof.

"*Treasury Rate*" means, in respect of any redemption date, the yield to maturity as of the time of computation of United States Treasury securities with a constant maturity (as compiled and published in the most recent Federal Reserve Statistical Release H.15 (519) that has become publicly available at least two Business Days prior to the redemption date (or, if such statistical release is no longer published, any publicly available source of similar market data)) most nearly equal to the period from the redemption date to April 30, 2028; *provided, however,* that if the period from the redemption date to April 30, 2028 is less than one year, the weekly average yield on actually traded United States Treasury securities adjusted to a constant maturity of one year will be used. The Company will calculate the Treasury Rate no later than the second (and no earlier than the fourth) Business Day preceding the applicable redemption date.

"*U.S. dollars*" or "*$*" means the lawful currency of the United States of America.

"*U.S. Government Obligations*" means direct obligations of, or obligations guaranteed by, the United States of America, and the payment for which the United States pledges its full faith and credit.

"*Unrestricted Subsidiary*" means any Subsidiary of the Company that is designated by the Board of Directors of the Company as an Unrestricted Subsidiary pursuant to a resolution of the Board of Directors, but only to the extent that such Subsidiary:

(1) has no Indebtedness other than Non-Recourse Debt; and

(2) except as permitted by the covenant described above under the caption "*—Certain covenants—Transactions with affiliates*," is not party to any agreement, contract, arrangement or understanding with the Company or any Restricted Subsidiary of the Company unless the terms of any such agreement, contract, arrangement or understanding are no less favorable to the Company or such Restricted Subsidiary than those that might be obtained at the time from Persons who are not Affiliates of the Company.

All Subsidiaries of an Unrestricted Subsidiary shall also be Unrestricted Subsidiaries.

"*U.S. Exchange Act*" means the United States Securities Exchange Act of 1934, as amended, and the rules and regulations of the SEC promulgated thereunder.

"*U.S. Securities Act*" means the United States Securities Act of 1933, as amended, and the rules and regulations of the SEC promulgated thereunder.

"*Volumetric Production Payments*" means production payment obligations recorded as deferred revenue in accordance with IFRS, together with all related undertakings and obligations.

"*Voting Stock*" of any specified Person as of any date means the Capital Stock of such Person that is at the time entitled to vote in the election of the Board of Directors of such Person.

"*Weighted Average Life to Maturity*" means, when applied to any Indebtedness at any date, the number of years obtained by dividing:

(1) the sum of the products obtained by multiplying (a) the amount of each then remaining installment, sinking fund, serial maturity or other required payments of principal, including payment at final maturity, in respect of the Indebtedness, by (b) the number of years (calculated to the nearest one- twelfth) that will elapse between such date and the making of such payment; by

(2) the then outstanding principal amount of such Indebtedness.

"*Wholly Owned Subsidiary*" means a Restricted Subsidiary, all of the Capital Stock of which (other than directors' qualifying shares or shares required by any applicable law or regulation to be held by a Person other than the Company or another Wholly Owned Subsidiary) is owned by the Company or another Wholly Owned Subsidiary, as the case may be.

BOOK-ENTRY, DELIVERY AND FORM

General

The Notes sold outside the United States pursuant to Regulation S under the U.S. Securities Act will initially be represented by a global note in registered form without interest coupons attached (the "**Regulation S Global Note**").

The Notes sold within the United States to qualified institutional buyers, pursuant to Rule 144A, will initially be represented by a global note in registered form without interest coupons attached (the "**144A Global Note**" and, together with the Regulation S Global Note, the "**Global Notes**"). On the closing date the Global Notes will be deposited with a custodian of DTC and registered in the name of Cede & Co., as nominee of DTC.

Investors who are qualified institutional buyers and who purchase Notes in reliance on Rule 144A may hold their interests in a Rule 144A Global Note directly through DTC if they are DTC participants, or indirectly through organizations that are DTC participants. Investors who hold beneficial interests in a Regulation S Global Note may hold such interests directly through DTC if they are DTC participants, or indirectly through organizations that are DTC participants. DTC will hold interests in the Regulation S Global Note on behalf of their participants through their respective depositaries, which in turn will hold the interests in the Regulation S Global Note in customers' securities accounts in the depositaries' names on the books of DTC. Book-Entry Interests will be shown on, and transfers thereof will be effected only through, records maintained in book-entry form by DTC and its participants. The Book-Entry Interests in the Global Notes will be issued only in denominations of $200,000 and integral multiples of $1,000 in excess thereof.

The Book-Entry Interests will not be held in definitive form. Instead, DTC will credit on its book-entry registration and transfer systems a participant's account with the interest beneficially owned by such a participant. The laws of some jurisdictions, including certain states of the United States, may require that certain purchasers of securities take physical delivery of such securities in definitive form. The foregoing limitations may impair the ability to own, transfer or pledge Book-Entry Interests. In addition, while the Notes are in global form, owners of interests in the Global Notes will not have the Notes registered in their names, will not receive physical delivery of the Notes in certificated form and will not be considered the registered owners or "holder" of Notes under the Indenture for any purpose.

So long as the Notes are held in global form, DTC (or its nominee) will be considered the holder of Global Notes for all purposes under the Indenture. As such, participants must rely on the procedures of DTC and indirect participants must rely on the procedures of DTC and the participants through which they own Book-Entry Interests to exercise any rights of holders under the Indenture.

None of the Company, any Guarantor, the Trustee, the Principal Paying Agent, the Registrar or the Transfer Agent under the indenture governing the Notes, nor any of their respective agents will have any responsibility or be liable for any aspect of the records relating to the Book-Entry Interests.

Issuance of definitive registered notes

Under the terms of the indenture governing the Notes, owners of Book-Entry Interests will receive definitive Notes in registered form (the "**Definitive Registered Notes**"):

- if DTC notifies the Company that it is unwilling or unable to continue to act as depository and the Company does not appoint a successor depositary within 120 days;
- if the Company, at its option but subject to DTC's rules, notifies the Trustee in writing that it elects to exchange in whole, but not in part, the Global Note for Definitive Registered Notes; or
- if DTC so requests following an event of default under the Indenture.

In such an event, the registrar will issue Definitive Registered Notes, registered in the name or names and issued in any approved denominations, requested by or on behalf of DTC or the Company, as applicable (in accordance with its customary procedures and based upon directions received from participants reflecting the beneficial ownership of Book-Entry Interests), and such Definitive Registered Notes will bear the restrictive

legend referred to in "*Notice to investors*," unless that legend is not required by the indenture governing the Notes or applicable law.

Redemption of global notes

In the event any Global Note, or any portion thereof, is redeemed, DTC will distribute the amount received by it in respect of the Global Note so redeemed to the holders of the Book-Entry Interests in such Global Note from the amount received by it in respect of the redemption of such Global Note. The redemption price payable in connection with the redemption of such Book-Entry Interests will be equal to the amount received by DTC in connection with the redemption of such Global Note (or any portion thereof). The Company understands that under existing practices of DTC if fewer than all of the Notes are to be redeemed at any time, DTC will credit their respective participants' accounts on a by lot basis (with adjustments to prevent fractions) or on such other basis as they deem fair and appropriate (DTC's current procedures dictate that selection of Notes for redemption will be by lot); provided, however, that no Book-Entry Interest of less than $200,000 in principal amount may be redeemed in part.

Payments on global notes

The Company will make payments of amounts owing in respect of the Global Notes (including principal, premium, interest and additional amounts) to the Principal Paying Agent. The Principal Paying Agent will, in turn, make such payments to DTC or its nominee, which will distribute such payments to participants in accordance with their respective procedures.

Under the terms of the indenture governing the Notes, the Company, the Trustee, the Principal Paying Agent, the Transfer Agent and the Registrar will treat the registered holder of the Global Notes (*i.e.*, the nominee for DTC) as the owner thereof for the purpose of receiving payments and for all other purposes. Consequently, neither the Company nor the Trustee or any of their respective agents has or will have any responsibility or liability for:

- any aspects of maintaining, supervising or reviewing the records of DTC or any participant or indirect participant relating to or payments made on account of a Book-Entry Interest; or
- DTC or any participant or indirect participant.

Payments by participants to owners of Book-Entry Interests held through participants are the responsibility of such participants, as is now the case with securities held for the accounts of subscribers registered in "street name."

To tender Book-Entry Interests in a change of control offer, the holder of the applicable Global Note must, within the period specified in such offer, give notice of such tender to the tender agent or depository for such offer and specify the principal amount of Book-Entry Interests to be tendered.

The principal of, premium, if any, and interest on, and all other amounts payable in respect of, the Global Notes will be paid to holders of interests in such Notes through DTC in dollars.

Action by owners of book-entry interests

DTC has advised the Company that it will take any action permitted to be taken by a holder of Notes (including the presentation of Notes for exchange as described above) only at the direction of one or more participants to whose account the Book-Entry Interests in the Global Notes are credited and only in respect of such portion of the aggregate principal amount of Notes as to which such participant or participants has or have given such direction. DTC will not exercise any discretion in the granting of consents, waivers or the taking of any other action in respect of the Global Notes. However, if there is an event of default under the Notes, DTC reserves the right to exchange the Global Notes for Definitive Registered Notes in certificated form, and to distribute such Definitive Registered Notes to their respective participants.

Transfers

Transfers between participants in DTC will be done in accordance with DTC rules and will be settled in immediately available funds. If a holder requires physical delivery of Definitive Registered Notes for any reason,

including to sell the Notes to persons in jurisdictions which require physical delivery of such securities or to pledge such securities, such holder must transfer its interest in the Global Notes in accordance with the normal procedures of DTC and in accordance with the provisions of the indenture governing the Notes.

The Global Notes will bear a legend to the effect set forth in "*Notice to investors*." Book-Entry Interests in the Global Notes will be subject to the restrictions on transfer discussed in "*Notice to investors*."

During the period ending 40 days after the commencement of the Offering of the Notes (the "**40-Day Period**"), beneficial interests in a Regulation S Global Note may be transferred to a U.S. person only if such transfer is made pursuant to Rule 144A and the transferor first delivers to the Trustee a certificate (in the form provided in the indenture governing the Notes) to the effect that such transfer is being made to a person who the transferor reasonably believes is a "qualified institutional buyer" within the meaning of Rule 144A in a transaction meeting the requirements of Rule 144A or otherwise in accordance with the transfer restrictions described under "*Notice to Investors*" and in accordance with all applicable securities laws of the states of the United States and other jurisdictions.

After the expiration of the 40 Day Period, beneficial interests in a Regulation S Global Note may be transferred to a U.S. person without compliance with these certification requirements.

Subject to the foregoing, and as set forth in "*Notice to investors*" Book-Entry Interests may be transferred and exchanged as described under "*Description of Notes—Transfer and exchange*." Any Book-Entry Interest in one of the Global Notes that is transferred to a person who takes delivery in the form of a Book-Entry Interest in the other Global Note will, upon transfer, cease to be a Book-Entry Interest in the first-mentioned Global Note and become a Book-Entry Interest in the other Global Note, and accordingly, will thereafter be subject to all transfer restrictions, if any, and other procedures applicable to Book-Entry Interests in such other Global Note for as long as it retains such a Book-Entry Interest.

Definitive Registered Notes may be transferred and exchanged for Book-Entry Interests in a Global Note only as described under "*Description of Notes—Transfer and exchange*" and, if required, only if the transferor first delivers to the Trustee a written certificate (in the form provided in the indenture governing the Notes) to the effect that such transfer will comply with the appropriate transfer restrictions applicable to such Notes. See "*Notice to investors*."

Transfers involving an exchange of a Regulation S Book-Entry Interest for 144A Book-Entry Interest will be done by DTC by means of an instruction originating from the Trustee through the DTC Deposit/Withdrawal at Custodian system. Accordingly, in connection with any such transfer, appropriate adjustments will be made to reflect a decrease in the principal amount of the Regulation S Global Note and a corresponding increase in the principal amount of the 144A Global Note. The policies and practices of DTC may prohibit transfers of Book-Entry Interests in the Regulation S Global Note prior to the expiration of the 40-Day Period. Any Book-Entry Interest in one of the Global Notes that is transferred to a person who takes delivery in the form of a Book Entry Interest in the other Global Note will, upon transfer, cease to be a Book Entry Interest in the first-mentioned Global Note and become a Book Entry interest in such other Global Note, and accordingly will thereafter be subject to all transfer restrictions, if any, and other procedures applicable to Book-Entry Interests in such other Global Note for as long as it remains such a Book Entry Interest.

Information concerning DTC

All Book-Entry Interests will be subject to the operations and procedures of DTC. The Company provides the following summaries of those operations and procedures solely for the convenience of investors. The operations and procedures of each settlement system are controlled by that settlement system and may be changed at any time. Neither the Company nor the Initial Purchasers nor the Trustee, the Principal Paying Agent, the Transfer Agent or the Registrar is responsible for those operations or procedures. DTC has advised the Company that it is:

- a limited purpose trust company organized under New York Banking Law;
- a "banking organization" under New York Banking Law;
- a member of the Federal Reserve System;

- a “clearing corporation” within the meaning of the New York Uniform Commercial Code; and
- a “clearing agency” registered under Section 17A of the U.S. Exchange Act.

DTC was created to hold securities for its participants and to facilitate the clearance and settlement of transactions among its participants. It does this through electronic book-entry changes in the accounts of securities participants, eliminating the need for physical movement of securities certificates. DTC participants include securities brokers and dealers, banks, trust companies, clearing corporations and certain other organizations (including Euroclear and Clearstream). DTC’s owners are the NYSE Euronext and the National Association of Securities Dealers, Inc. and a number of its direct participants. Other parties, such as banks, brokers and dealers and trust companies, who clear through or maintain a custodial relationship with a direct participant, also have access to the DTC system and are known as indirect participants.

Because DTC can only act on behalf of participants, who in turn act on behalf of indirect participants and certain banks, the ability of an owner of a beneficial interest to pledge such interest to persons or entities that do not participate in DTC or otherwise take actions in respect of such interest, may be limited by the lack of a definite certificate for that interest. The laws of some jurisdictions require that certain persons take physical delivery of securities in definitive form. Consequently, the ability to transfer beneficial interests to such person may be limited.

Global clearance and settlement under the book-entry system

The Notes represented by the Global Notes are expected to be admitted to listing on the Official List of the Exchange and to trade in DTC’s Same-Day Funds Settlement System, and any permitted secondary market trading activity in such Notes will, therefore be required by DTC to be settled in immediately available funds. You should be aware that investors will only be able to make and receive deliveries, payments and other communications involving Notes through DTC on days when such system is open for business. Such system may not be open for business on days when banks, brokers and other institutions are open for business in the United States.

In addition, because of time-zone differences, there may be problems with completing transactions involving DTC on the same business day as in the United States.

Although DTC currently follows the foregoing procedures to facilitate transfers of interests in the Global Notes among participants in DTC, it is under no obligation to perform or continue to perform such procedures, and such procedures may be discontinued or modified at any time. None of the Company, any Guarantor, the Trustee, the Principal Paying Agent, the Registrar, the Transfer Agent or any of their respective agents will have any responsibility for the performance by DTC or its respective participants or indirect participants, of their respective obligations under the rules and procedures governing their operations.

Initial settlement

Initial settlement for the Notes will be made in U.S. dollars. Book-Entry Interests owned through DTC accounts will follow the settlement procedures applicable to conventional bonds in registered form. Book-Entry Interests will be credited to the securities custody accounts of DTC participants on the business day following the settlement date against payment for value on the settlement date.

Secondary market trading

The Book-Entry Interests will trade through participants of DTC and will settle in same-day funds. Since the purchase determines the place of delivery, it is important to establish at the time of trading of any Book-Entry Interests where both the purchaser’s and the seller’s accounts are located to ensure that settlement can be made on the desired value date.

TAXATION

Certain United States federal income tax considerations to U.S. holders

The following discussion is a summary of certain U.S. federal income tax consequences of the purchase, ownership and disposition of the Notes, but does not purport to be a complete analysis of all potential tax effects. The summary is limited to consequences relevant to a U.S. holder (as defined below), and does not address the effects of any U.S. federal tax laws other than U.S. federal income tax laws (such as estate and gift tax laws) or any state, local or non-U.S. tax laws. This discussion is based upon the U.S. Internal Revenue Code of 1986, as amended (the "**Code**"), Treasury regulations issued thereunder, and judicial and administrative interpretations thereof, each as in effect on the date hereof, and all of which are subject to change, possibly with retroactive effect. No rulings from the U.S. Internal Revenue Service (the "**IRS**") have been or are expected to be sought with respect to the matters discussed below. There can be no assurance that the IRS will not take a different position concerning the tax consequences of the purchase, ownership or disposition of the Notes or that any such position would not be sustained.

This discussion does not address all of the U.S. federal income tax consequences that may be relevant to a holder in light of such holder's particular circumstances, including the impact of any alternative minimum tax or the unearned income Medicare contribution tax, or to holders subject to special rules, such as certain financial institutions, U.S. expatriates, insurance companies, dealers in securities or currencies, traders in securities, U.S. holders whose functional currency is not the U.S. dollar, tax exempt organizations, regulated investment companies, real estate investment trusts, partnerships or other pass through entities or arrangements and investors in such entities or arrangements, persons subject to special tax accounting rules as a result of any item of gross income with respect to the Notes being taken into account in an applicable financial statement, U.S. holders that hold Notes through non-U.S. brokers or other non-U.S. intermediaries and persons holding the Notes as part of a "straddle," "hedge," "conversion transaction" or other integrated transaction for U.S. federal income tax purposes. In addition, this discussion is limited to persons who purchase the Notes in the Offering hereby for cash at original issue and at their "issue price" (the first price at which a substantial amount of the Notes is sold to the public for cash, excluding sales to bond houses, brokers or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers) and who hold the Notes as capital assets within the meaning of Section 1221 of the Code (generally, property held for investment). This summary does not address holders who will have any of their debt issued by us redeemed substantially concurrently with the offering.

For purposes of this discussion, a "**U.S. holder**" is a beneficial owner of a Note that is, for U.S. federal income tax purposes, (i) an individual who is a citizen or resident of the United States; (ii) a corporation or any entity taxable as a corporation for U.S. federal income tax purposes created or organized in the United States or under the laws of the United States, any state thereof or the District of Columbia; (iii) any estate the income of which is subject to U.S. federal income taxation regardless of its source; or (iv) any trust if a court within the United States is able to exercise primary supervision over the administration of the trust and one or more U.S. persons have the authority to control all substantial decisions of the trust, or if a valid election is in place to treat the trust as a U.S. person.

If any entity or arrangement treated as a partnership for U.S. federal income tax purposes holds the Notes, the U.S. federal income tax treatment of a partner in the partnership generally will depend upon the status of the partner and the activities of the partner and the partnership. A partnership considering an investment in the Notes, and partners in such a partnership, should consult their tax advisors regarding the U.S. federal income tax consequences of the purchase, ownership and disposition of the Notes.

Prospective purchasers of the Notes should consult their tax advisors concerning the tax consequences of holding Notes in light of their particular circumstances, including the application of the U.S. federal income tax considerations discussed below, as well as the application of other U.S. federal tax laws (such as estate and gift tax laws) and state, local, non-U.S. or other tax laws.

Characterization of the Notes

In certain circumstances, we may be obligated to make payments on the Notes in excess of stated principal and interest. See, *e.g.*, "*Description of Notes—Additional amounts*" and "*Description of Notes—Repurchase at the option of holders—Change of control*". We intend to take the position that the foregoing contingencies should not cause the Notes to be treated as contingent payment debt instruments. This position is based, in part, on assumptions regarding the likelihood of such payments as of the date of issuance of the Notes.

Assuming such position is respected, a U.S. holder would be required to include in income the amount of any such additional payments at the time such payments are received or accrued in accordance with such U.S. holder's method of accounting for U.S. federal income tax purposes. Our position is binding on a holder unless the holder discloses in the proper manner to the IRS that it is taking a different position. If the IRS successfully challenged our position, and the Notes are treated as contingent payment debt instruments, U.S. holders could be required to accrue interest income at a rate higher than their yield to maturity and to treat as ordinary income, rather than capital gain, any gain recognized on a sale, exchange, retirement or redemption of a Note. This disclosure assumes that the Notes will not be considered contingent payment debt instruments. U.S. holders should consult their own tax advisors regarding the potential application of the contingent payment debt instrument rules to the Notes and the consequences thereof.

Payments of stated interest

Payments of stated interest on the Notes (as well as any additional amounts and without reduction for any taxes withheld) generally will be includible in the gross income of a U.S. holder as ordinary income at the time that such payments are received or accrued, in accordance with such U.S. holder's method of accounting for U.S. federal income tax purposes.

Original issue discount

The Notes may be issued with OID for U.S. federal income tax purposes. In such event, U.S. holders generally will be required to include OID in gross income (as ordinary income) for U.S. federal income tax purposes on an annual basis under a constant yield accrual method regardless of their regular method of accounting for U.S. federal income tax purposes. As a result, U.S. holders generally will include any OID in income in advance of the receipt of cash attributable to such income.

The Notes will be treated as issued with OID if the stated principal amount of such Notes exceeds the issue price (as defined above) by an amount equal to or more than a statutorily defined *de minimis* amount (generally, 0.0025 multiplied by the stated principal amount and the number of complete years to maturity from the issue date).

In the event that the Notes are issued with OID, the amount of any OID with respect to a Note includible in income by a U.S. holder is the sum of the "daily portions" of OID with respect to the Note for each day during the taxable year or portion thereof in which such U.S. holder holds the Note. A daily portion is determined by allocating to each day in any "accrual period" a pro rata portion of the OID that accrued in such period. The accrual period of a Note may be of any length and may vary in length over the term of the Note, provided that each accrual period is no longer than one year and each scheduled payment of principal or interest occurs either on the first or last day of an accrual period. The amount of OID that accrues with respect to any accrual period other than a final accrual period and an initial short accrual period is the excess of (i) the product of the Note's "adjusted issue price" at the beginning of such accrual period and its "yield to maturity," determined on the basis of compounding at the close of each accrual period and properly adjusted for the length of such period, over (ii) the amount of stated interest allocable to such accrual period. OID allocable to a final accrual period is the difference between the amount payable at maturity, other than a payment of stated interest, and the adjusted issue price at the beginning of the final accrual period. Special rules will apply for calculating OID for an initial short accrual period. The adjusted issue price of a Note at the start of any accrual period generally is equal to its issue price, increased by the accrued OID for each prior accrual period. The yield to maturity of a Note is the discount rate that, when used in computing the present value of all principal and interest payments to be made under the Note, produces an amount equal to the issue price of the Note. A U.S. holder may elect to treat all interest on a Note as OID and calculate the amount includible in gross income under the constant yield method described above. The election is to be made for the taxable year in which a U.S. holder acquired the Note and may not be revoked without the consent of the IRS. U.S. holders should consult their tax advisors about this election.

Foreign tax credit

Interest income (and any OID) on a Note generally will constitute foreign source income and generally will be considered "passive category income" in computing the foreign tax credit. A U.S. holder may be able to claim a credit (or, at such holder's election, a deduction in lieu of such credit) with respect to any non-U.S. withholding taxes deducted from a payment on the Notes in computing such holder's U.S. federal income tax liability, subject to applicable limitations. Treasury regulations may restrict a U.S. holder's ability to claim such credits based on the nature of the withholding tax imposed by the relevant foreign jurisdiction. However,

pursuant to subsequent guidance from the IRS which indicates that the U.S. Department of the Treasury and the IRS are considering proposing amendments to such Treasury regulations, taxpayers may, subject to certain conditions, defer the application of many aspects of such Treasury regulations for taxable years beginning on or after December 28, 2021 and ending before the date that a notice or other guidance withdrawing or modifying the temporary relief is issued (or any later date specified in such notice or other guidance). There are significant complex limitations on a U.S. holder's ability to claim foreign tax credits. U.S. holders should consult their tax advisors regarding the creditability or deductibility of any withholding taxes.

Sale*, *exchange*, *retirement*, *redemption or other taxable disposition of Notes

Upon the sale, exchange, retirement, redemption or other taxable disposition of a Note, a U.S. holder generally will recognize gain or loss equal to the difference, if any, between the amount realized upon such disposition (less any amount equal to any accrued but unpaid stated interest, which will be taxable as stated interest income as discussed above to the extent not previously included in income by the U.S. holder) and such U.S. holder's adjusted tax basis in the Note. A U.S. holder's adjusted tax basis in a Note generally will be the purchase price of such Note paid by such U.S. holder, increased by any OID accrued.

Any gain or loss recognized upon the sale, exchange, retirement, redemption or other taxable disposition of a Note generally will be U.S. source capital gain or loss and generally will be long-term capital gain or loss if the U.S. holder's holding period held the Note exceeds one year on the date of disposition. Long-term capital gains of non-corporate U.S. holders (including individuals) are generally eligible for reduced rates of taxation. The deductibility of capital losses is subject to limitations.

Information reporting and backup withholding

In general, payments of interest (and any OID) on the Notes and the proceeds of the sale or other disposition (including a retirement or redemption) of a Note paid to a U.S. holder may be required to be reported to the IRS unless the U.S. holder properly establishes that it is a corporation or other exempt recipient. Backup withholding may apply to such payments if the U.S. holder fails to provide the applicable withholding agent with a taxpayer identification number or a certification that it is not subject to backup withholding. U.S. holders may be required to provide such certification on IRS Form W-9.

Backup withholding is not an additional tax and any amounts withheld under the backup withholding rules may be allowed as a refund or a credit against a U.S. holder's U.S. federal income tax liability provided the required information is timely furnished to the IRS.

Tax return disclosure requirements

Individuals (and certain entities treated as individuals for this purpose) that own "specified foreign financial assets" (which includes debt of foreign entities) with an aggregate value in excess of certain thresholds generally are required to file an information report on IRS Form 8938 with respect to such assets with their tax returns. If a U.S. holder does not file a required IRS Form 8938, such holder may be subject to substantial penalties and the statute of limitations on the assessment and collection of all U.S. federal income taxes of such holder for the related tax year may not close before the date which is three years after the date on which such report is filed. The Notes may constitute specified foreign financial assets subject to these reporting requirements, unless the Notes are held in an account at certain financial institutions. Under certain circumstances, an entity may be treated as an individual for purposes of these rules.

U.S. holders are urged to consult their tax advisors regarding the application of the foregoing disclosure requirements to their ownership of the Notes, including the significant penalties for non-compliance.

Certain United Kingdom tax considerations

The following is a general summary of current United Kingdom tax law and published HM Revenue & Customs ("**HMRC**") practice (which HMRC may not act in accordance with, and which may not be binding on HMRC), both of which may be subject to change (sometimes with retrospective effect), relating only to the United Kingdom withholding tax treatment of payments of interest on the Notes, stamp tax considerations on the issue or transfer of the Notes and certain potential information reporting requirements in relation to the Notes. It does not purport to be a complete analysis of all U.K. tax considerations relating to the Notes. In particular, this summary does not deal with other United Kingdom tax consequences of acquiring, holding or disposing of the

Notes. The United Kingdom tax treatment of prospective Noteholders depends on their individual circumstances and may be subject to change in the future. It applies only to the position of persons who are the absolute beneficial owners of Notes, and some aspects may not apply to some classes of persons, such as dealers in securities.

This description does not purport to constitute legal or tax advice and does not describe all of the tax considerations that may be relevant to a prospective Noteholder. Prospective Noteholders who are in doubt as to their own tax position, or who may be subject to tax in a jurisdiction other than the United Kingdom, should consult their professional advisers.

Withholding tax on interest on the Notes

The Notes will constitute "quoted Eurobonds" within the meaning of section 987 of the Income Tax Act 2007, as long as they carry a right to interest and are and continue to be listed on a "recognised stock exchange" within the meaning of section 1005 of the Income Tax Act 2007 or are admitted to trading on a multilateral trading facility operated by an EEA, U.K. or Gibraltar regulated recognised stock exchange. The Exchange is a "recognised stock exchange." The Notes will satisfy this requirement if they are officially listed on the Official List of the Exchange in accordance with provisions corresponding to those generally applicable in EEA states and are admitted to trading on the Exchange in accordance with the rules of the Authority. Provided that the Notes carry a right to interest and are and remain so listed and admitted to trading, payments of interest on the Notes may be made without withholding or deduction for or on account of United Kingdom tax.

Interest on the Notes may also be paid without withholding or deduction for or on account of United Kingdom income tax where the Company reasonably believes (and any person by or through whom interest on the Notes is paid reasonably believes) at the time the payment is made that (a) the person beneficially entitled to the interest is a U.K. resident company or a non U.K. resident company that carries on a trade in the United Kingdom through a permanent establishment and the payment is one that the non U.K. resident company is required to bring into account when calculating its profits subject to U.K. corporation tax; or (b) the person to whom the payment is made is one of the further classes of bodies or persons, and meets any relevant conditions, set out in Sections 935-937 of the Income Tax Act 2007, provided that in either case HMRC has not given a direction, the effect of which is that the payment may not be made without that withholding or deduction.

In other cases, including in the event the Notes are not or cease to be listed on a "recognised stock exchange" and are not otherwise admitted to trading on a multilateral trading facility operated by a regulated recognised stock exchange, an amount must generally be withheld from payments of interest on the Notes on account of United Kingdom income tax at the basic rate (currently 20%), subject to the availability of other reliefs under domestic law or pursuant to the provisions of an applicable double taxation treaty. Where an applicable double taxation treaty provides for a lower rate of withholding tax (or for no tax to be withheld) in relation to a Noteholder, HMRC can issue a direction to the Company (following an application by that holder under an applicable double tax treaty) to pay interest to the Noteholder without deduction of tax (or for interest to be paid with tax deducted at the rate provided for in the relevant double taxation treaty).

Any premium payable on redemption (including any premium by reference to any original issue discount) may be treated as a payment of interest for United Kingdom tax purposes and may accordingly be subject to the withholding tax treatment described above.

The references to "interest" above are to "interest" as understood for the purposes of United Kingdom tax law. They do not take into account any different definition of "interest" or "principal" that may prevail under any other tax law or that may apply under the terms and conditions of the Notes or any related document.

Provision of information

The Noteholders may wish to note that, in certain circumstances, HMRC has power to obtain information (including the name and address of the beneficial owner of the interest) from any person in the United Kingdom by or through whom interest is paid or credited. The details provided to HMRC may, in certain cases, be passed on to the tax authorities of other jurisdictions.

Further United Kingdom tax issues

Interest on the Notes may be chargeable to United Kingdom tax by direct assessment (including self-assessment) even where paid without withholding or deduction, irrespective of the residence of the holder of the

Notes. However, where the interest is paid without withholding or deduction for or on account of United Kingdom income tax, the interest will not generally be assessed to United Kingdom tax in the hands of a holder of Notes (other than certain trustees) who is not resident for tax purposes in the United Kingdom, except where the holder of Notes carries on a trade, profession or vocation in the United Kingdom through a branch or agency, or in the case of a corporate holder, carries on a trade through a permanent establishment in the United Kingdom, in connection with which the interest is received or to which the Notes are attributable, in which case (subject to exemptions for interest received by certain categories of agent) tax may be levied on the United Kingdom branch or agency, or permanent establishment. However exemption from, or reduction of, such United Kingdom tax liability might be available under an applicable double taxation treaty.

Holders of the Notes should note that the provisions relating to additional amounts referred to in "*Description of the Notes—Additional Amounts*" would not apply if HMRC sought to assess directly the person entitled to the relevant interest and premium to U.K. tax. However, exemption from, or reduction of, such United Kingdom tax liability might be available under an applicable double taxation treaty.

Stamp duty and stamp duty reserve tax

No United Kingdom stamp duty or stamp duty reserve tax should be payable on the issue or transfer of or an agreement to transfer the Notes provided in each case that (i) the interest on the Notes does not exceed a reasonable commercial return on the nominal amount of the capital and (ii) any right on repayment of the Notes to an amount which exceeds the nominal amount of the Notes is reasonably comparable with what is generally repayable (in respect of a similar nominal amount of capital) under the terms of issue of loan capital listed on the Official List of the London Stock Exchange.

Other tax considerations

Prospective Noteholders should consult their own tax advisers concerning the consequences, in their particular circumstances, under European Union directives and other measures, and under the laws of any other taxing jurisdiction, of the ownership of or any dealing in the Notes. Any such dealing would need to comply with the selling restrictions and securities laws generally.

Payments by a Guarantor

If a Guarantor makes any payments in respect of interest on the Notes (or other amounts due under the Notes other than a repayment of amounts subscribed for the Notes) it is possible that such payments may be subject to withholding tax at applicable rates subject to such relief as may be available under the provisions of any applicable double taxation treaty or to any other exemption which may apply. Such payments by a Guarantor may not be eligible for the exemptions described above.

PLAN OF DISTRIBUTION

Subject to the terms and conditions set forth in a purchase agreement (the "**Purchase Agreement**") dated on or about the date of these Listing Particulars by and among the Company, the Guarantors and the Initial Purchasers, we have agreed to sell to each Initial Purchaser, and each Initial Purchaser has agreed, severally and not jointly, to purchase from us, together with all other Initial Purchasers, Notes in the aggregate principal amount of $675.0 million.

Subject to the terms and conditions set forth in the Purchase Agreement, the Initial Purchasers have agreed, severally and not jointly, to purchase all of the notes sold under the Purchase Agreement if any of these Notes are purchased. If an Initial Purchaser defaults, the Purchase Agreement provides that the purchase commitments of the non-defaulting Initial Purchasers may be increased or the Purchase Agreement may be terminated.

The Initial Purchasers initially propose to offer the Notes for resale at the issue price that appears on the cover of these Listing Particulars. After the initial offering, the Initial Purchasers may change the price at which the Notes are offered and any other selling terms at any time without notice. The Initial Purchasers may offer and sell the Notes through certain of their affiliates, including in respect of sales into the United States. To the extent that any Initial Purchaser that is not a U.S. registered broker-dealer intends to effect any sales of the Notes in the United States, it will do so through one or more U.S. registered broker-dealer affiliates. The Initial Purchasers reserve the right to withdraw, cancel or modify offers to investors and to reject, cancel or modify orders in whole or in part.

Persons who purchase Notes from the Initial Purchasers may be required to pay stamp duty, taxes and other charges in accordance with the laws and practice of the country of purchase in addition to the offering price set forth on the cover page hereof.

We have agreed to pay the Initial Purchasers certain customary fees for their services in connection with this Offering and to reimburse them for certain out of pocket expenses.

The Purchase Agreement provides that we will indemnify and hold harmless the Initial Purchasers against certain liabilities, including liabilities under the U.S. Securities Act, and will contribute to payments that the Initial Purchasers may be required to make in respect thereof. We have agreed, subject to certain limited exceptions, that during the period from the date hereof through and including the date that is 90 days after the date of the Purchase Agreement, neither we nor the Guarantors will, without the prior written consent of the Initial Purchasers, offer, sell, contract to sell or otherwise dispose of, except as provided in the Purchase Agreement, any debt securities issued or guaranteed by the Company or any of its subsidiaries and having a tenor of more than one year.

The Notes and the Note Guarantees have not been and will not be registered under the U.S. Securities Act and the Notes and the Note Guarantees have not been and will not be registered under the Securities Act and may not be offered or sold within the United States except to qualified institutional buyers in reliance on Rule 144A and outside the United States in offshore transactions in reliance on Regulation S. Until 40 days after the later of (i) the commencement of the Offering and (ii) the Issue Date of the Notes, an offer or sale of the Notes initially sold in reliance on Regulation S within the United States by a dealer (whether or not participating in the Offering) may violate the registration requirements of the Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A under the Securities Act. Terms used in this paragraph have the meanings given to them by Regulation S. Resales of the Notes are restricted as described under "*Notice to investors*."

As set forth in the Purchase Agreement, the Initial Purchasers represent and warrant, severally and not jointly, and agree that they:

- have only communicated or caused to be communicated and will only communicate or cause to be communicated any invitation or inducement to engage in investment activity (within the meaning of section 21 of the FSMA) received by it in connection with the issue or sale of any Notes in circumstances in which section 21(1) of the FSMA does not apply to us or the Guarantors; and

- have complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the Notes in, from or otherwise involving the United Kingdom.

No action has been taken in any jurisdiction, including the United States and the United Kingdom, by us or the Initial Purchaser that would permit a public offering of the Notes or the possession, circulation or distribution of these Listing Particulars or any other material relating to us or the Notes in any jurisdiction where action for this purpose is required. Accordingly, the Notes may not be offered or sold, directly or indirectly, and neither these Listing Particulars nor any other offering material or advertisements in connection with the Notes may be distributed or published, in or from any country or jurisdiction, except in compliance with any applicable rules and regulations of any such country or jurisdiction. These Listing Particulars do not constitute an offer to sell or a solicitation of an offer to purchase in any jurisdiction where such offer or solicitation would be unlawful. Persons into whose possession these Listing Particulars come are advised to inform themselves about and to observe any restrictions relating to the Offering of the Notes, the distribution of these Listing Particulars and resale of the Notes. See "*Notice to investors*."

We and the Guarantors have also agreed that we will not at any time offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, any securities under circumstances in which such offer, sale, pledge, contract or disposition would cause the exemption afforded by Section 4(a)(2) of the U.S. Securities Act or the safe harbor of Rule 144A and Regulation S under the U.S. Securities Act to cease to be applicable to the offer and sale of the Notes.

The Notes are a new issue of securities for which there currently is no market. We have applied to list the Notes on the Official List of the Exchange, however, we cannot assure you that such listing will be maintained.

The Initial Purchasers have advised us that they intend to make a market in the Notes as permitted by applicable law. The Initial Purchasers are not obligated, however, to make a market in the Notes, and any market-making activity may be discontinued at any time at the sole discretion of the Initial Purchasers without notice. In addition, any such market-making activity will be subject to the limits imposed by the U.S. Exchange Act. Accordingly, we cannot assure you that any market for the Notes will develop, that it will be liquid if it does develop, or that you will be able to sell any Notes at a particular time or at a price which will be favorable to you. See "*Risk factors—Risks relating to the Notes and our structure—There may not be an active trading market for the Notes*, *in which case your ability to sell the Notes may be limited*."

We expect that delivery of the Notes will be made against payment on the Notes on or about the date specified on the cover page of these Listing Particulars, which will be seven business days (as such term is used for purposes of Rule 15c6-1 of the U.S. Exchange Act) following the date of pricing of the Notes ("**T + 7**"). Under Rule 15c6-1 of the Exchange Act, trades in the secondary market generally are required to settle in the next succeeding business day, unless the parties to any such trade expressly agree otherwise. Accordingly, purchasers who wish to trade Notes prior to the date that is one business day preceding the settlement date will be required, by virtue of the fact that the Notes initially will settle on a delayed basis, to specify an alternate settlement cycle at the time of any such trade to prevent a failed settlement. Purchasers of the Notes who wish to make such trades during such period should consult their own legal advisor.

In connection with the Offering, the Initial Purchasers may purchase and sell the Notes in the open market. These transactions may include short sales and purchases on the open market to cover positions created by short sales. Short sales involve the sale by the Initial Purchasers of a greater principal amount of Notes than they are required to purchase in the Offering. The Initial Purchasers must close out any short position by purchasing Notes in the open market. A short position is more likely to be created if the Initial Purchasers are concerned that there may be downward pressure on the price of the Notes in the open market after pricing that could adversely affect investors who purchase in the Offering.

Similar to other purchase transactions, the Initial Purchasers' purchases to cover the syndicate short sales may have the effect of raising or maintaining the market price of the Notes or preventing or retarding a decline in the market price of the Notes. As a result, the price of the Notes may be higher than the price that might otherwise exist in the open market.

Neither we nor any of the Initial Purchasers make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the Notes. In addition, neither we nor any of the Initial Purchasers make any representation that the Initial Purchasers will engage in these transactions or that these transactions, once commenced, will not be discontinued without notice.

The Initial Purchasers and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory,

investment management, principal investment, hedging, financing and brokerage activities. The Initial Purchasers and their respective affiliates have in the past performed commercial banking, investment banking and advisory services for us from time to time for which they have received customary fees and reimbursement of expenses and may, from time to time, engage in transactions with and perform services for us in the ordinary course of their business for which they may receive customary fees and reimbursement of expenses.

In the ordinary course of their various business activities, the Initial Purchasers and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (which may include bank loans and/or credit default swaps) for their own account and for the accounts of their customers and may at any time hold long and short positions in such securities and instruments. Such investments and securities activities may involve securities and/or instruments of ours or our affiliates, including the Notes. The Initial Purchasers and their affiliates may receive allocations of the Notes (subject to customary closing conditions), which could affect future trading of the Notes. Certain of the Initial Purchasers are lenders and/or hold certain roles under our other outstanding indebtedness, including the RBL Facility.

Certain of the Initial Purchasers or their affiliates that have a lending relationship with us routinely hedge their credit exposure to us consistent with their customary risk management policies. Typically, such Initial Purchasers and their affiliates would hedge such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in our securities, including potentially the Notes offered hereby. Any such short positions could adversely affect future trading prices of the Notes offered hereby. The Initial Purchasers and their affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or financial instruments and may hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

Any of our shareholders or any of their respective affiliates or connected persons may purchase Notes in the offering at a purchase price per Note equal to the issue price set forth on the cover page of these Listing Particulars, and such amount could be material. The purchase agreement between the Company and the Initial Purchasers will not restrict the ability of the Company, any of its shareholders or any of their respective affiliates or connected persons to buy or sell Notes in the future and, as a result, the Company, any of its shareholders or any of their respective affiliates or connected persons may buy or sell the Notes in open market transactions at any time following the consummation of the offering of the Notes.

NOTICE TO INVESTORS

You are advised to consult legal counsel prior to making any offer, resale, pledge or other transfer of any of the Notes offered hereby.

The Notes and the Note Guarantees have not been and will not be registered under the U.S. Securities Act, or any state securities laws, and, unless so registered, may not be offered or sold except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the U.S. Securities Act and applicable state securities laws. Accordingly, the Notes offered hereby are being offered and sold only to qualified institutional buyers (as defined in Rule 144A under the U.S. Securities Act) in reliance on Rule 144A under the U.S. Securities Act and in offshore transactions in reliance on Regulation S under the U.S. Securities Act.

We have not registered and will not register the Notes or the Note Guarantees under the U.S. Securities Act and, therefore, the Notes may not be offered or sold within the United States or to, or for the account or benefit of, U.S. persons except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the U.S. Securities Act. Accordingly, we are offering and selling the Notes to the Initial Purchasers for re-offer and resale only:

- in the United States to "qualified institutional buyers," commonly referred to as "**QIBs,**" as defined in Rule 144A in compliance with Rule 144A; and
- outside the United States to persons other than U.S. persons in offshore transactions in accordance with Regulation S.

We use the terms "offshore transaction," "**U.S. person**" and "**United States**" with the meanings given to them in Regulation S.

Each purchaser of Notes, by its acceptance thereof, will be deemed to have acknowledged, represented to and agreed with us and the Initial Purchasers as follows:

(1) You understand and acknowledge that the Notes and the Note Guarantees have not been registered under the U.S. Securities Act or any other applicable securities laws and that the Notes are being offered for resale in transactions not requiring registration under the U.S. Securities Act or any other securities laws, including sales pursuant to Rule 144A under the U.S. Securities Act, and, unless so registered, may not be offered, sold or otherwise transferred except in compliance with the registration requirements of the U.S. Securities Act or any other applicable securities laws, pursuant to an exemption therefrom or in any transaction not subject thereto and in each case in compliance with the conditions for transfer set forth in paragraphs (4) and (5) below.

(2) You are not our "affiliate" (as defined in Rule 144 under the U.S. Securities Act) or acting on our behalf and that either:

(a) you are a QIB, within the meaning of Rule 144A under the U.S. Securities Act and are aware that any sale of these Notes to you will be made in reliance on Rule 144A under the U.S. Securities Act, and such acquisition will be for your own account or for the account of another QIB; or

(b) you are purchasing the Notes in an offshore transaction in accordance with Regulation S under the U.S. Securities Act and you are not a U.S. person (and are not purchasing for the account or benefit of a U.S. person) within the meaning of Regulation S under the U.S. Securities Act.

(3) You acknowledge that none of us, the Guarantors, or the Initial Purchasers, nor any person representing any of them, has made any representation to you with respect to us or the offer or sale of any of the Notes, other than the information contained in these Listing Particulars, which Listing Particulars have been delivered to you and upon which you are relying in making your investment decision with respect to the Notes. You acknowledge that neither the Initial Purchasers nor any person representing the Initial Purchasers make any representation or warranty as to the accuracy or completeness of these Listing Particulars. You have had access to such financial and other information concerning us and the Notes as you have deemed necessary in connection with your decision to purchase any of the Notes, including an opportunity to ask questions of, and request information from, us and the Initial Purchasers.

(4) You are purchasing the Notes for your own account, or for one or more investor accounts for which you are acting as a fiduciary or agent, in each case for investment, and not with a view to, or for offer or sale in connection with, any distribution thereof in violation of the U.S. Securities Act or any state securities laws, subject to any requirement of law that the disposition of your property or the property of such investor account or accounts be at all times within your or their control and subject to your or their ability to resell such Notes pursuant to Rule 144A, Regulation S or any other exemption from registration available under the U.S. Securities Act.

(5) You agree on your own behalf and on behalf of any investor account or accounts for which you are purchasing the Notes, and each subsequent holder of the Notes by its acceptance thereof will be deemed to agree, to offer, sell or otherwise transfer such Notes prior to the date (the "**Resale Restriction Termination Date**") that is one year (in the case of Rule 144A Notes) or 40 days (in the case of Regulation S Notes) after the later of the date of the original issue and the last date on which we or any of our affiliates were the owner of such Notes (or any predecessor thereto) only (i) to us, (ii) pursuant to a registration statement that has been declared effective under the U.S. Securities Act, (iii) for so long as the Notes are eligible pursuant to Rule 144A under the U.S. Securities Act, to a person you reasonably believe is a QIB that purchases for its own account or for the account of a QIB to whom notice is given that the transfer is being made in reliance on Rule 144A under the U.S. Securities Act, (iv) pursuant to offers and sales that occur outside the United States in compliance with Regulation S under the U.S. Securities Act or (v) pursuant to any other available exemption from the registration requirements of the U.S. Securities Act, subject in each of the foregoing cases to any requirement of law that the disposition of your property or the property of such investor account or accounts be at all times within your or their control and to compliance with any applicable state securities laws, and any applicable local laws and regulations, and further subject to our and the trustee's rights prior to any such offer, sale or transfer (I) pursuant to clause (v) to require the delivery of an opinion of counsel, certification and/or other information satisfactory to each of them and (II) in each of the foregoing cases, to require that a certificate of transfer in the form appearing in the Indenture is completed and delivered by the transferor to the Trustee. The foregoing restrictions on resale will not apply subsequent to the Resale Restriction Termination Date.

By acceptance of a Note, you will be deemed to have represented and agreed that (A) either (i) no portion of the assets used by you to acquire and hold the Notes or an interest therein constitutes assets of (a) any employee benefit plans that are subject to Title I of the United States Employee Retirement Income Security Act of 1974, as amended ("**ERISA**"), (b) plans, individual retirement accounts ("**IRAs**") and other arrangements that are subject to Section 4975 of the Code, (c) entities whose underlying assets are considered to include "plan assets" (within the meaning of 29 C.F.R. 2510.3-101, as modified by Section 3(42) of ERISA) of such employee benefit plans, plans, accounts or arrangements (each item described in clauses (a) through (c), an "**ERISA Plan**"), or (d) benefit plans that are governmental plans (as defined in Section 3(32) of ERISA), certain church plans (as defined in Section 3(33) of ERISA) and non-US plans (as described in Section 4(b)(4) of ERISA) that are not subject to ERISA or Section 4975 of the Code but which may be subject to non-US, federal, state, or local laws or regulations ("**Similar Laws**") that are substantially similar to Section 406 of ERISA or Section 4975 of the Code (together with ERISA Plans, "**Plans**") or (ii) (a) the acquisition and holding by you of the Notes or an interest therein will not constitute or result in a non-exempt prohibited transaction under Section 406 of ERISA or Section 4975 of the Code or violation of any applicable Similar Laws, and (b) if a portion of the assets used by you to acquire and hold the Notes or an interest therein constitutes assets of an ERISA Plan, neither we, the Initial Purchasers, the Guarantors nor any of their respective affiliates (the "**Transaction Parties**") has acted as the ERISA Plan's fiduciary (within the meaning of ERISA or the Code), or has been relied on for advice, with respect to your decision to acquire and hold the Notes or an interest therein, and (B) you will not sell or otherwise transfer such Note or any interest therein otherwise than to a purchaser or transferee that is deemed to make these same representations, warranties and agreements with respect to its acquisition and holding of such Note or any interest therein.

Each purchaser acknowledges that each Note will contain a legend substantially to the following effect (if applicable):

THE FOLLOWING INFORMATION IS SUPPLIED SOLELY FOR U.S. FEDERAL INCOME TAX PURPOSES. THIS SECURITY WAS ISSUED WITH "ORIGINAL ISSUE DISCOUNT" ("**OID**") WITHIN THE MEANING OF SECTION 1273 OF THE INTERNAL REVENUE CODE OF 1986, AS AMENDED (THE "CODE"), AND THIS LEGEND IS REQUIRED BY SECTION 1275(c) OF THE CODE. HOLDERS MAY OBTAIN INFORMATION REGARDING THE AMOUNT OF ANY OID, THE ISSUE PRICE, THE ISSUE DATE AND THE YIELD TO

MATURITY RELATING TO THE SECURITY BY CONTACTING THE ISSUER AT ENQUEST PLC, 2ND FLOOR, CHARLES HOUSE, 5-11 REGENT STREET, LONDON SW1Y 4LR, UNITED KINGDOM.

Each purchaser acknowledges that each Note will contain a legend substantially to the following effect:

THIS SECURITY HAS NOT BEEN AND WILL NOT BE REGISTERED UNDER THE US SECURITIES ACT OF 1933, AS AMENDED (THE "**US SECURITIES ACT**"), OR THE SECURITIES LAWS OF ANY STATE OR OTHER JURISDICTION. NEITHER THIS SECURITY NOR ANY INTEREST OR PARTICIPATION HEREIN MAY BE OFFERED, SOLD, ASSIGNED, TRANSFERRED, PLEDGED, ENCUMBERED OR OTHERWISE DISPOSED OF IN THE ABSENCE OF SUCH REGISTRATION OR UNLESS SUCH TRANSACTION IS EXEMPT FROM, OR NOT SUBJECT TO, THE REGISTRATION REQUIREMENTS OF THE US SECURITIES ACT.

THE HOLDER OF THIS SECURITY BY ITS ACCEPTANCE HEREOF (1) REPRESENTS THAT (A) IT IS A "**QUALIFIED INSTITUTIONAL BUYER**" (AS DEFINED IN RULE 144A UNDER THE US SECURITIES ACT ("**RULE 144A**")) OR (B) IT IS A NON-US PERSON AND IS ACQUIRING THIS SECURITY IN AN "**OFFSHORE TRANSACTION**" PURSUANT TO RULE 904 OF REGULATION S UNDER THE US SECURITIES ACT ("**REGULATION S**"), (2) AGREES ON ITS OWN BEHALF AND ON BEHALF OF ANY INVESTOR FOR WHICH IT HAS PURCHASED SECURITIES TO OFFER, SELL OR OTHERWISE TRANSFER SUCH SECURITY, PRIOR TO THE DATE (THE "**RESALE RESTRICTION TERMINATION DATE**") WHICH [IN THE CASE OF REGULATION S NOTES: IS 40 DAYS AFTER THE LATER OF THE ISSUE DATE HEREOF AND THE DATE ON WHICH THIS SECURITY WAS FIRST OFFERED TO PERSONS OTHER THAN DISTRIBUTORS (AS DEFINED IN RULE 902 OF REGULATION S)] [IN THE CASE OF THE RULE 144A NOTES: ONE YEAR AFTER THE LATER OF THE ISSUE DATE HEREOF AND THE LAST DATE ON WHICH THE COMPANY OR ANY AFFILIATE OF THE COMPANY WAS THE ISSUER OR ANY AFFILIATE OF THE ISSUER WAS THE OWNER OF THIS SECURITY (OR ANY PREDECESSOR OF SUCH NOTE)] ONLY (A) TO THE ISSUER, (B) PURSUANT TO A REGISTRATION STATEMENT WHICH HAS BEEN DECLARED EFFECTIVE UNDER THE US SECURITIES ACT, (C) FOR SO LONG AS THE SECURITIES ARE ELIGIBLE FOR RESALE PURSUANT TO RULE 144A, TO A PERSON IT REASONABLY BELIEVES IS A "**QUALIFIED INSTITUTIONAL BUYER**" AS DEFINED IN RULE 144A THAT PURCHASES FOR ITS OWN ACCOUNT OR FOR THE ACCOUNT OF A QUALIFIED INSTITUTIONAL BUYER TO WHOM NOTICE IS GIVEN THAT THE TRANSFER IS BEING MADE IN RELIANCE ON RULE 144A, (D) PURSUANT TO OFFSHORE TRANSACTIONS TO NON-US PERSONS OCCURRING OUTSIDE THE UNITED STATES IN COMPLIANCE WITH REGULATION S OR (E) PURSUANT TO ANY OTHER AVAILABLE EXEMPTION FROM THE REGISTRATION REQUIREMENTS OF THE US SECURITIES ACT, SUBJECT IN EACH OF THE FOREGOING CASES TO ANY REQUIREMENT OF LAW THAT THE DISPOSITION OF ITS PROPERTY OR THE PROPERTY OF SUCH INVESTOR ACCOUNT OR ACCOUNTS BE AT ALL TIMES WITHIN ITS OR THEIR CONTROL AND IN COMPLIANCE WITH ANY APPLICABLE STATE SECURITIES LAWS AND ANY APPLICABLE LOCAL LAWS AND REGULATIONS AND FURTHER SUBJECT TO THE ISSUER'S AND THE TRUSTEE'S RIGHTS PRIOR TO ANY SUCH OFFER, SALE OR TRANSFER (I) PURSUANT TO CLAUSE (E) TO REQUIRE THE DELIVERY OF AN OPINION OF COUNSEL, CERTIFICATION AND/OR OTHER INFORMATION SATISFACTORY TO EACH OF THEM AND (II) IN EACH OF THE FOREGOING CASES, TO REQUIRE THAT A CERTIFICATE OF TRANSFER IN THE FORM APPEARING ON THE OTHER SIDE OF THIS SECURITY IS COMPLETED AND DELIVERED BY THE TRANSFEROR TO THE TRUSTEE AND (3) AGREES THAT IT WILL GIVE TO EACH PERSON TO WHOM THIS SECURITY IS TRANSFERRED A NOTICE SUBSTANTIALLY TO THE EFFECT OF THIS LEGEND. AS USED HEREIN, THE TERMS "**US PERSON,**" "**OFFSHORE TRANSACTION**" AND "**UNITED STATES**" HAVE THE MEANING GIVEN TO THEM BY REGULATION S.

If you purchase Notes, you will also be deemed to acknowledge that the foregoing restrictions apply to holders of beneficial interests in these Notes as well as to holders of these Notes.

(6) You agree that you will give to each person to whom you transfer the Notes notice of any restrictions on the transfer of such Notes.

(7) You acknowledge that until 40 days after the commencement of the Offering, any offer or sale of the Notes within the United States by a dealer (whether or not participating in the Offering) may violate the registration requirements of the U.S. Securities Act if such offer or sale is made otherwise than in accordance with Rule 144A under the U.S. Securities Act.

(8) You acknowledge that the Registrar will not be required to accept for registration or transfer any Notes acquired by you except upon presentation of evidence satisfactory to us and the Registrar that the restrictions set forth therein have been complied with.

(9) You acknowledge that we, the Initial Purchasers and others will rely upon the truth and accuracy of your acknowledgements, representations, warranties and agreements and agrees that if any of the acknowledgements, representations, warranties and agreements deemed to have been made by your purchase of the Notes is no longer accurate, you shall promptly notify us and the initial purchasers. If you are acquiring any Notes as a fiduciary or agent for one or more investor accounts, you represent that you have sole investment discretion with respect to each such investor account and that you have full power to make the foregoing acknowledgements, representations and agreements on behalf of each such investor account.

(10) You understand that no action has been taken in any jurisdiction (including the United States) by us or the Initial Purchasers that would result in a public offering of the Notes or the possession, circulation or distribution of these Listing Particulars or any other material relating to us or the Notes in any jurisdiction where action for such purpose is required. Consequently, any transfer of the Notes will be subject to the selling restrictions set forth in this section of these Listing Particulars and/or in the front of these Listing Particulars under "*Notice to Certain Other Investors*" and "*Plan of distribution*."

(11) You confirm that you, or the investor account for which you act, is not an EEA retail investor. For the purposes of this paragraph, the expression "**EEA retail investor**" means a person who is one (or more) of the following: (i) a "retail client" as defined in point (11) of Article 4(1) of MiFID II; or (ii) a customer within the meaning of the Insurance Distribution Directive, where that customer would not qualify as a professional client as defined in point (10) of Article 4(1) of MiFID II; or (iii) not a "qualified investor" as defined in the Prospectus Regulation.

(12) You confirm that you, or the investor account for which you act, is not a U.K. retail investor. For the purposes of this paragraph, the expression "**U.K. retail investor**" means a person who is either one (or both) of the following: (i) not a professional client, as defined in point (8) of Article 2(1) of Regulation (EU) 600/2014 as it forms part of domestic law by virtue of the EUWA or (ii) not a qualified investor as defined in paragraph 15 of Schedule 1 to the POATRs.

(13) You understand that: (i) the Notes are not intended to be offered, sold or otherwise made available to and should not be offered, sold or otherwise made available to any "**EEA retail investor**" (as defined in paragraph (11) above) in the EEA; (ii) no key information document required by the PRIIPs Regulation for offering or selling the Notes or otherwise making them available to EEA retail investors in the EEA has been prepared and therefore offering or selling the Notes or otherwise making them available to any retail investor in the EEA may be unlawful under the PRIIPs Regulation; (iii) the Notes are not intended to be offered, sold or otherwise made available to and should not be offered, sold or otherwise made available to any "**U.K. retail investor**" (as defined in paragraph (12) above) in the U.K.; and (iv) no disclosure document required by the DISC for offering, selling or distributing the Notes or otherwise making them available to U.K. retail investors in the U.K. has been prepared and therefore offering, selling or distributing the Notes or making them available to any U.K. retail investor in the U.K. may be unlawful under the U.K. DISC.

(14) You understand that: (i) the Notes are not intended to be and should not be offered, sold, transferred or disposed of, whether directly or indirectly, to any person in Malaysia; and (ii) these Listing Particulars or any other document or material relating to any Note should not be distributed, cause to be distributed or circulated in Malaysia.

LEGAL MATTERS

The validity of the Notes, the Note Guarantees and certain other legal matters are being passed upon for us by Latham & Watkins (London) LLP with respect to matters of U.S. federal and New York state law and with respect to certain other legal matters of English law and Skrine & Co. as to matters of Malaysian law. Certain legal matters will be passed upon for the Initial Purchasers by Skadden, Arps, Slate, Meagher & Flom (UK) LLP with respect to matters of U.S. federal and New York state law, and with respect to certain other matters of English law and Shearn Delamore & Co. as to matters of Malaysian law.

INDEPENDENT AUDITORS

The Group Financial Statements as of and for the years ended December 31, 2023, 2024 and 2025, included in these Listing Particulars, have been audited by Deloitte LLP, independent auditors, as stated in their reports appearing herein.

INDEPENDENT RESERVE AUDITORS

Estimates of our 1P and 2P Reserves as of December 31, 2023, 2024 and 2025 included in these Listing Particulars were based in part upon annual reserve reports prepared by independent international energy advisory company, Gaffney, Cline & Associates Ltd. Estimates of our pro forma 1P and 2P Reserves as of December 31, 2024 included in these Listing Particulars were based in part upon the Vietnam Report prepared by independent international energy advisory company, Gaffney, Cline & Associates (Consultants) Pte Ltd. Estimates of 1P and 2P Reserves derived from the Annual Reserves Reports and *pro forma* 1P and 2P Reserves derived from the Vietnam Report have been included in reliance on the authority of such firm as an expert in such matters. Conversion of gas reserves volumes from Bscf to MMboe has been made by the Company assuming a conversion rate of 5.8 Bscf to 1 MMboe of oil for production data and reserves.

AVAILABLE INFORMATION

Each purchaser of Notes from an Initial Purchaser will be furnished a copy of these Listing Particulars and any related amendments or supplements to these Listing Particulars. Each person receiving these Listing Particulars and any related amendments or supplements to these Listing Particulars acknowledges that:

(1) such person has been afforded an opportunity to request from us and to review and has received, all additional information considered by it to be necessary to verify the accuracy and completeness of the information herein;

(2) such person has not relied on the Initial Purchasers or any person affiliated with the Initial Purchasers in connection with its investigation of the accuracy of such information or its investment decision; and

(3) except as provided pursuant to clause (1) above, no person has been authorized to give any information or to make any representation concerning the Notes or each Note Guarantee offered hereby other than those contained herein and, if given or made, such other information or representation should not be relied upon as having been authorized by either us or the Initial Purchasers.

For so long as any of the Notes remain outstanding and are "restricted securities" within the meaning of Rule 144(a)(3) under the U.S. Securities Act, we will, unless we are then subject to Section 13 or 15(d) under the U.S. Exchange Act, make available to any holder or beneficial holder of a Note, or to any prospective purchaser of a Note designated by such holder or beneficial holder, the information specified in, and meeting the requirements of, Rule 144A(d)(4) under the U.S. Securities Act upon the written request of any such holder or beneficial owner. Any such request should be directed to EnQuest PLC, 2nd Floor, Charles House, 5-11 Regent Street, London SW1Y 4LR, United Kingdom.

We are not subject to the periodic reporting and other information requirements of the U.S. Exchange Act. We are a listed company on the Official List of the London Stock Exchange using the code 'ENQ' and while we remain listed on the Official List of the London Stock Exchange, we must comply with the reporting requirements established by the Companies Act 2006, as amended, and the Disclosure & Transparency Rules of the United Kingdom Listing Authority. In addition to our ongoing reporting obligations under these regulations, we must send the United Kingdom Listing Authority our preliminary annual results and our annual financial report. We must also send our semi-annual financial reports, along with interim management statements. Pursuant to the indenture that will govern the Notes, we will agree to furnish periodic information to the holders of the Notes. See "*Description of Notes—Certain covenants—Reports*."

So long as the Notes are admitted to listing on the Official List of the Luxembourg Stock Exchange and admitted to trading on the Euro MTF market thereof, and the rules and regulations of such stock exchange so require, copies of the following documents will also be available for review during the normal business hours on any business day at the specified office of the Company:

- the organizational documents of the Company and the Guarantors;
- the most recent Group Financial Statements published by the Company;
- the Indenture (which includes the Guarantees and form of the Notes); and
- the Guarantee Subordination Agreement.

SERVICE OF PROCESS AND ENFORCEMENT OF CIVIL LIABILITIES

We are incorporated under the laws of England and Wales and the Guarantors are organized under the laws of England and Wales.

Most of our directors, officers and other executives are neither residents nor citizens of the United States. Furthermore, most of our assets are located outside the United States. As a result, it may not be possible for investors to effect service of process within the United States upon such persons, us or the Guarantors or to enforce against them, us or the Guarantors judgments of U.S. courts predicated upon the civil liability provisions of U.S. federal or state securities laws despite the fact that, pursuant to the terms of the Indenture, we and the Guarantors have appointed, or will appoint, an agent for the service of process in New York.

England and Wales

The United States and England and Wales currently do not have a treaty between them providing for the reciprocal recognition and enforcement of judgments (as opposed to arbitration awards) in civil and commercial matters. Consequently, a final judgment for payment rendered by any federal or state court in the United States based on civil liability, whether or not predicated solely upon U.S. federal securities laws, would not automatically be recognized or enforceable in England and Wales. In order to enforce any such U.S. judgment in England and Wales, fresh proceedings must first be initiated before a court of competent jurisdiction in England and Wales. In such an action, an English court would not generally reinvestigate the merits of the original matter decided by the U.S. court (subject to what is said below) and it would usually be possible to obtain summary judgment on such a claim (assuming that there is no good defense to it). Summary judgment is a procedure by which the English court can dispose of all or part of a claim without proceeding to a full trial. Recognition and enforcement of a U.S. judgment by an English court in such an action may be conditional upon (among other things) the following:

- the U.S. court having had, at the time the proceedings were served, jurisdiction over the original proceedings or the party against whom the judgment was given having properly submitted to the jurisdiction of the U.S. court which gave the U.S. judgment, in each case according to English conflicts of laws principles and rules of English private international law (in other words, it does not matter that the U.S. court had jurisdiction according to its own law, but instead whether it had jurisdiction according to the rules of English private international law);

- the U.S. judgment not having been obtained contrary to an agreement for the resolution of disputes under which the dispute in question was to be resolved otherwise than by proceedings in a United States court (to whose jurisdiction the judgment debtor did not submit);

- the U.S. judgment being final and conclusive on the merits in the sense of being final and unalterable in the court which pronounced it and being for a debt for a definite sum of money;

- the U.S. judgment not contravening English public policy or statute in England and Wales;

- the U.S. judgment not being for a sum payable in respect of taxes, or other charges of a like nature, or in respect of a penalty or fine, or otherwise involving the enforcement of a non-English penal or revenue law;

- the recognition and enforcement of the U.S. judgment not being restricted by the provisions of the Protection of Trading Interests Act 1980;

- the U.S. judgment not having been obtained by fraud or in breach of English principles of natural or substantial justice;

- there not having been a prior inconsistent, determinative or conflicting judgment of the courts of England and Wales or another court whose judgment is entitled to recognition in England and Wales;

- the party seeking enforcement providing security for costs, if ordered to do so by the English court; and

- the English enforcement proceedings being commenced within the relevant limitation period.

Subject to the foregoing, investors may be able to enforce in England and Wales judgments in civil and commercial matters that have been obtained from U.S. federal or state courts. However, we cannot assure you that those judgments will be recognized or enforceable in England and Wales. In addition, it is questionable whether an English court would accept jurisdiction and impose civil liability if proceedings were commenced in England and Wales, instead of the United States, in an original action predicated solely upon U.S. federal securities laws. Further, it may not be possible to obtain a judgment in England and Wales or to enforce the judgment if the judgment debtor is subject to any insolvency or similar proceedings, or if the judgment debtor has any setoff or counterclaim against the judgment creditor. Finally, note that, in any enforcement proceedings, the judgment debtor may raise any counterclaim that could have been brought if the action had been originally brought in England and Wales unless the subject of the counterclaim was in issue in the U.S. proceedings.

CERTAIN INSOLVENCY LAW CONSIDERATIONS

The following is a brief description of certain insolvency law considerations in the jurisdictions in which Note Guarantees are initially being provided. The descriptions below do not purport to be complete or discuss all of the limitations or considerations that may affect the Notes or the Note Guarantees. Proceedings of bankruptcy, insolvency or a similar event could be initiated in any of these jurisdictions and in the jurisdiction of organization of a future Guarantor of the Notes. The application of these various laws in multiple jurisdictions could trigger disputes over which jurisdiction's law should apply and could adversely affect your ability to enforce your rights and to collect payment in full under the Notes and the Note Guarantees. Prospective investors in the Notes should consult their own legal advisors with respect to such limitations and considerations. See "Risk factors—Risks relating to the Notes and our structure—The insolvency laws of England and Wales may not be as favorable to you as insolvency laws of jurisdictions with which you may be familiar and may preclude noteholders from recovering payments due on the Notes."

England and Wales

The Company and certain of the Guarantors are companies incorporated under the laws of England and Wales (the "**English Companies**").

Applicable legal framework and jurisdiction of the English courts

While the U.K was a member state of the EU, insolvency processes opened in the U.K. were subject to both EU and applicable U.K. domestic legislation. Following the U.K.'s departure from the EU on January 31, 2020 and the expiry of the subsequent transition period (the "**Transition Period**") on December 31, 2020, in accordance with the European Union (Withdrawal) Act 2018 (as amended by the European Union (Withdrawal Agreement) Act 2020), EU law as directly applicable in the U.K. at the end of the Transition Period (subject to certain exceptions) was transposed into U.K. domestic law subject to significant amendments. The Insolvency (Amendment) (EU Exit) Regulations 2019 (SI 2019/146) (as amended) effected key amendments to both EU insolvency laws previously directly applicable in the U.K., including the EU Insolvency Regulation, and domestic insolvency laws, including the Insolvency Act 1986 (the "**Insolvency Act**"), the Insolvency (England and Wales) Rules 2016 (SI 2016/1024) (the "**Insolvency Rules**") and the Cross-Border Insolvency Regulations 2006 (SI 2006/1030) (the "**Cross-Border Insolvency Regulations**").

Unless insolvency proceedings or certain related proceedings were opened prior to the expiry of the Transition Period, in which case the unmodified EU Insolvency Regulation and related EU insolvency legislation govern the proceedings, insolvency proceedings with respect to the English Companies would likely proceed under, and be governed by, English insolvency laws in force at the time of commencement of the relevant proceedings. However, to the extent that an English Company has its COMI in a member state of the EU (other than Denmark), insolvency proceedings could, pursuant to the EU Insolvency Regulation and subject to certain exceptions, be opened in the relevant EU member state and be subject to the laws of that EU member state. In addition, pursuant to the Cross-Border Insolvency Regulations, certain foreign courts may have jurisdiction to oversee the insolvency proceedings of any English Company which has its COMI or an "establishment" (being a place of operations where it carries out a non-transitory economic activity with human means and assets or services) in such foreign jurisdiction or has a "sufficient connection" with that jurisdiction.

Although the scope of the English courts' jurisdiction varies for the different insolvency proceedings available in England and Wales, English courts generally have jurisdiction to open insolvency proceedings in respect of any company which has its COMI in the UK or has its COMI in an EU member state (other than Denmark) and an "establishment" in the UK (also defined as being a place of operations where it carries out a non-transitory economic activity with human means and assets or services) or which is incorporated in an EEA member state. While this allows English courts to assume jurisdiction over certain foreign companies in respect of certain insolvency proceedings, the efficacy of such proceedings will significantly depend on the likelihood and extent of subsequent recognition of such proceedings in relevant other jurisdictions.

English insolvency law is different to the laws of the United States and other jurisdictions with which investors may be familiar. In the event that an English Company experiences financial difficulty, it is not possible to predict with certainty the outcome of insolvency or similar proceedings. The obligations under the Notes are guaranteed by the Notes Guarantees.

English insolvency laws and other limitations could limit the enforceability of the payment obligations of the Company in respect of the principal, interest and other amounts owing by the Company and of a Notes Guarantee against an English Company.

The following is a brief description of certain aspects of English insolvency law relating to certain limitations on English guarantees. The application of these laws could adversely affect investors and their ability to enforce their rights for payment of the principal, interest and other amounts owing by the Company and under the Notes Guarantees granted by an English Company and therefore may limit the amounts that investors may receive in an insolvency of an English Company.

Administration

The Insolvency Act (as amended) and the onshored version of the EU Insolvency Regulation empower English courts to make an administration order in respect of a company incorporated in England, Wales, Scotland or an EEA state, a company not incorporated in an EEA state but with its COMI in a member state of the EU (other than Denmark), a company (wherever incorporated) having its COMI in the UK or a company (wherever incorporated) with its COMI in a member state of the EU and an "establishment" in the UK, or upon request from courts in other parts of the UK or certain other countries and territories. In each case, and subject to specific conditions, an administration order can be made if the court is satisfied that the relevant company is or is likely to become "unable to pay its debts" and that the administration order is reasonably likely to achieve the purpose of administration. A company is unable to pay its debts if it is insolvent on a "cash flow" basis (unable to pay its debts as they fall due) or if it is insolvent on a "balance sheet" basis (the value of the company's assets is less than the amount of its liabilities, taking into account its contingent and prospective liabilities), as per Section 123 of the Insolvency Act. Such insolvency is presumed if, among other matters, the company fails either to satisfy a creditor's statutory demand for a debt exceeding £750 within 21 days of service or to satisfy in full or in part a judgment debt (or similar court order). Without limitation and subject to specific conditions, an English company, the directors of such company or the holder of a qualifying floating charge, where the floating charge has become enforceable, may also appoint an administrator out of court, and different procedures apply according to the identity of the appointer. The purpose of an administration is comprised of three parts that must be looked at successively: rescuing the company as a going concern or, if that is not reasonably practicable, achieving a better result for the company's creditors as a whole than would be likely upon immediate liquidation or, if neither of those objectives is reasonably practicable, and the interests of the creditors as a whole are not unnecessarily harmed thereby, realizing property to make a distribution to one or more secured or preferential creditors. The order of priority which applies to any distribution to creditors is set out in "*—Priority on insolvency*" below.

In addition, an administrator is given wide powers to conduct the business and, subject to certain requirements under the Insolvency Act, dispose of the property of a company in administration. While an administrator is in office in respect of an English Company, the powers of the board of directors of that English Company (save those that do not interfere with the exercise of the administrator's powers, and those permitted by the administrator) are suspended. A set proportion of the proceeds of the realization of any property subject to a floating charge will need to be set aside for satisfaction of the claims of preferential creditors and the ring-fencing of the Prescribed Part (see "*Prescribed Part*" below). An administrator may also, with prior approval by the court, deal with assets subject to a fixed charge, provided that disposing of the property is likely to promote the purpose of the administration and the administrator applies the net proceeds from the disposal towards discharging the obligations of the company to the fixed charge holder.

Certain rights of creditors, including secured creditors, are curtailed in an administration. Upon the appointment of an administrator, a statutory moratorium is imposed such that no step may be taken to enforce security or a guarantee over the company's property except with the consent of the administrator or permission of the court (although a demand for payment could be made under a guarantee granted by the company). The same requirements for consent or permission apply to the institution or continuation of legal process (including legal proceedings, execution, distress and diligence) against the company or property of the company. In either case, a court will consider discretionary factors in determining any application for leave in light of the hierarchy of statutory objectives of administration described above.

However, certain creditors of a company in administration may, in certain defined circumstances, be able to realize their security over certain of that company's property notwithstanding the statutory moratorium. This is by virtue of the disapplication of the moratorium in relation to any security interest created or otherwise arising under a "financial collateral arrangement" (generally, a charge over cash or financial instruments such as shares, bonds or

tradeable capital market debt instruments and credit claims) under the Financial Collateral Arrangements (No. 2) Regulations 2003 (as amended) (the "**Financial Collateral Regulations**").

Unless extended, administration terminates automatically after a year. An administration may be extended by court order or may also be extended with the consent of the creditors up to a maximum period of one further year, provided that the court has not previously extended the administration and that creditors have not previously consented to any prior extension. The relevant company may exit administration if the administrator is satisfied that one or more of the statutory objectives have been achieved (upon application to and by order of the court if the administration is pursuant to an administration order) and may resume normal business upon exiting administration. However, the administrator also has the power, should they conclude that there is no reasonable prospect of rescuing the company, to either place the company into liquidation or use their powers under, and in accordance with, the Insolvency Act to distribute the company's assets and thereby achieve substantially the same result as a liquidation.

Accordingly, if any English Company were to enter into administration, the Notes and the Note Guarantees could not be enforced while the relevant company was in administration without the permission of the court or consent of the administrator. There can be no assurance that the Trustee would obtain this permission of the court or consent of the administrator.

Qualifying Floating Charge and Administrative receivership

If a company grants a "qualifying floating charge" to a party for the purposes of English insolvency law, that party will be able to appoint an administrative receiver or an administrator out of court (see "Administration" above). The holder of a qualifying floating charge is also entitled to advance notice of an intention of a company or its directors to appoint an administrator, allowing the charge holder to either appoint its own administrator (or, where applicable, administrative receiver) in place of the proposed administrator, conduct negotiations with the proposed appointors over the identity or terms of appointment of the proposed administrator or (in an extreme case) prevent the company going into administration.

In the case of the ability to appoint an administrative receiver, the qualifying floating charge must, unless the security document pre-dates September 15, 2003 in England, fall within one of the exceptions under the Insolvency Act as amended by the Enterprise Act 2002 in England to the prohibition on the appointment of administrative receivers.

In order to constitute a qualifying floating charge, the floating charge must be created by an instrument which (a) states that the relevant statutory provision applies to it; (b) purports to empower the holder to appoint an administrator of the company or (c) purports to empower the holder to appoint an administrative receiver within the meaning given by Section 29(2) of the Insolvency Act in England. A party will be the holder of a qualifying floating charge if such floating charge, together (if necessary) with other forms of security granted to that party, relates to the whole or substantially the whole of the property of the relevant company and at least one such security interest is a qualifying floating charge. Please note that it is a matter of fact whether the extent of the security granted relates to 'the whole or substantially the whole' of the property of a company and there is no statutory guidance as to what percentage of a company's assets should be charged to satisfy this test.

The most relevant exception to the prohibition on the appointment of an administrative receiver is the exception relating to "capital market arrangements" (as defined in the Insolvency Act), which may apply if the issue of the Notes creates a debt of at least £50.0 million for the relevant English company during the life of the arrangement and the arrangement involves the issue of a "capital market investment" (which is defined in the Insolvency Act, and includes rated, listed or traded debt instruments, and debt instruments designed to be rated, listed or traded). If an administrative receiver has been appointed, an administrator can only be appointed by the court (and not by the company, its directors or the holder of a qualifying floating charge using the out of court procedure) and then only if the person who appointed the administrative receiver consents or the court considers that the security pursuant to which the administrative receiver was appointed is capable of challenge as a transaction at an undervalue or a preference (see "*Transactions at an undervalue*" and "*Preference*" below, respectively). If an administrator is appointed, any administrative receiver will vacate office, and any receiver of part of the company's property must resign if required to do so by the administrator.

Fixed charge receivership

A fixed charge receiver (as opposed to an administrative receiver, who is appointed under certain floating charges – see "*Qualifying Floating Charge and Administrative receivership*" above) may be appointed over some or all of the assets secured by a fixed charge in accordance with the terms of a security document creating a fixed charge or (in limited circumstances) pursuant to statute under the Law of Property Act 1925, although it is standard market practice to augment the powers of any receiver appointed through the relevant security document.

If appointed under the terms of a security agreement, grounds for appointment under the terms of the charge (such as a default) must exist and the charging company must have failed to satisfy the demand made for an appointment to take place. A receivership is not a process pursuant to English insolvency laws as such and a fixed charge receivership can be run in parallel to a liquidation or an administration. However, an administrator may require a fixed charge receiver to vacate office unless that fixed charge receiver was appointed under a charge created or otherwise arising under a "financial collateral arrangement", as per Regulation 8(4) of the Financial Collateral Regulations (see "*Administration*" above).

The primary duty of a fixed charge receiver is to realize the assets over which (s)he is appointed, meaning (s)he owes an over-riding duty of care to the appointor, although certain limited duties are also owed to the chargor. This contrasts with the duty of an administrator, who performs his/her duties in the interests of a company's creditors as a whole. In other words, receivership is a proprietary remedy whereas administration is a collective procedure. In realizing the charged assets, the receiver will need to take reasonable care to obtain the best price obtainable in the circumstances. In doing so, the fixed charge receiver will be entitled to a statutory indemnity in respect of any liabilities from the realizations made of the assets of the company (and may also have the benefit of a contractual indemnity from the appointor).

To the extent the receiver has been appointed under a crystallized floating charge, amounts will be deducted from the proceeds of the realization of the charged assets to pay the Prescribed Part and any preferential creditors (see "*Priority on insolvency*" below).

Liquidation/winding up

Liquidation is a company dissolution procedure under which the assets of a company are realized and distributed by the liquidator to creditors and (if applicable) members in the statutory order of priority prescribed by the Insolvency Act. See "*—Priority on insolvency*." There are two forms of winding up: (i) compulsory liquidation, by order of the court; and (ii) members' voluntary liquidation or creditors' voluntary liquidation, in each case by resolution of the company's members. The difference between the two voluntary proceedings is the solvency of the company in question; in a members' voluntary liquidation, the directors of the company swear a statutory declaration as to the company's solvency over the following 12 months whereas the primary ground for the creditors' voluntary liquidation of an insolvent company is that it is unable to pay its debts (as defined in Section 123 of the Insolvency Act – see "*Administration*" above). Note that while a creditors' voluntary liquidation (other than as an exit from administration) is initiated by resolution of the members, not the creditors, once in place the process is subject to some degree of control by the creditors. Whereas compulsory liquidation and creditors' voluntary liquidation proceedings are available to foreign companies with sufficient nexus to the UK in addition to companies within the English courts' general jurisdiction (see "*Applicable legal framework and jurisdiction of the English courts*" above), members' voluntary liquidation proceedings are only available to companies registered in England, Wales or Scotland.

The effect of a compulsory winding up differs in a number of respects from that of a voluntary winding up. In a compulsory winding up, under Section 127 of the Insolvency Act, any disposition of the relevant company's property made after the commencement of the winding up is, unless sanctioned by the court, void. However, this will not apply to any property or security interest subject to a disposition or created or otherwise arising under a "financial collateral arrangement" under the Financial Collateral Regulations and will not prevent a close-out netting provision taking effect in accordance with its terms.

Subject to certain exceptions, when an order is made for the winding up of a company by the court, it is deemed to have commenced from the time of the presentation of the winding up petition. Once a winding up order is made by the court, a stay of all proceedings against the company will be imposed. No action or proceeding may be continued or commenced against the company without permission of the court and subject to such terms as the court may impose although there is no freeze on enforcement of security.

In the context of a voluntary winding up, however, there is no equivalent to the retrospective effect of a winding up order; the winding up commences on the passing of the resolution to wind up. As a result, there is no equivalent of Section 127 of the Insolvency Act. There is also no automatic stay of proceedings in the case of a voluntary winding up—it is for the liquidator, or any creditor or contributory of the company, to apply for a stay to prevent the continuation of legal proceedings and enforcement of security. As with a compulsory liquidation, this is important because it means secured creditors for example can go ahead and enforce their security.

A liquidator has the power to bring or defend legal proceedings on behalf of the company, to carry on the business of the company as far as it is necessary for its beneficial winding up, to sell the company's property and execute documents in the name of the company and to challenge antecedent transactions (see "*Avoidance of transactions*" below).

Priority on insolvency

One of the primary functions of winding-up (and, where the company cannot be rescued as a going concern, one of the possible functions of administration) under English law is to realize the assets of the company in question and distribute the proceeds from those assets to the company's creditors.

In accordance with the Insolvency Act and the Insolvency Rules, creditors are placed into different classes, with the proceeds from the realization of the insolvent company's property applied in descending order of priority, as set out below. With the exception of the Prescribed Part (as defined below), distributions generally cannot be made to a class of creditors until the claims of the creditors in a prior ranking class have been paid in full. Unless creditors have agreed otherwise with the company, distributions are made on a *pari passu* basis, that is, the assets are distributed in proportion to the debts due to each creditor within a class.

Contractual setting-off arrangements entered into after a company enters liquidation or administration are only respected to the extent they fall within the definition of "mutual dealing" as applied by the mandatory insolvency set-off regime. This regime sees an account being taken of what is due from each party to the other in respect of their mutual dealings, and only the resulting net balance is either provable by the creditor in the administration or liquidation of the company (if amounts remain due to the creditor) or, conversely, is payable by the creditor to the company (if amounts remain due to the company).

The general priority on insolvency is as follows (in descending order of priority):

- First ranking: holders of fixed charge security (but only to the extent the value of the secured assets covers that indebtedness) and parties with a proprietary interest in assets in the possession (but not under the full legal and beneficial ownership) of the debtor (but only with respect to the assets in which they have a proprietary interest);

- Second ranking: moratorium debts and priority pre-moratorium debts in respect of a moratorium under Part A1 of the U.K. Insolvency Act as well as, if applicable, any prescribed fees or expenses of the official receiver acting in any capacity in relation to the company (which will take priority over the moratorium debts and priority pre-moratorium debts). Where a company goes into administration, or proceedings for the winding-up of a company are begun, within 12 weeks of the end of a moratorium under Part A1 of the U.K. Insolvency Act, certain categories of debt must be paid in priority of all other claims (though this does not affect the rights or ranking in liquidation or administration, of creditors holding fixed charges, nor does it apply against any charge created or otherwise arising under a financial collateral arrangement within the meaning of the Financial Collateral Arrangements (No. 2) Regulations 2003). However, as the moratorium is not available to companies which are party to "capital market arrangements" where the debt incurred or expected to be incurred is at least £10 million (at any time during the life of the capital market arrangement) and the arrangement involves the issue of a capital market investment, details of such debts are omitted;

- Third ranking: expenses of the insolvent estate (there are statutory provisions setting out the order of priority in which expenses are paid);

- Fourth ranking: ordinary and secondary preferential creditors.

    - Ordinary preferential debts include (but are not limited to) debts owed by the insolvent company in relation to: (i) contributions to occupational and state pension schemes; (ii) wages and

salaries of employees for work done in the four months before the insolvency date, up to a maximum of £800 per person; (iii) holiday pay due to any employee whose contract has been terminated, whether the termination takes place before or after the insolvency date; and (iv) bank and building society deposits eligible for compensation under the Financial Services Compensation Scheme ("**FSCS**") up to the statutory limit. As between one another, ordinary preferential debts rank equally.

- Secondary preferential debts rank for payment after the discharge of the ordinary preferential debts. Such secondary preferential debts include: (a) bank and building deposits eligible for compensation under the FSCS to the extent that claims exceed the statutory limit and (b) claims by HMRC for taxes including VAT, PAYE income tax, employee NI contributions and Construction Industry Scheme deductions which are held by the company on behalf of employees and customers but excluding corporation tax and employers' NI contributions. As between one another, secondary preferential debts rank equally;

- Fifth ranking: holders of floating charge security, according to the priority of their security. This would include any security interest that was stated to be a fixed charge in the document that created it but which, on proper interpretation by the court, was rendered a floating charge. However, before distributing asset realizations to the holders of floating charges, the Prescribed Part (as defined below) must, subject to certain exceptions, be set aside for distribution to unsecured creditors;

- Sixth ranking:

  - firstly, provable debts of unsecured creditors and any secured creditor to the extent of any unsecured shortfall, in each case including accrued and unpaid interest on those debts up to the date of commencement of the relevant insolvency proceedings. To pay the secured creditors any unsecured shortfall, the insolvency officeholder can only use realizations from unsecured assets, as secured creditors are not entitled to any distribution from the Prescribed Part unless the Prescribed Part is sufficient to pay out all unsecured creditors or the secured creditor elects to surrender its security;

  - secondly, interest on the company's debts (at the higher of the applicable contractual rate and the official rate) in respect of any period after the commencement of liquidation, or after the commencement of any administration which either preceded such liquidation or which had been converted into a distributing administration. However, in the case of interest accruing on amounts due under the Notes or the Note Guarantees, such interest due to the Noteholders may, if there are sufficient realizations from the secured assets, be discharged out of such security recoveries; and

  - thirdly, non-provable liabilities, being liabilities that do not fall within any of the categories above and therefore are only recovered in the (unusual) event that all categories above are fully paid. This does not include currency conversion claims; and

- Seventh ranking: shareholders. If after the repayment of all unsecured creditors in full, any remaining funds exist, these will be distributed to the shareholders of the insolvent company.

Subject to the above, subordinated creditors are ranked according to the terms of the subordination language in the relevant documentation (provided that such terms do not contravene the Insolvency Act or English common law).

Prescribed Part

An insolvency practitioner of the company (e.g. administrator, administrative receiver or liquidator) will generally be required to ring-fence a certain percentage of the proceeds of enforcement of floating charge security for the benefit of unsecured creditors (after making full provision for preferential creditors and expenses out of floating charge realizations) (the "**Prescribed Part**"). This ring-fence applies to (a) 50% of the first £10,000 of the company's net property and (b) 20% of the remainder of the company's net property over £10,000, with a maximum aggregate cap of £800,000 (except where the company's net property is available to be distributed to the holder of a first-ranking floating charge created before April 6, 2020, in which case the maximum aggregate

cap is £600,000). The Prescribed Part must be made available to unsecured creditors unless the cost of doing so would be disproportionate to the resulting benefit to creditors.

The Prescribed Part will not be available for any shortfall claims of secured creditors unless the Prescribed Part is sufficient to first pay out all unsecured creditors. The requirement of the insolvency officeholder to set aside a Prescribed Part will not apply to any charge created or otherwise arising under a financial collateral arrangement under the Financial Collateral Regulations.

Avoidance of transactions

There are circumstances under English insolvency law in which the granting by a company of guarantees or the entry by a company into a transaction can be challenged. In most cases, this will only arise if the company is placed into administration or liquidation within a specified period after the granting of the guarantee or the entry into the transaction. Therefore, if during the specified period an administrator or liquidator is appointed to an English company, the administrator or liquidator may challenge the validity of the guarantee given by such company or certain transactions entered into by the company.

The Company cannot be certain that, in the event that the onset of an English Company's insolvency (as described below) is within any of the requisite time periods, the grant of a guarantee in respect of the Notes would not be challenged or that a court would uphold the transaction as valid.

The potential grounds for challenge available under the English insolvency legislation that may apply to any guarantee granted by an English company include, without limitation, the following described below.

Transactions at an undervalue

Under English insolvency law, a liquidator or administrator could apply to the court for an order to set aside a guarantee (or grant other relief) where the creation of such guarantee constituted a transaction at an undervalue.

A transaction will only be a transaction at an undervalue if, at the time of the transaction or as a consequence of the transaction, the company is unable to pay its debts or becomes unable to pay its debts (as defined in Section 123 of the Insolvency Act). The transaction can be challenged if the onset of the company's insolvency (as described below) is within a period of two years from the date such company grants the guarantee. A transaction may be set aside as a transaction at an undervalue if the company made a gift to a person, if the company received no consideration or if the company received consideration of significantly less value, in money or money's worth, than the consideration given by such company. However, a court shall not make an order if it is satisfied that a company entered into the transaction in good faith for the purpose of carrying on its business and at the time it did so there were reasonable grounds for believing the transaction would benefit such company. In any proceedings, it is for the administrator or liquidator to demonstrate that the company was unable to pay its debts except where the relevant transaction at an undervalue was made with a connected person (as described below), in which case there is a presumption that the company was insolvent at the time unless it can be shown otherwise by the connected person.

If the court determines that the transaction was a transaction at an undervalue, the court shall make such order as it thinks fit to restore the company to the position it would have been in had it not entered into the transaction, which may include reducing payments due under the guarantees or setting aside guarantees.

An order by the court for a transaction at an undervalue may affect the property of, or impose any obligation on, any person whether or not they are the person with whom the company entered into the transaction, but such an order will not prejudice any interest in property which was acquired from a person other than the company in good faith and for value or prejudice any interest deriving from such an interest, and will not require a person who received a benefit from the transaction in good faith and for value to pay a sum to the liquidator or administrator of the company, except where the person was a party to the transaction.

Preference

Under English insolvency law, a liquidator or administrator could apply to the court for an order to set aside payments or a guarantee (or grant other relief) where such payment or guarantee constituted a preference.

A transaction will only be a preference if, at the time of the transaction or in consequence of the transaction, the company is unable to pay its debts or becomes unable to pay its debts (as defined in Section 123 of the Insolvency Act). The transaction can be challenged if the company enters into insolvency within a period of six months (if the beneficiary of the guarantee is not a connected person) or two years (if the beneficiary is a connected person, except where such beneficiary is a connected person by reason only of being the company's employee) from the date the company grants the guarantee. A transaction may constitute a preference if a transaction has the effect of putting a creditor of the company (or a surety or guarantor of any of the company's debts or liabilities) in a better position (in the event of the company going into insolvent liquidation) than such creditor, guarantor or surety would otherwise have been in had that transaction not been entered into. However, a court shall not make an order unless the company which entered into the transaction was influenced by a desire to produce a preferential position in relation to that person when taking their decision. This provision of English insolvency law may affect transactions entered into or payments made by any of the Guarantors during the relevant period prior to the Guarantor's liquidation or administration.

In any proceedings, it is for the administrator or liquidator to demonstrate that the company was unable to pay its debts at the relevant time and that there was such desire to prefer the relevant creditor. If, however, the beneficiary of the transaction was a connected person (except where such beneficiary is a connected person by reason only of being the company's employee), it is presumed that the company intended to put that person in a better position and the connected person must demonstrate that there was, in fact, no such desire, on the part of the company, to prefer them.

If the court determines that the transaction was a preference, the court shall make such order as it sees fit to restore the company to the position it would have been in had it not entered into the transaction, which may include reducing payment due under or setting aside guarantees. An order by the court for a preference may affect the property of, or impose any obligation on, any person whether or not he is the person to whom the preference was given, but such an order will not prejudice any interest in property which was acquired from a person other than the company in good faith and for value, or prejudice any interest deriving from such an interest, and will not require a person who received a benefit from the preference in good faith and for value to pay a sum to the liquidator or administrator of the company, except where the payment is to be in respect of a preference given to that person at a time when he was a creditor of the company.

Onset of insolvency

The date of the onset of insolvency, for the purposes of transactions at an undervalue and preferences (as discussed above), depends on the insolvency procedure in question.

In administration, the onset of insolvency is the date on which: (a) the court application for an administration order is issued; (b) the notice of intention to appoint an administrator is filed at court; or (c) otherwise, the date on which the appointment of an administrator takes effect.

In a compulsory liquidation the onset of insolvency is the date the winding-up petition is presented to court, whereas in a voluntary liquidation it is the date the company passes a winding-up resolution. Where liquidation follows administration, the onset of insolvency will be the same as the initial administration.

Connected persons

If the given transaction at an undervalue or preference has been entered into by the company with a "connected person," then particular specified time periods and presumptions will apply to any challenge by an administrator or liquidator (as set out above).

A connected person of a company granting a security interest or guarantee for the purposes of transactions at an undervalue and preferences is a party who is: (a) a director of the company; (b) shadow director; (c) an associate of such director or shadow director; or (d) an associate of the relevant company.

A party is associated with an individual if they are: (a) a relative of the individual; (b) the individual's husband, wife or civil partner; (c) a relative of the individual's husband, wife or civil partner; (d) the husband, wife or civil partner of a relative of the individual; or (e) the husband, wife or civil partner of a relative of the individual's husband, wife or civil partner. A party is associated with a company if employed by that company. A person is an associate of any person with whom they are in partnership, and of the husband, wife or civil partner or a relative of any individual with whom they are in partnership.

A company is associated with another company if the same person has control of both companies, or a person has control of one and persons who are his associates, or he and persons who are his associates, have control of the other, or if a group of two or more persons has control of each company, and the groups either consist of the same persons or could be regarded as consisting of the same persons by treating (in one or more cases) a member of either group as replaced by a person of whom he is an associate.

A person is to be taken as having control of a company if the directors of the company or of another company which has control of it (or any of them) are accustomed to act in accordance with his directions or instructions, or he is entitled to exercise, or control the exercise of, one third or more of the voting power at any general meeting of the company or of another company which has control of it. Where two or more persons together satisfy either of these conditions, they are to be taken as having control of the company.

Transactions defrauding creditors

Under English insolvency law, where a transaction was at an undervalue and the court is satisfied that it was made for the substantial purpose of putting assets beyond the reach of a person who is making, or may make, a claim against that company, or of otherwise prejudicing the interests of a person in relation to the claim which that person is making or may make, then the transaction may be set aside by the court as a transaction defrauding creditors. Any person who is a "victim" of the transaction (with the leave of the court if the company is in liquidation or administration), and not just liquidators or administrators, may assert such a claim. Subject to certain conditions, this provision may also be used by the U.K. Financial Conduct Authority and the U.K. Pensions Regulator. There is no statutory time limit within which a claim must be made (subject to the normal statutory limitation periods) and the relevant company need not be insolvent at the time of, or as result of, the transaction.

If the court determines that the transaction was a transaction defrauding creditors, the court may make such order as it thinks fit to restore the position to what it would have been if the transaction had not been entered into and to protect the interests of the victims of the transaction, which may include reducing payments due under the Notes or setting aside guarantees. The relevant court order may affect the property of, or impose any obligation on, any person, whether or not he is the person with whom the transaction was entered into. However, such an order will not prejudice any interest in property which was acquired from a person other than the debtor company in good faith, for value and without notice of the relevant circumstances, and will not require a person who received a benefit from such transaction in good faith, for value and without notice of the relevant circumstances to pay any sum to the liquidator or administrator of the company unless such person was a party to the transaction.

Extortionate credit transaction

An administrator or a liquidator can apply to court to set aside an extortionate credit transaction. The court can review extortionate credit transactions entered into by a company for up to three years ending with the day on which the company entered into administration or went into liquidation. A transaction is "extortionate" if, having regard to the risk accepted by the person providing the credit, the terms of it are (or were) such as to require grossly exorbitant payments to be made (whether unconditionally or in certain contingencies) in respect of the provision of the credit or it otherwise grossly contravened ordinary principles of fair dealing. It is presumed, unless otherwise proved by the person extending the credit, that a transaction with respect to which an administrator or liquidator makes an application to set aside an extortionate credit transaction is extortionate. That order may set aside, either in whole or in part, any obligation created by the transaction. It may also vary the terms of the transaction for the purposes of the transaction. The court may require any party to the transaction to repay the liquidator or administrator sums already paid under the transaction.

Limitation on enforcement

Constitutional documents, corporate benefit and financial assistance

The grant of a Guarantee by any of the English Companies in respect of the obligations of another group company must satisfy certain legal requirements. More specifically, such a transaction must be allowed by the respective company's memorandum and articles of association. To the extent that these documents do not allow such an action, there is the risk that the grant of the guarantee can be found to be void and the respective creditor's rights unenforceable. Some comfort may be obtained for third parties if they are dealing with an English company in good faith; however, the relevant legislation is not without difficulties in its interpretation. Further, corporate benefit must be established for each English Company in question by virtue of entering into the proposed transaction. Section 172 of the Companies Act 2006 provides that a director must act in the way that he considers,

in good faith, would be most likely to promote the success of the company (as applicable) for the benefit of its members as a whole. If the directors enter into a transaction where there is no or insufficient commercial benefit, they may be found as abusing their powers as directors and such a transaction may be vulnerable to being set aside by a court.

Section 172(3) of the Companies Act 2006 additionally provides that, in certain circumstances, the directors need to consider or act in the interests of the creditors of the company. While the statutory provisions do not prescribe when this shift arises, the UK Supreme Court has held that it takes place when the company in question is either insolvent or is bordering on insolvency, or an insolvent liquidation or administration is probable.

Notes Guarantees granted by an English Company may also be subject to potential limitations to the extent they would result in unlawful financial assistance contrary to English company law.

Foreign currency

Under English insolvency law, where creditors are asked to submit formal proofs of claim for their debts, any debt of a company payable in a currency other than pounds sterling (such as U.S. dollars in the case of the Notes) must be converted by the insolvency office-holder into pounds sterling at a single exchange rate for that currency determined by the insolvency office-holder by reference to the exchange rates prevailing on the relevant date. This provision overrides any agreement between the parties.

Accordingly, in the event of an English Company's liquidation or administration, the Noteholders may be subject to exchange rate risk between the relevant date on which such English Company goes into liquidation or administration and receipt of any amounts to which such the Noteholders may become entitled. Any losses resulting from currency fluctuations are not recoverable from the insolvent estate. If a creditor considers the rate to be unreasonable, they may apply to the court.

Moratoriums

As outlined above, certain of the insolvency processes available in England and Wales provide for the automatic or optional moratorium imposing a period of time during which third parties including creditors are unable to institute or continue legal action, enforce certain rights and/or call upon security or guarantees.

Besides the moratorium available to companies undergoing administration (see "*Administration*" above) or liquidation (see "*Liquidation/winding up*" above), a standalone moratorium procedure is also available under Part A1 of the Insolvency Act. The Part A1 moratorium process was introduced into the Insolvency Act from June 26, 2020. It is designed to allow a short moratorium of up to 40 business days to be obtained by companies in financial distress, without the need for creditor or court consent. Such moratorium prevents enforcement action by certain types of creditors in order to make a rescue viable, and can be extended to up to a year with creditor consent, or longer by court order. Note that the moratorium does not restrict enforcement or payment of debts due under contracts involving financial services.

The moratorium is a "debtor in possession" process which allows the company's management to remain in control of it during the process. This is overseen by an insolvency practitioner who is required to monitor the process. To be eligible for a moratorium, the company's management must certify that the company is, or is likely to become, unable to pay its debts. The insolvency practitioner, in its role as monitor, must also certify in its view that a moratorium would result in the company being rescued as a going concern.

However, companies are ineligible for the standalone moratorium if (among other exclusions) the company is party to an agreement which is or forms part of a "capital market arrangement" (including the grant of security or a guarantee) under which a party has incurred, or when the agreement was entered into was expected to incur, a debt of at least £10 million (at any time during the life of the capital market arrangement), where the arrangement involves the issue of a capital market investment. This includes, among other things, secured and unsecured debt that is rated, listed, traded (or designed to be rated, listed or traded), or bonds or commercial paper issued to certain professional, high net worth or sophisticated investors.

Restriction on the operation and exercise of ipso facto provisions

Recent changes to the Insolvency Act introduced a restriction on the operation and exercise of ipso facto clauses in order to preserve the continuity of the provision of goods and services to companies undergoing

insolvency procedures. In general terms, ipso facto clauses are provisions in supply of goods or services contracts which allow suppliers to terminate the contract or supply or take any other action, or provide for the automatic termination of the contract or supply or the occurrence of any other event, upon the counterparty entering an insolvency procedure. Under the new approach, to the extent that the trigger event is the counterparty's entry into a 'relevant insolvency procedure' (i.e. an administration, administrative receivership, company voluntary arrangement, liquidation and/or a restructuring plan), such clauses will be deemed void and suppliers will be unable to terminate the relevant contracts unless the company or the relevant office-holder consents to the termination or the court grants permission on the basis that it is satisfied that the continuation of the contract would cause the supplier hardship.

The restrictions do not apply to a range of contracts involving financial services or entities involved in the provision of financial services, including contracts for the provision of lending, financial leasing or guarantees, contracts for the purchase, sale or loan of securities or commodities and agreements which are, or form part of, arrangements involving the issue of a capital market investment (as defined in the Insolvency Act).

The Corporate Insolvency and Governance Act 2020 further confers on the U.K. government extensive powers to make a range of further amendment to corporate insolvency and governance legislation under delegated regulations. For example, regulations may be made to amend or modify the conditions that must be met before an insolvency procedure applies to certain entities, or the way in which the procedure applies, or to change or disapply a person's corporate duties and liabilities.

Company voluntary arrangements

A company voluntary arrangement is a procedure intended to allow companies to avoid potentially terminal insolvency proceedings and to address their financial difficulties by obtaining a binding agreement or compromise with their unsecured creditors. Although it does not result in the insolvency of a company, a company voluntary arrangement is implemented under the supervision of an insolvency practitioner who acts as the nominee before the company voluntary proposals are approved, and as the supervisor afterwards. A company voluntary arrangement may also be used as a tool alongside a formal insolvency procedure, such as administration, in order to implement a compromise between the debtor company and its creditors.

In order to propose a company voluntary arrangement, a company must either (i) fall within the English courts' general jurisdiction (see "*Applicable legal framework and jurisdiction of the English courts*" above); or (ii) be registered in England and Wales or Scotland; or (iii) be incorporated in an EEA state; or (iv) if not incorporated in an EEA state, have its COMI in the UK or an EU member state (other than Denmark).

Pursuant to Part I of the Insolvency Act, a company (by its directors or its administrator or liquidator as applicable) may propose a company voluntary arrangement to the company's shareholders and creditors which entails a compromise, or other arrangement, between the company and its creditors, typically a rescheduling or reducing of the company's debts. Provided that the proposal is approved by the requisite majority of creditors (by way of a decision procedure), it will bind all unsecured creditors who were entitled to vote on the proposal. A company voluntary arrangement cannot affect the right of a secured creditor to enforce its security, except with its consent. A company voluntary arrangement also cannot affect the rights of a preferential creditor to be paid in priority to non-preferential creditors, or to be paid on an unequal basis relative to other preferential creditors, except with its consent.

In order for the company voluntary arrangement proposal to be passed, it must be approved by at least 75% (by value) of the company's creditors who respond in the decision procedure, and no more than 50% (by value) of unconnected creditors may vote against it. A simple majority of the company's members must also have voted on the proposal. However, if the company's creditors approve the proposal, the company voluntary arrangement will be implemented notwithstanding a vote against by the members. Secured debt cannot be voted in a company voluntary arrangement. However, a secured creditor may vote to the extent that it is undersecured. A secured creditor who proves in the company voluntary arrangement for the whole of its debt may be deemed to have given up its security.

Unlike an administration proceeding, a company voluntary arrangement does not automatically trigger a moratorium of claims or proceedings.

Scheme of arrangement

Although not an insolvency proceeding, pursuant to Part 26 of the Companies Act 2006, the English courts have jurisdiction to sanction a scheme of arrangement that effects a compromise of a company's liabilities between a company and its creditors (or any class of its creditors). An English Company may be able to pursue a scheme in respect of their financial liabilities. In addition, a foreign company which is liable to be wound up under the Insolvency Act and has a "sufficient connection" to the English jurisdiction could also pursue a scheme. In practice, a foreign company is likely to satisfy the first limb of this test and the second limb has been found to be satisfied where, amongst other things, the company's COMI is in England, the company's finance documents are English law governed, or the company's finance documents have been amended in accordance with their terms to be governed by English law. Ultimately, each case will be considered on its particular facts and circumstances so previous cases will not necessarily determine whether or not any of the grounds of the second limb are satisfied in the present case.

Before the court in England considers the sanction of a scheme of arrangement at a hearing where the fairness and reasonableness of the scheme will be considered, affected creditors will vote on the proposed compromise or arrangement in respect of their claims in a single class or in a number of classes, depending on the rights of such creditors that will be affected by the proposed scheme and any new rights that such creditors are given under the scheme. Such compromise can be proposed by the company or its creditors. If a majority in number representing 75% or more by value of those creditors present and voting at the meeting(s) of each class of creditors vote in favor of the proposed scheme, irrespective of the terms and approval thresholds contained in the finance documents, then that scheme will (subject to the sanction of the court) be binding on all affected creditors, including those affected creditors who did not participate in the vote and those who voted against the scheme. The scheme then needs to be sanctioned by the court at a sanction hearing where the court will review the fairness of the scheme and consider whether it is reasonable. The court has the discretion as to whether to sanction the scheme as approved, make an order conditional upon modifications being made or reject the scheme. In exercising its discretion to sanction a scheme of a foreign company, the court will need to be satisfied that the scheme of arrangement would have substantial effect in the jurisdictions in which the company has its main assets or operations, in the jurisdictions of any other obligors of the debt and under the governing law the affected debt documents (if not English law). This is typically achieved by providing expert evidence that the scheme of arrangement (or its effect) is likely to be recognized in such jurisdictions. Once sanctioned, the scheme of arrangement binds all affected stakeholders whose rights will be as set out in the scheme of arrangement, which shall be effective (in accordance with its terms) upon delivery of the court's order sanctioning the scheme of arrangement to the Registrar of Companies.

Unlike an administration proceeding, the commencement of a scheme of arrangement does not automatically trigger a moratorium of claims or proceedings.

Restructuring plan

Like a scheme of arrangement, a restructuring plan is a procedure under the Companies Act 2006, namely Part 26A thereof, which allows the English courts to effect a compromise of a company's liabilities between a company and its creditors (or any class of its creditors), but with the added possibility of a 'cross-class cram-down'. While generally available to the same domestic and foreign companies as schemes of arrangement, a company seeking to enter into a restructuring plan process must show that (a) it has encountered, or is likely to encounter, financial difficulties that are affecting, or will or may affect, its ability to carry on business as a going concern, and (b) a compromise or arrangement has been proposed between the company and its creditors (or any class of them) for the purpose of eliminating, reducing or preventing, or mitigating the effect of, any of those financial difficulties.

A restructuring plan may be proposed by the debtor company, any creditor of the company or any liquidator or administrator appointed to the company. The consent of the company (or its insolvency officeholder) is required if the plan is proposed by a creditor or shareholder. As with a scheme of arrangement, affected creditors will vote on the proposed compromise or arrangement in respect of their claims in a single class or in a number of classes depending on the rights of such creditors which will be affected by the proposed restructuring plan and any new rights that such creditors are given under the restructuring plan. Unlike a scheme of arrangement, the court may order that a class of creditors or shareholders with no genuine economic interest in the company be excluded from voting on the restructuring plan but still bound by it if the court subsequently sanctions the restructuring plan.

A restructuring plan will be deemed to be approved if at least 75% in value of the creditors and/or members (if applicable) present and voting at the meeting of at least one class of creditors vote in favor of the proposed compromise. There is no requirement for the approving creditors to constitute a majority in number of those creditors present and voting, and there is crucially no requirement for each and every voting class to approve of the plan, provided that the court is satisfied that (a) none of the members of a dissenting class would be any worse off if the restructuring plan were to be sanctioned than they would be in the event of the 'relevant alternative' and (b) the restructuring plan was approved by at least one class of creditors who would receive a payment or have a genuine economic interest in the company in the event of the 'relevant alternative'. The 'relevant alternative' for the purposes of this assessment is whatever the court considers would be most likely to occur in relation to the company if the restructuring plan were not sanctioned. By virtue of these mechanics, the restructuring plan process provides for the possibility of a 'cross-class cram-down', meaning the courts may sanction a restructuring plan even if one or more classes of affected creditors do not vote in favor of the restructuring plan, effectively allowing the vote of one class of stakeholders to bind other classes.

Following approval of the restructuring plan at the creditor meeting(s), the restructuring plan needs to be sanctioned by the court at a sanction hearing where the court will review whether the applicable statutory conditions have been met and may also consider whether the restructuring plan is just and equitable. The court has discretion as to whether to sanction the restructuring plan as approved, make an order conditional upon modifications being made or refuse to sanction the restructuring plan. Once sanctioned, the restructuring plan binds all affected stakeholders whose rights will be as set out in the restructuring plan, which shall be effective (in accordance with its terms) upon delivery of the court's order sanctioning the restructuring plan to the Registrar of Companies or, where the company is an overseas company, publication of the court's order in the Gazette.

As with schemes of arrangement, the commencement of a restructuring plan process does not automatically trigger a moratorium of claims or proceedings.

Cross-border recognition of English insolvency and restructuring proceedings

General position

The recognition of English insolvency and restructuring proceedings in other jurisdictions is governed by applicable treaties in respect of the mutual recognition (or otherwise) of courts' jurisdiction, proceedings and judgments and general principles of private international law such as comity and conflicts of laws rules applicable in the relevant jurisdictions.

One of the key insolvency-related treaties is the UNCITRAL Model Law on Cross-Border Insolvency (the "**Model Law**"), which has been adopted in a number of jurisdictions, including the United States and the UK, where it was implemented by the Cross-Border Insolvency Regulations (and the Cross-Border Insolvency Regulations (Northern Ireland) 2006 (SI 2007/115) with respect to Northern Ireland). The Model Law provides for recognition of certain UK insolvency proceedings in other signatory states as either foreign main proceedings (if the COMI of the relevant debtor is determined to be in the UK) or foreign non-main proceedings (if the COMI is determined to be in another jurisdiction but the debtor has an establishment in the UK) upon application by the relevant insolvency officeholder. The nature and scope of recognition will depend on the way that the Model Law has been implemented into the domestic law of the jurisdiction in question. Conversely, the Cross-Border Insolvency Regulations provide for recognition in the UK of foreign insolvency proceedings as either main proceedings (if the proceedings are taking place in the jurisdiction where the debtor has its COMI) or non-main proceedings (if the proceedings are taking place in a jurisdiction in which the debtor has only an establishment).

The recognition of English courts' jurisdiction and orders in respect of schemes of arrangement, which are restructuring rather than insolvency proceedings, will be subject to treaties regarding matters relating to the jurisdiction of courts in civil proceedings and the enforcement of civil judgments such as (i) the Hague Convention on Choice of Court Agreements 2005 (the "**Hague Convention 2005**") and (ii) the Hague Convention of July 2, 2019 on the Recognition and Enforcement of Foreign Judgments in Civil or Commercial Matters (the "**Hague Convention 2019**"), which came into force on July 1, 2025 with respect to the United Kingdom and applies to judgments in proceedings commenced after that date. In addition, recognition may still be available under principles of private international law and Regulation (EC) No 593/2008 of the European Parliament and of the Council of June 17, 2008 on the law applicable to contractual obligations ("**Rome I**").

The recognition of English courts' jurisdiction and orders in respect of restructuring plans is a developing area of law. It remains to be seen whether restructuring plans will fall within the scope of treaties regarding matters

relating to the jurisdiction of courts in civil proceedings and the enforcement of civil judgments such as the Hague Convention 2005 and the Hague Convention 2019, or whether they will be treated more akin to insolvency and restructuring proceedings and fall within related exceptions to such treaties (the one case to date in which this point has been considered adopted the latter position with respect to the Lugano Convention, to which the United Kingdom has not acceded following its withdrawal from the European Union).

Recognition in the EU

Following the UK's departure from the EU and the expiry of the Transition Period, UK proceedings no longer benefit from automatic and guaranteed recognition in EU member states. As the trade and cooperation terms agreed between the EU and the UK do not include a replacement regime for the current automatic recognition of UK insolvency procedures across the EU (and vice versa) or otherwise address insolvency matters, cross-border insolvencies involving the UK and one or more EU member states will be subject to a degree of uncertainty and increased complexity.

Unless or until a mutual recognition agreement is reached in the future, it is likely to be more problematic for UK restructuring and insolvency proceedings to be recognized in EU member states and for UK office holders to effectively deal with assets located in EU member states. The general position outlined above will apply and recognition will depend on the private international law rules adopted in the relevant EU member state and the need may well arise to open parallel proceedings, increasing the element of risk as well as costs. In particular in cases where the appointment of a UK office holder is made in reliance on a UK domestic approach rather than COMI rules, it is much less certain that such appointment will be recognized in other EU member states. To the extent relevant proceedings are deemed to fall within the remit of contract law, Rome I may offer an alternative basis for recognition in EU member states.

As a consequence, the recognition of English insolvency and restructuring proceedings across the EU member states may be different from what investors may have experienced in the past when the UK was a member state of the EU. It is not possible to predict with certainty if and to what extent proceedings will be recognized and whether investors may be adversely affected as a result.

LISTING AND GENERAL INFORMATION

1. Application has been made to list the Notes on the Official List of the Luxembourg Stock Exchange and for admission to trading on the Euro MTF market thereof. There can be no assurance that such listing will be maintained. The Notes are only intended to be offered in the primary market to, and held by, investors who are particularly knowledgeable in investment matters.

2. The Company has obtained all necessary consents, approvals and authorizations in connection with the issue of the Notes and performance of the obligations under the Notes. The issue of the Notes was authorized by a resolution of the Board of Directors of the Company passed on April 19, 2026.

3. Notice to holders of the Notes will be published on the official website of the Exchange (luxse.com).

   For so long as the Notes are listed on the Exchange and the listing rules so require, copies of the following documents may be inspected and obtained, free of charge, at the specified office of the Company during normal business hours on any weekday (Saturdays, Sundays and public holidays excluded):

   - the organizational documents of the Company and the Guarantors;
   - the most recent Group Financial Statements published by the Company;
   - the Indenture (which includes the Guarantees and form of the Notes); and
   - the Guarantee Subordination Agreement.

   Application may also be made to the Exchange to have the Notes removed from listing on the Official List of the Luxembourg Stock Exchange, including if necessary to avoid any new withholding taxes in connection with the listing.

4. We accept responsibility for the information contained in these Listing Particulars. To the best of our knowledge, except as otherwise noted, the information contained in these Listing Particulars is in accordance with the facts and does not omit anything likely to affect the import of these Listing Particulars.

5. Neither we nor any of our subsidiaries is a party to any litigation that, in our judgment, is material in the context of the issue of the Notes, except as disclosed herein.

6. We will have appointed Deutsche Bank Trust Company Americas as our Principal Paying Agent and Transfer Agent in New York. We reserve the right to vary such appointment and shall publish notice of such change of appointment on the Luxembourg Stock Exchange's website. Information on the Luxembourg Stock Exchange's website does not form part of these Listing Particulars. The Principal Paying Agent will act as intermediary between the holders of the Notes and us so long as the Notes are listed on the Official List of the Luxembourg Stock Exchange.

7. The Notes have been accepted for clearance through the facilities of DTC. The Rule 144A Global Notes have a CUSIP of 29357J AF3 and the Regulation S Global Notes have a CUSIP of G315AP AM0. The Rule 144A Global Notes have an ISIN of US29357JAF30 and the Regulation S Global Notes have an ISIN of USG315APAM05.

8. The Company, which was formed on January 29, 2010, is incorporated as a public limited company under the laws of England and Wales with registered number 07140891. Both its registered office and its principal place of business are located at 2nd Floor, Charles House, 5-11 Regent Street, London SW1Y 4LR, United Kingdom and its telephone number is +44 20 7925 4900. The registered office of the Guarantors is located at 2nd Floor, Charles House, 5-11 Regent Street, London SW1Y 4LR, United Kingdom.

9. The Company's legal entity identifier (the "**LEI**") is 2138008LJU6WFQWOXJ73.

GLOSSARY

"**1P**"	Proved Reserves. Pursuant to the classifications and definitions provided by the PRMS, "Proved Reserves" is defined as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations
"**2C**"	best estimate scenario of Contingent Resources. Pursuant to the classifications and definitions provided by the PRMS, Contingent Resources are those quantities estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not currently considered to be commercially recoverable due to one or more contingencies. The 2C Resources represent the "best estimate" scenario; there is a probability of at least 50% that the amount actually recovered will equal or exceed the 2C estimate, in the event that the development project goes ahead
"**2P**"	Proved Reserves plus Probable Reserves. Pursuant to the classifications and definitions provided by the PRMS, "Proved Reserves" is defined as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations and "Probable Reserves" is defined as those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves; it is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved Reserves plus Probable Reserves (2P Reserves)
"**3D seismic**"	geophysical data that depicts the subsurface strata in three dimensions
"**4D seismic**"	geophysical data that involves comparing the results of 3D seismic surveys at different times in the life of an oil and/or gas field
"**accumulation**"	an individual body of moveable petroleum. A known accumulation (one determined to contain Reserves or Contingent Resources) must have been penetrated by a well
"**API**"	American Petroleum Institute

"**API gravity**"	a measure of density based on density of oil at 15.6 degrees Celsius
"**appraisal well**"	well drilled to assess characteristics (such as flow rate or volume) of a proven hydrocarbon accumulation
"**Atlantic Margins**"	a passive margin which lies within a plate at the boundary between continental and oceanic crust
"**back-in rights**"	a reversionary interest in a lease which entitles a party to a specified share of the working interest when the assignee has recovered specified costs from production
"**barrel**" **or** "**b**" **or** "**bbl**"	a stock tank barrel, a standard measure of volume for oil, condensate and natural gas liquids, which equals 42 U.S. gallons
"**bcpd**"	barrels of condensate per day
"**bcf**"	billions of cubic feet
"**bcm**"	billions of cubic meters
"**block**"	a designated area of 250 square kilometers or a subpart thereof, comprising one-thirtieth of a quadrant
"**boe**"	barrels of oil equivalent
"**boepd**"	barrels of oil equivalent per day
"**bopd**"	barrels of oil per day
"**Brent**"	a particular type of crude oil that is a light, sweet oil produced in the North Sea with most of it being refined in Northwest Europe. Brent is a benchmark oil
"**Bscf**"	billions of cubic feet at standard conditions
"**burner tip**"	the physical point at which natural gas is consumed
"**bwpd**"	barrels of water per day

"**CALM Buoy**"	a Catenary Anchor Leg Mooring (CALM) buoy is a description of how the buoyed platform is anchored to the seabed. CALM Buoys can be used offshore in deep water to allow ships to offload or load liquid cargo (*e.g.*, crude oil) without the need for a jetty extension into the deeper water
"**christmas tree**"	an assembly of valves, spools and fittings used for both surface and subsea oil, gas and water injection wells to control the flow out of the wells
"**crude oil**"	unrefined oil
"**Contingent Resources**"	those quantities of oil and gas estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies
"**Dated Brent**"	a cargo of Brent that has been assigned a date when it will be loaded onto a tanker
"**ESP well**"	an electrical submersible pump well
"**exploration well**"	a well drilled to find hydrocarbons in an unproved area or to extend significantly a known oil or natural gas reservoir
"**farm-down**" **or** "**farm-out**"	to assign an interest in a license to another party
"**farm-in**"	to acquire an interest in a license from another party
"**field**"	an area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition
"**formation**"	a body of rock that is sufficiently distinctive and continuous that it can be mapped
"**FPSO**"	a floating production, storage and offloading vessel used by the offshore oil and gas industry for the processing of hydrocarbons and for storage of oil
"**FSO**"	a floating storage and offloading vessel used only to store and offload oil (and not process it)
"**FTG survey**"	full tensor gradiometry gravity survey

"**Full Tensor Gradiometry**"	a method of measuring the density of the subsurface to detect subsurface anomalies, which can then be used to more accurately locate oil, gas and mineral deposits
"**heavy crude**"	crude oil that generally has an API gravity of 22 degrees or less
"**hub-class commercial discovery**"	smaller oil and gas field discoveries within a region that, individually, would not be economically feasible to develop, but when aggregated reach a commercial development threshold
"**hydrocarbons**"	compounds formed primarily from the elements hydrogen and carbon and existing in solid, liquid or gaseous forms
"**ICE Brent**"	a futures contract for Brent based on delivery with an option to cash settle
"**kb/d**"	thousand barrels per day
"**kboepd**"	thousand barrels of oil equivalent per day
"**lifting**"	the process of loading a tanker with oil or otherwise transporting production from a production site to a terminal or place of sale
"**light crude**"	crude that generally has an API gravity of 38 degrees or more
"**liquid fuels**"	all petroleum, which includes crude oil and products of petroleum refining, natural gas liquids, biofuels and liquids derived from other hydrocarbon sources but does not include LNG and liquid hydrogen
"**LNG**"	liquefied natural gas
"**LPG**"	liquefied petroleum gas
"**mb/d**"	thousand barrels per day
"**mcm/d**"	million cubic meters per day
"**MMbbl**"	million barrels of oil
"**MMbblpd**"	million barrels of oil per day

"**MMboe**"	million barrels of oil equivalent
"**MMBtu**"	million British thermal units
"**NGL**"	natural gas liquids
"**OIP**"	the amount of crude first estimated to be in a reservoir. Oil in place differs from oil reserves, as OIP refers to the total amount of oil that is potentially in a reservoir and not the amount of oil that can be recovered
"**overlift**"	oil lifted at a field by a commercial partner at the balance sheet date that exceeds such partner's working interest in such field
"**play**"	a project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in an effort to define specific leads or prospects
"**Possible Reserves**"	those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves
"**PRMS**"	the Petroleum Resources Management System
"**Probable Reserves**"	those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves
"**production**"	the cumulative quantity of oil and gas that has been recovered at a given date
"**production well**"	a well drilled to obtain production from a proven oil or gas field. Production wells may be used either to extract hydrocarbons from a field or to inject water or gas into a reservoir to improve production
"**prospect**"	a project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target
"**Proved Reserves**"	are those quantities of oil and gas, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations

"**PSC**"	production sharing contracts
"**P&A**"	plugging and abandonment
"**quadrant**"	a designated area of one degree longitude by one degree latitude
"**Recovery Factor**"	is the recoverable amount of hydrocarbon initially in place, normally expressed as a percentage. The recovery factor is a function of the displacement mechanism. An important objective of enhanced oil recovery is to increase the Recovery Factor
"**reserve life**"	the quotient of dividing volume of reserves as of a given date by the volume of production during a given period
"**reserve-replacement ratio**"	the quotient of dividing the volume of 2P Reserves added during a given period by the volume produced during that period
"**Reserves**"	are those quantities of petroleum anticipated commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions
"**reservoir**"	a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. A reservoir is a critical component of a complete oil and gas system
"**Resources**"	are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects but which are not then considered to be commercially recoverable due to one or more contingencies
"**Russian Export Blend**"	a medium, sour crude oil with an API gravity of approximately 32 and a sulfur content of approximately 1.2%, the Russian benchmark blend
"**seal**"	a relatively impermeable rock, commonly shale, anhydrite or salt that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir. A seal is a critical component of a complete oil and gas system

"**seismic survey**"	a method by which an image of the earth's subsurface is created through the generation of shockwaves and analysis of their reflection from rock strata. Such surveys can be done in two, three or four dimensional form. See "*3D seismic*" and "*4D seismic*"
"**single point mooring**".....	a loading buoy anchored offshore that serves as a mooring point and interconnect for tankers loading or offloading gas or liquid products
"**SPE**"	the Society of Petroleum Engineers
"**SPEE**".....	the Society of Petroleum Evaluation Engineers
"**subsea manifold**"	a large metal piece of equipment, made up of pipes and valves and designed to transfer oil or gas from wellheads into a pipeline
"**Tscf**"	trillion standard cubic feet (gas volume)
"**underlift**".....	oil lifted at a field by a commercial partner at the balance sheet date that is less than its working interest in such field
"**upstream**".....	activities related to the exploration, appraisal, development and extraction of crude oil, condensate and gas
"**wellhead**".....	all connections, valves, nozzles, pressure gauges, thermometers, installed at the exits from a production well
"**West Texas Intermediate**"	a light, sweet crude oil with an API gravity of approximately 40 and a sulfur content of approximately 0.3%, the U.S. benchmark blend
"**wildcat**"	wells drilled outside of and not in the vicinity of known oil or gas fields
"**workover**"	refers to any kind of oil well intervention involving invasive techniques, such as repairing lines and casing or removing sand build up

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Independent auditor's report

Report on the audit of the financial statements

1. Opinion

In our opinion :

- the financial statements of EnQuest PLC (the 'parent company') and its subsidiaries (the 'Group') give a true and fair view of the state of the Group's and of the parent company's affairs as at 31 December 2025 and of the Group's profit for the year then ended;
- the Group financial statements have been properly prepared in accordance with United Kingdom adopted international accounting standards;
- the parent company financial statements have been properly prepared in accordance with United Kingdom Generally Accepted Accounting Practice, including Financial Reporting Standard 101 *Reduced Disclosure Framework*; and
- the financial statements have been prepared in accordance with the requirements of the Companies Act 2006.

We have audited the financial statements which comprise:

- the Group Income Statement;
- the Group Balance Sheet;
- the Group Statement of Changes in Equity;
- the Group Statement of Cash Flows;
- the related notes 1 to 31 to the Group financial statements;
- the parent company Balance Sheet;
- the parent company Statement of Changes in Equity; and
- the related notes 1 to 13 to the parent company financial statements

The financial reporting framework that has been applied in the preparation of the Group financial statements is applicable law and United Kingdom adopted international accounting standards. The financial reporting framework that has been applied in the preparation of the parent company financial statements is applicable law and United Kingdom Accounting Standards, including FRS 101 "Reduced Disclosure Framework" (United Kingdom Generally Accepted Accounting Practice).

2. Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)) and applicable law. Our responsibilities under those standards are further described in the auditor's responsibilities for the audit of the financial statements section of our report.

We are independent of the Group and the parent company in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the Financial Reporting Council's (the 'FRC's') Ethical Standard as applied to listed public interest entities, and we have fulfilled our other ethical responsibilities in accordance with these requirements. The non-audit services provided to the Group and parent company for the year are disclosed in note 4(f) to the financial statements. We confirm that we have not provided any non-audit services prohibited by the FRC's Ethical Standard to the Group or the parent company.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

3. Summary of our audit approach

Key audit matters	The key audit matters that we identified in the current year were: • Valuation of oil and gas related assets and liabilities • Valuation of decommissioning liability Within this report, key audit matters are identified as follows: Newly identified Increased level of risk Similar level of risk Decreased level of risk
Materiality	The materiality that we used for the Group financial statements was $16.8m which was determined on the basis of 3.3% of adjusted EBITDA (the Group have presented a reconciliation of profit from operations before tax and finance costs to adjusted EBITDA in the glossary to the financial statements on page 192).
Scoping	EnQuest PLC has three components, being the North Sea, Malaysia and Vietnam. They account for 100% of the Group's revenue, 100% of its adjusted EBITDA and 100% of its net assets, therefore account balances of all components were scoped in.
Significant changes in our approach	During the current year, our Group audit scope was expanded to include the newly acquired Vietnam business as a material component, with the results of this component subject to a full scope audit by a component team based in Vietnam.

4. Conclusions relating to going concern

In auditing the financial statements, we have concluded that the Directors' use of the going concern basis of accounting in the preparation of the financial statements is appropriate.

Our evaluation of the Directors' assessment of the Group's and parent company's ability to continue to adopt the going concern basis of accounting included:

- assessing the reasonableness of the assumptions used in the cash flow forecasts, in particular commodity prices, production profiles and cash costs, by comparison to those used in the Group's impairment tests, as outlined in section 5.1, and obtaining an understanding of any differences
- assessing the historical accuracy of forecasts prepared by management across production, operating expenditure and capital expenditure;
- considering whether the going concern period considered by the Directors, being 12 months from the date of approval of the financial statements, is appropriate and takes into consideration the maturity of the Group's bonds in the 4th quarter of 2027;
- assessing the financing facilities throughout the going concern period, including repayment terms and financial covenants;
- considering the levels of cash and covenant headroom throughout the going concern period, including sensitivity analysis and reverse stress testing;
- assessing the mathematical accuracy of the forecasts and the going concern model; and
- assessing the appropriateness of the Group's and parent company's going concern related financial statement disclosures.

Based on the work we have performed, we have not identified any material uncertainties relating to events or conditions that, individually or collectively, may cast significant doubt on the Group's and parent company's ability to continue as a going concern for a period of at least twelve months from when the financial statements are authorised for issue.

In relation to the reporting on how the Group has applied the UK Corporate Governance Code, we have nothing material to add or draw attention to in relation to the Directors' statement in the financial statements about whether the Directors considered it appropriate to adopt the going concern basis of accounting.

Our responsibilities and the responsibilities of the Directors with respect to going concern are described in the relevant sections of this report.

5. Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial statements of the current period and include the most significant assessed risks of material misstatement (whether or not due to fraud) that we identified. These matters included those which had the greatest effect on: the overall audit strategy; the allocation of resources in the audit; and directing the efforts of the engagement team.

These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

5.1. Valuation of oil and gas related assets and liabilities

Key audit matter description

The Group is required to assess the carrying value of oil and gas related assets and liabilities, in line with the relevant accounting standard, at each balance sheet date. In order to appropriately value these assets and liabilities, management is required to forecast future cash flows. These forecast cash flows are used consistently across the:

- Impairment assessment of oil and gas assets;
- Impairment assessment of goodwill;
- Impairment assessment of the parent company investments; and
- Valuation of the deferred tax asset.

The forecast future cash flows contain a high level of management judgement and estimation, particularly in relation to the following significant assumptions:

- Forecast commodity prices;
- Discount rate applied; and
- Reserve estimates and production profiles.

Commodity prices, reserve estimates and production profiles are also impacted by climate-related risks, which increases the level of estimation uncertainty.

Given the level of management judgement and estimation applied in determining the recoverable value of the oil and gas related assets and liabilities, including estimation uncertainty within the significant assumptions outlined above, we consider this to be a key audit matter related to the potential risk of fraud. Our work in this area in respect of the Group was focused on the oil and gas related assets in the North Sea, as these represent 90% of the Group's property, plant and equipment and goodwill.

Impairment assessment of oil and gas assets, goodwill and parent company investments

The Group has performed an impairment assessment for oil and gas assets and goodwill carrying value, by reference to IAS 36 *Impairment of Assets*. As at 31 December 2025, the net book value of property, plant and equipment, which primarily relates to oil and gas assets, was $2,370 million (2024: $2,298 million) and the Group has recorded a pre-tax impairment reversal of $6 million (2024: impairment charge of $71 million) against certain oil and gas assets, including related right of use assets, as disclosed in note 9.

As at 31 December 2025, the net book value of goodwill was $140 million (2024: $134 million) with the increase in the year relating to the acquisition of Block 12W in Vietnam, as disclosed in note 10. No goodwill impairment charge has been recorded in 2025 (2024: nil).

The Group has also performed an assessment of the carrying value of the parent company's investment in subsidiaries by reference to IAS 36 *Impairment of Assets* and IFRS 9 *Financial Instruments*. As at 31 December 2025, the net book value of investments recognised in the parent company balance sheet was $374 million (2024: $372 million) and an impairment reversal of $2 million (2024: $71 million) has been recorded, as disclosed in note 3 of the parent company financial statements.

In 2025, revisions were made to the key assumptions used in impairment tests for oil and gas assets. These revisions included updated oil and gas price assumptions and a change in the Group's post-tax discount rate for these assets from 10% to 9% compared to the prior year. Further details of these assumptions are set out in Note 2.

Valuation of Magnus contingent consideration

The Magnus contingent consideration was valued at $60 million as at 31 December 2025 (2024: $451 million), resulting in a pre-tax gain of $391 million being recognised. In previous years the valuation was based on the estimated future cash flows of the Magnus oil and gas asset. In the current year the valuation was based on the price agreed with bp plc of $60 million to settle this profit share arrangement, in line with IFRS 13 *Fair Value Measurements*. As this agreement was not finalised until February 2026, judgement was applied by the Directors in concluding that all key terms of the settlement agreement had been finalised with bp prior to year end and hence that the settlement price represented the fair value of the arrangement as of 31 December 2025. Further details of this judgement are provided in note 2 and note 21.

Valuation of the deferred tax asset

As at 31 December 2025, a deferred tax asset of $271 million (2024: $506 million) was recognised, in line with IAS 12 *Income Taxes*, and based on expected utilisation of both historical tax losses, underpinned by forecasts of future profits, and other temporary differences including that relating to the Magnus contingent consideration arrangement outlined above. The forecast cash flows used to value the deferred tax asset are consistent with the cash flows used for impairment purposes. Further details of the deferred tax asset are disclosed in note 6(c).

Given the interrelated nature of the key areas noted above, management have applied consistent assumptions across all of these valuations where appropriate.

Further details on this matter have been disclosed in the audit committee report on page 103 to 108 and in the "critical accounting judgements and key sources of estimation uncertainty" section of note 2.

5.1. Valuation of oil and gas related assets and liabilities continued

How the scope of our audit responded to the key audit matter

Our procedures comprised the following:

Procedures on internal controls, valuation models and disclosures

- obtaining an understanding of relevant controls over management's process for identifying indicators of impairment and for performing their impairment assessment and related valuations;
- assessing management's forecasting accuracy through a retrospective review of previous forecasts;
- assessing whether forecast cash flows were consistent with board approved forecasts and budgets, and forecasts used elsewhere, including for going concern and viability purposes;
- assessing, with input from our tax specialists, whether the models appropriately incorporate tax cash flows;
- working with our modelling specialists to evaluate the arithmetical accuracy of the models;
- challenging management's determination of oil and gas cash generating units for impairment purposes, in comparison to the requirements of IAS 36;
- assessing the reasonableness of the various valuations on an aggregate basis, as part of our stand-back procedures;
- evaluating compliance with the relevant accounting standards, including IAS 12 *Income Taxes*, IAS 36 *Impairment of Assets* and IFRS 13 *Fair Value Measurements*; and
- evaluating the adequacy of management's disclosures in relation to impairment and related valuations, including related sensitivity analyses and climate-related disclosures.

Procedures related to the key assumptions used for valuation purposes

Our procedures related to the key assumptions in this key audit matter are:

Forecast commodity prices

- assessing the appropriateness of management's forecast commodity prices, through benchmarking against forward curves, peer information, market data and climate aligned price scenarios;
- performing sensitivity analysis on the pricing assumptions to determine the impact on the valuation conclusions of reasonably possible changes;
- evaluating whether management's pricing assumptions have adequately considered the impact of the risk of lower oil and gas demand due to climate change; and
- assessing future commodity price differentials applied relative to observed differentials experienced from liftings from 2025.

Discount rate

- evaluating, with input from our valuations specialists, the Group's discount rates used in impairment tests and valuations;
- comparing to discount rates of peer UK Continental Shelf upstream companies; and
- assessing whether country risks are appropriately reflected in the Group's discount rates.

Reserves estimates and production profiles

- comparing management's reserves estimates and production profiles to those of their independent reserves expert;
- assessing the technical competence, capabilities and objectivity of management's internal and external experts;
- evaluating, with involvement from our oil and gas reserves specialist, the reasonableness of reserves estimates and production profiles; and
- working with our oil and gas reserves specialist to challenge management on significant changes in the reserves estimates and production profiles.

Magnus contingent consideration valuation

Our audit procedures to challenge management's judgment that the year end fair value was equal to the post-year-end settlement price included:

- obtaining and evaluating evidence of the status of negotiations with bp plc as at 31 December 2025, including reading the latest draft of the settlement agreement at that date and related correspondence with bp plc;
- understanding the extent and significance of changes made to the draft settlement agreement subsequent to year end, based on discussions with the Directors and a comparison to the terms in the final agreement;
- assessing whether the significant difference between the settlement price and previous cash flow forecasts for the Magnus oil and gas asset has any impact on the reliability of the cash flow forecasts used in the impairment test for this asset.

5.1. Valuation of oil and gas related assets and liabilities continued

Key observations

We are satisfied with the Group's conclusions in respect of the valuation of oil and gas related assets and liabilities, including the reversal of impairment and the fair value gain recognised in respect of the Magnus consideration arrangement.

In reaching this conclusion, we observed that:

- Future commodity price assumptions are within our acceptable range for all years;
- Impairment discount rates are within the independent range calculated by our valuations specialist;
- Reserves estimates and production profiles were concluded as reasonable, based on estimates from management's reserves expert;
- The carrying value of the investment in subsidiaries, including the related impairment reversal, is reasonable;
- The carrying value of the Magnus contingent consideration is within a reasonable range; and
- The deferred tax asset recognition is appropriate and the carrying value is a reasonable estimate.

We are also satisfied that the disclosures in the financial statements are appropriate.

5.2. Valuation of decommissioning liability

Key audit matter description

The Group is required by law to decommission the oil and gas assets and associated infrastructure at the end of their operating life. An estimate of the future cost of decommissioning is required to be provided for in accordance with IAS 37 *'Provisions, Contingent Liabilities and Contingent Assets'*.

The decommissioning provision at 31 December 2025 is $931 million (2024: $760 million). The provision represents the present value of decommissioning costs which are expected to be incurred during the decommissioning period, which is assumed to run to 2050, assuming no further development of the Group's assets. Further details on the key sources of estimation uncertainty underpinning the valuation of decommissioning provisions can be found in Note 2. We consider this to be a key audit matter related to the potential risk of fraud.

Decommissioning liabilities are inherently judgemental areas, particularly in relation to cost estimates and the related assumptions. The key management estimates containing the most estimation uncertainty, and therefore the focus of our key audit matter, are:

- internal well cost estimates included in the decommissioning model in respect of oil and gas assets operated by the Group;
- the extent to which management's estimates for non-operated oil and gas assets should be aligned with the latest estimates provided by the operator; and
- discount rate applied, calculated as a risk-free rate using an average of year-end 5-, 10- and 20-year UK Gilts, weighted to reflect the expected timing profile of future decommissioning spend.

The Group maintained the discount rate used in calculating its decommissioning provisions at 4.5% as at 31 December 2025.

In deriving its cost estimates the Group used internal and external experts, including its own in-house engineering team as well as, for certain elements of the cost estimate, an external engineering firm.

Further details on this matter have been disclosed in the audit committee report on page 103 to 108 and in note 22.

5.2. Valuation of decommissioning liability continued

How the scope of our audit responded to the key audit matter

Our procedures comprised the following:

Procedures on internal controls, the decommissioning model and disclosures

- obtaining an understanding of the relevant controls relating to the decommissioning provision;
- assessing the technical competence, capabilities and objectivity of management's internal and external experts;
- assessing the decommissioning provision for compliance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*;
- working with our modelling specialists to evaluate the arithmetical accuracy of the decommissioning model;
- assessing available benchmarking reports for indications of developments in industry practice and prevailing cost trends;
- challenging the cost reduction factors applied to the decommissioning model, through comparison with available evidence for the factors applied including industry benchmarking reports;
- testing a sample of actual decommissioning spend incurred during the period, by agreeing to invoices and payments from bank statements;
- assessing the historical forecasting accuracy of management for decommissioning expenditure, by comparing actual spend with historical estimates;
- re-calculating the closing decommissioning provision from the gross decommissioning cost estimate, and agreeing this to the Group's financial records; and
- evaluating the adequacy of the Group's disclosures, including the key sources of estimation uncertainty and associated sensitivity analysis of decommissioning assumptions.

Procedures on cost estimates and related assumptions

Internal well cost estimates

- challenging the Group's assumptions within the cost estimate by comparing to available third-party data and benchmarking to industry publications, peer and market rates; and
- assessing the assumed durations for plug and abandonment of wells, by comparison to available benchmarking data and potential contradictory evidence available from active decommissioning projects or other operator estimates.

Estimates for non-operated oil and gas assets

- comparing management's estimates for non-operated assets to those of the most recent operator estimate; and
- to the extent management's estimates are significantly different, understanding the basis for this difference and the evidence available to either corroborate or contradict management's estimate, including comparison to industry publications, market data and evidence available from active decommissioning projects.

Discount rate

- evaluating the Group's discount rates used in valuing the decommissioning liability with reference to external risk free market rates; and
- recalculating the discount rate by agreeing key inputs, being the year-end 5, 10- and 20-year UK Gilt rates and expected timing profile of future decommissioning spend, to supporting evidence and confirming the calculations are applied in accordance with the method and are mathematically accurate.

Key observations

We are satisfied that the Group's decommissioning provision is reasonable and prepared in accordance with the requirements of IAS 37 Provisions, Contingent Liabilities and Contingent Assets.

In reaching this conclusion we observed that:

- The key assumptions within the well cost estimates for operated oil and gas assets are reasonable;
- The estimates used for non-operated oil and gas assets are not materially misstated; and
- The decommissioning discount rate is reasonable.

We are also satisfied the disclosures in the financial statements are appropriate.

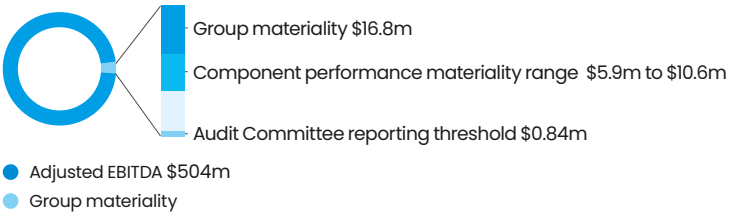
6. Our application of materiality

6.1. Materiality

We define materiality as the magnitude of misstatement in the financial statements that makes it probable that the economic decisions of a reasonably knowledgeable person would be changed or influenced. We use materiality both in planning the scope of our audit work and in evaluating the results of our work.

Based on our professional judgement, we determined materiality for the financial statements as a whole as follows:

	Group financial statements	Parent company financial statements
Materiality	$16.8 million (2024: $20.3 million)	$10.6 million (2024: $16.8 million)
Basis for determining materiality	3.3% of adjusted EBITDA (2024: 3% of adjusted EBITDA). The directors have presented a reconciliation of profit from operations before tax and finance costs to adjusted EBITDA in the glossary to the financial statements on page 192.	1.9% of net assets (2024: 2.9% of net assets)
Rationale for the benchmark applied	Adjusted EBITDA was considered to be the most relevant benchmark as it is a key performance measure used by the Group and by investors. It represents a consistent profit measure used widely by stakeholders.	The parent company acts primarily as a holding company and therefore net assets is the most appropriate benchmark to use.



6.2. Performance materiality

We set performance materiality at a level lower than materiality to reduce the probability that, in aggregate, uncorrected and undetected misstatements exceed the materiality for the financial statements as a whole.

	Group financial statements	Parent company financial statements
Performance materiality	70% (2024: 70%) of Group materiality	70% (2024: 70%) of parent company materiality
Basis and rationale for determining performance materiality	In determining performance materiality, we considered the following factors: • our risk assessment, including our assessment of the Group's overall control environment and whether we are able to rely on controls; • our past experience of the audit, which has indicated a low number of corrected and uncorrected misstatements identified in prior periods; and • management's willingness to correct errors identified in the prior year and current year; and • macro-economic factors such as commodity price volatility and geo-political instability.	

6.3. Error reporting threshold

We agreed with the Audit Committee that we would report to the Committee all audit differences in excess of $0.84 million (2024: $1.02 million), as well as differences below that threshold that, in our view, warranted reporting on qualitative grounds. We also report to the Audit Committee on disclosure matters that we identified when assessing the overall presentation of the financial statements.

7. An overview of the scope of our audit

7.1. Identification and scoping of components

Our audit was scoped by obtaining an understanding of the Group and its environment, including Group-wide controls, and assessing the risks of material misstatement at the Group level. In the current year, we performed an audit of one or more account balances of the North Sea, Malaysia and Vietnam components. The Group audit team conducted audit procedures for the North Sea component, whilst the Malaysia and Vietnam components were audited by their respective component teams with oversight from the Group audit team.

The performance materiality applied for the Malaysia component was $5.9 million (2024: $7.1 million). The performance materiality applied for the Vietnam component was $5.9m million (2024: not applicable). The performance materiality applied for the North Sea component was $10.6 million (2024: $12.8 million).

The North Sea, Malaysia and Vietnam components, where we performed an audit of one or more account balances, accounted for 100% of the Group's revenue, 100% of the Group's adjusted EBITDA and 100% of the Group's net assets, consistent with the prior year.

7.2. Our consideration of the control environment

We obtained an understanding of relevant controls in relation to a number of key business cycles, including impairment, decommissioning, financial reporting and close, and revenue, as well as IT systems that were relevant to the audit, being the financial reporting system. Additionally, we tested relevant controls relating to revenue cut-off. Progress continues to be made in addressing the control weaknesses that were identified in relation to the general IT control environment in the prior year, but we did not place reliance on these IT controls for the purposes of our audit testing. Overall, we did not plan to take a control reliance approach in the current year, other than in respect of revenue as outlined above.

7.3. Our consideration of climate-related risks

We performed enquiries of management to understand the impact of climate-related risks and controls relevant to the Group. We performed a review of the climate change risk assessment and related documentation prepared by management and considered the completeness and accuracy of the climate-related risks identified and summarised in the Task Force on Climate-related Financial Disclosures report from page 76 to 85.

As disclosed in note 2, management identified key judgements and estimates with elevated climate-related risk, relating to property, plant and equipment and goodwill and deferred tax as well as the timing (and hence valuation) of the decommissioning provision.

We considered whether the risks identified by management within their climate change risk assessment and related documentation are complete and challenged assumptions impacting the financial statements. The key piece of climate-related regulation enacted to date and impacting the Group continues to relate to carbon costs and emission allowances. The key market-related matter which could have a material impact on the valuation of the items noted above is in respect of future demand for, and pricing of, oil and gas as the energy mix evolves in response to climate change risk and other matters. There continues to be a climate-related risk relating to the early cessation of production of oil and gas assets, which would impact all of the judgements and estimates outlined above. This is disclosed in the annual report on page 65.

We performed a review of the climate disclosures within the Annual Report, including the climate-related financial disclosures referred to in note 2, with the involvement of our climate specialists. We considered whether these were materially consistent with the financial disclosures and consistent with our understanding of the climate-related risks, assumptions and judgements during the year. Both of our key audit matters are considered to contain climate-related risks, being the risks to commodity prices and cessation of production, which could have a material impact on the valuation of oil and gas related assets and liabilities and valuation of the decommissioning provision. The procedures performed for these key audit matters are discussed in detail in the key audit matters section above.

7.4. Working with other auditors

We engaged Deloitte Malaysia and Deloitte Vietnam as our component auditors, directed and supervised by the Group engagement team in the UK. Detailed referral instructions were sent to the component audit team as part of planning procedures.

The Group engagement team directed and supervised the component teams throughout the year via attendance at planning meetings, regular communication between the teams and attendance at closing meetings. The Group engagement team reviewed and challenged the reporting deliverables and audit file as part of concluding procedures.

We are satisfied that the level of involvement of the lead audit partner and team in the component audit has been appropriate and has enabled us to conclude that sufficient appropriate audit evidence has been obtained in support of our opinion on the Group financial statements as a whole.

8. Other information

The other information comprises the information included in the annual report, other than the financial statements and our auditor's report thereon. The Directors are responsible for the other information contained within the annual report.

Our opinion on the financial statements does not cover the other information and, except to the extent otherwise explicitly stated in our report, we do not express any form of assurance conclusion thereon.

Our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the course of the audit, or otherwise appears to be materially misstated.

If we identify such material inconsistencies or apparent material misstatements, we are required to determine whether this gives rise to a material misstatement in the financial statements themselves. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact.

We have nothing to report in this regard.

9. Responsibilities of Directors

As explained more fully in the Directors' responsibilities statement, the Directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view, and for such internal control as the Directors determine is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, the Directors are responsible for assessing the Group's and the parent company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors either intend to liquidate the Group or the parent company or to cease operations, or have no realistic alternative but to do so.

10. Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs (UK) will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

A further description of our responsibilities for the audit of the financial statements is located on the FRC's website at: www.frc.org.uk/auditorsresponsibilities. This description forms part of our auditor's report.

11.Extent to which the audit was considered capable of detecting irregularities, including fraud

Irregularities, including fraud, are instances of non-compliance with laws and regulations. We design procedures in line with our responsibilities, outlined above, to detect material misstatements in respect of irregularities, including fraud. The extent to which our procedures are capable of detecting irregularities, including fraud is detailed below.

11.1. Identifying and assessing potential risks related to irregularities

In identifying and assessing risks of material misstatement in respect of irregularities, including fraud and non-compliance with laws and regulations, we considered the following:

- the nature of the industry and sector, control environment and business performance including the design of the Group's remuneration policies, key drivers for Directors' remuneration, bonus levels and performance targets;
- the Group's own assessment of the risks that irregularities may occur either as a result of fraud or error that was approved by the board;
- results of our enquiries of management, internal audit, the Directors and the Audit Committee about their own identification and assessment of the risks of irregularities, including those that are specific to the Group's sector;
- any matters we identified having obtained and reviewed the Group's documentation of their policies and procedures relating to:
  - identifying, evaluating and complying with laws and regulations and whether they were aware of any instances of non-compliance;
  - detecting and responding to the risks of fraud and whether they have knowledge of any actual, suspected or alleged fraud; and
  - the internal controls established to mitigate risks of fraud or non-compliance with laws and regulations;
- the matters discussed among the audit engagement team including the component audit teams and relevant internal specialists, including tax, valuations, IT, modelling and oil and gas reserves specialists, regarding how and where fraud might occur in the financial statements and any potential indicators of fraud.

As a result of these procedures, we considered the opportunities and incentives that may exist within the organisation for fraud and identified the greatest potential for fraud in the following areas:

- valuation of oil and gas related assets and liabilities;
- valuation of decommissioning liability; and
- Vietnam revenue recognition.

In common with all audits under ISAs (UK), we are also required to perform specific procedures to respond to the risk of management override.

We also obtained an understanding of the legal and regulatory framework that the Group operates in, focusing on provisions of those laws and regulations that had a direct effect on the determination of material amounts and disclosures in the financial statements. The key laws and regulations we considered in this context included the UK Companies Act 2006 and the Listing Rules of the UK Listing Authority and the relevant tax compliance regulations in the jurisdictions in which the Group operates.

In addition, we considered provisions of other laws and regulations that do not have a direct effect on the financial statements but compliance with which may be fundamental to the Group's ability to operate or to avoid a material penalty. These included environmental laws and regulations in the countries in which the Group operates as well as licence terms for the Group's oil and gas assets.

11.2. Audit response to risks identified

As a result of performing the above, we identified the valuation of oil and gas related assets and liabilities and the valuation of the decommissioning provision as key audit matters related to the potential risk of fraud. The key audit matters section of our report explains the matters in more detail and also describes the specific procedures we performed in response to those key audit matters.

In addition to the above, our procedures to respond to risks identified included the following:

- reviewing the financial statement disclosures and testing to supporting documentation to assess compliance with provisions of relevant laws and regulations described as having a direct effect on the financial statements;
- enquiring of management, the Audit Committee and in-house legal counsel concerning actual and potential litigation and claims;
- performing analytical procedures to identify any unusual or unexpected relationships that may indicate risks of material misstatement due to fraud;
- reading minutes of meetings of those charged with governance, reviewing internal audit reports and reviewing correspondence with relevant authorities;
- in addressing the risk of fraud in Vietnam's revenue recognition, we tested the crude oil transactions during the year by sampling from the sales transactional listing and agreeing to supporting documentation; and
- in addressing the risk of fraud through management override of controls, testing the appropriateness of journal entries and other adjustments; assessing whether the judgements made in making accounting estimates are indicative of a potential bias; and evaluating the business rationale of any significant transactions that are unusual or outside the normal course of business.

We also communicated relevant identified laws and regulations and potential fraud risks to all engagement team members including internal specialists and component audit teams, and remained alert to any indications of fraud or non-compliance with laws and regulations throughout the audit.

Report on other legal and regulatory requirements

12. Opinions on other matters prescribed by the Companies Act 2006

In our opinion the part of the Directors' remuneration report to be audited has been properly prepared in accordance with the Companies Act 2006.

In our opinion, based on the work undertaken in the course of the audit:

- the information given in the strategic report and the Directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements; and
- the strategic report and the Directors' report have been prepared in accordance with applicable legal requirements.

In the light of the knowledge and understanding of the Group and the parent company and their environment obtained in the course of the audit, we have not identified any material misstatements in the strategic report or the Directors' report.

13. Corporate Governance Statement

The Listing Rules require us to review the Directors' statement in relation to going concern, longer-term viability and that part of the Corporate Governance Statement relating to the Group's compliance with the provisions of the UK Corporate Governance Code specified for our review.

Based on the work undertaken as part of our audit, we have concluded that each of the following elements of the Corporate Governance Statement is materially consistent with the financial statements and our knowledge obtained during the audit:

- the Directors' statement with regards to the appropriateness of adopting the going concern basis of accounting and any material uncertainties identified set out on page 40;
- the Directors' explanation as to its assessment of the Group's prospects, the period this assessment covers and why the period is appropriate set out on page 41;
- the Directors' statement on fair, balanced and understandable set out on page 104;
- the board's confirmation that it has carried out a robust assessment of the emerging and principal risks set out on pages 62 to 74;
- the section of the annual report that describes the review of effectiveness of risk management and internal control systems set out on page 108; and
- the section describing the work of the audit committee set out on pages 103 to 109.

14. Matters on which we are required to report by exception

14.1. Adequacy of explanations received and accounting records

Under the Companies Act 2006 we are required to report to you if, in our opinion:

- we have not received all the information and explanations we require for our audit; or
- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or
- the parent company financial statements are not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

14.2. Directors' remuneration

Under the Companies Act 2006 we are also required to report if in our opinion certain disclosures of Directors' remuneration have not been made or the part of the Directors' remuneration report to be audited is not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

15. Other matters which we are required to address

15.1. Auditor tenure

Following the recommendation of the audit committee, we were appointed by shareholders on 21 May 2020 to audit the financial statements for the year ending 31 December 2020 and subsequent financial periods. The period of total uninterrupted engagement including previous renewals and reappointments of the firm is six years, covering the years ending 31 December 2020 to 31 December 2025.

15.2. Consistency of the audit report with the additional report to the audit committee

Our audit opinion is consistent with the additional report to the audit committee we are required to provide in accordance with ISAs (UK).

16. Use of our report

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

As required by the Financial Conduct Authority (FCA) Disclosure Guidance and Transparency Rule (DTR) 4.1.15R – DTR 4.1.18R, these financial statements will form part of the Electronic Format Annual Financial Report filed on the National Storage Mechanism of the FCA in accordance with DTR 4.1.15R – DTR 4.1.18R. This auditor's report provides no assurance over whether the Electronic Format Annual Financial Report has been prepared in compliance with DTR 4.1.15R – DTR 4.1.18R.

David Paterson ACA (Senior statutory auditor)
For and on behalf of Deloitte LLP
Statutory Auditor
London, United Kingdom
24 March 2026

Group Income Statement

For the year ended 31 December 2025

	Notes	2025 $'000	2024 $'000
Revenue and other operating income	4(a)	**1,118,300**	1,180,709
Cost of sales	4(b)	**(837,540)**	(787,383)
Gross profit/(loss)		**280,760**	393,326
Net impairment reversal/(charge) to oil and gas assets	9	**5,819**	(71,414)
General and administration expenses	4(c)	**(7,482)**	(5,702)
Other income/(expenses)	4(d)	**369,697**	(4,682)
Profit/(loss) from operations before tax and finance income/(costs)		**648,794**	311,528
Finance costs	5	**(164,591)**	(159,422)
Finance income	5	**9,224**	14,508
Profit/(loss) before tax		**493,427**	166,614
Income tax[(i)]	6	**(491,865)**	(72,841)
Profit/(loss) for the year attributable to owners of the parent	13	**1,562**	93,773
Total comprehensive profit/(loss) for the year, attributable to owners of the parent		**1,562**	93,773

There is no comprehensive income attributable to the shareholders of the Group other than the profit/(loss) for the period. Revenue and operating profit/(loss) are all derived from continuing operations.

	Notes	$	$
Earnings per share	7		
Basic		**0.001**	0.050
Diluted		**0.001**	0.049

The attached notes 1 to 31 form part of these Group financial statements.

(i) Inclusive of a deferred tax charge of $374.7 million (2024: $60.7 million) which includes a one-off non-cash impact of $123.9 million from the two-year extension to the UK Energy Profits Levy enacted in March 2025 (2024: $42.2 million from the change in Energy Profits Levy tax rate to 38% and removal of investment allowances)

Group Balance Sheet
At 31 December 2025

	Notes	2025 $'000	2024 $'000
ASSETS			
Non-current assets			
Property, plant and equipment	9	**2,370,131**	2,297,954
Goodwill	10	**139,510**	134,400
Intangible assets	11	**24,615**	20,563
Deferred tax assets	6(c)	**271,375**	506,481
Other receivables	15	**128,166**	2,102
Other financial assets	18	**50,818**	38,459
		2,984,615	2,999,959
Current assets			
Intangible assets	11	**1,110**	1,138
Inventories	12	**32,759**	48,976
Trade and other receivables	15	**245,469**	230,971
Current tax receivable		**2,021**	1,256
Cash and cash equivalents	13	**268,846**	280,239
Other financial assets	18	**59,491**	69
		609,696	562,649
TOTAL ASSETS		**3,594,311**	3,562,608
EQUITY AND LIABILITIES			
Equity			
Share capital and premium	19	**392,054**	392,054
Treasury shares	19	**(3,540)**	(4,425)
Share-based payments reserve	19	**12,395**	13,949
Capital redemption reserve	19	**2,006**	2,006
Retained earnings	19	**125,144**	138,882
TOTAL EQUITY		**528,059**	542,466
Non-current liabilities			
Loans and borrowings	17	**638,211**	621,440
Lease liabilities	23	**285,767**	288,262
Contingent consideration	21	**24,302**	452,891
Provisions[(i)]	22	**877,954**	710,976
Deferred income	24	**138,095**	138,095
Deferred tax liabilities	6(c)	**250,364**	104,698
		2,214,693	2,316,362
Current liabilities			
Loans and borrowings	17	**69,253**	43,417
Lease liabilities	23	**86,323**	46,994
Contingent consideration	21	**60,318**	20,403
Provisions[(i)]	22	**54,082**	55,130
Trade and other payables	16	**454,650**	414,390
Other financial liabilities	18	**10,391**	21,580
Current tax payable		**116,542**	101,866
		851,559	703,780
TOTAL LIABILITIES		**3,066,252**	3,020,142
TOTAL EQUITY AND LIABILITIES		**3,594,311**	3,562,608

(i) Decommissioning provision includes EnQuest's share of the total Block 12W decommissioning liability, noting $92.1 million has been pre-funded through an abandonment fund held in Vietnam which is disclosed within non-current other receivables

The attached notes 1 to 31 form part of these Group financial statements.

The financial statements were approved by the Board of Directors and authorised for issue on 24 March 2026 and signed on its behalf by:

Jonathan Copus
Chief Financial Officer

Group Statement of Changes in Equity

For the year ended 31 December 2025

	Notes	Share capital $'000	Share premium $'000	Treasury shares $'000	Share-based payments reserve $'000	Capital redemption reserve $'000	Retained earnings $'000	Total $'000
Balance at 1 January 2024		**133,285**	**260,546**	**–**	**13,195**	**–**	**49,702**	**456,728**
Profit for the year		**–**	**–**	**–**	**–**	**–**	**93,773**	**93,773**
Total comprehensive income for the year		**–**	**–**	**–**	**–**	**–**	**93,773**	**93,773**
Issue of shares to Employee Benefit Trust		**229**	**–**	**–**	**(229)**	**–**	**–**	**–**
Repurchase and cancellation of shares		**(2,006)**	**–**	**(4,425)**	**–**	**2,006**	**(4,593)**	**(9,018)**
Share-based payment		**–**	**–**	**–**	**983**	**–**	**–**	**983**
Balance at 31 December 2024		**131,508**	**260,546**	**(4,425)**	**13,949**	**2,006**	**138,882**	**542,466**
Profit for the year		**–**	**–**	**–**	**–**	**–**	**1,562**	**1,562**
Total comprehensive income for the year		**–**	**–**	**–**	**–**	**–**	**1,562**	**1,562**
Transfer of shares to Employee Benefit Trust	19	**–**	**–**	**885**	**(885)**	**–**	**–**	**–**
Share-based payment	20	**–**	**–**	**–**	**(669)**	**–**	**–**	**(669)**
Dividend paid		**–**	**–**	**–**	**–**	**–**	**(15,300)**	**(15,300)**
Balance at 31 December 2025		**131,508**	**260,546**	**(3,540)**	**12,395**	**2,006**	**125,144**	**528,059**

The attached notes 1 to 31 form part of these Group financial statements.

Group Statement of Cash Flows
For the year ended 31 December 2025

	Notes	2025 $'000	2024 $'000
CASH FLOW FROM OPERATING ACTIVITIES			
Cash generated from operations	29	**497,819**	685,946
Cash received/(paid) on sale/(purchase) of financial instruments		**9,075**	(10,306)
Net cash received for trading of other intangible assets		**26,829**	–
Cash paid for purchase of other intangible assets		**(6,472)**	(1,138)
Cash paid in relation to amounts previously provided for		**(481)**	(9,063)
Decommissioning spend		**(56,810)**	(60,544)
Income taxes paid		**(107,235)**	(97,264)
Net cash flows from/(used in) operating activities		**362,725**	507,631
INVESTING ACTIVITIES			
Purchase of property, plant and equipment		**(175,025)**	(249,165)
Proceeds from farm-down		**–**	1,263
Vendor financing facility repaid	18(f),24	**–**	107,518
Purchase of intangible oil and gas assets	11	**(4,225)**	(3,686)
Payment of Magnus contingent consideration – Profit share	21	**–**	(48,465)
Acquisition	30	**(20,278)**	–
Interest received		**5,286**	10,100
Net cash flows (used in)/from investing activities		**(194,242)**	(182,435)
FINANCING ACTIVITIES			
Proceeds from loans and borrowings		**152,432**	31,662
Repayment of loans and borrowings		**(146,451)**	(162,304)
Payment for repurchase of shares		**–**	(9,018)
Payment of obligations under financing leases	23	**(83,061)**	(130,065)
Dividend paid	8	**(15,300)**	–
Interest paid		**(96,997)**	(83,162)
Other finance expenses paid		**(3,606)**	–
Net cash flows (used in)/from financing activities		**(192,983)**	(352,887)
NET (DECREASE)/INCREASE IN CASH AND CASH EQUIVALENTS		**(24,500)**	(27,691)
Net foreign exchange on cash and cash equivalents		**13,107**	(5,642)
Cash and cash equivalents at 1 January		**280,239**	313,572
CASH AND CASH EQUIVALENTS AT 31 DECEMBER		**268,846**	280,239
Reconciliation of cash and cash equivalents			
Total cash at bank and in hand	13	**265,886**	226,317
Restricted cash	13	**2,960**	53,922
Cash and cash equivalents per balance sheet		**268,846**	280,239

The attached notes 1 to 31 form part of these Group financial statements.

1. Corporate information

EnQuest PLC ('EnQuest' or the 'Company') is a public company limited by shares incorporated in the United Kingdom under the Companies Act and is registered in England and Wales and listed on the London Stock Exchange. The address of the Company's registered office is shown on the inside back cover of the Group Annual Report and Accounts.

EnQuest PLC is the ultimate controlling party. The principal activities of the Company and its subsidiaries (together the 'Group') are to responsibly optimise production, leverage existing infrastructure, deliver a strong decommissioning performance and explore new energy and decarbonisation opportunities.

The Group's financial statements for the year ended 31 December 2025 were authorised for issue in accordance with a resolution of the Board of Directors on 24 March 2026.

A listing of the Group's companies is contained in note 28 to these Group financial statements.

2. Basis of preparation

The consolidated financial statements have been prepared in accordance with United Kingdom international accounting standards ('IFRS') in conformity with the requirements of the Companies Act 2006. The accounting policies which follow set out those policies which apply in preparing the financial statements for the year ended 31 December 2025.

The Group continues to present various Alternative Performance Measures ('APMs') when assessing and discussing the Group's financial performance, balance sheet and cash flows that are not defined or specified under IFRS but consistent with the measurement basis applied to the financial statements. The Group uses these APMs, which are not considered to be a substitute for, or superior to, IFRS measures, to provide stakeholders with additional useful information to aid the understanding of the Group's underlying financial performance, balance sheet and cash flows by adjusting for certain items which impact upon IFRS measures or, by defining new measures. See the Glossary – Non-GAAP Measures on page 192 for more information.

The Group financial information has been prepared on a historical cost basis, except for the fair value remeasurement of certain financial instruments, including derivatives and contingent consideration, as set out in the accounting policies. The presentation currency of the Group financial information is US Dollars ('$') and all values in the Group financial information are rounded to the nearest thousand ($'000) except where otherwise stated.

Going concern

The financial statements have been prepared on the going concern basis.

During 2025, EnQuest has continued to focus on optimisation of its capital structure and the maximisation of its available transactional capacity.

In November, EnQuest signed a new six-year senior secured reserves-based lending facility which replaced the previous RBL, providing the Group with an enhanced capital structure that is simple, flexible and aligned with its growth ambitions. Details of the amended facility are provided in note 17. In February 2026, the Group made final settlement for the Magnus profit share contingent consideration, securing 100% of future Magnus cash flows while maintaining its limited exposure to future decommissioning expenditure at the asset. This credit-enhancing settlement, simplifies the Group's balance sheet, unlocks the full upside of one of EnQuest's core assets, and further secures longer term capacity under its RBL.

EnQuest closely monitors and manages its funding position and liquidity requirements throughout the year, including forecast covenant results. Cash forecasts are regularly produced and discussed, with sensitivities considered for, but not limited to, changes in crude oil prices (adjusted for hedging undertaken by the Group), production rates and costs. These forecasts and sensitivity analyses allow management to mitigate liquidity or covenant compliance risks in a timely manner. Management have considered the impact of the situation in the Middle East, particularly on future oil prices. Reflecting the uncertainty as to how long the conflict and the period of elevated oil prices will last, management have assumed in the Base Case that the average oil price for the going concern period will be $70.0/bbl. Although this is slightly higher than that used in its impairment assessment (see note 2) to reflect post year-end pricing trends, it is considerably below current spot prices.

The Group's latest approved budget and long term plan underpins management's base case ('Base Case'), upon which a reverse stress test has been performed. This indicates that an oil price of c.$45.0/bbl is required to maintain covenant compliance over the going concern period. The low level of this required price reflects the Group's strong liquidity position.

The Base Case has also been subjected to further testing through a scenario that explores the impact of the following plausible downside risks (the 'Downside Case'):

- 10% discount to Base Case prices resulting in Downside Case prices of $63.0/bbl for 2026 and 2027;
- Production risking of 5.0%; and
- 2.5% increase in operating costs.

The Base Case and Downside Case indicate that the Group is able to operate as a going concern and remain covenant compliant for 12 months from the date of publication of its full-year results (the "going concern period").

After making appropriate enquiries and assessing the progress against the forecast, the Directors have a reasonable expectation that the Group will continue in operation and meet its commitments as they fall due over the going concern period. Accordingly, the Directors continue to adopt the going concern basis in preparing these financial statements.

2. Basis of preparation continued

New standards and interpretations

The following new standards became applicable for the current reporting period. No material impact was recognised upon application:

- Lack of Exchangeability (Amendments to IAS 21)

Standards issued but not yet effective

At the date of authorisation of these financial statements, the Group has not applied the following new and revised IFRS Standards that have been issued but are not yet effective:

IFRS 9 and IFRS 7	Amendments to the Classification and Measurement of Financial Instruments
IFRS 18	Presentation and disclosure in financial statements
IFRS 19	Subsidiaries without Public Accountability: Disclosures

Other than IFRS 18, the Directors do not expect that the adoption of the Standards listed above will have a material impact on the financial statements of the Group in future periods. The Directors noted IFRS 18 may change the presentation and disclosure information in the financial statements when effective, which is for periods commencing on or after 1 January 2027.

Basis of consolidation

The consolidated financial statements incorporate the financial statements of EnQuest PLC and entities controlled by the Company (its subsidiaries) made up to 31 December each year. Control is achieved when the Company:

- has power over the investee;
- is exposed, or has rights, to variable returns from its involvement with the investee; and
- has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control listed above. Consolidation of a subsidiary begins when the Company obtains control over the subsidiary and ceases when the Company loses control of the subsidiary. Specifically, the results of subsidiaries acquired or disposed of during the year are included in profit or loss from the date the Company gains control until the date the Company ceases to control the subsidiary.

Where necessary, adjustments are made to the financial statements of subsidiaries to bring the accounting policies used into line with the Group's accounting policies. All intra-Group assets and liabilities, equity, income, expenses and cash flows relating to transactions between the members of the Group are eliminated on consolidation.

Joint arrangements

Oil and gas operations are usually conducted by the Group as co-licensees in unincorporated joint operations with other companies. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the consent of the relevant parties sharing control. The joint operating agreement is the underlying contractual framework to the joint arrangement, which is historically referred to as the joint venture. The Annual Report and Accounts therefore refers to 'joint ventures' as a standard term used in the oil and gas industry, which is used interchangeably with joint operations.

Most of the Group's activities are conducted through joint operations, whereby the parties that have joint control of the arrangement have the rights to the assets, and obligations for the liabilities relating to the arrangement. The Group recognises its share of assets, liabilities, income and expenses of the joint operation in the consolidated financial statements on a line-by-line basis. During 2025, the Group did not have any material interests in joint ventures or in associates as defined in IAS 28.

Foreign currencies

Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates ('functional currency'). The Group's financial statements are presented in US Dollars, the currency which the Group has elected to use as its presentation currency.

In the financial statements of the Company and its individual subsidiaries, transactions in currencies other than a company's functional currency are recorded at the prevailing rate of exchange on the date of the transaction. At the year end, monetary assets and liabilities denominated in foreign currencies are retranslated at the rates of exchange prevailing at the balance sheet date. Non-monetary assets and liabilities that are measured at historical cost in a foreign currency are translated using the rate of exchange at the dates of the initial transactions. Non-monetary assets and liabilities measured at fair value in a foreign currency are translated using the rate of exchange at the date the fair value was determined. All foreign exchange gains and losses are taken to profit and loss in the Group income statement.

Emissions liabilities

The Group operates in an energy intensive industry and is therefore required to partake in emission trading schemes ('ETS'). The Group recognises an emission liability in line with the production of emissions that give rise to the obligation. To the extent the liability is covered by allowances held, the liability is recognised at the cost of these allowances held and if insufficient allowances are held, the remaining uncovered portion is measured at the spot market price of allowances at the balance sheet date. The expense is presented within 'production costs' under 'cost of sales' and the accrual is presented in 'trade and other payables'. Any allowance purchased to settle the Group's liability is recognised on the balance sheet as an intangible asset. Both the emission allowances and the emission liability are derecognised upon settling the liability with the respective regulator.

2. Basis of preparation continued

Use of judgements, estimates and assumptions

The preparation of the Group's consolidated financial statements requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the accompanying disclosures, at the date of the consolidated financial statements. Estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

The accounting judgements and estimates that have a significant impact on the results of the Group are set out below and should be read in conjunction with the information provided in the Notes to the financial statements. The Group does not consider deferred taxation (including EPL) to represent a significant estimate or judgement as the estimates and assumptions relating to projected earnings and cash flows used to assess deferred taxation are the same as those applied in the Group impairment process as described below in Recoverability of asset carrying values. Judgements and estimates, not all of which are significant, made in assessing the impact of climate change and the transition to a lower carbon economy on the consolidated financial statements are also set out below. Where an estimate has a significant risk of resulting in a material adjustment to the carrying amounts of assets and liabilities within the next financial year, this is specifically noted.

Climate change and energy transition

As covered in the Group's principal risks on Price and Foreign Exchange Risk on page 70, the Group recognises that the energy transition is likely to impact the demand, and hence the future prices, of commodities such as oil and natural gas. This in turn may affect the recoverable amount of property, plant and equipment and goodwill and deferred tax, as well as an acceleration of cessation of production and subsequent decommissioning expenditure, in the oil and gas industry. The Group acknowledges that there are a range of possible energy transition scenarios that may indicate different outcomes for oil prices. There are inherent limitations with scenario analysis and it is difficult to predict which, if any, of the scenarios might eventuate.

The Group has assessed the potential impacts of climate change and the transition to a lower carbon economy in preparing the consolidated financial statements, including the Group's current assumptions relating to demand for oil and natural gas and their impact on the Group's long-term price assumptions. See Recoverability of asset carrying values: Oil prices.

While the pace of transition to a lower carbon economy is uncertain, oil and natural 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 useful lives of the Group's current portfolio of oil and gas assets, a material adverse change is not expected to the carrying values of EnQuest's assets and liabilities within the next financial year as a result of climate change and the transition to a lower carbon economy.

Management will continue to review price assumptions as the energy transition progresses and this may result in impairment charges or reversals in the future.

Critical accounting judgements and key sources of estimation uncertainty

The Group has considered its critical accounting judgements and key sources of estimation uncertainty, and these are set out below.

Recoverability of asset carrying values

Judgements: The Group assesses each asset or cash-generating unit ('CGU') (excluding goodwill, which is assessed annually regardless of indicators) in each reporting period to determine whether any indication of impairment or impairment reversal exists. Assessment of indicators of impairment or impairment reversal and the determination of the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment purposes require significant management judgement. For example, individual oil and gas properties may form separate CGUs, whilst certain oil and gas properties with shared infrastructure may be grouped together to form a single CGU. Alternative groupings of assets or CGUs may result in a different outcome from impairment testing. See note 10 for details on how these groupings have been determined in relation to the impairment testing of goodwill.

Estimates: Where an indicator of impairment exists, a formal estimate of the recoverable amount is made, which is considered to be the higher of the fair value less costs to dispose ('FVLCD') and value in use ('VIU'). The assessments require the use of estimates and assumptions, such as the effects of inflation and deflation on operating expenses, cost profile changes including those related to emission reduction initiatives such as alternative fuel provision at Kraken, discount rates, capital expenditure, production profiles, reserves and resources, and future commodity prices, including the outlook for global or regional market supply-and-demand conditions for crude oil and natural gas. Such estimates reflect management's best estimate of the related cash flows based on management's plans for the assets and their future development.

As described above, the recoverable amount of an asset is the higher of its VIU and its FVLCD. When the recoverable amount is measured by reference to FVLCD, in the absence of quoted market prices or binding sale agreement, estimates are made regarding the present value of future post-tax cash flows. These estimates are made from the perspective of a market participant and include prices, life of field production profiles based on reserves and resources to which it is considered probable that a market participant would attribute value to them, operating costs, capital expenditure, decommissioning costs, tax attributes, risking factors applied to cash flows, and discount rates.

Details of impairment charges and reversals recognised in the income statement and details on the carrying amounts of assets are shown in note 9, note 10 and note 11.

2. Basis of preparation continued

The estimates for assumptions made in impairment tests in 2025 relating to discount rates and oil prices are discussed below. Changes in the economic environment or other facts and circumstances may necessitate revisions to these assumptions and could result in a material change to the carrying values of the Group's assets within the next financial year.

Discount rates

For discounted cash flow calculations, future cash flows are adjusted for risks specific to the CGU. FVLCD discounted cash flow calculations use the post-tax discount rate. The discount rate is derived using the weighted average cost of capital methodology. The discount rates applied in impairment tests are reassessed each half-year and, in 2025, the post-tax discount rate was estimated at 9.0% (2024: 10.0%) reflecting the impact from the Group's reduced debt position and clarity over the UK fiscal system.

Oil prices

The price assumptions used for FVLCD impairment testing were based on latest internal forecasts as at 31 December 2025. These price forecasts reflect EnQuest's views of global supply and demand, including the potential financial impacts on the Group of climate change and the transition to a low carbon economy as outlined in the Basis of Preparation, and are benchmarked with external sources of information such as analyst forecasts. The Group's price forecasts are reviewed and approved by management, the Audit Committee and the Board of Directors.

EnQuest revised its oil price assumptions for FVLCD impairment testing compared to those used in 2024, with nearer-term prices reflecting current market dynamics and external forecasts. A summary of the Group's revised price assumptions is provided below. These assumptions, which represent management's best estimate of future prices, sit within the range of external forecasts. Discounts or premiums are applied to price assumptions based on the characteristics of the oil produced and the terms of the relevant sales contracts.

When compared to the latest available Paris-consistent climate scenario modelling data released by the World Business Council of Sustainable Development ('WBCSD') in May 2024, EnQuest's assumption is broadly aligned with the top end of a range of Paris-consistent scenario's. When compared to the International Energy Agency's ('IEA') forecast prices under its Net Zero Emissions by 2050 Scenario ('NZE') ,published in November 2025, which is also considered a Paris-consistent scenario and maps out a pragmatic but ambitious global pathway for the energy sector to achieve net zero CO2 emissions by 2050 and is consistent with a long-term goal of limiting the rise in global average temperatures to 1.5 °C (with a 50% probability), EnQuest's short-term assumptions are below those assumed under the NZE, while its medium and longer-term prices are significantly higher. As further considered later in this note, management believes a 10% reduction in crude oil price assumptions to be a reasonably possible change and has provided an impairment sensitivity on this basis. However, the potential impact of applying the IEA NZE Scenario, which is just one view of the possible impact of climate change, would result in a materially higher impairment charge.

An inflation rate of 2% (2024: 2%) is applied from 2030 onwards to determine the price assumptions in nominal terms (see table below).

The price assumptions used in 2024 were $75.0/bbl (2025), $75.0/bbl (2026), $75.0/bbl (2027) and $76.5/bbl real thereafter, inflated at 2.0% per annum from 2028.

Note	2026	2027	2028	2029>[i]
Brent oil ($/bbl)	65.0	67.5	72.5	75.0

(i) Inflated at 2% from 2030

Oil and natural gas reserves

Hydrocarbon reserves are estimates of the amount of hydrocarbons that can be economically and legally extracted from the Group's oil and gas properties. The business of the Group is to responsibly optimise production, leverage existing infrastructure, deliver a strong decommissioning performance and explore new energy and decarbonisation opportunities. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity, and drilling of new wells all impact on the determination of the Group's estimates of its oil and gas reserves and result in different future production profiles affecting prospectively the discounted cash flows used in impairment testing, the anticipated date of decommissioning and the depletion charges in accordance with the unit of production method, as well as the going concern assessment. Economic assumptions used to estimate reserves change from period to period as additional technical and operational data is generated. This process may require complex and difficult geological judgements to interpret the data.

The Group uses proven and probable ('2P') reserves (see page 34) and, for the Kraken CGU, 2C resources associated with the Bressay gas well as an alternative fuel provision for the Kraken FPSO as the basis for calculations of expected future cash flows from underlying assets because this represents the reserves and resources management intends to develop and it is probable that a market participant would attribute value to them. Third-party audits of EnQuest's reserves and resources are conducted annually.

2. Basis of preparation continued

Sensitivity analyses

Changes in price and its consequential impact on impairment and deferred tax along with the discount rate impact on impairment and decommissioning are considered to be the only key sources of estimation uncertainty, although other sensitivities that the Group believes are useful for users of these accounts but are not considered to have a significant risk of resulting in material changes to carrying amounts in the next 12 months, may also be provided.

Management tested the impact of a change in cash flows in FVLCD impairment testing arising from a 10% reduction in crude price assumptions, which it believes to be a reasonably possible change given the prevailing macroeconomic environment.

Price reductions of this magnitude in isolation could indicatively lead to a further reduction in the carrying amount of EnQuest's oil and gas properties by approximately $198.7 million, which is approximately 8% of the net book value of property, plant and equipment as at 31 December 2025.

The oil price sensitivity analysis above does not, however, represent management's best estimate of any impairments that might be recognised as it does not fully incorporate consequential changes that may arise, such as reductions in costs and changes to business plans, phasing of development, levels of reserves and resources, and production volumes. As the extent of a price reduction increases, the more likely it is that costs would decrease across the industry. The oil price sensitivity analysis therefore does not reflect a linear relationship between price and value that can be extrapolated.

Management also tested the impact of a one percentage point change in the discount rate of 9.0% used for FVLCD impairment testing of oil and gas properties, which is considered a reasonably possible change given the prevailing macroeconomic environment. If the discount rate was one percentage point higher across all tests performed, the net impairment charge in 2025 would have been approximately $51.9 million higher. If the discount rate was one percentage point lower, the net impairment reversal would have been approximately $24.3 million higher.

Goodwill

Irrespective of whether there is any indication of impairment, EnQuest is required to test annually for impairment of goodwill acquired in business combinations. The Group carries goodwill of approximately $139.5 million on its balance sheet (2024: $134.4 million), principally relating to the acquisitions of the Magnus oil field (acquired in 2018) in the UK and Block 12W in Vietnam (acquired in 2025). Sensitivities and additional information relating to impairment testing of goodwill are provided in note 10.

Deferred tax

The Group assesses the recoverability of its deferred tax assets at each period end. Sensitivities and additional information relating to deferred tax assets/liabilities are provided in note 6(d).

75% Magnus acquisition contingent consideration

Judgement: During 2025, management commenced discussions with bp to settle the 75% Magnus contingent consideration arrangement. Management assessed that the agreement to settle the Magnus contingent consideration, signed and concluded in February 2026, was substantially agreed with bp at 31 December 2025. Therefore the agreement price of $60.0 million was deemed to be a reasonable fair value in line with IFRS 13, for the contingent consideration as at 31 December 2025, resulting in a pre-tax gain of $391.3 million. If management had concluded the agreement was not substantially complete at year end, the contingent consideration would have continued to be valued based on the present value of the future expected cash flows from the Magnus field, which at 30 June 2025 resulted in a provision of $432.9 million being recorded.

Provisions

Estimates: Decommissioning costs will be incurred by the Group at the end of the operating life of some of the Group's oil and gas production facilities and pipelines. The Group assesses its decommissioning provision at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal requirements, estimates of the extent and costs of decommissioning activities, the emergence of new restoration techniques and experience at other production sites. The expected timing, extent and amount of expenditure may also change, for example, in response to changes in oil and gas reserves or changes in laws and regulations or their interpretation. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning. As a result, there could be significant adjustments to the provisions established which would affect future financial results.

The timing and amount of future expenditures relating to decommissioning and environmental liabilities are reviewed annually. The rate used in discounting the cash flows is reviewed half-yearly. The Group assesses discount rates in each geography in which it operates using an appropriate benchmark, usually government bonds. As such, the nominal discount rate used to determine the balance sheet obligations ranged from 3.1% to 4.5% (2024: 3.1% to 4.5%) Costs at future prices are determined by applying inflation rates. The inflation rates applied are usually management's estimate based on relevant in-country benchmarking, but in certain circumtances inflation is applied in accordance with the relevant operating agreement. As such, where inflation has been applied to decommissioning costs, it has ranged between 1.0% and 2.0% per annum thereafter (2024: 1.0% to 2.0%). The weighted average period over which North Sea decommissioning costs are generally expected to be incurred is estimated to be approximately 12 years.

Further information about the Group's provisions is provided in note 22. Changes in assumptions could result in a material change in their carrying amounts within the next financial year. A sensitivity has only been run for the UK North Sea segment given its materiality compared to Malaysia and Vietnam. A one percentage point decrease in the nominal discount rate applied, which is considered a reasonably possible change given the prevailing macroeconomic environment, could increase the Group's provision balances by approximately $58.6 million (2024: $59.4 million). The pre-tax impact on the Group income statement would be a charge of approximately $57.5 million (2024: $58.7 million).

2. Basis of preparation continued

Business combination

Judgement: The Group determined that the acquisition of Block 12W in Vietnam during the year was the acquisition of a business, due to the acquired set of activities and assets including inputs and processes critical to the ability to continue producing outputs.

Estimates: While the risk that the acquisition fair value of Block 12W in Vietnam materially changes in the next 12 months is low and so is not considered a key source of estimation uncertainty, for business combinations the Group determines the fair value of property, plant and equipment acquired based on the discounted cash flows at the time of acquisition from the proven and probable reserves. In assessing the discounted cash flows, the estimated future cash flows attributable to the asset are discounted to their present value using a discount rate that reflects the market assessments of the time value of money and the risks specific to the asset at the time of the acquisition. In calculating the asset fair value, the Group will apply oil price assumptions representing management's view of the long-term oil price.

3. Segment information

The Group's organisational structure reflects the various activities in which EnQuest is engaged. Management has considered the requirements of IFRS 8 Operating Segments in regard to the determination of operating segments and concluded that at 31 December 2025, the Group had two significant operating segments: the North Sea and Malaysia. The Vietnam, Indonesia and Brunei operations, which are new for 2025, are not yet deemed significant in accordance with the quantitative thresholds for separate disclosure under IFRS 8, and so these operations have been aggregated into one reporting group, alongside other Corporate activities. Operations are managed by location and all information is presented per geographical segment. The Group's segmental reporting structure remained in place throughout 2025. The North Sea's activities include Upstream, Midstream, Decommissioning and Veri Energy. Veri Energy is not considered a separate operating segment as it does not yet earn revenues and is not yet a material part of the Group from a capital and human resources allocation perspective. Malaysia's activities include Upstream and Decommissioning. The Group's reportable segments may change in the future depending on the way that resources may be allocated and performance assessed by the Chief Operating Decision Maker, who for EnQuest is the Chief Executive. The information reported to the Chief Operating Decision Maker does not include an analysis of assets and liabilities, and accordingly this information is not presented, in line with IFRS 8 paragraph 23.

Year ended 31 December 2025 $'000	North Sea	Malaysia	All other segments	Total segments	Adjustments and eliminations[(i), (iii)]	Consolidated
Revenue and other operating income:						
Revenue from contracts with customers	**895,313**	**114,110**	**52,842**	**1,062,265**	**–**	**1,062,265**
Other operating income/(expense)	**1,770**	**–**	**343**	**2,113**	**53,922**	**56,035**
Total revenue and other operating income/(expense)	**897,083**	**114,110**	**53,185**	**1,064,378**	**53,922**	**1,118,300**
Income/(expenses) line items:						
Depreciation and depletion	**(244,937)**	**(18,183)**	**(9,308)**	**(272,428)**	**–**	**(272,428)**
Net impairment reversal/(charge) to oil and gas assets	**5,819**	**–**	**–**	**5,819**	**–**	**5,819**
Exploration write-off and impairments	**(173)**	**–**	**–**	**(173)**	**–**	**(173)**
Segment profit/(loss)[(ii), (iii)]	**489,959**	**43,770**	**9,090**	**542,819**	**105,975**	**648,794**
Other disclosures:						
Capital expenditure[(iv)]	**148,814**	**63,214**	**1,328**	**213,356**	**–**	**213,356**

Year ended 31 December 2024 $'000	North Sea	Malaysia	All other segments	Total segments	Adjustments and eliminations[(i), (iii)]	Consolidated
Revenue and other operating income:						
Revenue from contracts with customers	1,063,829	123,728	–	1,187,557	–	1,187,557
Other operating income/(expense)	2,709	–	260	2,969	(9,817)	(6,848)
Total revenue and other operating income/(expense)	1,066,538	123,728	260	1,190,526	(9,817)	1,180,709
Income/(expenses) line items:						
Depreciation and depletion	(252,208)	(17,042)	(41)	(269,291)	–	(269,291)
Net impairment (charge)/reversal to oil and gas assets	(71,414)	–	–	(71,414)	–	(71,414)
Exploration write-off and impairments	–	(183)	–	(183)	–	(183)
Segment profit/(loss)[(ii), (iii)]	274,354	45,536	9,013	328,903	(17,375)	311,528
Other disclosures:						
Capital expenditure[(iv)]	313,557	32,774	15	346,346	–	346,346

(i) Finance income and costs and gains and losses on derivatives are not allocated to individual segments as the underlying instruments are managed on a Group basis
(ii) The consolidated profit/(loss) figure reconciles with Profit/(loss) from operations before tax and finance income/(costs) in the income statement. Tax is not included as this is not disclosed to the Chief Operating Decision Maker within the segment profit/(loss)
(iii) Inter-segment revenues are eliminated on consolidation. All other adjustments are part of the reconciliations presented further below
(iv) Capital expenditure consists of property, plant and equipment and intangible exploration and appraisal assets

3. Segment information continued

Reconciliation of profit/(loss):

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Segment profit/(loss) before tax and finance income/(costs)	**542,819**	328,903
Finance costs	**(164,591)**	(159,422)
Finance income	**9,224**	14,508
Gain/(loss) on derivatives[(i)]	**105,975**	(17,375)
Profit/(loss) before tax	**493,427**	166,614

(i) Includes $28.5 million realised gains on derivatives (2024: $17.6 million realised losses) and $77.5 million unrealised gains on derivatives (2024: $0.3 million). See note 18(b) for further detail

Revenue from three customers each exceeds 10% of the Group's consolidated revenue arising from sales of crude oil, with amounts of $414.3 million, $103.6 million and $93.0 million per each single customer (2024: three customers; $394.8 million, $156.0 million, and $115.7 million per each single customer).

4. Revenue and expenses

(a) Revenue and other operating income

Accounting policy

Revenue from contracts with customers

The Group generates revenue through the sale of crude oil, gas and condensate to third parties, and through the provision of infrastructure to its customers for tariff income. Revenue from contracts with customers is recognised when control of the goods or services is transferred to the customer at an amount that reflects the consideration to which the Group expects to be entitled in exchange for those goods or services. The Group has concluded that it is the principal in its revenue arrangements because it typically controls the goods or services before transferring them to the customer. The normal credit term is 30 days or less upon performance of the obligation.

Sale of crude oil, gas and condensate

The Group sells crude oil, gas and condensate directly to customers. The sale represents a single performance obligation, being the sale of barrels equivalent to the customer on taking physical possession or on delivery of the commodity into an infrastructure. At this point the title passes to the customer and revenue is recognised. The Group principally satisfies its performance obligations at a point in time; the amounts of revenue recognised relating to performance obligations satisfied over time are not significant. Transaction prices are referenced to quoted prices, plus or minus an agreed fixed premium or discount rate to an appropriate benchmark, if applicable.

Tariff revenue for the use of Group infrastructure

Tariffs are charged to customers for the use of infrastructure owned by the Group. The revenue represents the performance of an obligation for the use of Group assets over the life of the contract. The use of the assets is not separable as they are interdependent in order to fulfil the contract and no one item of infrastructure can be individually isolated. Revenue is recognised as the performance obligations are satisfied over the period of the contract, generally a period of 12 months or less, on a monthly basis based on throughput at the agreed contracted rates.

Other operating income

Other operating revenue is recognised to the extent that it is probable economic benefits will flow to the Group and the revenue can be reliably measured.

The Group enters into commodity derivative trading transactions which can be settled net in cash. Accordingly, any gains or losses are not considered to constitute revenue from contracts with customers in accordance with the requirements of IFRS 15, rather are accounted for in line with IFRS 9 and included within other operating income (see note 18).

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Revenue from contracts with customers:		
Revenue from crude oil sales	**858,166**	1,020,266
Revenue from gas and condensate sales[(i)]	**200,526**	164,647
Tariff revenue	**3,573**	2,644
Total revenue from contracts with customers	**1,062,265**	1,187,557
Realised gains/(losses) on commodity derivative contracts (see note 18)	**8,744**	(12,907)
Unrealised gains/(losses) on commodity derivative contracts (see note 18)	**45,178**	3,090
Other	**2,113**	2,969
Total revenue and other operating income	**1,118,300**	1,180,709

(i) Includes onward sale of third-party gas purchases not required for injection activities at Magnus (see note 4(b))

4. Revenue and expenses continued

Disaggregation of revenue from contracts with customers

	Year ended 31 December 2025 $'000				Year ended 31 December 2024 $'000			
	North Sea	Malaysia	Vietnam	Total	North Sea	Malaysia	Vietnam	Total
Revenue from contracts with customers:								
Revenue from crude oil sales	**703,071**	**103,299**	**51,796**	**858,166**	900,310	119,956	–	1,020,266
Revenue from gas and condensate sales[(i)]	**192,074**	**7,406**	**1,046**	**200,526**	162,951	1,696	–	164,647
Tariff revenue	**168**	**3,405**	**–**	**3,573**	568	2,076	–	2,644
Total revenue from contracts with customers	**895,313**	**114,110**	**52,842**	**1,062,265**	1,063,829	123,728	–	1,187,557

(i) Includes onward sale of third-party gas purchases not required for injection activities at Magnus (see note 4(b))

(b) Cost of sales

Accounting policy

Production imbalances, movements in under/over-lift and movements in inventory are included in cost of sales. The over-lift liability is recorded at the cost of the production imbalance to represent a provision for production costs attributable to the volumes sold in excess of entitlement. The under-lift asset is recorded at the lower of cost and net realisable value ('NRV'), consistent with IAS 2, to represent a right to additional physical inventory. An under-lift of production from a field is included in current receivables and an over-lift of production from a field is included in current liabilities.

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Production costs	**344,580**	307,634
Tariff and transportation expenses	**69,189**	70,449
Realised (gain)/loss on derivative contracts related to operating costs (see note 18)	**(19,711)**	4,735
Unrealised (gains)/losses on derivative contracts related to operating costs (see note 18)	**(32,342)**	2,823
Other non-cash UKA losses	**11,490**	1,335
Change in lifting position	**3,350**	3,528
Crude oil inventory movement	**14,057**	(1,356)
Depletion of oil and gas assets[(i)]	**267,299**	263,251
Other cost of operations[(ii)]	**179,628**	134,984
Total cost of sales	**837,540**	787,383

(i) Includes $29.2 million (2024: $27.9 million) Kraken and Vietnam FPSO right-of-use asset depreciation charge and $26.3 million (2024: $23.5 million) of other right-of-use assets depreciation charge
(ii) Includes $166.2 million (2024: $125.7 million) of purchases and associated costs of third-party gas not required for injection activities at Magnus, which is sold on

(c) General and administration expenses

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Staff costs (see note 4(e))	**73,634**	75,833
Depreciation[(i)]	**5,129**	6,040
Other general and administration costs	**26,359**	26,748
Recharge of costs to operations and joint venture partners	**(97,640)**	(102,919)
Total general and administration expenses	**7,482**	5,702

(i) Includes $3.7 million (2024: $3.4 million) right-of-use assets depreciation charge on buildings

4. Revenue and expenses continued

(d) Other income/(expenses)

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Net foreign exchange (losses)/gains	**(28,330)**	9,975
Rental income from office sublease	**1,893**	2,201
Fair value changes in contingent consideration (see note 21)	**387,145**	(15,904)
Change in decommissioning provisions (see note 22)	**(9,727)**	(6,666)
Change in Thistle decommissioning provision (see note 22)	**(4,772)**	(412)
Drilling rig contract cancellation costs[(i)]	**–**	(14,629)
Write-down of relinquished assets/unsuccessful exploration expenditure (see note 11)	**(173)**	(183)
Insurance income	**(53)**	1,663
Reversal of provisions	**4,685**	–
Other	**19,029**	19,273
Total other income/(expenses)	**369,697**	(4,682)

(i) In 2024, drilling rig contract at Kraken was terminated due to a deferral of infill drilling

(e) Staff costs

Accounting policy

Short-term employee benefits, such as salaries, social premiums and holiday pay, are expensed when incurred.

The Group's pension obligations consist of defined contribution plans. The Group pays fixed contributions with no further payment obligations once the contributions have been paid. The amount charged to the Group income statement in respect of pension costs reflects the contributions payable in the year. Differences between contributions payable during the year and contributions actually paid are shown as either accrued liabilities or prepaid assets in the balance sheet.

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Wages and salaries	**62,286**	66,700
Social security costs	**6,202**	5,899
Defined contribution pension costs	**5,932**	5,265
(Credit)/expense of share-based payments (see note 20)	**(669)**	983
Other staff costs	**13,969**	12,300
Total employee costs	**87,720**	91,147
Contractor costs	**46,529**	37,493
Total staff costs	**134,249**	128,640
General and administration staff costs (see note 4(c))	**73,634**	75,833
Non-general and administration costs	**60,615**	52,807
Total staff costs	**134,249**	128,640

The monthly average number of persons, excluding contractors, employed by the Group during the year was 694, with 359 in the general and administration staff costs and 335 directly attributable to assets (2024: 673 of which 336 in general and administration and 337 directly attributable to assets). Compensation of key management personnel is disclosed in note 26.

(f) Auditor's remuneration

The following amounts for the year ended 31 December 2025 and for the comparative year ended 31 December 2024 were payable by the Group to Deloitte:

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Fees payable to the Company's auditor for the audit of the parent company and Group financial statements	**1,476**	1,367
The audit of the Company's subsidiaries	**303**	173
Total audit	**1,779**	1,540
Audit-related assurance services[(i)]	**694**	589
Total audit and audit-related assurance services	**2,473**	2,129
Total auditor's remuneration	**2,473**	2,129

(i) Audit-related assurance services in both years primarily include the review of the Group's interim results, G&A assurance review and the provision of customary comfort letters in respect of the Group's refinancing activities. Included within 2025 is £30,000 (2024: nil) related to other services that are not assurance related

5. Finance costs/income

Accounting policy

Borrowing costs are recognised as interest payable within finance costs at amortised cost using the effective interest method.

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Finance costs:		
Loan interest payable	**6,027**	18,524
Bond interest payable	**69,269**	54,971
Unwinding of discount on decommissioning provisions (see note 22)	**35,912**	30,290
Unwinding of discount on other provisions (see note 22)	**755**	911
Debt refinancing fees (see note 17)	**–**	4,809
Finance charges payable under leases (see note 23)	**25,100**	27,673
Finance fees on loans and bonds including amortisation of capitalised fees	**15,337**	14,473
Other financial expenses	**12,191**	7,771
Total finance costs	**164,591**	159,422
Finance income:		
Bank interest receivable	**6,535**	11,110
RockRose loan interest (see note 18(f))	**2,639**	3,263
Other financial income	**50**	135
Total finance income	**9,224**	14,508

6. Income tax

(a) Income tax

Accounting policy

Current tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities, based on tax rates and laws that are enacted or substantively enacted by the balance sheet date.

The Group's operations are subject to a number of specific tax rules which apply to exploration, development and production. 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 estimates and judgements, including those required in calculating the effective tax rate.

Deferred tax is provided in full on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the Group financial statements. However, deferred tax is not accounted for if a temporary difference arises from initial recognition of other assets or liabilities in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit or loss. Deferred tax is measured on an undiscounted basis using tax rates (and laws) that have been enacted or substantively enacted by the balance sheet date and are expected to apply when the related deferred tax asset is realised or the deferred tax liability is settled. Deferred tax assets are recognised to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilised.

Deferred tax liabilities are recognised for taxable temporary differences arising on investments in subsidiaries, except where the Group is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

The carrying amount of deferred income tax assets is reviewed at each balance sheet date. Deferred income tax assets and liabilities are offset only if a legal right exists to offset current tax assets against current tax liabilities, the deferred income taxes relate to the same taxation authority and that the Group intends to make a single net payment.

The Group has applied the mandatory exception to recognising and disclosing information about the deferred tax assets and liabilities relating to Pillar Two income taxes in accordacne with the amendments to IAS 12 published by the International Accounting Standards Board ('IASB') on 23 May 2023.

Production taxes

In addition to corporate income taxes, the Group's financial statements also include and disclose production taxes on net income determined from oil and gas production.

Production tax relates to Petroleum Revenue Tax ('PRT') within the UK and is accounted for under IAS 12 Income Taxes since it has the characteristics of an income tax as it is imposed under government authority and the amount payable is based on taxable profits of the relevant fields. Current and deferred PRT is provided on the same basis as described above for income taxes.

Investment allowance

The UK taxation regime provides for a reduction in ring-fence supplementary charge tax where investment in new or existing UK assets qualify for a relief known as investment allowance. Investment allowance must be activated by commercial production from the same field before it can be claimed. The Group has both unactivated and activated investment allowances which could reduce future supplementary charge taxation. The Group's policy is that investment allowance is recognised as a reduction in the charge to taxation in the years claimed.

6. Income tax continued

Energy Profits Levy

The Energy (Oil & Gas) Profits Levy Act 2022 ('EPL') applies an additional tax on the profits earned by oil and gas companies from the production of oil and gas on the United Kingdom Continental Shelf until 31 March 2030. This is accounted for under IAS 12 Income Taxes since it has the characteristics of an income tax as it is imposed under government authority and the amount payable is based on taxable profits of the relevant UK companies. Current and deferred tax is provided on the same basis as described above for income taxes.

The major components of income tax expense/(credit) are as follows:

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Current UK income tax		
Current income tax charge	**1,051**	–
Current overseas income tax		
Current income tax charge	**12,351**	11,432
Adjustments in respect of current income tax of previous years	**307**	(746)
UK Energy Profits Levy		
Current year charge	**84,069**	10,262
Adjustments in respect of current charge of previous years(i)	**19,378**	(8,803)
Total current income tax	**117,156**	12,145
Deferred UK income tax		
Relating to origination and reversal of temporary differences	**222,897**	42,745
Adjustments in respect of deferred income tax of previous years(i)	**12,209**	(9,103)
Deferred overseas income tax		
Relating to origination and reversal of temporary differences	**7,581**	7,071
Adjustments in respect of deferred income tax of previous years	**(363)**	31
Deferred UK Energy Profits Levy		
Relating to origination and reversal of temporary differences	**134,985**	11,156
Adjustments in respect of changes in tax rates	**–**	6,889
Adjustments in respect of deferred charge of previous years	**(2,600)**	1,907
Total deferred income tax	**374,709**	60,696
Income tax expense reported in profit or loss	**491,865**	72,841

(i) Adjustments in respect of previous years arose upon finalisation of various UK tax returns and include an additional EPL current tax liability of $19.4 million and an additional deferred tax liability of $7.8 million. These adjustments reflect corrections to the amount of tax relief accrued in the 2024 financial year end group tax position arising as a result of reclassifications made during that year from inventory to property, plant and equipment as part of a review of well supplies

6. Income tax continued

(b) Reconciliation of total income tax charge

A reconciliation between the income tax charge and the product of accounting profit multiplied by the UK statutory tax rate is as follows:

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Profit/(loss) before tax	**493,427**	166,614
UK statutory tax rate applying to North Sea oil and gas activities of 40% (2024: 40%)	**197,371**	66,646
Supplementary corporation tax non-deductible expenditure	**4,383**	5,809
Non-deductible expenditure[(i)]	**8,537**	26,114
Non-taxable gain on sale of assets	**–**	505
Petroleum revenue tax (net of income tax benefit)	**(363)**	(8,938)
Tax in respect of non-ring-fence trade	**13,776**	7,298
Deferred tax asset not recognised in respect of non-ring-fence trade	**21,426**	12,243
Deferred tax asset recognised on previously unrecognised losses	**–**	(48,115)
UK Energy Profits Levy[(ii)]	**95,179**	(13,921)
UK Energy Profits Levy – changes in tax rates [(iii)]	**–**	6,889
UK Energy Profits Levy – abolishment of Investment Allowance [(iii)]	**–**	35,339
UK Energy Profits Levy – extension to March 2030[(iv)]	**123,875**	–
Adjustments in respect of prior years	**28,931**	(16,713)
Overseas tax rate differences	**(1,323)**	2,045
Share-based payments	**(132)**	(1,407)
Other differences	**205**	(953)
At the effective income tax rate of 100% (2024: 44%)	**491,865**	72,841

(i) Predominantly in relation to non-qualifying expenditure relating to the initial recognition exemption utilised under IAS 12 upon acquisition of Golden Eagle given that at the time of the transaction, it affected neither accounting profit nor taxable profit
(ii) This consists of an Energy Profits Levy current tax charge of $84.1 million (2024: $10.30 million) and deferred Energy Profits Levy charge of $11.1 million (2024: $18.0 million. The 2025 charge was impacted by the higher rate of 38% which applied from 1 November 2024 (Period to 31 October 2024: 35%) and the removal of investment allowances
(iii) Refers to the impact of the increased rate and removal of investment allowances that were substantially enacted in 2024
(iv) Reflects the impact of the substantively enacted two-year extension referred to in part (e) below

(c) Deferred income tax

Deferred income tax relates to the following:

	Group balance sheet		Charge/(credit) for the year recognised in profit or loss	
	2025 $'000	2024 $'000	2025 $'000	2024 $'000
Deferred tax liability				
Accelerated capital allowances	**1,039,396**	911,501	**126,945**	33,701
	1,039,396	911,501		
Deferred tax asset				
Losses	**(627,124)**	(717,900)	**90,777**	(22,012)
Decommissioning liability	**(296,069)**	(263,705)	**(33,047)**	2,095
Other temporary differences[(i)]	**(137,214)**	(331,679)	**190,034**	46,912
	(1,060,407)	(1,313,284)	**374,709**	60,696
Net deferred tax (assets)[(ii)]	**(21,011)**	(401,783)		
Reflected in the balance sheet as follows:				
Deferred tax assets	**(271,375)**	(506,481)		
Deferred tax liabilities	**250,364**	104,698		
Net deferred tax (assets)	**(21,011)**	(401,783)		

(i) Predominantly includes $107.7 million on deferred income in note 24 and $17.5 million Petroleum Revenue Tax refunds
(ii) The total amounts for EPL included in net deferred assets are $276.3 million for accelerated capital allowances offset by $56.7 million for other items, which predominantly includes $52.5 million related to deferred income (note 24)

6. Income tax continued

Reconciliation of net deferred tax assets/(liabilities)

	2025 $'000	2024 $'000
At 1 January	**401,783**	462,479
Tax expense during the period recognised in profit or loss	**(374,709)**	(60,696)
Deferred taxes acquired in business combinations (see note 30)	**(6,063)**	–
At 31 December	**21,011**	401,783

(d) Tax losses

The Group's deferred tax assets at 31 December 2025 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. In accordance with IAS 12 Income Taxes, the Group assesses the recoverability of its deferred tax assets at each period end. Sensitivities have been run on the oil price assumption, with a 10% change being considered a reasonable possible change for the purposes of sensitivity analysis (see note 2). The Group is currently recognising all UK tax losses (with the exception of those noted below) and neither a 10% increase or 10% decrease in oil price would result in any change to the full recognition.

The Group has unused UK mainstream corporation tax losses of $578.4 million (2024: $496.1 million) and ring-fence tax losses of $1,117.5 million (2024: $1,117.5 million) associated with EnQuest Progress Limited, for which no deferred tax asset has been recognised at the balance sheet date as recovery of these losses is to be established. In addition, the Group has not recognised a deferred tax asset for the adjustment to bond valuations on the adoption of IFRS 9. The benefit of this deduction is taken over ten years, with a deduction of $2.2 million being taken in the current period and the remaining benefit of $4.2 million (2024: $6.3 million) remaining unrecognised.

The Group has unused Malaysian income tax losses of $16.3 million (2024: $14.7 million) arising in respect of the Tanjong Baram RSC for which no deferred tax asset has been recognised at the balance sheet date due to uncertainty of recovery of these losses.

No deferred tax has been provided on unremitted earnings of overseas subsidiaries. The Finance Act 2009 exempted foreign dividends from the scope of UK corporation tax where certain conditions are satisfied.

(e) Changes in legislation

On 29 July 2024, the UK Government announced various changes to the EPL including an extension to 31 March 2030 (previously 31 March 2028) to which the EPL applies. This extension was substantively enacted on 3 March 2025, with the impact on the current period financial statements tax charge and deferred tax for EPL being $123.9 million.

7. Earnings per share

The calculation of basic earnings per share is based on the profit after tax and on the weighted average number of Ordinary shares in issue during the period. Diluted earnings per share is adjusted for the effects of Ordinary shares granted under the share-based payment plans, which are held in the Employee Benefit Trust, unless it has the effect of increasing the profit or decreasing the loss attributable to each share.

At 31 December 2025, the Group held 20,000,000 Ordinary shares (2024: 25,000,000 Ordinary shares) which were classified in the balance sheet as Treasury shares. The Treasury shares have been excluded for the purposes of calculating the basic and diluted earnings per share at 31 December 2025.

Basic and diluted earnings per share are calculated as follows:

	Profit/(loss) after tax		Weighted average number of Ordinary shares		Earnings per share	
	Year ended 31 December		Year ended 31 December		Year ended 31 December	
	2025 $'000	2024 $'000	2025 million	2024 million	2025 $	2024 $
Basic	**1,562**	93,773	**1,859.9**	1,891.9	**0.001**	0.050
Dilutive potential of Ordinary shares granted under share-based incentive schemes	**–**	–	**24.2**	24.3	**–**	(0.001)
Diluted	**1,562**	93,773	**1,884.1**	1,916.2	**0.001**	0.049

8. Distributions paid and proposed

The Company paid dividends of 0.616 pence per share during the year ended 31 December 2025 (2024: none).

Following the successful implementation of its capital discipline strategy, EnQuest remains committed to delivering sustainable shareholder returns. Building on the inaugural dividend paid last year, the Board is pleased to propose a second final ordinary dividend of 0.801 pence per share (equivalent to approximately $20.0million). This proposed dividend is subject to approval by shareholders at the Annual General Meeting scheduled for 22 May 2026, and accordingly has not been recognised as a liability as at 31 December 2025. If approved, the dividend will be paid on 5 June 2026 to shareholders on the register at 8 May 2026, with shares trading ex-dividend from 7 May 2026.

9. Property, plant and equipment

Accounting policy

Property, plant and equipment is stated at cost less accumulated depreciation and accumulated impairment charges.

Cost

Cost comprises the purchase price or cost relating to development, including the construction, installation and completion of infrastructure facilities such as platforms, pipelines and development wells and any other costs directly attributable to making that asset capable of operating as intended by management. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

The carrying amount of an item of property, plant and equipment is derecognised on disposal or when no future economic benefits are expected from its use. The gain or loss arising from the derecognition of an item of property, plant and equipment is included in the other operating income or expense line item in the Group income statement when the asset is derecognised.

Development assets

Expenditure relating to development of assets, including the construction, installation and completion of infrastructure facilities such as platforms, pipelines and development wells, is capitalised within property, plant and equipment.

Carry arrangements

Where amounts are paid on behalf of a carried party, these are capitalised. Where there is an obligation to make payments on behalf of a carried party and the timing and amount are uncertain, a provision is recognised. Where the payment is a fixed monetary amount, a financial liability is recognised.

Borrowing costs

Borrowing costs directly attributable to the construction of qualifying assets, which are assets that necessarily take a substantial period of time to prepare for their intended use, are capitalised during the development phase of the project until such time as the assets are substantially ready for their intended use.

Depletion and depreciation

Oil and gas assets are depleted, on a field-by-field basis, using the unit of production method based on entitlement to proven and probable reserves, taking account of estimated future development expenditure relating to those reserves. Changes in factors which affect unit of production calculations are dealt with prospectively. Depletion of oil and gas assets is taken through cost of sales.

Depreciation on other elements of property, plant and equipment is provided on a straight-line basis, and taken through general and administration expenses, at the following rates:

Office furniture and equipment	Five years
Fixtures and fittings	Ten years
Right-of-use assets[(i)]	Lease term

(i) Excludes Kraken and Vietnam FPSOs which are depleted using the unit of production method in accordance with the related oil and gas assets

Each asset's estimated useful life, residual value and method of depreciation is reviewed and adjusted if appropriate at each financial year end. Any changes in estimate are accounted for on a prospective basis.

9. Property, plant and equipment continued

Impairment of tangible (excluding goodwill)

At each balance sheet date, discounted cash flow models comprising asset-by-asset life-of-field projections and risks specific to assets, using Level 3 inputs (based on IFRS 13 fair value hierarchy), have been used to determine the recoverable amounts for each CGU. The life of a field depends on the interaction of a number of variables; see note 2 for further details. Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis, including operating and capital expenditure, are derived from the Group's business plan. Oil price assumptions and discount rate assumptions used were as disclosed in note 2. If the recoverable amount of an asset (or CGU) is estimated to be less than its carrying amount, the carrying amount of the asset (or CGU) is reduced to its recoverable amount. An impairment loss is recognised immediately in the Group income statement.

Where an impairment loss subsequently reverses, the carrying amount of the asset (or CGU) is increased to the revised estimate of its recoverable amount, but only so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset (or CGU) in prior years. A reversal of an impairment loss is recognised immediately in the Group income statement.

	Oil and gas assets $'000	Office furniture, fixtures and fittings $'000	Right-of-use assets (note 23) $'000	Total $'000
Cost:				
At 1 January 2024	9,243,807	68,578	904,994	10,217,379
Additions	325,813	394	16,453	342,660
Change in decommissioning provision	(741)	–	–	(741)
At 1 January 2025	**9,568,879**	**68,972**	**921,447**	**10,559,298**
Additions	**176,552**	**277**	**32,302**	**209,131**
Acquisition (see note 30)	**24,716**	**–**	**33,002**	**57,718**
Disposals	**(1,672)**	**–**	**(37,881)**	**(39,553)**
Change in decommissioning provision (note 22)	**77,862**	**–**	**–**	**77,862**
At 31 December 2025	**9,846,337**	**69,249**	**948,870**	**10,864,456**
Accumulated depreciation, depletion and impairment:				
At 1 January 2024	7,364,063	59,314	497,262	7,920,639
Charge for the year	211,873	2,683	54,735	269,291
Net impairment charge/(reversal) for the year	75,428	–	(4,014)	71,414
At 1 January 2025	**7,651,364**	**61,997**	**547,983**	**8,261,344**
Charge for the year	**211,616**	**1,628**	**59,184**	**272,428**
Net impairment (reversal)/charge for the year	**23,019**	**–**	**(28,838)**	**(5,819)**
Disposal	**–**	**–**	**(33,628)**	**(33,628)**
At 31 December 2025	**7,885,999**	**63,625**	**544,701**	**8,494,325**
Net carrying amount:				
At 31 December 2025	**1,960,338**	**5,624**	**404,169**	**2,370,131**
At 31 December 2024	1,917,515	6,975	373,464	2,297,954
At 1 January 2024	1,879,744	9,264	407,732	2,296,740

The amount of borrowing costs capitalised during the year ended 31 December 2025 was nil (2024: nil), reflecting the short-term nature of the Group's capital expenditure programmes.

Impairments

Impairments to the Group's producing assets and reversals of impairments are set out in the table below:

	Impairment reversal/(charge)		Recoverable amount(i)	
	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000	31 December 2025 $'000	31 December 2024 $'000
North Sea	**5,819**	(71,414)	**1,100,312**	1,172,487
Net pre-tax impairment reversal/(charge)	**5,819**	(71,414)		

(i) Recoverable amount has been determined on a fair value less costs of disposal basis (see note 2 for further details of judgements, estimates and assumptions made in relation to impairments). The amounts disclosed above are in respect of assets where an impairment (or reversal) has been recorded. Assets which did not have any impairment or reversal are excluded from the amounts disclosed

For information on judgements, estimates and assumptions made in relation to impairments, along with sensitivity analysis, see Use of judgements, estimates and assumptions: recoverability of asset carrying values within note 2.

9. Property, plant and equipment continued

The 2025 net impairment reversal of $5.8 million relates to producing assets in the UK North Sea (an impairment reversal of $94.3 million at Kraken offset by charges of $33.5 million for GKA and Scolty/Crathes CGU, $43.5 million for Golden Eagle and $11.5 million for Alba). Impairment reversals/charges were primarily driven by a combination of lower discount rate, changes in production and cost profiles, including the impact of weaker USD, and lower near-term oil price assumptions.

The 2024 net impairment charge of $71.4 million related to producing assets in the UK North Sea (charges of $2.0 million for GKA and Scolty/Crathes CGU, $62.5 million for Golden Eagle and $20.1 million for Alba offset by an impairment reversal of $13.2 million at Kraken). Impairment charges/reversals were primarily driven by EPL revisions, lower near-term oil price assumptions and changes in production profiles, partially offset by a lower discount rate.

10. Goodwill

Accounting policy

Cost

Goodwill arising on a business combination is initially measured at cost, being the excess of the cost of the business combination over the net fair value of the identifiable assets, liabilities and contingent liabilities of the entity at the date of acquisition. If the fair value of the net assets acquired is in excess of the aggregate consideration transferred, the Group reassesses whether it has correctly identified all of the assets acquired and all of the liabilities assumed and reviews the procedures used to measure the amounts to be recognised at the acquisition date. If the reassessment still results in an excess of the fair value of net assets acquired over the aggregate consideration transferred, the gain is recognised in profit or loss.

Impairment of goodwill

Following initial recognition, goodwill is stated at cost less any accumulated impairment losses. In accordance with IAS 36 Impairment of Assets, goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the recoverable amount of the CGU (or group of CGUs) to which the goodwill relates should be assessed.

For the purposes of impairment testing, goodwill acquired is allocated to the CGU (or group of CGUs) that is expected to benefit from the synergies of the combination. Each unit or units to which goodwill is allocated represents the lowest level within the Group at which the goodwill is monitored for internal management purposes. Impairment is determined by assessing the recoverable amount of the CGU (or groups of CGUs) to which the goodwill relates. Where the recoverable amount of the CGU (or groups of CGUs) is less than the carrying amount of the CGU (or group of CGUs) containing goodwill, an impairment loss is recognised. Impairment losses relating to goodwill cannot be reversed in future periods. For information on significant estimates and judgements made in relation to impairments, see Use of judgements, estimates and assumptions: recoverability of asset carrying values within note 2.

A summary of goodwill is presented below:

	2025 $'000	2024 $'000
Cost and net carrying amount		
At 1 January	**134,400**	134,400
Acquisition (see note 30)	**5,110**	–
At 31 December	**139,510**	134,400

The majority of the goodwill relates to the 75% acquisition of the Magnus oil field and associated interests. The remaining opening balance relates to the acquisition of the GKA and Scolty Crathes fields. During 2025, the Group acquired Block 12W in Vietnam (see note 30) resulting in goodwill recognised of $5.1 million.

Impairment testing of goodwill

Goodwill, which has been acquired through business combinations, has been allocated as appropriate to the UK North Sea segment grouping of CGUs and the Vietnam CGU, and these are therefore the lowest level at which goodwill is reviewed. The UK North Sea is a combination of oil and gas assets, as detailed within property, plant and equipment (note 9), while the Vietnam CGU relates to the Block 12W asset.

The recoverable amounts of the segment and fields have been determined on a fair value less costs of disposal basis. See notes 2 and 9 for further details. An impairment charge of nil was taken in 2025 (2024: nil) based on a fair value less costs to dispose valuation of the CGUs as described above.

Sensitivity to changes in assumptions

The Group's recoverable value of assets is highly sensitive, inter alia, to oil price achieved and production volumes. A sensitivity has been run on the oil price assumptions, with a 10% change being considered to be a reasonably possible change for the purposes of sensitivity analysis (see note 2). A 10% reduction in oil price would result in an impairment charge of $70.7 million (2024: 10% reduction would result in an impairment charge of $66.7 million). A 15% reduction in oil price would fully impair goodwill (2024: 17%), however Management do not consider this to be a reasonably possible change.

11. Intangible assets

Accounting policy

Exploration and appraisal assets

Exploration and appraisal assets have indefinite useful lives and are accounted for using the successful efforts method of accounting. Pre-licence costs are expensed in the period in which they are incurred. Expenditure directly associated with exploration, evaluation or appraisal activities is initially capitalised as an intangible asset. Such costs include the costs of acquiring an interest, appraisal well drilling costs, payments to contractors and an appropriate share of directly attributable overheads incurred during the evaluation phase. For such appraisal activity, which may require drilling of further wells, costs continue to be carried as an asset, whilst related hydrocarbons are considered capable of commercial development. Such costs are subject to technical, commercial and management review to confirm the continued intent to develop, or otherwise extract value. When this is no longer the case, the costs are written off as exploration and evaluation expenses in the Group income statement. When exploration licences are relinquished without further development, any previous impairment loss is reversed and the carrying costs are written off through the Group income statement. When assets are declared part of a commercial development, related costs are transferred to property, plant and equipment. All intangible oil and gas assets are assessed for any impairment prior to transfer and any impairment loss is recognised in the Group income statement.

During the year ended 31 December 2025, there was no impairment of historical exploration and appraisal expenditures (2024: nil).

Other intangibles

UK emissions allowances ('UKAs') purchased to settle the Group's liability related to emissions are recognised on the balance sheet as an intangible asset at cost. The UKAs will be derecognised upon settling the liability with the respective regulator.

	Exploration and appraisal assets $'000	UK emissions allowances $'000	Total $'000
Cost:			
At 1 January 2024	127,476	876	128,352
Additions	3,686	1,138	4,824
Write-off of unsuccessful exploration expenditure	(183)	–	(183)
Disposal	(1,263)	(876)	(2,139)
At 1 January 2025	**129,716**	**1,138**	**130,854**
Additions	**4,225**	**6,472**	**10,697**
Write-off of relinquished licence	**(173)**	**–**	**(173)**
Disposal	**–**	**(6,500)**	**(6,500)**
At 31 December 2025	**133,768**	**1,110**	**134,878**
Accumulated impairment:			
At 1 January 2024, 1 January 2025 and 31 December 2025	**(109,153)**	**–**	**(109,153)**
Net carrying amount:			
At 31 December 2025	**24,615**	**1,110**	**25,725**
At 31 December 2024	20,563	1,138	21,701
At 1 January 2024	18,323	876	19,199

12. Inventories

Accounting policy

Inventories of consumable well supplies and inventories of hydrocarbons are stated at the lower of cost and NRV, cost being determined on an average cost basis.

	2025 $'000	2024 $'000
Hydrocarbon inventories	**8,487**	22,544
Well supplies	**24,272**	26,432
	32,759	48,976

During 2025, a net charge of $16.9 million was recognised within cost of sales in the Group income statement relating to inventory, reflecting additional sales related to Magnus hydrocarbon stock (2024: net gain of $6.9 million).

The inventory valuation at 31 December 2025 is stated net of a provision of $22.5 million (2024: $28.5 million) to write-down well supplies to their estimated net realisable value.

13. Cash and cash equivalents

Accounting policy

Cash and cash equivalents includes cash at bank, cash in hand, cash deposited in relation to decommissioning security arrangements and highly liquid interest-bearing securities with original maturities of three months or fewer.

	2025 $'000	2024 $'000
Available cash	**265,886**	226,317
Restricted cash	**2,960**	53,922
Cash and cash equivalents	**268,846**	280,239

The carrying value of the Group's cash and cash equivalents is considered to be a reasonable approximation to their fair value due to their short-term maturities.

Restricted cash

Restricted cash at 31 December 2025 includes a residual $1.2 million in accounts relating to 2025 decommissioning security agreement obligations (31 December 2024: $53.4 million). The remaining $1.8 million of restricted cash relates to a Performance Bond in Indonesia (31 December 2024: $0.5 million related to bank guarantees for the Group's Malaysian assets).

14. Financial instruments and fair value measurement

Accounting policy

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument of another entity. Financial instruments are recognised when the Group becomes a party to the contractual provisions of the financial instrument.

Financial assets and financial liabilities are offset and the net amount is reported in the Group balance sheet if there is a currently enforceable legal right to offset the recognised amounts and there is an intention to settle on a net basis.

Financial assets

Financial assets are classified, at initial recognition, as amortised cost, fair value through other comprehensive income ('FVOCI'), or fair value through profit or loss ('FVPL'). The classification of financial assets at initial recognition depends on the financial assets' contractual cash flow characteristics and the Group's business model for managing them. The Group does not currently hold any financial assets at FVOCI, i.e. debt financial assets.

Financial assets are derecognised when the contractual rights to the cash flows from the financial asset expire, or when the financial asset and substantially all the risks and rewards are transferred.

Financial assets at amortised cost

Trade receivables, other receivables and joint operation receivables are measured initially at fair value and subsequently recorded at amortised cost, using the effective interest rate ('EIR') method, and are subject to impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired and EIR amortisation is included within finance costs.

The Group measures financial assets at amortised cost if both of the following conditions are met:

- The financial asset is held in a business model with the objective to hold financial assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Prepayments, which are not financial assets, are measured at historical cost.

14. Financial instruments and fair value measurement continued

Impairment of financial assets

The Group recognises a loss allowance for expected credit loss ('ECL'), where material, for all financial assets held at the balance sheet date. ECLs are based on the difference between the contractual cash flows due to the Group, and the discounted actual cash flows that are expected to be received. Where there has been no significant increase in credit risk since initial recognition, the loss allowance is equal to 12-month expected credit losses. Where the increase in credit risk is considered significant, lifetime credit losses are provided. For trade receivables, a lifetime credit loss is recognised on initial recognition where material.

The provision rates are based on days past due for groupings of customer segments with similar loss patterns (i.e. by geographical region, product type, customer type and rating) and are based on historical credit loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment. The Group evaluates the concentration of risk with respect to trade receivables and contract assets as low, as its customers are joint venture partners and there are no indications of change in risk. Generally, trade receivables are written off when they become past due for more than one year and are not subject to enforcement activity.

Financial liabilities

Financial liabilities are classified, at initial recognition, as amortised cost or at FVPL.

Financial liabilities are derecognised when they are extinguished, discharged, cancelled or they expire. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as the derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised in the Group income statement.

Financial liabilities at amortised cost

Loans and borrowings, trade payables and other creditors are measured initially at fair value net of directly attributable transaction costs and subsequently recorded at amortised cost, using the EIR method. Loans and borrowings are interest bearing. Gains and losses are recognised in profit or loss when the liability is derecognised and EIR amortisation is included within finance costs.

Financial instruments at FVPL

The Group holds derivative financial instruments classified as held for trading, not designated as effective hedging instruments. The derivative financial instruments include forward currency contracts and commodity contracts, to address the respective risks; see note 27. The Group also enters into forward contracts for the purchase of UKAs to manage its exposure to carbon emission credit prices. Derivatives are carried as financial assets when the fair value is positive and as financial liabilities when the fair value is negative.

Financial instruments at FVPL are carried in the Group balance sheet at fair value, with net changes in fair value recognised in the Group income statement.

Financial assets with cash flows that are not solely payments of principal and interest are classified and measured at FVPL, irrespective of the business model. All financial assets not classified as measured at amortised cost or FVOCI as described above are measured at FVPL. Financial instruments with embedded derivatives are considered in their entirety when determining whether their cash flows are solely payment of principal and interest.

The Group also holds contingent consideration (see note 21) and a listed equity investment (see note 18). The movements of both are recognised within the Group income statement.

14. Financial instruments and fair value measurement continued

Fair value measurement

The following table provides the fair values and fair value measurement hierarchy of the Group's other financial assets and liabilities:

31 December 2025	Notes	Carrying Value $'000	Total $'000	Quoted prices in active markets (Level 1) $'000	Significant observable inputs (Level 2) $'000	Significant unobservable inputs (Level 3) $'000
Financial assets measured at fair value:						
Derivative financial assets measured at FVPL						
Commodity contracts	18(a)	**36,754**	**36,754**	**–**	**36,754**	**–**
Forward foreign currency contracts	18(a)	**932**	**932**	**–**	**932**	**–**
Forward UKA contracts	18(a)	**28,721**	**28,721**	**–**	**28,721**	**–**
Other financial assets measured at FVPL						**–**
Quoted equity shares		**6**	**6**	**6**	**–**	**–**
Total financial assets measured at fair value		**66,413**	**66,413**	**6**	**66,407**	**–**
Financial assets measured at amortised cost:						
Vendor financing facility	18(f)	**43,896**	**43,896**	**–**	**43,896**	**–**
Total financial assets measured at amortised cost[(i)]		**43,896**	**43,896**	**–**	**43,896**	**–**
Liabilities measured at fair value:						
Derivative financial liabilities measured at FVPL						
Commodity contracts	18(a)	**1,997**	**1,997**	**–**	**1,997**	**–**
Forward UKA contracts	18(a)	**8,394**	**8,394**	**–**	**8,394**	**–**
Other financial liabilities measured at FVPL						
Contingent consideration	21	**84,620**	**84,620**	**–**	**–**	**84,620**
Total liabilities measured at fair value		**95,011**	**95,011**	**–**	**10,391**	**84,620**
Liabilities measured at amortised cost						
Interest-bearing loans and borrowings[(i)]	17	**60,324**	**60,324**	**–**	**60,324**	**–**
GBP retail bond 9.00%[(ii)]	17	**181,812**	**180,892**	**180,892**	**–**	**–**
USD high yield bond 11.625%[(ii)]	17	**465,328**	**470,878**	**470,878**	**–**	**–**
Total liabilities measured at amortised cost[(iii)]		**707,464**	**712,094**	**651,770**	**60,324**	**–**

(i) Amortised cost is a reasonable approximation of the fair value, carrying value includes accrued interest
(ii) Carrying value includes accrued interest and related fees
(iii) Amounts included in the Total column, exclude related fees

14. Financial instruments and fair value measurement continued

31 December 2024	Notes	Carrying Value $'000	Total $'000	Quoted prices in active markets (Level 1) $'000	Significant observable inputs (Level 2) $'000	Significant unobservable inputs (Level 3) $'000
Financial assets measured at fair value:						
Derivative financial assets measured at FVPL						
Gas commodity contracts	18(a)	69	69	–	69	–
Other financial assets measured at FVPL						–
Quoted equity shares		6	6	6	–	–
Total financial assets measured at fair value		75	75	6	69	–
Financial assets measured at amortised cost:						
Vendor financing facility	18(f)	38,453	38,453	–	38,453	–
Total financial assets measured at amortised cost[(i)]		38,453	38,453	–	38,453	–
Liabilities measured at fair value:						
Derivative financial liabilities measured at FVPL						
Commodity derivative contracts	18(a)	10,497	10,497	–	10,497	–
Forward foreign currency contracts	18(a)	2,354	2,354	–	2,354	–
Forward UKA contracts	18(a)	8,729	8,729	–	8,729	–
Other financial liabilities measured at FVPL						
Contingent consideration	21	473,294	473,294	–	–	473,294
Total liabilities measured at fair value		494,874	494,874	–	21,580	473,294
Liabilities measured at amortised cost						
Interest-bearing loans and borrowings[(i)]	17	33,972	33,972	–	33,972	–
GBP retail bond 9.00%[(ii)]	17	169,371	161,461	161,461	–	–
USD high yield bond 11.625%[(ii)]	17	461,514	466,102	466,102	–	–
Total liabilities measured at amortised cost[(iii)]		664,857	661,535	627,563	33,972	–

(i) Amortised cost is a reasonable approximation of the fair value, carrying value includes accrued interest
(ii) Carrying value includes accrued interest and related fees
(iii) Amounts included in the Total column, exclude related fees

Fair value hierarchy

All financial instruments for which fair value is recognised or disclosed are categorised within the fair value hierarchy, based on the lowest level input that is significant to the fair value measurement as a whole, as follows:

Level 1: Quoted (unadjusted) market prices in active markets for identical assets or liabilities;

Level 2: Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly (i.e. prices) or indirectly (i.e. derived from prices) observable; and

Level 3: Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable.

Derivative financial instruments are valued by counterparties, with the valuations reviewed internally and corroborated with readily available market data (Level 2). Contingent consideration is measured at FVPL using the Level 3 valuation processes, details of which and a reconciliation of movements are disclosed in note 21. There have been no transfers between Level 1 and Level 2 during the period (2024: no transfers).

For the financial assets and liabilities measured at amortised cost but for which fair value disclosures are required, the fair value of the bonds classified as Level 1 was derived from quoted prices for that financial instrument, while interest-bearing loans and borrowings and the vendor financing facility were calculated at amortised cost using the effective interest method to capture the present value (Level 2). A reconciliation of movements is disclosed in note 29.

15. Trade and other receivables

	2025 $'000	2024 $'000
Current		
Trade receivables	**15,357**	20,151
Joint venture receivables	**104,608**	106,963
Under-lift position	**18,073**	16,806
VAT receivable	**12,377**	7,574
Vietnam lease receivable from joint venture partners	**5,122**	–
Other receivables[(i)]	**55,015**	25,989
Prepayments	**13,821**	5,720
Accrued income	**21,096**	47,768
Total current	**245,469**	230,971
Non-current		
Vietnam abandonment fund	**92,079**	–
Vietnam lease receivable from joint venture partners	**19,473**	–
Other receivables	**16,614**	2,102
Total non-current	**128,166**	2,102

(i) Predominantly relates to amounts charged to SVT owners and users

The carrying values of the Group's trade, joint venture and other receivables as stated above are considered to be a reasonable approximation to their fair value largely due to their short-term maturities. Under-lift is valued at the lower of cost or NRV at the prevailing balance sheet date (note 4(b)).

Trade receivables are non-interest-bearing and are generally on 15 to 30-day terms. Joint venture receivables relate to amounts billable to, or recoverable from, joint venture partners. Receivables are reported net of any ECL with no losses recognised as at 31 December 2025 or 2024.

Non-current receivables mainly comprise the Group's share of cash contributions made into an abandonment fund which was established to ensure that sufficient funds exist to meet future abandonment obligations on Block 12W in Vietnam. The funds are maintained in a bank account by PetroVietnam and the joint venture partners retain the legal rights and obligations to all monies contributed to the abandonment funds, pending commencement of abandonment operations.

The lease receivable relates to the Group's lease of an FPSO used on Block 12W in Vietnam. The related liability is recorded on a gross basis as EnQuest is the sole signatory to the lease, with joint venture partners providing a parent company guarantee with respect to their share of the lease liability. The Group's share of this liability is recorded as a right of use asset (see note 23) with the remainder, representing the share of future payments to be reimbursed by the other partners in Block 12W in Vietnam, recorded as an "other receivable", split between current and non-current based on the expected timing of reimbursement by the partners.

Other non-current receivables represents capitalised fees associated with the Group's Reserve Based Lending Facility disclosed within trade and other receivables to better reflect the variable nature of drawings under the facility.

16. Trade and other payables

	2025 $'000	2024 $'000
Current		
Trade payables	**124,806**	138,822
Accrued expenses	**287,408**	209,225
Over-lift position	**8,136**	16,849
Joint venture creditors	**25,750**	46,187
Other payables	**8,550**	3,307
Total current	**454,650**	414,390

The carrying value of the Group's current trade and other payables as stated above is considered to be a reasonable approximation to their fair value largely due to the short-term maturities. Certain trade and other payables will be settled in currencies other than the reporting currency of the Group, mainly in Sterling. Trade payables are normally non-interest-bearing and settled on terms of between ten and 30 days.
Accrued expenses include accruals for capital and operating expenditure in relation to the oil and gas assets and interest accruals.

17. Loans and borrowings

	2025 $'000	2024 $'000
Loans	**60,324**	33,972
Bonds	**647,140**	630,885
	707,464	664,857

The Group's borrowings are carried at amortised cost as follows:

	2025			2024		
	Principal $'000	Fees $'000	Total $'000	Principal $'000	Fees $'000	Total $'000
SVT working capital facility	**36,331**	**–**	**36,331**	33,972	–	33,972
Vendor loan facility	**22,096**	**–**	**22,096**	–	–	–
USD high yield bond 11.625%	**465,000**	**(6,156)**	**458,844**	465,000	(10,661)	454,339
GBP retail bond 9.00% (GBP 133.3 million)	**179,367**	**–**	**179,367**	167,101	–	167,101
Accrued interest(i)	**10,826**	**–**	**10,826**	9,445	–	9,445
Total borrowings	**713,620**	**(6,156)**	**707,464**	675,518	(10,661)	664,857
Due within one year			**69,253**			43,417
Due after more than one year			**638,211**			621,440
Total borrowings			**707,464**			664,857

(i) Accrued interest includes vendor loan facility interest accruals of $1.9 million (2024: $nil) and bond interest accruals of $8.9 million (2024: $9.4 million)

See liquidity risk – note 27 for the timing of cash outflows relating to loans and borrowings.

Reserve Based Lending facility ('RBL')

In November 2025, the Group agreed a new six-year Senior Secured Reserves Based Lending ('RBL') facility totalling $800.0 million comprising a $400.0 million multi-currency revolving loan facility, $400.0 million multi-currency revolving letter of credit facility and an accordion of up to $800.0 million which, although uncommitted, provides the potential to extend the secured revolving loan facility and the revolving letter of credit facility by up to $400.0 million each. The maturity of the facility is December 2031. Funds can only be drawn under the loan facility to a maximum amount of the lesser of: (i) the total commitments; and (ii) the borrowing base amount. Interest accrues at 4.00%, plus a combination of an agreed credit adjustment spread and the Secured Overnight Financing Rate ('SOFR'). The facility replaced the Group's previous reserves based lending facility, which was signed in October 2022 and accrued interest at 4.50%, plus a combination of an agreed credit adjustment spread and the SOFR.

Fees associated with the new RBL of $20.4 million were capitalised within trade and other receivables (note 15) and are being amortised over the period of the facility on a straight-line basis. The remaining unamortised fees relating to the previous RBL of $2.4 million were expensed within finance costs.

At 31 December 2025, there were no loan drawdowns under the RBL (2024: $nil), with $400.0 million remaining available for drawdown (2024: $176.4 million). At 31 December 2025, Letter of Credit utilisation was $381.5 million (2024: $54.1 million). The increased utilisation of Letters of Credit reflected their use in providing security under the Group's decommissioning security obligations, replacing the Group's prior period's use of surety bonds and cash.

SVT working capital facility

In 2024, EnQuest extended the £42.0 million revolving loan facility with a joint operations partner to fund the short-term working capital cash requirements of SVT and associated interests until April 2027. The facility is guaranteed by BP EOC Limited (joint operations partner) until the earlier of: a) the date on which production from Magnus permanently ceases; or b) if the operating agreements for both SVT and associated infrastructure are amended to allow for cash calling. The facility is able to be drawn down against, in instalments, and accrues interest at 2.05% per annum plus GBP Sterling Over Night Index Average ('SONIA').

Vendor Loan facility

In August 2024, the Group entered into a deferred payment facility agreement with a third-party vendor providing capacity based on certain qualifying invoices that EnQuest has paid up to an amount of £23.7 million, with interest payable monthly at a rate of 9.50% per annum. At 31 December 2025, $22.1 million had been drawn down on the facility (2024: $nil).

US Dollar high yield bond 11.625%

In October 2022, the Group concluded an offer of $305.0 million for a US Dollar high yield bond. In October 2024, the Group concluded a tap of an additional $160.0 million of the US Dollar high yield bond on the same terms and conditions as the existing bond. The notes accrue a fixed coupon of 11.625% payable semi-annually in arrears with a maturity date of November 2027.

The above carrying value of the bond as at 31 December 2025 is $458.8 million (2024: $454.3 million). This includes bond principal of $465.0 million (2024: $465.0 million) and unamortised issue premium on the tap of $1.0 million (2024: $1.4 million) less the unamortised original issue discount of $1.5 million (2024: $2.4 million) and unamortised fees of $5.8 million (2024: $9.7 million). The fair value of the US Dollar high yield bond is disclosed in note 14.

GBP retail bond 9.00%

On 27 April 2022, the Group issued a new 9.00% GBP retail bond following a successful partial exchange and cash offer. The principal of the GBP retail bond 9.00% raised by the partial exchange and cash offer totalled £133.3 million. The notes accrue a fixed coupon of 9.00% payable semi-annually in arrears and are due to mature in October 2027.

The above carrying value of the bond as at 31 December 2025 is $179.4 million (2024: $167.1 million). All fees associated with this offer were recognised in the income statement in 2022. The fair value of the GBP retail bond 9.00% is disclosed in note 14.

18. Other financial assets and financial liabilities

(a) Summary as at year end

	2025		2024	
	Assets $'000	Liabilities $'000	Assets $'000	Liabilities $'000
Fair value through profit or loss:				
Derivative commodity contracts	**35,009**	**1,997**	69	10,497
Forward foreign currency contracts	**932**	**–**	–	2,354
Derivative UKA contracts	**23,550**	**8,394**	–	8,729
Total current	**59,491**	**10,391**	69	21,580
Fair value through profit or loss:				
Derivative commodity contracts	**1,745**	**–**	–	–
Derivative UKA contracts	**5,171**	**–**	–	–
Quoted equity shares	**6**	**–**	6	–
Amortised cost:				
Other receivables (Vendor financing facility) (notes 18(f), 24)	**43,896**	**–**	38,453	–
Total non-current	**50,818**	**–**	38,459	–
Total other financial assets and liabilities	**110,309**	**10,391**	38,528	21,580

(b) Income statement impact

The income/(expense) recognised for derivatives are as follows:

	Revenue and other operating income		Cost of sales	
Year ended 31 December 2025	Realised $'000	Unrealised $'000	Realised $'000	Unrealised $'000
Commodity options	**(6,561)**	**7,766**	**–**	**–**
Commodity swaps	**15,567**	**37,225**	**–**	**–**
Commodity futures	**(262)**	**187**	**–**	**–**
Foreign exchange contracts	**–**	**–**	**20,766**	**3,286**
UKA contracts	**–**	**–**	**(1,055)**	**29,056**
	8,744	**45,178**	**19,711**	**32,342**

	Revenue and other operating income		Cost of sales	
Year ended 31 December 2024	Realised $'000	Unrealised $'000	Realised $'000	Unrealised $'000
Commodity options	(19,899)	10,617	–	–
Commodity swaps	7,467	(7,340)	–	–
Commodity futures	(475)	(187)	–	–
Foreign exchange contracts	–	–	2,859	(2,354)
UKA contracts	–	–	(7,594)	(469)
	(12,907)	3,090	(4,735)	(2,823)

(c) Commodity contracts

The Group uses derivative financial instruments to manage its exposure to the oil price, including put and call options, swap contracts and futures.

For the year ended 31 December 2025, gains totalling $53.9 million (2024: losses of $9.8 million) were recognised in respect of commodity contracts measured as FVPL. This included gains totalling $8.7 million (2024: losses of $12.9 million) realised on contracts that matured during the year, and mark-to-market unrealised gains totalling $45.2 million (2024: gains of $3.1 million).

The mark-to-market value of the Group's open commodity contracts as at 31 December 2025 was a net asset of $34.8 million (2024: net liability of $10.4 million).

18. Other financial assets and financial liabilities continued

(d) Foreign currency contracts

The Group enters into a variety of foreign currency contracts, primarily in relation to Sterling. During the year ended 31 December 2025, gains totalling $24.1 million (2025: gains of $0.5 million) were recognised in the Group income statement. This included realised gains totalling $20.8 million (2024: gains of $2.9 million) on contracts that matured in the year.

The mark-to-market value of the Group's open contracts as at 31 December 2025 was a net asset of $0.9 million (2024: net liability of $2.4 million).

(e) UK emissions allowance forward contracts

The Group enters into forward contracts for the purchase of UKAs to manage its exposure to carbon emission credit prices. During the year ended 31 December 2025, gains totalling $28.0 million (2024: losses of $8.1 million) were recognised in the Group income statement. This included realised losses totalling $1.1 million (2024: losses of $7.6 million) on contracts that matured in the year.

The mark-to-market value of the Group's open contracts as at 31 December 2025 was a net asset of $20.3 million (2024: net liability of $8.7 million).

(f) Other receivables

	Other receivables $'000	Equity shares $'000	Total $'000
At 1 January 2024	145,103	6	145,109
Interest	3,263	–	3,263
Repayments	(107,518)	–	(107,518)
Foreign Exchange	(2,395)	–	(2,395)
At 31 December 2024	**38,453**	**6**	**38,459**
Interest	**2,639**	**–**	**2,639**
Foreign Exchange	**2,804**	**–**	**2,804**
At 31 December 2025	**43,896**	**6**	**43,902**
Current			**–**
Non-current			**43,902**
			43,902

Other receivables relate to a vendor financing facility entered into with RockRose Energy Limited on 29 December 2023 following the farm-down of a 15.0% share in the EnQuest Producer FPSO and capital items associated with the Bressay development. $107.5 million was repaid in the first quarter of 2024 with the remainder repayable through future net cash flows from the Bressay field. Interest on the outstanding amount accrues at 2.5% plus the Bank of England's Base Rate.

19. Share capital and reserves

Accounting policy

Share capital and share premium

The balance classified as equity share capital includes the total net proceeds (both nominal value and share premium) on issue of registered share capital of the parent company. Share issue costs associated with the issuance of new equity are treated as a direct reduction of proceeds. The share capital comprises only one class of Ordinary share. Each Ordinary share carries an equal voting right and right to a dividend.

Treasury shares

Represents amounts transferred following purchase of the Company's own shares out of distributable profits, with those shares available for resale into the market, transfer to the Group's Employee Benefit Trust ('EBT') where they can be used to satisfy awards made under the Company's share-based incentive schemes, or cancelled.

Capital redemption reserve

Represents the par value of shares cancelled following the purchase of the Company's own shares out of distributable profits.

Retained earnings

Retained earnings contain the accumulated profits/(losses) of the Group.

19. Share capital and reserves continued

Share-based payments reserve

Equity-settled share-based payment transactions are measured at the fair value of the services received, and the corresponding increase in equity is recorded. EnQuest PLC shares held by the Group in the EBT are recognised at cost and are deducted from the share-based payments reserve, as they are held to satisfy awards made under equity-settled share-based payment transactions. Consideration received for the sale of such shares is also recognised in equity, with any difference between the proceeds from the sale and the original cost being taken to reserves. No gain or loss is recognised in the Group income statement on the purchase, sale, issue or cancellation of equity shares.

Authorised, issued and fully paid	Ordinary shares of £0.05 each Number	Share capital $'000	Share premium $'000	Treasury shares $'000	Capital redemption reserve $'000	Total $'000
At 1 January 2025	**1,885,029,503**	**131,508**	**260,546**	**(4,425)**	**2,006**	**389,635**
Shares transferred to EBT	**–**	**–**	**–**	**885**	**–**	**885**
At 31 December 2025	**1,885,029,503**	**131,508**	**260,546**	**(3,540)**	**2,006**	**390,520**

At 31 December 2025, 20,000,000 (2024: 25,000,000) Ordinary shares were held in Treasury for issue in due course to the Company's EBT to satisfy the anticipated future exercise of options and awards made to employees and Executive Directors of EnQuest PLC pursuant to certain of the Company's existing share plans. During the year, 5,000,000 shares were transferred to the Company's EBT.

At 31 December 2025, there were 3,948,076 shares held by the EBT (2024: 972,269) which are included within the share-based payment reserve. The movement in the year was 2,975,807 shares used to satisfy awards made under the Company's share-based incentive schemes offset by a transfer of shares from Treasury.

20. Share-based payment plans

Accounting policy

Eligible employees (including Executive Directors) of the Group receive remuneration in the form of share-based payment transactions, whereby employees render services in exchange for shares or rights over shares of EnQuest PLC.

Information on these plans for Executive Directors is shown in the Directors' Remuneration Report on page 116.

The cost of these equity-settled transactions is measured by reference to the fair value at the date on which they are granted. The fair value of awards is calculated in reference to the scheme rules at the market value, being the average middle market quotation of a share for the three immediately preceding dealing days as derived from the Daily Official List of the London Stock Exchange, provided such dealing days do not fall within any period when dealings in shares are prohibited because of any dealing restriction.

The cost of equity-settled transactions is recognised over the vesting period in which the relevant employees become fully entitled to the award. The cumulative expense recognised for equity-settled transactions at each reporting date until the vesting date reflects the extent to which the vesting period has expired and the Group's best estimate of the number of equity instruments that will ultimately vest. The Group income statement charge or credit for a period represents the movement in cumulative expense recognised as at the beginning and end of that period.

In valuing the transactions, no account is taken of any service or performance conditions, other than conditions linked to the price of the shares of EnQuest PLC (market conditions) or 'non-vesting' conditions, if applicable. No expense is recognised for awards that do not ultimately vest, except for awards where vesting is conditional upon a market or non-vesting condition, which are treated as vesting irrespective of whether or not the market or non-vesting condition is satisfied, provided that all other performance conditions are satisfied. Equity awards cancelled are treated as vesting immediately on the date of cancellation, and any expense not previously recognised for the award at that date is recognised in the Group income statement.

The Group operates a number of equity-settled employee share plans under which share units are granted to the Group's senior leaders and certain other employees. These plans typically have a three-year performance or restricted period. Leaving employment will normally preclude the conversion of units into shares, but special arrangements apply for participants that leave for qualifying reasons.

The share-based payment (income)/expense recognised for each scheme was as follows:

	2025 $'000	2024 $'000
Performance Share Plan	**(806)**	511
Other performance share plans	**(8)**	64
Sharesave Plan	**145**	408
	(669)	983

20. Share-based payment plans continued

The following table shows the number of shares potentially issuable under the Group's various equity-settled employee share plans, including the number of options outstanding and the number of options exercisable at the end of each year.

Share plans	2025 Number	2024 Number
Outstanding at 1 January	**88,617,683**	87,367,455
Granted during the year	**27,138,555**	35,353,664
Exercised during the year	**(1,493,821)**	(7,291,023)
Forfeited during the year	**(17,282,431)**	(26,812,413)
Outstanding at 31 December	**96,979,986**	88,617,683
Exercisable at 31 December	**15,172,474**	9,138,271

Within the Group's equity-settled employee share plans detailed above, the Group operates an approved savings-related share option scheme (the 'Sharesave Plan'). The plan is based on eligible employees being granted options and their agreement to opening a Sharesave account with a nominated savings carrier and to save over a specified period, either three or five years. The right to exercise the option is at the employee's discretion at the end of the period previously chosen, for a period of six months.

The following table shows the number of shares potentially issuable under equity-settled employee share option plans, including the number of options outstanding, the number of options exercisable at the end of each year and the corresponding weighted average exercise prices.

	2025		2024	
Sharesave options	Number	Weighted average exercise price $	Number	Weighted average exercise price $
Outstanding at 1 January	**9,956,017**	**0.15**	18,658,144	0.16
Exercised during the year	**–**	**–**	(5,478,693)	0.13
Forfeited during the year	**(1,575,108)**	**0.21**	(3,223,434)	0.15
Outstanding at 31 December	**8,380,909**	**0.15**	9,956,017	0.15
Exercisable at 31 December	**155,925**	**0.28**	323,886	0.24

21. Contingent consideration

Accounting policy

When the consideration transferred by the Group in a business combination includes a contingent consideration arrangement, the contingent consideration is measured at its acquisition-date fair value and included as part of the consideration transferred in a business combination. 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 acquisition date) about facts and circumstances that existed at the acquisition date.

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 depicted below is remeasured to fair value at subsequent reporting dates with changes in fair value recognised in profit or loss. Contingent consideration that is classified as equity if any, is not remeasured at subsequent reporting dates and its subsequent settlement is accounted for within equity.

Contingent consideration is discounted at a risk-free rate combined with a risk premium, calculated in alignment with IFRS 13 and the unwinding of the discount is presented as part of the overall fair value charge within other expenses/income.

Any contingent consideration included in the consideration payable for an asset acquisition is recorded at fair value at the date of acquisition and included in the initial measurement of cost.

Settlement of contingent consideration recorded at fair value through profit or loss is recorded as investing outflows in the cash flow statement to the extent 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 contingent consideration relating to an asset acquisition is recorded as an investing cash outflow.

21. Contingent consideration continued

	Magnus 75% $'000	Magnus decommissioning-linked liability $'000	Total $'000
At 31 December 2024	**451,333**	**21,961**	**473,294**
Unwinding of discount (see note 4(d))	**51,002**	**2,645**	**53,647**
Other change in fair value (see note 4(d))	**(442,335)**	**1,543**	**(440,792)**
Utilisation	**–**	**(1,529)**	**(1,529)**
At 31 December 2025	**60,000**	**24,620**	**84,620**
Classified as:			
Current	**60,000**	**318**	**60,318**
Non-current	**–**	**24,302**	**24,302**
	60,000	**24,620**	**84,620**

75% Magnus acquisition contingent consideration

On 1 December 2018, EnQuest completed the acquisition of the additional 75% interest in the Magnus oil field ('Magnus') and associated interests (collectively the 'Transaction assets') which was part funded through a profit share arrangement with bp whereby EnQuest and bp share the net cash flow generated by the 75% interest on a 50:50 basis, subject to a cap of $1.0 billion received by bp. This contingent consideration is a financial liability classified as measured at FVPL.

In February 2026, an agreement was concluded with bp for EnQuest to settle the profit share arrangement for $60.0 million, with payment made the same month. As the agreement was substantially agreed at 31 December 2025, this value has been used to fair value the contingent consideration which resulted in a decrease in fair value (excluding the impact of unwind of discount) of $442.3 million (2024: decrease of $43.4 million). The decrease in 2024 reflected a reduction in the Group's near-term oil price assumptions and changes in the assets cost and production profile. The overall fair value accounting effect relating to the contingent consideration, including the unwinding of discount, totalled income of $391.3 million (2024: charge of $11.8 million) which was recognised in the Group income statement. Within the statement of cash flows, the profit share element of the repayment is disclosed separately under investing activities. There were no profit share payments during the year (2024: $48.5 million). At 31 December 2025, the contingent consideration for Magnus was $60.0 million (31 December 2024: $451.3 million).

Magnus decommissioning-linked contingent consideration

As part of the Magnus and associated interests acquisition, bp retained the decommissioning liability in respect of the existing wells and infrastructure and EnQuest agreed to pay additional consideration in relation to the management of the physical decommissioning costs of Magnus. At 31 December 2025, the amount due to bp calculated on an after-tax basis by reference to 30% of bp's decommissioning costs on Magnus was $24.6 million (2024: $22.0 million). Any reasonably possible change in assumptions would not have a material impact on the provision.

22. Provisions

Accounting policy

Decommissioning

Provision for future decommissioning costs is made in full when the Group has an obligation: to dismantle and remove a facility or an item of plant; to restore the site on which it is located; and when a reasonable estimate of that liability can be made. The Group's provision primarily relates to the future decommissioning of production facilities and pipelines.

A decommissioning asset and liability are recognised within property, plant and equipment and provisions, respectively, at the present value of the estimated future decommissioning costs. The decommissioning asset is amortised over the life of the underlying asset on a unit of production basis over proven and probable reserves, included within depletion in the Group income statement. Any change in the present value of estimated future decommissioning costs is reflected as an adjustment to the provision and the oil and gas asset for producing assets. For assets that have ceased production, the change in estimate is reflected as an adjustment to the provision and the Group income statement, via other income or expense. The unwinding of the decommissioning liability is included under finance costs in the Group income statement.

These provisions have been created based on internal and third-party estimates. Assumptions based on the current economic environment have been made which management believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required, which will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning liabilities is likely to depend on the dates when the fields cease to be economically viable. This in turn depends on future oil prices, which are inherently uncertain. See Use of judgements, estimates and assumptions: provisions within note 2.

Other

Provisions are recognised when the Group has a present legal or constructive obligation as a result of past events; it is probable that an outflow of resources will be required to settle the obligation; and a reliable estimate can be made of the amount of the obligation.

	Decommissioning provision $'000	Thistle decommissioning provision $'000	Other provisions $'000	Total $'000
At 31 December 2024	**741,565**	**18,348**	**6,193**	**766,106**
Acquisition (see note 30)	**89,052**	**–**	**–**	**89,052**
Additions during the year[(i)]	**46,721**	**–**	**461**	**47,182**
Changes in estimates[(i)]	**40,868**	**4,772**	**(5,083)**	**40,557**
Unwinding of discount	**35,912**	**755**	**–**	**36,667**
Utilisation[(ii)]	**(38,486)**	**(8,589)**	**(481)**	**(47,556)**
Foreign exchange	**–**	**–**	**28**	**28**
At 31 December 2025	**915,632**	**15,286**	**1,118**	**932,036**
Classified as:				
Current	**48,853**	**4,915**	**314**	**54,082**
Non-current	**866,779**	**10,371**	**804**	**877,954**
	915,632	**15,286**	**1,118**	**932,036**

(i) Includes $77.9 million related to producing assets disclosed in note 9 and $9.7 million relating to assets in decommissioning disclosed in note 4(d)

(ii) Utilisation differs to amounts paid in the cash flow statement due to movements in accruals recognised within trade and other payables

Decommissioning provision

The Group's total provision represents the present value of decommissioning costs which are expected to be incurred up to 2050, assuming no further development of the Group's assets. The Group's decommissioning provision has increased by $174.0 million in the period. This primarily reflects the discounted decommissioning liability acquired as part of the Vietnam asset acquisition of $89.1 million (which is largely pre-funded as set out below), additional liability recognised in relation to Seligi Non-Associated Gas rights in Malaysia of $41.5 million and higher cost estimates of $40.9 million, predominantly due to a weaker US Dollar, offset partly by the ongoing decommissioning programmes utilisation of $38.5 million.

At 31 December 2025, an estimated $364.3 million is expected to be utilised between one and five years (2024: $281.1 million), $373.1 million within six to ten years (2024: $280.0 million), and the remainder in later periods. For sensitivity analysis see Use of judgements, estimates and assumptions within note 2.

The Vietnam PSC requires the expected decommissioning liability to be pre-funded via a quarterly cash payment into an abandonment cess fund. The balance of amounts previously deposited into the cess fund is held in escrow to be drawn against when abandonment takes place. As at 31 December 2025, EnQuest's share of the cess fund was $92.1 million and is disclosed in non-current trade and other receivables (note 15).

The Group uses Letters of Credit, surety bonds and cash deposits to provide security for its decommissioning obligations. Following the agreement of a new RBL facility in November 2025, the Group utilised Letters of Credit totalling $381.5 million to provide security for its decommissioning obligations at 31 December 2025 (2024: surety bonds totalling $277.0 million and cash deposits of $53.4 million).

22. Provisions continued

Thistle decommissioning provision

In 2018, EnQuest exercised the option to receive $50.0 million from bp in exchange for undertaking the management of the physical decommissioning activities for Thistle and Deveron and making payments by reference to 7.5% of bp's share of decommissioning costs of the Thistle and Deveron fields, with the liability recognised within provisions. At 31 December 2025, the amount due to bp by reference to 7.5% of bp's decommissioning costs on Thistle and Deveron was $15.3 million (2024: $18.3 million), with the reduction mainly reflecting the utilisation in the period. Change in estimates of $4.8 million are included within other expense (2024: $0.4 million) and unwinding of discount of $0.8 million is included within finance costs (2024: $0.9 million).

23. Leases

Accounting policy

As a lessee

The Group recognises a right-of-use asset and a lease liability at the lease commencement date.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted by using the rate implicit in the lease, or, if that rate cannot be readily determined, the Group uses its incremental borrowing rate.

The incremental borrowing rate is the rate that the Group would have to pay for a loan of a similar term, and with similar security, to obtain an asset of similar value. The incremental borrowing rate is determined based on a series of inputs including: the term, the risk-free rate based on government bond rates and a credit risk adjustment based on EnQuest bond yields.

Lease payments included in the measurement of the lease liability comprise:

- fixed lease payments (including in-substance fixed payments), less any lease incentives;
- variable lease payments that depend on an index or rate, initially measured using the index or rate at the commencement date;
- the exercise price of purchase options, if the lessee is reasonably certain to exercise the options; and
- payments of penalties for terminating the lease, if the lease term reflects the exercise of an option to terminate the lease.

The lease liability is subsequently recorded at amortised cost, using the effective interest rate method. The liability is remeasured when there is a change in future lease payments arising from a change in an index or rate or if the Group changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero. The Group did not make any such adjustments during the periods presented.

The right-of-use asset is measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. Right-of-use assets are depreciated over the shorter period of lease term and useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use asset reflects that the Group expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset. The depreciation starts at the commencement date of the lease.

The Group applies the short-term lease recognition exemption to those leases that have a lease term of 12 months or less from the commencement date. It also applies the low-value assets recognition exemption to leases of assets below £5,000. Lease payments on short-term leases and leases of low-value assets are recognised as an expense on a straight-line basis over the lease term.

The Group applies IAS 36 Impairment of Assets to determine whether a right-of-use asset is impaired and accounts for any identified impairment loss as described in the 'property, plant and equipment' policy (see note 9).

Variable rents that do not depend on an index or rate are not included in the measurement of the lease liability and the right-of-use asset. The related payments are recognised as an expense in the period in which the event or condition that triggers those payments occurs and are included within 'cost of sales' or 'general and administration expenses' in the Group income statement.

For leases within joint ventures, the Group assesses on a lease-by-lease basis the facts and circumstances. Where all parties to a joint operation jointly have the right to control the use of the identified asset and all parties have a legal obligation to make lease payments to the lessor, the Group's share of the right-of-use asset and its share of the lease liability will be recognised on the Group balance sheet. This may arise in cases where the lease is signed by all parties to the joint operation or the joint operation partners are named within the lease. However, in cases where EnQuest is the sole signatory and the only party with the legal obligation to make lease payments to the lessor but the joint venture partners provide guarantees in relation to their share of the liability, the full lease liability will be recognised, along with the Group's share of the right-of-use asset and a receivable balance representing amounts owed by joint venture partners. In cases where EnQuest is the only party with the legal obligation to make lease payments to the lessor, the full lease liability and right-of-use asset will be recognised on the Group balance sheet. This may be the case if, for example, EnQuest, as operator of the joint operation, is the sole signatory to the lease. If the underlying asset is used for the performance of the joint operation agreement, EnQuest will recharge the associated costs in line with the joint operating agreement.

23. Leases continued

As a lessor

When the Group acts as a lessor, it determines at lease inception whether each lease is a finance lease or an operating lease. Whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee, the contract is classified as a finance lease. All other leases are classified as operating leases.

When the Group is an intermediate lessor, it accounts for the head-lease and the sub-lease as two separate contracts. The sub-lease is classified as a finance or operating lease by reference to the right-of-use asset arising from the head-lease.

Rental income from operating leases is recognised on a straight-line basis over the term of the relevant lease. Initial direct costs incurred in negotiating and arranging an operating lease are added to the carrying amount of the leased asset and recognised on a straight-line basis over the lease term.

Amounts due from lessees under finance leases are recognised as receivables at the amount of the Group's net investment in the leases. Finance lease income is allocated to reporting periods so as to reflect a constant periodic rate of return on the Group's net investment outstanding in respect of the leases.

When a contract includes lease and non-lease components, the Group applies IFRS 15 to allocate the consideration under the contract to each component.

Right-of-use assets and lease liabilities

Set out below are the carrying amounts of the Group's right-of-use assets and lease liabilities and the movements during the period:

	Right-of-use assets $'000	Lease liabilities $'000
As at 31 December 2023	407,732	422,174
Additions in the period	16,453	16,453
Depreciation expense	(54,735)	–
Impairment reversal	4,014	–
Interest expense	–	27,673
Payments	–	(130,065)
Foreign exchange movements	–	(980)
As at 31 December 2024	**373,464**	**335,255**
Acquisition (see note 30)	**33,002**	**60,681**
Additions in the period (see note 9)	**32,302**	**32,302**
Depreciation expense (see note 9)	**(59,184)**	**–**
Impairment reversal (see note 9)	**28,838**	**–**
Interest expense	**–**	**25,100**
Payments	**–**	**(83,061)**
Foreign exchange movements	**–**	**5,818**
Disposal	**(4,253)**	**(4,005)**
As at 31 December 2025	**404,169**	**372,090**
Current		**86,323**
Non-current		**285,767**
		372,090

The carrying value of the right-of-use assets include $373.9 million (2024: $340.9 million) of oil and gas assets and $30.3 million (2024: $32.6 million) of buildings.

The Group leases assets, including the Kraken and Vietnam FPSOs, property, and oil and gas vessels, with a weighted average lease term of three years. The maturity analysis of lease liabilities is disclosed in note 27.

23. Leases continued

Amounts recognised in profit or loss

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Depreciation expense of right-of-use assets	**59,184**	54,735
Impairment reversal of right-of-use assets	**(28,838)**	(4,014)
Interest expense on lease liabilities	**25,100**	27,673
Rent expense – short-term leases	**9,018**	13,860
Rent expense – leases of low-value assets	**297**	33
Total amounts recognised in profit or loss	**64,761**	92,287

Amounts recognised in statement of cash flows

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Total cash outflow for leases	**83,061**	130,065

Leases as lessor

The Group sub-leases part of Annan House, the Aberdeen office. The sub-lease is classified as an operating lease, as all the risks and rewards incidental to the ownership of the right-of-use asset are not all substantially transferred to the lessee. Rental income recognised by the Group during 2025 was $1.9 million (2024: $2.2 million).

The following table sets out a maturity analysis of the lessees lease payments to EnQuest as lessor, showing the undiscounted lease payments to be received after the reporting date:

	2025 $'000	2024 $'000
Less than one year	**1,291**	2,029
One to two years	**1,293**	858
Two to three years	**1,310**	860
Three to four years	**1,317**	875
Four to five years	**821**	882
More than five years	**1,326**	1,856
Total undiscounted lease payments	**7,358**	7,360

24. Deferred income

Accounting policy

Income is not recognised in the income statement until it is highly probable that the conditions attached to the income will be met.

	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Deferred income	**138,095**	138,095

In December 2023 a farm-down of an equity interest in the EnQuest Producer FPSO and certain capital spares related to the Bressay development was completed and cash received of $141.3 million. The same amount was lent back to the acquirer in December 2023 as vendor financing (see note 18(f)). Proceeds from the farm-down are reported within deferred income, as these are contingent upon the Bressay development project achieving regulatory approval. Both parties are committed to delivering the development, however should the project not achieve regulatory approval there remains the option to deploy the assets on an alternative project.

25. Commitments and contingencies

Capital commitments

At 31 December 2025, the Group had commitments for future capital expenditure amounting to $48.4 million (2024: $13.3 million). The increase primarily relates to commitments for the development of the non-associated gas resources in the PM8/Seligi PSC contract area under the Seligi 1b gas agreement. The key remaining components of this relate to minimum work commitments in Indonesia and Brunei. Where the commitment relates to a joint venture, the amount represents the Group's net share of the commitment. Where the Group is not the operator of the joint venture then the amounts are based on the Group's net share of committed future work programmes.

Other commitments

In the normal course of business, the Group will obtain surety bonds, Letters of Credit and guarantees. At 31 December 2025, the Group utilised Letters of Credit totalling $381.5 million under its new RBL facility to provide security for its decommissioning obligations, having held surety bonds totalling $277.0 million in 2024. See note 22 for further details.

Contingencies

The Group becomes involved from time to time in various claims and lawsuits arising in the ordinary course of its business. For example, in 2025, the NSTA engaged with EnQuest with regards to the timing/scheduling of certain plug and abandon obligations, which remain under discussion. Regardless, the Group is not, nor has been during the past 12 months, involved in any governmental, legal or arbitration proceedings which, either individually or in the aggregate, have had, or are expected to have, a material adverse effect on the Group balance sheet or profitability. Nor, so far as the Group is aware, are any such proceedings pending or threatened.

A contingent payment of $15.0 million to Equinor is due upon regulatory approval of a Bressay field development plan.

26. Related party transactions

The Group financial statements include the financial statements of EnQuest PLC and its subsidiaries. A list of the Group's principal subsidiaries is contained in note 28 to these Group financial statements.

Balances and transactions between the Company and its subsidiaries, which are related parties, have been eliminated on consolidation and are not disclosed in this note.

All sales to and purchases from related parties are made at normal market prices and the pricing policies and terms of these transactions are approved by the Group's management. With the exception of the transactions disclosed below, there have been no transactions with related parties who are not members of the Group during the year ended 31 December 2025 (2024: none).

Compensation of key management personnel

The following table details remuneration of key management personnel of the Group. Key management personnel comprise Executive and Non-Executive Directors of the Company and the Executive Committee.

	2025 $'000	2024 $'000
Short-term employee benefits	**5,206**	5,138
Share-based payments	**30**	124
Post-employment pension benefits	**278**	226
Termination payments	**133**	947
	5,647	6,435

27. Risk management and financial instruments

Risk management objectives and policies

The Group's principal financial assets and liabilities comprise trade and other receivables, cash and cash equivalents, interest-bearing loans, borrowings and leases, derivative financial instruments and trade and other payables. The main purpose of the financial instruments is to manage cash flow and to provide liquidity for organic and inorganic growth initiatives.

The Group's activities expose it to various financial risks particularly associated with fluctuations in oil price, foreign currency risk, liquidity risk and credit risk. The Group is also exposed to interest rate risks related to SOFR on cash balances and the RBL. As the RBL was undrawn at 31 December 2025, no sensitivities have been provided. Management reviews and agrees policies for managing each of these risks, which are summarised below. Also presented below is a sensitivity analysis to indicate sensitivity to changes in market variables on the Group's financial instruments and to show the impact on profit and shareholders' equity, where applicable. The sensitivity has been prepared for periods ended 31 December 2025 and 2024, using the amounts of debt and other financial assets and liabilities held at those reporting dates.

27. Risk management and financial instruments continued

Commodity price risk – oil prices

The Group is exposed to the impact of changes in Brent oil prices on its revenues and profits generated from sales of crude oil.

The Group's policy is to have the ability to hedge oil prices up to a maximum of 75% of the next 12 months' production on a rolling annual basis, up to 60% in the following 12-month period and 50% in the subsequent 12-month period. On a rolling quarterly basis, under the RBL facility, the Group is required to hedge production based on the proportion of the loan facility utilised. Where the relevant amounts utilised are 10% or less of the amounts available, the Group is required to hedge a minimum of 10% of volumes of net entitlement production expected in the next 12 months and the following 12 months. Where the relevant amounts utilised are more than 10% but less than 50% of the amounts available, the Group is required to hedge a minimum of 30% of volumes of net entitlement production expected in the next 12 months and a minimum of 15% of volumes of net entitlement production expected in the following 12 months. Where the relevant amounts utilised are 50% or more of the amounts available, the Group is required to hedge a minimum of 45% of volumes of net entitlement production expected in the next 12 months and a minimum of 30% of volumes of net entitlement production expected in the following 12 months.

Details of the commodity derivative contracts entered into during and open at the end of 2025 are disclosed in note 18. As of 31 December 2025, the Group held financial instruments (options and swaps) related to crude oil that covered 3.4 MMbbls of 2026 production and 0.9 MMbbls of 2027 production. The instruments have an effective average floor price of around $68.3/bbl in 2026 and $63.5/bbl in 2027. The Group utilises multiple benchmarks when hedging production to achieve optimal results for the Group. No derivatives were designated in hedging relationships at 31 December 2025.

The following table summarises the impact on the Group's pre-tax profit of a reasonably possible change in the Brent oil price on the fair value of derivative financial instruments, with all other variables held constant. The impact in equity is the same as the impact on profit before tax.

	Pre-tax profit	
	+$10/bbl increase $'000	-$10/bbl decrease $'000
31 December 2025	**(42,600)**	**42,900**
31 December 2024	(47,600)	47,200

Foreign exchange risk

The Group is exposed to foreign exchange risk arising from movements in currency exchange rates. Such exposure arises from sales or purchases in currencies other than the Group's functional currency, the 9.00% retail bond, the vendor financing facility and any UK EPL cash tax payments which are denominated in Sterling. To mitigate the risks of large fluctuations in the currency markets, the hedging policy agreed by the Board allows for up to 70% of the non-US Dollar portion of the Group's annual capital budget and operating expenditure to be hedged. For specific contracted capital expenditure projects, up to 100% can be hedged. Approximately 17% (2024: 12%) of the Group's sales and 98% (2024: 97%) of costs (including operating and capital expenditure and general and administration costs) are denominated in currencies other than the functional currency.

The Group also enters into foreign currency swap contracts from time to time to manage short-term exposures. The following tables summarise the Group's financial assets and liabilities exposure to foreign currency.

Year ended 31 December 2025	GBP $'000	MYR $'000	Other $'000	Total $'000
Total financial assets	**357,349**	**30,762**	**12,015**	**400,126**
Total financial liabilities	**783,464**	**28,336**	**13,364**	**825,164**

Year ended 31 December 2024	GBP $'000	MYR $'000	Other $'000	Total $'000
Total financial assets	396,168	22,570	3,024	421,762
Total financial liabilities	714,626	21,731	3,801	740,158

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 in equity is the same as the impact on profit before tax. The Group's exposure to foreign currency changes for all other currencies is not material:

	Pre-tax profit	
	10% rate increase $'000	10% rate decrease $'000
31 December 2025	**(22,189)**	**22,189**
31 December 2024	(28,263)	28,263

27. Risk management and financial instruments continued

Credit risk

Credit risk is managed on a Group basis. Credit risk in financial instruments arises from cash and cash equivalents and derivative financial instruments where the Group's exposure arises from default of the counterparty, with a maximum exposure equal to the carrying amount of these instruments. For banks and financial institutions only those rated with an A-/A3 credit rating or better are accepted. Cash balances can be invested in short-term bank deposits and AAA-rated liquidity funds, subject to Board-approved limits and with a view to minimising counterparty credit risks.

In addition, there are credit risks of commercial counterparties, including exposures in respect of outstanding receivables. The Group trades only with recognised international oil and gas companies, commodity traders and shipping companies and at 31 December 2025, there were no trade receivables past due but not impaired (2024: nil) and no joint venture receivables past due but not impaired (2024: nil). Receivable balances are monitored on an ongoing basis with appropriate follow-up action taken where necessary. Any impact from ECL is disclosed in note 15.

At 31 December 2025, the Group had one customer accounting for 65% of outstanding trade receivables (2024: two customers, 91%) and four joint venture partners accounting for over 75% of outstanding joint venture receivables (2024: four partners, over 70%).

Liquidity risk

The Group monitors its risk of a shortage of funds by reviewing its cash flow requirements on a regular basis relative to its existing bank facilities and the maturity profile of its borrowings. Specifically, the Group's policy is to ensure that sufficient liquidity or committed facilities exist within the Group to meet its operational funding requirements and to ensure the Group can service its debt and adhere to its financial covenants. At 31 December 2025, $409.8 million (2024: $194.3 million) was available for drawdown under the Group's facilities (see note 17).

The following tables detail the maturity profiles of the Group's non-derivative financial liabilities, including projected interest thereon. The amounts in these tables are different from the balance sheet as the table is prepared on a contractual undiscounted cash flow basis and includes future interest payments.

By reference to the conditions existing at the reporting period end, the maturity analysis of the contingent consideration is disclosed below. All of the Group's liabilities, except for the RBL, are unsecured.

Year ended 31 December 2025	On demand $'000	Up to 1 year $'000	1 to 2 years $'000	2 to 5 years $'000	Over 5 years $'000	Total $'000
Loans	**–**	**60,888**	**–**	**–**	**–**	**60,888**
Bonds	**–**	**69,945**	**714,312**	**–**	**–**	**784,257**
Contingent consideration	**–**	**60,335**	**6,681**	**1,382**	**65,571**	**133,969**
Obligations under lease liabilities	**–**	**97,363**	**231,189**	**59,547**	**26,328**	**414,427**
Trade and other payables	**–**	**446,527**	**–**	**–**	**–**	**446,527**
	–	**735,058**	**952,182**	**60,929**	**91,899**	**1,840,068**

Year ended 31 December 2024	On demand $'000	Up to 1 year $'000	1 to 2 years $'000	2 to 5 years $'000	Over 5 years $'000	Total $'000
Loans	–	34,168	–	–	–	34,168
Bonds	–	69,095	69,095	701,197	–	839,387
Contingent consideration	–	20,675	64,877	265,854	425,027	776,433
Obligations under lease liabilities	–	66,092	71,600	222,093	31,696	391,481
Trade and other payables	–	397,543	–	–	–	397,543
	–	587,573	205,572	1,189,144	456,723	2,439,012

27. Risk management and financial instruments continued

The following tables detail the Group's expected maturity of payables for its derivative financial instruments. The amounts in these tables are different from the balance sheet as the table is prepared on a contractual undiscounted cash flow basis. When the amount receivable or payable is not fixed, the amount disclosed has been determined by reference to a projected forward curve at the reporting date.

Year ended 31 December 2025	On demand $'000	Less than 3 months $'000	3 to 12 months $'000	1 to 2 years $'000	Over 2 years $'000	Total $'000
Commodity derivative contracts	**–**	**2,563**	**66**	**–**	**–**	**2,629**
Other derivative contracts	**–**	**43,411**	**7,485**	**22,015**	**–**	**72,911**
	–	**45,974**	**7,551**	**22,015**	**–**	**75,540**

Year ended 31 December 2024	On demand $'000	Less than 3 months $'000	3 to 12 months $'000	1 to 2 years $'000	Over 2 years $'000	Total $'000
Commodity derivative contracts	–	546	8,908	999	–	10,453
Foreign exchange derivative contracts	–	1,105	1,249	–	–	2,354
Other derivative contracts	–	23,902	3,802	1,928	–	29,632
	–	25,553	13,959	2,927	–	42,439

Capital management

The capital structure of the Group consists of debt, which includes the borrowings disclosed in note 17, cash and cash equivalents and equity attributable to the equity holders of the parent company, comprising issued capital, reserves and retained earnings as in the Group statement of changes in equity.

The primary objective of the Group's capital management is to optimise the return on investment, by managing its capital structure to achieve capital efficiency whilst also maintaining flexibility for downside protection and growth initiatives. 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 the Board to hedge external risks, see Commodity price risk: oil prices and foreign exchange risk. This is designed to reduce the risk of adverse movements in exchange rates and market prices eroding the return on the Group's projects and operations.

The Board regularly reassesses the existing dividend policy to ensure that shareholder value is maximised. Any future shareholder distributions are expected to depend on the earnings and financial condition of the Company and such other factors as the Board considers appropriate.

The Group monitors capital using the gearing ratio and return on shareholders' equity as follows. Further information relating to the movement year-on-year is provided within the relevant notes and within the Financial review (pages 37 to 41).

	2025 $'000	2024 $'000
Loans, borrowings and bond[(i)] (A) (see note 17)	**702,794**	666,073
Cash and cash equivalents (see note 13)	**268,846**	(280,239)
EnQuest net debt (B)[(ii)]	**433,948**	385,834
Equity attributable to EnQuest PLC shareholders (C)	**528,059**	542,466
Profit/(loss) for the year attributable to EnQuest PLC shareholders (D)	**1,562**	93,773
Adjusted EBITDA (F)[(ii)]	**503,823**	673,919
Gross gearing ratio (A/C)	**1.3**	1.2
Net gearing ratio (B/C)	**0.8**	0.7
EnQuest net debt/adjusted EBITDA (B/F)[(ii)]	**0.9**	0.6
Shareholders' return on investment (D/C)	**0.3%**	17.3%

(i) Principal amounts drawn, excludes netting off of fees and accrued interest (see note 17)
(ii) See Glossary – non GAAP measures on pages 192 to 195

28. Subsidiaries

At 31 December 2025, EnQuest PLC had investments in the following subsidiaries:

Name of company	Principal activity	Country of incorporation	Proportion of nominal value of issued Ordinary shares controlled by the Group
EnQuest Britain Limited	Intermediate holding company and provision of Group manpower and contracting/procurement services	England	100%
EnQuest Heather Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest ENS Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Heather Leasing Limited(i)	Dormant	England	100%
EQ Petroleum Sabah Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Dons Leasing Limited(i)	Leasing	England	100%
EnQuest Energy Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Production Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Global Limited	Intermediate holding company	England	100%
EnQuest NWO Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EQ Petroleum Production Malaysia Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
NSIP (GKA) Limited[1]	Dormant	Scotland	100%
EnQuest Global Services Limited(i)[2]	Provision of Group manpower and contracting/ procurement services for the international business	Jersey	100%
EnQuest Marketing and Trading Limited	Marketing and trading of crude oil	England	100%
EnQuest Petroleum Developments Malaysia SDN. BHD(i)[3]	Exploration, extraction and production of hydrocarbons	Malaysia	100%
EnQuest Advance Holdings Limited(i)	Intermediate holding company	England	100%
EnQuest Advance Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Progress Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
North Sea (Golden Eagle) Resources Ltd(i)	Exploration, extraction and production of hydrocarbons	England	100%
Veri Energy (CCS) Limited(i)	Assessment and development of new energy and decarbonisation opportunities	England	100%
Veri Energy (Hydrogen) Limited(i)	Assessment and development of new energy and decarbonisation opportunities	England	100%
Veri Energy Holdings Limited	Intermediate holding company	England	100%
Veri Energy Limited(i)	Assessment and development of new energy and decarbonisation opportunities	England	100%
Premier Oil (Vietnam) Limited(i)[4]	Exploration, extraction and production of hydrocarbons	British Virgin Islands	100%
Premier Oil Vietnam Offshore B.V(i)[5]	Exploration, extraction and production of hydrocarbons	Netherlands	100%
EnQuest EP Gaea Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest EP Gaea II Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest EP BV Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%

(i) Held by subsidiary undertaking

The Group has five branches outside the UK (all held by subsidiary undertakings): EnQuest Global Services Limited (Dubai), EnQuest Global Services Limited (Bahrain), EnQuest Petroleum Production Malaysia Limited (Malaysia), Premier Oil Vietnam Offshore B.V (Vietnam) and EnQuest EP BV Limited (Brunei).

In January 2026, EnQuest Group Holdings Limited was incorporated in England and Wales as a holding company.

Other than those listed below, all entities have a registered office address as Charles House, 2nd Floor, 5-11 Regent Street, London, SW1Y 4LR United Kingdom.

1 Annan House, Palmerston Road, Aberdeen, Scotland, AB11 5QP, United Kingdom
2 Ground Floor, Colomberie House, St Helier, JE4 0RX,, Jersey
3 c/o TMF, 10th Floor, Menara Hap Seng, No. 1 & 3, Jalan P. Ramlee 50250 Kuala Lumpur, Malaysia
4 PO Box 3140, Road Town, Tortola, VG1110, British Virgin Islands
5 Lairessestraat 145 C,1075 HJ Amsterdam, the Netherlands

29. Cash flow information

Cash generated from operations

	Notes	Year ended 31 December 2025 $'000	Year ended 31 December 2024 $'000
Profit/(loss) before tax		**493,427**	166,614
Depreciation	4(c)	**5,129**	6,040
Depletion	4(b)	**267,299**	263,252
Exploration and appraisal expense	11	**173**	183
Net impairment (reversal)/charge to oil and gas assets	9	**(5,819)**	71,414
Net disposal/(write-back) of inventory		**2,800**	(5,539)
Share-based payment (credit)/charge	4(e)	**(669)**	983
Change in Magnus related contingent consideration	21	**(387,145)**	15,904
Change in provisions	22	**46,544**	39,116
Other non-cash UKA losses	4(b)	**11,490**	1,335
Unrealised (gain)/loss on commodity financial instruments	4(a)	**(45,178)**	(3,090)
Unrealised (gain)/loss on other financial instruments	4(b)	**(32,342)**	2,823
Unrealised exchange loss/(gain)		**21,973**	(8,714)
Net finance expense[(i)]		**118,700**	113,711
Operating cashflow before working capital changes		**496,382**	664,032
Decrease/(increase) in trade and other receivables		**38,656**	(4,561)
Decrease/(increase) in inventories		**12,366**	(5,786)
(Decrease)/increase in trade and other payables		**(49,585)**	32,261
Cash generated from operations		**497,819**	685,946

(i) Excludes unwind of discount on provisions (see note 5)

Changes in liabilities arising from financing activities

	Loans and borrowings $'000	Bonds $'000	Lease liabilities $'000	Total $'000
At 1 January 2024	(311,210)	(471,019)	(422,174)	(1,204,403)
Cash movements:				
Repayments of loans and borrowings	312,304	–	–	312,304
Proceeds from loans and borrowings	(26,928)	(160,000)	–	(186,928)
Payment of lease liabilities	–	–	130,065	130,065
Cash interest paid in year	18,524	52,494	–	71,018
Non-cash movements:				
Additions	–	3,362	(16,453)	(13,091)
Interest/finance charge payable	(18,524)	(54,971)	(27,673)	(101,168)
Fee amortisation	(5,036)	(3,493)	–	(8,529)
Foreign exchange and other non-cash movements	(3,102)	2,742	980	620
At 31 December 2024	(33,972)	(630,885)	(335,255)	(1,000,112)
Cash movements:				
Repayments of loans and borrowings[(i)]	**196,451**	**–**	**–**	**196,451**
Proceeds from loans and borrowings[(ii)]	**(217,420)**	**–**	**–**	**(217,420)**
Payment of lease liabilities	**–**	**–**	**83,061**	**83,061**
Cash interest paid in year[(iii)]	**4,130**	**69,884**	**–**	**74,014**
Non-cash movements:				
Additions	**20,448**	**–**	**(32,302)**	**(11,854)**
Disposals	**–**	**–**	**4,005**	**4,005**
Acquired (see note 30)	**–**	**–**	**(60,681)**	**(60,681)**
Interest/finance charge payable	**(6,027)**	**(69,269)**	**(25,100)**	**(100,396)**
Fee amortisation	**(2,927)**	**(4,505)**	**–**	**(7,432)**
Foreign exchange and other non-cash movements	**(21,007)**	**(12,365)**	**(5,818)**	**(39,190)**
At 31 December 2025	**(60,324)**	**(647,140)**	**(372,090)**	**(1,079,554)**

(i) Repayments of loans and borrowings include $120.0 million repaid under the previous RBL facility, $70.0 million under the new RBL facility, and $6.5 million repaid under the SVT working capital facility (note 17). In the Group Cash Flow Statement, the repayment of loans and borrowings line does not include the balance of the previous RBL facility at the date of refinancing of $50.0 million. This was fully repaid utilising the proceeds from the new facility and as such is netted against the proceeds of the new RBL facility in the Group Cash Flow Statement on the proceeds from loans and borrowings line

(ii) Proceeds from loans and borrowings include $120.0 million drawdown under the previous RBL facility prior to refinancing and $70.0 million under new RBL facility on refinancing, $6.7 million drawdowns under the SVT working capital facility and $20.7 million under the vendor loan facility. In the Group Cash Flow Statement, proceeds from loans and borrowings of $152.4 million include amounts outlined in the table above less the previous RBL facility balance of $50.0 million and associated new arrangement fees of $15.0 million. See note 17 for further details

(iii) The cash flow statement includes interest on decommissioning bonds, Letters of Credit and the EPL

29. Cash flow information continued

Reconciliation of carrying value

	Loans (see note 17) $'000	Bonds (see note 17) $'000	Lease liabilities (see note 23) $'000	Total $'000
Principal	(33,972)	(632,101)	(335,255)	(1,001,328)
Unamortised fees	–	10,661	–	10,661
Accrued interest	–	(9,445)	–	(9,445)
At 31 December 2024	(33,972)	(630,885)	(335,255)	(1,000,112)
Principal	**(58,427)**	**(644,367)**	**(372,090)**	**(1,074,884)**
Unamortised fees	**–**	**6,156**	**–**	**6,156**
Accrued interest	**(1,897)**	**(8,929)**	**–**	**(10,826)**
At 31 December 2025	**(60,324)**	**(647,140)**	**(372,090)**	**(1,079,554)**

30. Business combination

Accounting policy

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, which is measured at acquisition date fair value, and the amount of any non-controlling interests in the acquiree. For each business combination, the Group elects whether to measure the non-controlling interests in the acquiree at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition-related costs are expensed as incurred and included in administrative expenses. The Group determines that it has acquired a business when the acquired set of activities and assets include an input and a substantive process that together significantly contribute to the ability to create outputs. The acquired process is considered substantive if it is critical to the ability to continue producing outputs, and the inputs acquired include an organised workforce with the necessary skills, knowledge, or experience to perform that process or it significantly contributes to the ability to continue producing outputs and is considered unique or scarce or cannot be replaced without significant cost, effort, or delay in the ability to continue producing outputs.

Acquisition of Block 12W Vietnam

The Group acquired a 53.125% interest in the Chim Sao and Dua fields ('Block 12W') in Vietnam from Harbour Energy on 9 July 2025 through acquisition of 100% of the share capital of two entities Premier Oil (Vietnam) Limited and Premier Oil Vietnam Offshore BV.

The Group acquired this business as it represents a key step in delivering the Group's diversified growth across South East Asia and aligns with its strategic aim to expand its footprint by investing in fast-payback assets with low capex and reduced carbon intensity. The Group acquired control through payment of cash.

The Transaction assets constitute a business and the acquisition has been accounted for using the acquisition method, in accordance with IFRS 3 Business Combinations. The fair values and resulting goodwill are provisional and will be finalised in EnQuest's half year 2026 financial statements.

30. Business combination continued

The provisional fair values of the net identifiable assets as at the date of acquisition are as follows:

	Notes	Fair value recognised on acquisition $'000
Non-current assets		
Property, plant and equipment	9	24,716
Right-of-use assets	9	33,002
Other receivables[(i)]	15	111,787
Current assets		
Trade and other receivables		32,541
Taxation receivable		41
Cash and cash equivalents		5,850
Total assets		**207,937**
Non-current liabilities		
Provisions[(ii)]	22	89,052
Lease creditor[(iii)]	23	44,845
Deferred tax	6	6,063
Current liabilities		
Trade and other payables		30,546
Lease creditor[(iii)]	23	15,836
Current tax liabilities		1,002
Total liabilities		**187,344**
Total identifiable net assets at fair value		**20,593**
Goodwill arising on acquisition		**5,110**
Purchase consideration transferred:		
Cash transferred		25,703
Total consideration		**25,703**

(i) Represents EnQuest's share of a central abandonment fund of $91.2 million which will be used to pay for future abandonment of the Vietnam asset and amounts owed by JV Partners of $20.6 million, with a further $7.1 million shown within current receivables in respect of the lease liability associated with the FPSO
(ii) Represents a decommissioning liability
(iii) Includes a lease liability predominantly in relation to the FPSO

	$'000
Analysis of cashflows on acquisition	
Total consideration	25,703
Net cash acquired with the subsidiaries	(5,850)
Transaction costs of the acquisition	425
Net cashflow on acquisition	**20,278**

The goodwill has arisen primarily due to the requirement to recognise deferred tax liabilities for the difference between the assigned fair values and the tax bases of the acquired assets and liabilities assumed in a business combination. The assessment of fair values of oil and gas assets acquired is based on cash flows after tax. Nevertheless, in accordance with IAS 12 Income Taxes, a provision is made for deferred tax corresponding to the tax rate multiplied by the difference between the acquisition date fair value and the tax base. The offsetting entry to this deferred tax is goodwill. The acquisition date fair value of the trade receivables amounts to $0.3 million which is expected to be collected within contractual terms.

From the date of acquisition, the Transaction assets have contributed $52.8 million of revenue and $8.0 million to the profit before tax from continuing operations of the Group. If the combination had taken place at the beginning of the year, Group revenue from continuing operations would have been $1,162.9 million and the Group profit before tax from continuing operations would have been $508.4 million.

31. Subsequent events

On 26 February 2026, EnQuest paid bp $60.0 million as final settlement of the 75% profit share contingent consideration liability, securing 100.0% of future Magnus cash flows.

In February, EnQuest was notified by the Vietnam Ministry of Industry and Trade that it had been successful in extending the Block 12W PSC by four years to July 2034, on its existing terms. The PSC extension provides EnQuest and its joint venture partners with the opportunity to access upside across Block 12W and progress discovered resources into reserves, with prospectivity spread across three gas discoveries and several additional targets.

In February, EnQuest received a Letter of Award ('LOA') for a participating interest in the Cendramas PSC by Petronas. The terms of the LOA, subject to the finalisation and signing of the Joint Operating Agreement and the Cendramas PSC, are effective from 23 September 2026.

The Group continues to monitor the situation in the Middle East following the start of the conflict in February. At the date of this report, there has been no material disruption to the Group's day-to-day business.

Report on the audit of the financial statements

1. Opinion

In our opinion :

- the financial statements of EnQuest PLC (the 'parent company') and its subsidiaries (the 'group') give a true and fair view of the state of the group's and of the parent company's affairs as at 31 December 2024 and of the group's profit for the year then ended;
- the group financial statements have been properly prepared in accordance with United Kingdom adopted international accounting standards;
- the parent company financial statements have been properly prepared in accordance with United Kingdom Generally Accepted Accounting Practice, including Financial Reporting Standard 101 "Reduced Disclosure Framework" and
- the financial statements have been prepared in accordance with the requirements of the Companies Act 2006.

We have audited the financial statements which comprise:

- the group Income Statement;
- the group Balance Sheet;
- the group Statement of Changes in Equity;
- the group Statement of Cash Flows;
- the related notes 1 to 30 to the group Financial Statements;
- the parent company Balance Sheet;
- the parent company Statement of Changes in Equity; and
- the related notes 1 to 13 to the parent company Financial Statements.

The financial reporting framework that has been applied in the preparation of the group financial statements is applicable law and United Kingdom adopted international accounting standards. The financial reporting framework that has been applied in the preparation of the parent company financial statements is applicable law and United Kingdom Accounting Standards, including FRS 101 "Reduced Disclosure Framework" (United Kingdom Generally Accepted Accounting Practice).

2. Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)) and applicable law. Our responsibilities under those standards are further described in the auditor's responsibilities for the audit of the financial statements section of our report.

We are independent of the group and the parent company in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the Financial Reporting Council's (the 'FRC's') Ethical Standard as applied to listed public interest entities, and we have fulfilled our other ethical responsibilities in accordance with these requirements. The non-audit services provided to the group and parent company for the year are disclosed in note 4f to the group financial statements. We confirm that we have not provided any non-audit services prohibited by the FRC's Ethical Standard to the group or the parent company.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

3. Summary of our audit approach

Key audit matters	The key audit matters that we identified in the current year were: • Valuation of oil and gas related assets and liabilities • Valuation of decommissioning liability Within this report, key audit matters are identified as follows: Newly identified Increased level of risk Similar level of risk Decreased level of risk
Materiality	The materiality that we used for the group financial statements was $20.3m which was determined on the basis of 3.0% of adjusted EBITDA (management have presented a reconciliation of profit from operations before tax and interest to adjusted EBITDA in the glossary to the financial statements on page 189).
Scoping	EnQuest PLC has two components, being the North Sea and Malaysia. They account for 100% of the group's revenue, 100% of its adjusted EBITDA and 100% of its net assets, therefore account balances of both components were scoped in.
Significant changes in our approach	There were no significant changes in our approach compared to the prior year.

4. Conclusions relating to going concern

In auditing the financial statements, we have concluded that the direc preparation of the financial statements is appropriate.

Our evaluation of the directors' assessment of the group's and parent accounting included:

- assessing the reasonableness of the assumptions used in the cash profiles and cash costs;
- assessing the historical accuracy of forecasts prepared by manage capital expenditure;
- assessing the financing facilities throughout the going concern peri
- considering the levels of cash and covenant headroom throughout reverse stress testing;
- assessing the mathematical accuracy of the forecasts and the goin
- assessing the appropriateness of the group's and parent company

Based on the work we have performed, we have not identified any ma or collectively, may cast significant doubt on the group's and parent c least twelve months from when the financial statements are authorise

In relation to the reporting on how the group has applied the UK Corpo attention to in relation to the directors' statement in the financial state adopt the going concern basis of accounting.

Our responsibilities and the responsibilities of the directors with respec this report.

5. Key audit matters

Key audit matters are those matters that, in our professional judgeme of the current period and include the most significant assessed risks o identified. These matters included those which had the greatest effec audit; and directing the efforts of the engagement team.

These matters were addressed in the context of our audit of the financ we do not provide a separate opinion on these matters.

5.1. Valuation of oil and gas related assets and liabilities

Key audit matter description	Management is required to assess the carrying value of oil and gas related assets and liabilities, in line with the relevant accounting standard, at each balance sheet date. In order to appropriately value these assets and liabilities, management is required to forecast future cash flows. These forecast cash flows are used consistently across the: • Impairment assessment of oil and gas assets; • Impairment assessment of goodwill; • Impairment assessment of the parent company investments; • Valuation of Magnus contingent consideration; and • Valuation of the deferred tax asset. The forecast future cash flows contain a high level of management judgement and estimation, particularly in relation to the following significant assumptions: • Forecast commodity prices; • Discount rate applied; and • Reserve estimates and production profiles. Commodity prices, reserve estimates and production profiles are also impacted by climate-related risks, which increases the level of estimation uncertainty. Given the level of management judgement and estimation applied in determining the recoverable value of the oil and gas related assets and liabilities, including estimation uncertainty within the significant assumptions outlined above, we consider this to be a key audit matter related to the potential risk of fraud. Impairment assessment of oil and gas assets, goodwill and parent company investments Management performed an impairment assessment for oil and gas assets and goodwill carrying value, by reference to IAS 36 Impairment of Assets. As at 31 December 2024, the net book value of property, plant and equipment, which primarily relates to oil and gas assets was $2,298 million (2023: $2,297 million) and management have recorded a pre-tax impairment of $71 million (2023: $117 million) against certain oil and gas assets, including related right of use assets, as disclosed in note 9. As at 31 December 2024, the net book value of goodwill was $134 million (2023: $134 million). No goodwill impairment charge has been recorded in 2024 (2023: nil), as disclosed in note 10. Management also performed an assessment of the carrying values of the parent company's investment in subsidiaries by reference to IAS36 Impairment of Assets and IFRS9 Financial Instruments. As at 31 December 2024, the net book value of investments recognised in the parent company balance sheet was $372 million (2023: $300 million) and management have recorded an impairment reversal of $71 million (2023: $74 million impairment charge), as disclosed in note 3 to the parent company financial statements. Valuation of Magnus contingent consideration The valuation of Magnus contingent consideration was $451 million (2023: $488 million) as at 31 December 2024, based on the estimated future cash flows for the Magnus oil and gas asset, as disclosed in note 21. Given the interrelationship with production and the profit-share agreement, considerations have been made to the relationship of the key accounting estimates relating to commodity prices. Valuation of the deferred tax asset As at 31 December 2024, a deferred tax asset of $506m (2023: $540m) was recognised, based on the expected utilisation of historical tax losses, underpinned by forecasts of future profitability. The forecast cash flows used to value the deferred tax asset are consistent with the cash flows used for impairment purposes. Further details on the deferred tax asset are disclosed in note 6(c). Given the interrelated nature of the key areas noted above, management have applied consistent assumptions across all of these valuations where appropriate. Further details on this matter have been disclosed in the audit committee report on page 104 and 105 and in the "critical accounting judgements and key sources of estimation uncertainty" section of note 2.

5.1. Valuation of oil and gas related assets and liabilities co

How the scope of our audit responded to the key audit matter	Our procedures comprised the following: Procedures on internal controls and va • obtaining an understanding of relevant c impairment and for performing their imp • assessing management's forecasting ac • assessing whether forecast cash flows w forecasts used elsewhere, including for g • challenging the reasonableness of the op • assessing, with input from our tax special including the Energy Profits Levy; • working with our modelling specialists to • challenging management's determinati in comparison to the requirements of IAS • assessing the reasonableness of the vari procedures; • evaluating compliance with the relevant Impairment of Assets and IFRS13 Fair Valu • evaluating the adequacy of managemer including related sensitivity analysis and Procedures related to the key assump Our procedures related to the key assumpt *Forecast commodity prices* • assessing the appropriateness of manag forward curves, peer information, market • performing sensitivity analysis on the pric conclusions of reasonably possible chan • evaluating whether management's pricin of lower oil and gas demand due to clima • assessed future commodity price differe liftings from 2024. *Discount rate* • evaluating, with input from our valuations and valuations; • comparing discount rate of peer UKCS up • assessing whether country risks are appr ***Reserves estimates and production profile*** • comparing management's reserves estim reserves expert; • assessing the technical competence, cap • evaluating, with involvement from our oil estimates and production profiles; and • working with our oil and gas reserves spe reserves estimates and production profil
Key observations	We are satisfied with management's concl liabilities, including the related impairment In reaching this conclusion, we observed th • Future commodity price assumptions are • Impairment discount rates were within ou • Reserves estimates and production profi management's reserves expert; • The carrying value of the oil and gas asset • The carrying value of the investment in su • The carrying value of the Magnus contin • The deferred tax asset recognition is app

5.2. Valuation of decommissioning liability

Key audit matter description	The group is required by law to decommission the oil and gas assets and associated infrastructure at the end of their operating life. An estimate of the future cost of decommissioning is required to be provided for in accordance with IAS37 Provisions, Contingent Liabilities and Contingent Assets. The decommissioning provision at 31 December 2024 is $760 million (2023: $781 million). The provision represents the present value of decommissioning costs which are expected to be incurred during the decommissioning period, which is assumed to run to 2050, assuming no further development of the group's assets. Further details on the key sources of estimation uncertainty underpinning the valuation of decommissioning provisions can be found in note 2. This key audit matter is considered to be a risk due to fraud. Decommissioning liabilities are inherently judgemental areas, particularly in relation to cost estimates and the related assumptions. The key management estimates containing the most estimation uncertainty, and therefore the focus of our key audit matter, are: • internal well cost estimates included in the decommissioning model; and • discount rate applied, calculated as a risk-free rate using an average of year-end 5-, 10- and 20-year UK Gilts, weighted to reflect expected timing profile of future decommissioning spend. Further details on this matter have been disclosed in the audit committee report on page 104 and in note 22.
How the scope of our audit responded to the key audit matter	Our procedures comprised the following: Procedures on internal controls and the decommissioning model • obtaining an understanding of the relevant controls relating to the decommissioning provision; • assessing the technical competence, capabilities and objectivity of management's internal and external experts; • assessing the decommissioning provision for compliance with IAS 37 Provisions, Contingent Liabilities and Contingent Assets; • working with our modelling specialists to evaluate the arithmetical accuracy of the decommissioning model; • assessing available benchmarking reports for indications of developments in industry practice and prevailing cost trends; • challenging the cost reduction factors applied to the decommissioning model, through comparison with available evidence for the factors applied including industry benchmarking reports; • testing a sample of actual decommissioning spend incurred during the period, by agreeing to invoices and payments from bank statements; • assessing the historical forecasting accuracy of management for decommissioning expenditure, by comparing actual spend with historical estimates; • re-calculating the closing decommissioning provision from the gross decommissioning cost estimate, and agreeing this to the group's financial records; and • evaluating the adequacy of management's disclosures, including the key sources of estimation uncertainty and associated sensitivity analysis of decommissioning assumptions. Procedures on cost estimates and related assumptions *Internal well cost estimates* • challenging the group's assumptions within the cost estimate by referencing to available third-party data and benchmarking to industry publications, peer and market rates; and • assessing the assumed durations for plug and abandonment of wells, by comparison to available benchmarking data and potential contradictory evidence available from active decommissioning projects or operator estimates. *Discount rate* • evaluating the group's discount rates used in valuing the decommissioning liability with reference to external risk free market rates; and • recalculating the discount rate by agreeing key inputs, being the year-end 5-, 10- and 20- year UK Gilt rates and expected timing profile of future decommissioning spend, to supporting evidence and confirming the calculations are applied in accordance with the method and are mathematically accurate.
Key observations	• The key assumptions within the well cost estimates are reasonable; • The decommissioning discount rate is reasonable; and • We are satisfied that the group's decommissioning provision is reasonable and prepared in accordance with the requirements of IAS 37 Provisions, Contingent Liabilities and Contingent Assets. We are satisfied the disclosures in the financial statements are adequate.

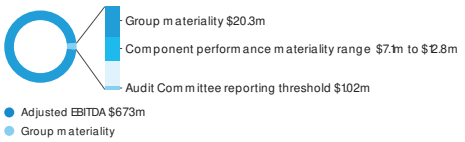
6. Our application of materiality

6.1. Materiality

We define materiality as the magnitude of misstatement in the financ
of a reasonably knowledgeable person would be changed or influenc
and in evaluating the results of our work.

Based on our professional judgement, we determined materiality for t

	Group financial statements
Materiality	$20.3 million (2023: $23 million)
Basis for determining materiality	3.0% of adjusted EBITDA, (2023: 2.8% of adjus EBITDA).
Rationale for the benchmark applied	Adjusted EBITDA was considered to be the m relevant benchmark as it is a key performan measure used by the group and by investor represents a consistent profit measure used by stakeholders.



6.2. Performance materiality

We set performance materiality at a level lower than materiality to red
misstatements exceed the materiality for the financial statements as

	Group financial statements
Performance materiality	70% (2023: 70%) of group materiality
Basis and rationale for determining performance materiality	In determining performance materiality, we • our risk assessment, including our assess • our past experience of the audit, which ha misstatements identified in prior periods; • management's willingness to correct erro • macro-economic factors such as comm

6.3. Error reporting threshold

We agreed with the Audit Committee that we would report to the Com
as differences below that threshold that, in our view, warranted reporti
disclosure matters that we identified when assessing the overall prese

7. An overview of the scope of our audit

7.1. Identification and scoping of components

Our audit was scoped by obtaining an understanding of the group and its environment, including group-wide controls, and assessing the risks of material misstatement at the group level. In the current year we performed an audit of one or more account balances of the North Sea and Malaysia components. Audit procedures were performed by the group audit team for the North Sea component and by the Malaysia component team for the Malaysia component.

The performance materiality applied for the Malaysia component was $7.1 million (2023: $8.1 million). The performance materiality applied for the North Sea component was $12.8 million (2023: $14.5 million).

The North Sea and Malaysia components, where we performed an audit of one or more account balances, accounted for 100% of the group's revenue, 100% of the group's adjusted EBITDA and 100% of the group's net assets, consistent with the prior year.

7.2. Our consideration of the control environment

We obtained an understanding of relevant controls in relation to a number of key business cycles, including impairment, decommissioning, financial reporting and close and revenue, as well as IT systems that were relevant to the audit, being the financial reporting system. Additionally, we tested relevant controls relating to revenue cut-off. Significant progress has been made in addressing the control weaknesses that were identified in relation to the general IT control environment in the prior year but we did not place reliance on these IT controls for the purposes of our audit testing. Overall, we did not plan to take a control reliance approach in the current year, other than in respect of revenue as outlined above.

7.3. Our consideration of climate- related risks

We performed enquiries of management to understand the impact of climate-related risks and controls relevant to the group. We performed a review of the climate change risk assessment and related documentation prepared by management and considered the completeness and accuracy of the climate-related risks identified and summarised in the Task Force on Climate-related Financial Disclosures report from page 74 to 83.

As disclosed in note 2, management identified key judgements and estimates with elevated climate-related risk, relating to property, plant and equipment and goodwill, valuation of contingent consideration and deferred tax as well as the timing and valuation of the decommissioning provision.

We considered whether the risks identified by management within their climate change risk assessment and related documentation are complete and challenged assumptions impacting the financial statements. The key piece of climate-related regulation enacted to date and impacting the group continues to relate to carbon costs and emission allowances. The key market-related matter which could have a material impact on the valuation of the items noted above is in respect of future demand for, and pricing of, oil and gas as the energy mix evolves in response to climate change risk and other matters. There continues to be a climate-related risk relating to the early cessation of production of oil and gas assets, which would impact all of the judgements and estimates outlined above. This is disclosed in the annual report on page 57.

We performed a review of the climate disclosures within the Annual Report, including the climate-related financial disclosures referred to in note 2, with the involvement of our climate specialists. We considered whether these were materially consistent with the financial disclosures and consistent with our understanding of the climate-related risks, assumptions and judgements during the year. Both of our key audit matters are considered to contain climate-related risks, being the risks to commodity prices and cessation of production, which could have a material impact on the valuation of oil and gas related assets and liabilities and valuation of the decommissioning provision. The procedures performed for these key audit matters are discussed in detail in the key audit matters section above.

7.4. Working with other auditors

We engaged Deloitte Malaysia as our component auditor, directed and supervised by the group engagement team in the UK. Detailed referral instructions were sent to the component audit team as part of planning procedures.

The group engagement team directed and supervised the component team throughout the year via attendance at planning meetings, regular communication between the teams and attendance at closing meetings. The group engagement team reviewed and challenged the reporting deliverables and audit file as part of concluding procedures.

We are satisfied that the level of involvement of the lead audit partner and team in the component audit has been appropriate and has enabled us to conclude that sufficient appropriate audit evidence has been obtained in support of our opinion on the group financial statements as a whole.

8. Other information

The other information comprises the information included in the annu
report thereon. The directors are responsible for the other information

Our opinion on the financial statements does not cover the other infor
report, we do not express any form of assurance conclusion thereon.

Our responsibility is to read the other information and, in doing so, con
the financial statements or our knowledge obtained in the course of th

If we identify such material inconsistencies or apparent material miss
a material misstatement in the financial statements themselves. If, ba
material misstatement of this other information, we are required to rep

We have nothing to report in this regard.

9. Responsibilities of directors

As explained more fully in the directors' responsibilities statement, the
statements and for being satisfied that they give a true and fair view, a
to enable the preparation of financial statements that are free from m

In preparing the financial statements, the directors are responsible for
as a going concern, disclosing as applicable, matters related to going
directors either intend to liquidate the group or the parent company or

10. Auditor's responsibilities for the audit of the financial state

Our objectives are to obtain reasonable assurance about whether the
misstatement, whether due to fraud or error, and to issue an auditor's
high level of assurance, but is not a guarantee that an audit conducte
misstatement when it exists. Misstatements can arise from fraud or er
they could reasonably be expected to influence the economic decisio

A further description of our responsibilities for the audit of the financia
auditorsresponsibilities. This description forms part of our auditor's rep

11. Extent to which the audit was considered capable of detecting irregularities, including fraud

Irregularities, including fraud, are instances of non-compliance with laws and regulations. We design procedures in line with our responsibilities, outlined above, to detect material misstatements in respect of irregularities, including fraud. The extent to which our procedures are capable of detecting irregularities, including fraud is detailed below.

11.1. Identifying and assessing potential risks related to irregularities

In identifying and assessing risks of material misstatement in respect of irregularities, including fraud and non-compliance with laws and regulations, we considered the following:

- the nature of the industry and sector, control environment and business performance including the design of the group's remuneration policies, key drivers for directors' remuneration, bonus levels and performance targets;
- the group's own assessment of the risks that irregularities may occur either as a result of fraud or error that was approved by the board;
- results of our enquiries of management, internal audit, the directors and the Audit Committee about their own identification and assessment of the risks of irregularities, including those that are specific to the group's sector;
- any matters we identified having obtained and reviewed the group's documentation of their policies and procedures relating to:
- identifying, evaluating and complying with laws and regulations and whether they were aware of any instances of non-compliance;
- detecting and responding to the risks of fraud and whether they have knowledge of any actual, suspected or alleged fraud; and
- the internal controls established to mitigate risks of fraud or non-compliance with laws and regulations;
- the matters discussed among the audit engagement team including the component audit teams and relevant internal specialists, including tax, valuations, IT, modelling and oil and gas reserves specialists, regarding how and where fraud might occur in the financial statements and any potential indicators of fraud.

As a result of these procedures, we considered the opportunities and incentives that may exist within the organisation for fraud and identified the greatest potential for fraud in the following areas:

- valuation of oil and gas related assets and liabilities; and
- valuation of decommissioning provision.

In common with all audits under ISAs (UK), we are also required to perform specific procedures to respond to the risk of management override.

We also obtained an understanding of the legal and regulatory framework that the group operates in, focusing on provisions of those laws and regulations that had a direct effect on the determination of material amounts and disclosures in the financial statements. The key laws and regulations we considered in this context included the UK Companies Act 2006 and the Listing Rules of the UK Listing Authority and the relevant tax compliance regulations in the jurisdictions in which the group operates.

In addition, we considered provisions of other laws and regulations that do not have a direct effect on the financial statements but compliance with which may be fundamental to the group's ability to operate or to avoid a material penalty. These included environmental laws and regulations in the countries in which the group operates as well as licence terms for the group's oil and gas assets.

11.2. Audit response to risks identified

As a result of performing the above, we identified the valuation of oil a
decommissioning provision as key audit matters related to the potent
the matters in more detail and also describes the specific procedures

In addition to the above, our procedures to respond to risks identified i

- reviewing the financial statement disclosures and testing to suppor
relevant laws and regulations described as having a direct effect or
- enquiring of management, the Audit Committee and in-house lega
- performing analytical procedures to identify any unusual or unexpe
due to fraud;
- reading minutes of meetings of those charged with governance, re
relevant authorities; and
- in addressing the risk of fraud through management override of co
adjustments; assessing whether the judgements made in making a
evaluating the business rationale of any significant transactions tha

We also communicated relevant identified laws and regulations and p
internal specialists and component audit team, and remained alert to
regulations throughout the audit.

Report on other legal and regulatory requirements

12. Opinions on other matters prescribed by the Companies Act 2006

In our opinion the part of the directors' remuneration report to be audited has been properly prepared in accordance with the Companies Act 2006.

In our opinion, based on the work undertaken in the course of the audit:

- the information given in the strategic report and the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements; and
- the strategic report and the directors' report have been prepared in accordance with applicable legal requirements.

In the light of the knowledge and understanding of the group and the parent company and their environment obtained in the course of the audit, we have not identified any material misstatements in the strategic report or the directors' report.

13. Corporate Governance Statement

The Listing Rules require us to review the directors' statement in relation to going concern, longer-term viability and that part of the Corporate Governance Statement relating to the group's compliance with the provisions of the UK Corporate Governance Code specified for our review.

Based on the work undertaken as part of our audit, we have concluded that each of the following elements of the Corporate Governance Statement is materially consistent with the financial statements and our knowledge obtained during the audit:

- the directors' statement with regards to the appropriateness of adopting the going concern basis of accounting and any material uncertainties identified set out on page 37;
- the directors' explanation as to its assessment of the group's prospects, the period this assessment covers and why the period is appropriate set out on page 38;
- the directors' statement on fair, balanced and understandable set out on page 102;
- the board's confirmation that it has carried out a robust assessment of the emerging and principal risks set out on pages 54 to 71;
- the section of the annual report that describes the review of effectiveness of risk management and internal control systems set out on page 105; and
- the section describing the work of the audit committee set out on pages 101 to 106.

14. Matters on which we are required to report by exception

14.1. Adequacy of explanations received and accounting records

Under the Companies Act 2006 we are required to report to you if, in our opinion:

- we have not received all the information and explanations we require for our audit; or
- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or
- the parent company financial statements are not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

14.2. Directors' remuneration

Under the Companies Act 2006 we are also required to report if in our opinion certain disclosures of directors' remuneration have not been made or the part of the directors' remuneration report to be audited is not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

15. Other matters which we are required to address

15.1. Auditor tenure

Following the recommendation of the audit committee, we were appoi
for the year ending 31 December 2020 and subsequent financial period
renewals and reappointments of the firm is five years, covering the yea

15.2. Consistency of the audit report with the additional report

Our audit opinion is consistent with the additional report to the audit c

16. Use of our report

This report is made solely to the company's members, as a body, in ac
audit work has been undertaken so that we might state to the compa
auditor's report and for no other purpose. To the fullest extent permitte
than the company and the company's members as a body, for our au

As required by the Financial Conduct Authority (FCA) Disclosure Guida
financial statements will form part of the Electronic Format Annual Fin
accordance with DTR 4.1.15R – DTR 4.1.18R. This auditor's report provides
Report has been prepared in compliance with DTR 4.1.15R – DTR 4.1.18R.

David Paterson ACA (Senior statutory auditor)
For and on behalf of Deloitte LLP
Statutory Auditor

London, United Kingdom
26 March 2025

Group Income Statement
For the year ended 31December 2024

	Notes	2024 $'000	2023 $'000
Revenue and other operating income	4(a)	1,180,709	1,487,419
Cost of sales	4(b)	(787,383)	(946,752)
Gross profit/(loss)		393,326	540,667
Net impairment charge to oil and gas assets	9	(71,414)	(117,396)
General and administration expenses	4(c)	(5,702)	(6,348)
Other (expenses)/income	4(d)	(4,682)	(19,550)
Profit/(loss) from operations before tax and finance income/(costs)		311,528	397,373
Finance costs	5	(159,422)	(172,087)
Finance income	5	14,508	6,493
Profit/(loss) before tax		166,614	231,779
Income tax	6	(72,841)	(262,612)
Profit/(loss) for the year attributable to owners of the parent		93,773	(30,833)
Total comprehensive profit/(loss) for the year, attributable to owners of the parent		93,773	(30,833)

There is no comprehensive income attributable to the shareholders of the Group other than the profit/(loss) for the period. Revenue and operating profit/(loss) are all derived from continuing operations.

		$	$
Earnings per share	7		
Basic		0.050	(0.016)
Diluted		0.049	(0.016)

The attached notes 1 to 30 form part of these Group financial statements.

Group Balance Sheet
At 31December 2024

ASSETS
Non-current assets
Property, plant and equipment
Goodwill
Intangible assets
Deferred tax assets
Trade and other receivables
Other financial assets
Current assets
Intangible assets
Inventories
Trade and other receivables
Current tax receivable
Cash and cash equivalents
Other financial assets
TOTAL ASSETS
EQUITY AND LIABILITIES
Equity
Share capital and premium
Treasury shares
Share-based payments reserve
Capital redemption reserve
Retained earnings
TOTAL EQUITY
Non-current liabilities
Loans and borrowings
Lease liabilities
Contingent consideration
Provisions
Deferred income
Trade and other payables
Deferred tax liabilities
Current liabilities
Loans and borrowings
Lease liabilities
Contingent consideration
Provisions
Trade and other payables
Other financial liabilities
Current tax payable
TOTAL LIABILITIES
TOTAL EQUITY AND LIABILITIES

The attached notes 1 to 30 form part of these Group financial statemer

The financial statements were approved by the Board of Directors and

Jonathan Copus
Chief Financial Officer

Group Statement of Changes in Equity
For the year ended 31December 2024

	Notes	Share capital $'000	Share premium $'000	Treasury shares $'000	Share-based payments reserve $'000	Capital redemption reserve $'000	Retained earnings $'000	Total $'000
Balance at 1 January 2023		131,650	260,546	–	11,510	–	80,535	484,241
Loss for the year		–	–	–	–	–	(30,833)	(30,833)
Total comprehensive expense for the year		–	–	–	–	–	(30,833)	(30,833)
Issue of shares to Employee Benefit Trust		1,635	–	–	(1,635)	–	–	–
Share-based payment		–	–	–	3,320	–	–	3,320
Balance at 31 December 2023		133,285	260,546	–	13,195	–	49,702	456,728
Profit for the year		–	–	–	–	–	93,773	93,773
Total comprehensive income for the year		–	–	–	–	–	93,773	93,773
Issue of shares to Employee Benefit Trust	19	229	–	–	(229)	–	–	–
Repurchase and cancellation of shares	19	(2,006)	–	(4,425)	–	2,006	(4,593)	(9,018)
Share-based payment	20	–	–	–	983	–	–	983
Balance at 31 December 2024		131,508	260,546	(4,425)	13,949	2,006	138,882	542,466

The attached notes 1 to 30 form part of these Group financial statements.

Group Statement of Cash Flows
For the year ended 31December 2024

CASH FLOW FROM OPERATING ACTIVITIES
Cash generated from operations
Cash received from insurance
Cash (paid)/received on purchase of financial instruments
Cash paid in relation to amounts previously provided for
Decommissioning spend
Income taxes paid
Net cash flows from/(used in) operating activities
INVESTING ACTIVITIES
Purchase of property, plant and equipment
Proceeds from farm-down
Vendor financing facility repaid/(loaned)
Purchase of intangible oil and gas assets
Purchase of other intangible assets
Payment of Magnus contingent consideration – Profit share
Payment of Golden Eagle contingent consideration – Acquisition
Interest received
Net cash flows (used in)/from investing activities
FINANCING ACTIVITIES
Proceeds from loans and borrowings
Repayment of loans and borrowings
Payment for repurchase of shares
Payment of obligations under financing leases
Interest paid
Net cash flows (used in)/from financing activities
NET (DECREASE)/INCREASE IN CASH AND CASH EQUIVALENTS
Net foreign exchange on cash and cash equivalents
Cash and cash equivalents at 1 January
CASH AND CASH EQUIVALENTS AT 31DECEMBER
Reconciliation of cash and cash equivalents
Total cash at bank and in hand
Restricted cash
Cash and cash equivalents per balance sheet

The attached notes 1 to 30 form part of these Group financial stateme

Notes to the Group Financial Statements
For the year ended 31 December 2024

1. Corporate information
EnQuest PLC ('EnQuest' or the 'Company') is a public company limited by shares incorporated in the United Kingdom under the Companies Act and is registered in England and Wales and listed on the London Stock Exchange. The address of the Company's registered office is shown on the inside back cover of the Group Annual Report and Accounts.

EnQuest PLC is the ultimate controlling party. The principal activities of the Company and its subsidiaries (together the 'Group') are to responsibly optimise production, leverage existing infrastructure, deliver a strong decommissioning performance and explore new energy and decarbonisation opportunities.

The Group's financial statements for the year ended 31 December 2024 were authorised for issue in accordance with a resolution of the Board of Directors on 26 March 2025.

A listing of the Group's companies is contained in note 28 to these Group financial statements.

2. Basis of preparation
The consolidated financial statements have been prepared in accordance with United Kingdom international accounting standards ('IFRS') in conformity with the requirements of the Companies Act 2006. The accounting policies which follow set out those policies which apply in preparing the financial statements for the year ended 31 December 2024.

For the year ended 31 December 2024, the Group removed the separate disclosure of remeasurements and exceptional items from the presentation of the Group income statement to simplify their presentation for users of accounts and bring them more in line with peers. The Group continues to present various Alternative Performance Measures ('APMs') when assessing and discussing the Group's financial performance, balance sheet and cash flows that are not defined or specified under IFRS but consistent with the measurement basis applied to the financial statements. The Group uses these APMs, which are not considered to be a substitute for, or superior to, IFRS measures, to provide stakeholders with additional useful information to aid the understanding of the Group's underlying financial performance, balance sheet and cash flows by adjusting for certain items, such as those previously classified as remeasurements and exceptional items, which impact upon IFRS measures or, by defining new measures. See the Glossary – Non-GAAP Measures on page 189 for more information.

The Group financial information has been prepared on a historical cost basis, except for the fair value remeasurement of certain financial instruments, including derivatives and contingent consideration, as set out in the accounting policies. The presentation currency of the Group financial information is US Dollars ('$') and all values in the Group financial information are rounded to the nearest thousand ($'000) except where otherwise stated.

Going concern
The financial statements have been prepared on the going concern basis.

In recent years, EnQuest has focused on deleveraging and optimising its capital structure, to simplify its balance sheet and maximise available financial transactional capacity.

In 2024, the Group deleveraged further, reducing EnQuest net debt by $95.1 million, to $385.8 million at 31 December 2024. This was driven by robust adjusted free cash flow generation and repayment of the first of two vendor loans that was provided to RockRose as part of the 2023 Bressay farm-down. In the period EnQuest fully repaid its Reserve Based Lending ('RBL') facility (from $140.0 million) and completed a $160.0 million tap of its high yield bonds. By using this tap to repay a $150.0 million term loan facility, additional RBL capacity was opened. At 31 December 2024, EnQuest's net debt to adjusted EBITDA ratio was 0.6x. The Group ended 2024 with a positive RBL redetermination, which expanded RBL capacity by 34%. Cash and available facilities at 28 February 2025 totalled $549.0 million.

Against this robust backdrop, EnQuest continues to closely monitor and manage its funding position and liquidity requirements throughout the year, including monitoring forecast covenant results. Cash forecasts are regularly produced and sensitivities considered for, but not limited to, changes in crude oil prices (adjusted for hedging undertaken by the Group), production rates and costs. These forecasts and sensitivity analyses allow management to mitigate liquidity or covenant compliance risks in a timely manner.

The Group's latest approved business plan underpins management's base case ('Base Case'). It is in line with EnQuest's production guidance (including the acquisition and contribution of the Block 12W in Vietnam – completion expected in the second quarter of 2025) and an oil price assumption of $75.0/bbl is used for 2025 and 2026.

A reverse stress test has been performed on the Base Case. This indicates that an oil price of c.$40.0/bbl is required to maintain covenant compliance over the going concern period. The low level of this required price reflects the Group's strong liquidity position.

The Base Case has also been subjected to further testing through a scenario that explores the impact of the following plausible downside risks (the 'Downside Case'):

- 10% discount to Base Case prices resulting in Downside Case prices of $67.50/bbl for 2025 and 2026;
- Production risking of 5.0%; and
- 2.5% increase in operating costs.

The Base Case and Downside indicate that the Group is able to operate as a going concern and remain covenant compliant for 12 months from the date of publication of its full-year results.

After making appropriate enquiries and assessing the progress against the forecast, the Directors have a reasonable expectation that the Group will continue in operation and meet its commitments as they fall due over the going concern period. Accordingly, the Directors continue to adopt the going concern basis in preparing these financial statements.

New standards and interpretations
The following new standards became applicable for the current reporting period. No material impact was recognised upon application:

- Supplier Finance Arrangements (Amendments to IAS 7 and IFRS 7)
- Classification of Liabilities as Current or Non-current and Non-current Liabilities with Covenants (Amendments to IAS 1)
- Lease Liability in a Sale and Leaseback (Amendment to IFRS 16)

2. Basis of preparation continued
Standards issued but not yet effective
At the date of authorisation of these financial statements, the Group h
have been issued but are not yet effective:

IFRS 18	Presentation of financial statements
IFRS 9 and IFRS 7	Amendments to the Classification and Me
IFRS 19	Subsidiaries without Public Accountability:
Amendments to IAS 21	Lack of Exchangeability

The Directors do not expect that the adoption of the Standards listed a
Group in future periods. The Directors noted IFRS 18 may change the pr
when effective.

Basis of consolidation
The consolidated financial statements incorporate the financial statem
(its subsidiaries) made up to 31 December each year. Control is achiev

- has power over the investee;
- is exposed, or has rights, to variable returns from its involvement wit
- has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee if facts
of the three elements of control listed above. Consolidation of a subsid
and ceases when the Company loses control of the subsidiary. Specifi
year are included in profit or loss from the date the Company gains co

Where necessary, adjustments are made to the financial statements
the Group's accounting policies. All intra-Group assets and liabilities, e
between the members of the Group are eliminated on consolidation.

Joint arrangements
Oil and gas operations are usually conducted by the Group as co-lice
Joint control is the contractually agreed sharing of control of an arran
activities require the consent of the relevant parties sharing control. Th
framework to the joint arrangement, which is historically referred to as
to 'joint ventures' as a standard term used in the oil and gas industry, v

Most of the Group's activities are conducted through joint operations,
the rights to the assets, and obligations for the liabilities relating to the
income and expenses of the joint operation in the consolidated financ
not have any material interests in joint ventures or in associates as de

Foreign currencies
Items included in the financial statements of each of the Group's entit
environment in which the entity operates ('functional currency'). The G
which the Group has elected to use as its presentation currency.

In the financial statements of the Company and its individual subsidia
currency are recorded at the prevailing rate of exchange on the date
denominated in foreign currencies are retranslated at the rates of exc
and liabilities that are measured at historical cost in a foreign currenc
transactions. Non-monetary assets and liabilities measured at fair va
the date the fair value was determined. All foreign exchange gains an

Emissions liabilities
The Group operates in an energy intensive industry and is therefore re
recognises an emission liability in line with the production of emission
by allowances held, the liability is recognised at the cost of these allow
uncovered portion is measured at the spot market price of allowance
'production costs' under 'cost of sales' and the accrual is presented in
Group's liability is recognised on the balance sheet as an intangible a
derecognised upon settling the liability with the respective regulator.

2. Basis of preparation continued

Use of judgements, estimates and assumptions

The preparation of the Group's consolidated financial statements requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the accompanying disclosures, at the date of the consolidated financial statements. Estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

The accounting judgements and estimates that have a significant impact on the results of the Group are set out below and should be read in conjunction with the information provided in the Notes to the financial statements. The Group does not consider contingent consideration and deferred taxation (including EPL) to represent a significant estimate or judgement as the estimates and assumptions relating to projected earnings and cash flows used to assess contingent consideration and deferred taxation are the same as those applied in the Group impairment process as described below in *Recoverability of asset carrying values*. Judgements and estimates, not all of which are significant, made in assessing the impact of climate change and the transition to a lower carbon economy on the consolidated financial statements are also set out below. Where an estimate has a significant risk of resulting in a material adjustment to the carrying amounts of assets and liabilities within the next financial year, this is specifically noted.

Climate change and energy transition

As covered in the Group's principal risks on oil and gas prices on page 59, the Group recognises that the energy transition is likely to impact the demand, and hence the future prices, of commodities such as oil and natural gas. This in turn may affect the recoverable amount of property, plant and equipment and goodwill, valuation of contingent consideration and deferred tax, as well as an acceleration of cessation of production and subsequent decommissioning expenditure, in the oil and gas industry. The Group acknowledges that there are a range of possible energy transition scenarios that may indicate different outcomes for oil prices. There are inherent limitations with scenario analysis and it is difficult to predict which, if any, of the scenarios might eventuate.

The Group has assessed the potential impacts of climate change and the transition to a lower carbon economy in preparing the consolidated financial statements, including the Group's current assumptions relating to demand for oil and natural gas and their impact on the Group's long-term price assumptions. See *Recoverability of asset carrying values: Oil prices*.

While the pace of transition to a lower carbon economy is uncertain, oil and natural 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 useful lives of the Group's current portfolio of oil and gas assets, a material adverse change is not expected to the carrying values of EnQuest's assets and liabilities within the next financial year as a result of climate change and the transition to a lower carbon economy.

Management will continue to review price assumptions as the energy transition progresses and this may result in impairment charges or reversals in the future.

Critical accounting judgements and key sources of estimation uncertainty

The Group has considered its critical accounting judgements and key sources of estimation uncertainty, and these are set out below.

Recoverability of asset carrying values

Judgements: The Group assesses each asset or cash-generating unit ('CGU') (excluding goodwill, which is assessed annually regardless of indicators) in each reporting period to determine whether any indication of impairment exists. Assessment of indicators of impairment or impairment reversal and the determination of the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment purposes require significant management judgement. For example, individual oil and gas properties may form separate CGUs, whilst certain oil and gas properties with shared infrastructure may be grouped together to form a single CGU. Alternative groupings of assets or CGUs may result in a different outcome from impairment testing. See note 10 for details on how these groupings have been determined in relation to the impairment testing of goodwill.

Estimates: Where an indicator of impairment exists, a formal estimate of the recoverable amount is made, which is considered to be the higher of the fair value less costs to dispose ('FVLCD') and value in use ('VIU'). The assessments require the use of estimates and assumptions, such as the effects of inflation and deflation on operating expenses, cost profile changes including those related to emission reduction initiatives such as alternative fuel provision at Kraken, discount rates, capital expenditure, production profiles, reserves and resources, and future commodity prices, including the outlook for global or regional market supply-and-demand conditions for crude oil and natural gas. Such estimates reflect management's best estimate of the related cash flows based on management's plans for the assets and their future development.

As described above, the recoverable amount of an asset is the higher of its VIU and its FVLCD. When the recoverable amount is measured by reference to FVLCD, in the absence of quoted market prices or binding sale agreement, estimates are made regarding the present value of future post-tax cash flows. These estimates are made from the perspective of a market participant and include prices, life of field production profiles based on reserves and resources to which it is considered probable that a market participant would attribute value to them, operating costs, capital expenditure, decommissioning costs, tax attributes, risking factors applied to cash flows, and discount rates.

Details of impairment charges and reversals recognised in the income statement and details on the carrying amounts of assets are shown in note 9, note 10 and note 11.

The estimates for assumptions made in impairment tests in 2024 relating to discount rates and oil prices are discussed below. Changes in the economic environment or other facts and circumstances may necessitate revisions to these assumptions and could result in a material change to the carrying values of the Group's assets within the next financial year.

2. Basis of preparation continued

Discount rates

For discounted cash flow calculations, future cash flows are adjusted t
use the post-tax discount rate. The discount rate is derived using the w
rates applied in impairment tests are reassessed each year and, in 20
reflecting the impact from the Group's reduced debt position and clar

Oil prices

The price assumptions used for FVLCD impairment testing were based
forecasts reflect EnQuest's views of global supply and demand, includ
and the transition to a low carbon economy as outlined in the Basis of
information such as analyst forecasts. The Group's price forecasts are
and the Board of Directors.

EnQuest revised its oil price assumptions for FVLCD impairment testing
reflecting current market dynamics and external forecasts. A summar
assumptions, which represent management's best estimate of future
to the International Energy Agency's ('IEA') forecast prices under its An
commitments made by governments and industries around the world
net zero or carbon neutrality pledges will be met in full and on time, En
assumed under the APS, while its longer-term prices are slightly highe
scenario modelling data released by the World Business Council of Su
aligned with the top end of a range of Paris-consistent scenarios. A 10%
believes to be a reasonably possible change as further considered lat
consistent scenarios. Discounts or premiums are applied to price assu
terms of the relevant sales contracts.

An inflation rate of 2% (2023: 2%) is applied from 2028 onwards to deter

The price assumptions used in 2023 were $80.0/bbl (2024), $80.0/bbl (
per annum from 2027.

Brent oil ($/bbl)

(i) Inflated at 2% from 2028

Oil and natural gas reserves

Hydrocarbon reserves are estimates of the amount of hydrocarbons t
oil and gas properties. The business of the Group is to responsibly opti
strong decommissioning performance and explore new energy and c
geological and engineering data, reservoir performance data, acquis
on the determination of the Group's estimates of its oil and gas reserv
prospectively the discounted cash flows used in impairment testing a
date of decommissioning and the depletion charges in accordance w
assessment. Economic assumptions used to estimate reserves chang
data is generated. This process may require complex and difficult geo

The Group uses proven and probable ('2P') reserves (see page 32) and
well as an alternative fuel provision for the Kraken FPSO as the basis fo
because this represents the reserves and resources management int
attribute value to them. Third-party audits of EnQuest's reserves and r

2. Basis of preparation continued

Sensitivity analyses

Changes in price and its consequential impact on impairment, contingent consideration and deferred tax, along with the discount rate impact on impairment and decommissioning are considered to be the only key sources of estimation uncertainty, although other sensitivities that the Group believes are useful for users of these accounts but are not considered to have a significant risk of resulting in material changes to carrying amounts in the next 12 months, may also be provided.

Management tested the impact of a change in cash flows in FVLCD impairment testing arising from a 10% reduction in crude price assumptions, which it believes to be a reasonably possible change given the prevailing macroeconomic environment.

Price reductions of this magnitude in isolation could indicatively lead to a further reduction in the carrying amount of EnQuest's oil and gas properties by approximately $221.6 million, which is approximately 10% of the net book value of property, plant and equipment as at 31 December 2024.

The oil price sensitivity analysis above does not, however, represent management's best estimate of any impairments that might be recognised as it does not fully incorporate consequential changes that may arise, such as reductions in costs and changes to business plans, phasing of development, levels of reserves and resources, and production volumes. As the extent of a price reduction increases, the more likely it is that costs would decrease across the industry. The oil price sensitivity analysis therefore does not reflect a linear relationship between price and value that can be extrapolated.

Management also tested the impact of a one percentage point change in the discount rate of 10.0% used for FVLCD impairment testing of oil and gas properties, which is considered a reasonably possible change given the prevailing macroeconomic environment. If the discount rate was one percentage point higher across all tests performed, the net impairment charge in 2024 would have been approximately $51.2 million higher. If the discount rate was one percentage point lower, the net impairment charge would have been approximately $55.9 million lower.

Goodwill

Irrespective of whether there is any indication of impairment, EnQuest is required to test annually for impairment of goodwill acquired in business combinations. The Group carries goodwill of approximately $134.4 million on its balance sheet (2023: $134.4 million), principally relating to the acquisition of Magnus oilfield. Sensitivities and additional information relating to impairment testing of goodwill are provided in note 10.

Deferred tax

The Group assesses the recoverability of its deferred tax assets at each period end. Sensitivities and additional information relating to deferred tax assets/liabilities are provided in note 6(d).

75% Magnus acquisition contingent consideration

Estimates: The Group reassessed the fair value discount rate associated with the Magnus contingent consideration and estimated it to be 11.3% as at the end of 2024 (2023: 11.3%), as calculated in line with IFRS 13. Sensitivities and additional information relating to the 75% Magnus acquisition contingent consideration are provided in note 21.

Provisions

Estimates: Decommissioning costs will be incurred by the Group at the end of the operating life of some of the Group's oil and gas production facilities and pipelines. The Group assesses its decommissioning provision at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal requirements, estimates of the extent and costs of decommissioning activities, the emergence of new restoration techniques and experience at other production sites. The expected timing, extent and amount of expenditure may also change, for example, in response to changes in oil and gas reserves or changes in laws and regulations or their interpretation. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning. As a result, there could be significant adjustments to the provisions established which would affect future financial results.

The timing and amount of future expenditures relating to decommissioning and environmental liabilities are reviewed annually. The rate used in discounting the cash flows is reviewed half-yearly. The nominal discount rate used to determine the balance sheet obligations at the end of 2024 was 4.5% (2023: 3.5%), reflecting the UK Gilt interest rate environment. The weighted average period over which decommissioning costs are generally expected to be incurred is estimated to be approximately 13 years. Costs at future prices are determined by applying inflation rates at 2.0% per annum thereafter (2023: 2.5% (2024) and a long-term inflation rate of 2% thereafter) to decommissioning costs.

Further information about the Group's provisions is provided in note 22. Changes in assumptions could result in a material change in their carrying amounts within the next financial year. A one percentage point decrease in the nominal discount rate applied, which is considered a reasonably possible change given the prevailing macroeconomic environment, could increase the Group's provision balances by approximately $59.4 million (2023: $68.0 million). The pre-tax impact on the Group income statement would be a charge of approximately $58.7 million (2023: $67.1 million).

3. Segment information

The Group's organisational structure reflects the various activities in w
requirements of IFRS 8 Operating Segments in regard to the determina
2024, the Group had two significant operating segments: the North Se
information is presented per geographical segment. The Group's segr
The North Sea's activities include Upstream, Midstream, Decommissio
operating segment as it does not yet earn revenues and is not yet a m
allocation perspective. Malaysia's activities include Upstream and De
the future depending on the way that resources may be allocated and
who for EnQuest is the Chief Executive. The information reported to the
assets and liabilities, and accordingly this information is not presented

Year ended 31 December 2024

$'000	North
Revenue and other operating income:	
Revenue from contracts with customers	1,063,8
Other operating income/(expense)	2,7
Total revenue and other operating income/(expense)	1,066,5
Income/(expenses) line items:	
Depreciation and depletion	(252,2
Net impairment (charge)/reversal to oil and gas assets	(71,4
Exploration write-off and impairments	
Segment profit/(loss)[ii],[iii]	274,3
Other disclosures:	
Capital expenditure[iv]	313,5

Year ended 31 December 2023

$'000	North
Revenue and other operating income:	
Revenue from contracts with customers	1,325,2
Other operating income/(expense)	2,2
Total revenue and other operating income/(expense)	1,327,4
Income/(expenses) line items:	
Depreciation and depletion	(278,2
Net impairment (charge)/reversal to oil and gas assets	(117,3
Exploration write-off and impairments	
Segment profit/(loss)[ii],[iii]	330,4
Other disclosures:	
Capital expenditure[iv]	149,0

(i) Finance income and costs and gains and losses on derivatives are not allocated to ind
(ii) Tax is not included as this is not disclosed to the Chief Operating Decision Maker within t
(iii) Inter-segment revenues are eliminated on consolidation. All other adjustments are par
(iv) Capital expenditure consists of property, plant and equipment and intangible explorati

Reconciliation of profit/(loss):

Segment profit/(loss) before tax and finance income/(costs)	
Finance costs	
Finance income	
(Loss)/gain on derivatives[i]	
Profit/(loss) before tax	

(i) Includes $17.6 million realised losses on derivatives (2023: $8.4 million) and $0.3 million u

Revenue from three customers relating to the North Sea operating seg
from sales of crude oil, with amounts of $394.8 million, $156.0 million an
$491.2 million and $201.3 million per each single customer).

4. Revenue and expenses

(a) Revenue and other operating income

Accounting policy

Revenue from contracts with customers

The Group generates revenue through the sale of crude oil, gas and condensate to third parties, and through the provision of infrastructure to its customers for tariff income. Revenue from contracts with customers is recognised when control of the goods or services is transferred to the customer at an amount that reflects the consideration to which the Group expects to be entitled in exchange for those goods or services. The Group has concluded that it is the principal in its revenue arrangements because it typically controls the goods or services before transferring them to the customer. The normal credit term is 30 days or less upon performance of the obligation.

Sale of crude oil, gas and condensate

The Group sells crude oil, gas and condensate directly to customers. The sale represents a single performance obligation, being the sale of barrels equivalent to the customer on taking physical possession or on delivery of the commodity into an infrastructure. At this point the title passes to the customer and revenue is recognised. The Group principally satisfies its performance obligations at a point in time; the amounts of revenue recognised relating to performance obligations satisfied over time are not significant. Transaction prices are referenced to quoted prices, plus or minus an agreed fixed premium or discount rate to an appropriate benchmark, if applicable.

Tariff revenue for the use of Group infrastructure

Tariffs are charged to customers for the use of infrastructure owned by the Group. The revenue represents the performance of an obligation for the use of Group assets over the life of the contract. The use of the assets is not separable as they are interdependent in order to fulfil the contract and no one item of infrastructure can be individually isolated. Revenue is recognised as the performance obligations are satisfied over the period of the contract, generally a period of 12 months or less, on a monthly basis based on throughput at the agreed contracted rates.

Other operating income

Other operating revenue is recognised to the extent that it is probable economic benefits will flow to the Group and the revenue can be reliably measured.

The Group enters into commodity derivative trading transactions which can be settled net in cash. Accordingly, any gains or losses are not considered to constitute revenue from contracts with customers in accordance with the requirements of IFRS 15, rather are accounted for in line with IFRS 9 and included within other operating income (see note 18).

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Revenue from contracts with customers:		
Revenue from crude oil sales	1,020,266	1,127,419
Revenue from gas and condensate sales[(i)]	164,647	338,973
Tariff revenue	2,644	1,318
Total revenue from contracts with customers	1,187,557	1,467,710
Realised (losses)/gains on commodity derivative contracts (see note 18)	(12,907)	(11,264)
Unrealised gains/(losses) on commodity derivative contracts (see note 18)	3,090	28,463
Other	2,969	2,510
Total revenue and other operating income	1,180,709	1,487,419

(i) Includes onward sale of third-party gas purchases not required for injection activities at Magnus (see note 4(b))

Disaggregation of revenue from contracts with customers

	Year ended 31 December 2024 $'000			Year ended 31 December 2023 $'000		
	North Sea	Malaysia	Total	North Sea	Malaysia	Total
Revenue from contracts with customers:						
Revenue from crude oil sales	900,310	119,956	1,020,266	987,610	139,809	1,127,419
Revenue from gas and condensate sales[(i)]	162,951	1,696	164,647	336,902	2,071	338,973
Tariff revenue	568	2,076	2,644	689	629	1,318
Total revenue from contracts with customers	1,063,829	123,728	1,187,557	1,325,201	142,509	1,467,710

(i) Includes onward sale of third-party gas purchases not required for injection activities at Magnus (see note 4(b))

4. Revenue and expenses continued

(b) Cost of sales

Accounting policy

Production imbalances, movements in under/over-lift and movement
recorded at the cost of the production imbalance to represent a provi
of entitlement. The under-lift asset is recorded at the lower of cost and
to additional physical inventory. An under-lift of production from a fiel
from a field is included in current liabilities.

Production costs
Tariff and transportation expenses
Realised loss/(gain) on derivative contracts related to operating co
Unrealised losses/(gains) on derivative contracts related to operati
Change in lifting position
Crude oil inventory movement
Depletion of oil and gas assets[(i)]
Movement in contractor dispute provision
Other cost of operations[(ii)]
Total cost of sales

(i) Includes $27.9 million (2023: $28.6 million) Kraken FPSO right-of-use asset depreciation ch
(ii) Includes $125.7 million (2023: $294.0 million) of purchases and associated costs of third-

(c) General and administration expenses

Staff costs (see note 4(e))
Depreciation[(i)]
Other general and administration costs
Recharge of costs to operations and joint venture partners
Total general and administration expenses

(i) Includes $3.4 million (2023: $3.4 million) right-of-use assets depreciation charge on bui

(d) Other (expenses)/income

Net foreign exchange gains/(losses)
Rental income from office sublease
Fair value changes in contingent consideration (see note 21)[(i)]
Change in decommissioning provisions (see note 22)
Change in Thistle decommissioning provision (see note 22)
Drilling rig contract cancellation costs [(ii)]
Unsuccessful exploration expenditure (see note 11)
Insurance income
Reversal of provisions
Other
Total other (expenses)/income

(i) In previous periods, the element of the movement in the fair value of the Magnus contin
recorded within finance costs, with remaining fair value movements recorded within ot
market practice, it has been concluded that it would be more appropriate for the impa
other income/expense, with comparative information restated. This restatement results
expense, with no impact on net income or closing retained earnings for that year
(ii) Drilling rig contract at Kraken was terminated due to a deferral of infill drilling

4. Revenue and expenses continued

(e) Staff costs

Accounting policy

Short-term employee benefits, such as salaries, social premiums and holiday pay, are expensed when incurred.

The Group's pension obligations consist of defined contribution plans. The Group pays fixed contributions with no further payment obligations once the contributions have been paid. The amount charged to the Group income statement in respect of pension costs reflects the contributions payable in the year. Differences between contributions payable during the year and contributions actually paid are shown as either accrued liabilities or prepaid assets in the balance sheet.

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Wages and salaries	66,700	63,458
Social security costs	5,899	5,457
Defined contribution pension costs	5,265	5,038
Expense of share-based payments (see note 20)	983	3,320
Other staff costs	12,300	11,079
Total employee costs	91,147	88,352
Contractor costs	37,493	38,304
Total staff costs	128,640	126,656
General and administration staff costs (see note 4(c))	75,833	77,517
Non-general and administration costs	52,807	49,139
Total staff costs	128,640	126,656

The monthly average number of persons, excluding contractors, employed by the Group during the year was 673, with 336 in the general and administration staff costs and 337 directly attributable to assets (2023: 697 of which 343 in general and administration and 354 directly attributable to assets). Compensation of key management personnel is disclosed in note 26 and in the Directors' Remuneration Report on pages 111 to 114.

(f) Auditor's remuneration

The following amounts for the year ended 31 December 2024 and for the comparative year ended 31 December 2023 were payable by the Group to Deloitte:

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Fees payable to the Company's auditor for the audit of the parent company and Group financial statements	1,367	1,239
The audit of the Company's subsidiaries	173	149
Total audit	1,540	1,388
Audit-related assurance services[(i)]	589	314
Total audit and audit-related assurance services	2,129	1,702
Total auditor's remuneration	2,129	1,702

(i) Audit-related assurance services in both years include the review of the Group's interim results, G&A assurance review and the provision of customary comfort letters in respect of the debt refinancing

5. Finance costs/income

Accounting policy

Borrowing costs are recognised as interest payable within finance cos

Finance costs:	
Loan interest payable	
Bond interest payable	
Unwinding of discount on decommissioning provisions (see note 22	
Unwinding of discount on other provisions (see note 22)	
Debt refinancing fees (see note 17)	
Finance charges payable under leases (see note 23)	
Finance fees on loans and bonds including amortisation of capitalised	
Other financial expenses[(i)]	
Total finance costs	
Finance income:	
Bank interest receivable	
RockRose loan interest (see note 18(f))	
Other financial income	
Total finance income	

(i) 2023 includes unwinding of discount on Golden Eagle contingent consideration of $1.7 r

6. Income tax

(a) Income tax

Accounting policy

Current tax assets and liabilities are measured at the amount expecte tax rates and laws that are enacted or substantively enacted by the b

The Group's operations are subject to a number of specific tax rules w the tax provision is prepared before the relevant companies have filed before these have been agreed. As a result of these factors, the tax pro estimates and judgements, including those required in calculating the

Deferred tax is provided in full on temporary differences arising betwe in the Group financial statements. However, deferred tax is not accoun other assets or liabilities in a transaction other than a business combi nor taxable profit or loss. Deferred tax is measured on an undiscounte substantively enacted by the balance sheet date and are expected to tax liability is settled. Deferred tax assets are recognised to the extent t which the temporary differences can be utilised.

Deferred tax liabilities are recognised for taxable temporary difference Group is able to control the reversal of the temporary difference and it foreseeable future.

The carrying amount of deferred income tax assets is reviewed at eac are offset only if a legal right exists to offset current tax assets against taxation authority and that the Group intends to make a single net pa

Production taxes

In addition to corporate income taxes, the Group's financial statement determined from oil and gas production.

Production tax relates to Petroleum Revenue Tax ('PRT') within the UK a characteristics of an income tax as it is imposed under government a the relevant fields. Current and deferred PRT is provided on the same b

Investment allowance

The UK taxation regime provides for a reduction in ring-fence supplem qualify for a relief known as investment allowance. Investment allowa same field before it can be claimed. The Group has both unactivated supplementary charge taxation. The Group's policy is that investment in the years claimed.

6. Income tax continued

Energy Profits Levy

The Energy (Oil & Gas) Profits Levy Act 2022 ('EPL') applies an additional tax on the profits earned by oil and gas companies from the production of oil and gas on the United Kingdom Continental Shelf until 31 March 2028. This is accounted for under IAS 12 Income Taxes since it has the characteristics of an income tax as it is imposed under government authority and the amount payable is based on taxable profits of the relevant UK companies. Current and deferred tax is provided on the same basis as described above for income taxes.

The major components of income tax expense/(credit) are as follows:

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Current UK income tax		
Current income tax charge	–	–
Adjustments in respect of current income tax of previous years	–	(14)
Current overseas income tax		
Current income tax charge	11,432	24,685
Adjustments in respect of current income tax of previous years	(746)	(2,567)
UK Energy Profits Levy		
Current year charge	10,262	175,118
Adjustments in respect of current charge of previous years	(8,803)	(11,605)
Total current income tax	12,145	185,617
Deferred UK income tax		
Relating to origination and reversal of temporary differences	42,745	160,712
Adjustments in respect of deferred income tax of previous years	(9,103)	4,974
Deferred overseas income tax		
Relating to origination and reversal of temporary differences	7,071	(3,761)
Adjustments in respect of deferred income tax of previous years	31	1,430
Deferred UK Energy Profits Levy		
Relating to origination and reversal of temporary differences	11,156	(58,661)
Adjustments in respect of changes in tax rates	6,889	–
Adjustments in respect of deferred charge of previous years	1,907	(27,699)
Total deferred income tax	60,696	76,995
Income tax expense reported in profit or loss	72,841	262,612

(b) Reconciliation of total income tax charge

A reconciliation between the income tax charge and the product of accounting profit multiplied by the UK statutory tax rate is as follows:

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Profit/(loss) before tax	166,614	231,779
UK statutory tax rate applying to North Sea oil and gas activities of 40% (2023: 40%)	66,646	92,712
Supplementary corporation tax non-deductible expenditure	5,809	10,580
Non-deductible expenditure[i]	26,114	69,494
Non-taxable gain on sale of assets	505	–
Petroleum revenue tax (net of income tax benefit)	(8,938)	(8,200)
Tax in respect of non-ring-fence trade	7,298	7,418
Deferred tax asset not recognised in respect of non-ring-fence trade	12,243	11,696
Deferred tax asset recognised on previously unrecognised losses	(48,115)	–
UK Energy Profits Levy[ii]	(13,921)	116,457
UK Energy Profits Levy – changes in tax rates[ii]	6,889	–
UK Energy Profits Levy – abolishment of Investment Allowance[ii]	35,339	–
Adjustments in respect of prior years	(16,713)	(35,481)
Overseas tax rate differences	2,045	(1,114)
Share-based payments	(1,407)	(90)
Other differences	(953)	(860)
At the effective income tax rate of 44% (2023: 113%)	72,841	262,612

(i) Predominantly in relation to non-qualifying expenditure relating to the initial recognition exemption utilised under IAS 12 upon acquisition of Golden Eagle given that at the time of the transaction, it affected neither accounting profit nor taxable profit

(ii) Total current year EPL charge only. This consists of an EPL current tax charge of $10.3 million (2023: $175.1 million charge) and deferred EPL charge of $18.0 million (2023: $58.7 million credit). The impact of the substantially enacted Autumn Statement changes referred to in part (e) below are included within these amounts and have been disclosed separately above

6. Income tax continued

(c) Deferred income tax

Deferred income tax relates to the following:

Deferred tax liability	
Accelerated capital allowances	
Deferred tax asset	
Losses	
Decommissioning liability	
Other temporary differences[i]	
Net deferred tax (assets)[ii]	
Reflected in the balance sheet as follows:	
Deferred tax assets	
Deferred tax liabilities	
Net deferred tax (assets)	

(i) Predominantly includes $199.2 million related to Magnus acquisition contingent consid
(ii) The total amounts for EPL included in net deferred assets are $160.7 million for accelerat $18.7 million Magnus acquisition contingent consideration (note 21) and $52.5 million de

Reconciliation of net deferred tax assets/(liabilities)

At 1 January	
Tax expense during the period recognised in profit or loss	
At 31 December	

(d) Tax losses

The Group's deferred tax assets at 31 December 2024 are recognised t against which tax losses and allowances in the UK can be utilised. In a recoverability of its deferred tax assets at each period end. Sensitivitie being considered a reasonable possible change for the purposes of s result in a deferred tax asset derecognition of $62.1 million while a 10% i currently recognising all UK tax losses (with the exception of those note

The Group has unused UK mainstream corporation tax losses of $496. $1,117.5 million (2023: $1,163.0 million) associated with the Bentley acquis balance sheet date as recovery of these losses is to be established. In the adjustment to bond valuations on the adoption of IFRS 9. The bene $2.2 million being taken in the current period and the remaining benef

The Group has unused Malaysian income tax losses of $14.7 million (20 which no deferred tax asset has been recognised at the balance shee

No deferred tax has been provided on unremitted earnings of overseo from the scope of UK corporation tax where certain conditions are sati

6. Income tax continued

(e) Changes in legislation

In June 2023, the UK introduced legislation implementing the Organisation for Economic Co-operation and Development's ('OECD') proposals for a global minimum corporation tax rate (Pillar Two) which is effective for periods beginning on or after 31 December 2023. This legislation will ensure that profits earned internationally are subject to a minimum tax rate of 15%. The Group has performed an assessment of the exposure to Pillar Two income taxes from 1 January 2024 and it does not have an exposure to Pillar Two income taxes in any jurisdictions. The Group has applied the mandatory exception to recognising and disclosing information about the deferred tax assets and liabilities related to Pillar Two income taxes in accordance with the amendments to IAS 12 published by the International Accounting Standards Board ('IASB') on 23 May 2023.

In the Autumn Statement on 22 November 2023, the UK Government confirmed that it will bring in legislation for the Energy Security Investment Mechanism ('ESIM') 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, and agreed to index link the trigger floor price to the CPI from April 2024. From April 2024, the ESIM threshold prices were revised to $74.21 per barrel for oil and £0.57 per therm for gas. EnQuest does not currently forecast that the floor price will be met for both oil and gas prices and therefore there is currently no impact from this on tax carrying values.

In the Autumn Statement on 30 October 2024, the UK Government confirmed that from 1 November 2024 the rate of Energy Profits Levy ('EPL') would be increased from 35% to 38%. They also announced that the EPL Investment Allowance would be abolished from 1 November 2024 (although First Year Allowances would be retained) and decarbonisation relief would be reduced from 80% to 66%. The impact of these changes on the current year financial statements is an increase in the tax charge and deferred tax for EPL of $42.2 million. The announcement to extend the EPL period to 31 March 2030 was not substantively enacted at 31 December 2024 and therefore is not included in the tax balances included in these financial statements. It is expected that this extension, which was substantively enacted on 3 March 2025, will result in the recognition of an additional deferred tax liability of approximately $115.9 million.

7. Earnings per share

The calculation of basic earnings per share is based on the profit after tax and on the weighted average number of Ordinary shares in issue during the period. Diluted earnings per share is adjusted for the effects of Ordinary shares granted under the share-based payment plans, which are held in the Employee Benefit Trust, unless it has the effect of increasing the profit or decreasing the loss attributable to each share.

During the year to 31 December 2024, the Group repurchased 55,894,836 Ordinary shares, of which 25,000,000 Ordinary shares have been classified in the balance sheet as Treasury shares with the balance cancelled (see note 8). The Treasury shares have been excluded for the purposes of calculating the basic and diluted earnings per share at 31 December 2024.

Basic and diluted earnings per share are calculated as follows:

	Profit/(loss) after tax		Weighted average number of Ordinary shares		Earnings per share	
	Year ended 31 December		Year ended 31 December		Year ended 31 December	
	2024 $'000	2023 $'000	2024 million	2023 million	2024 $	2023 $
Basic	93,773	(30,833)	1,891.9	1,871.9	0.050	(0.016)
Dilutive potential of Ordinary shares granted under share-based incentive schemes	–	–	24.3	32.4	(0.001)	–
Diluted[(i)]	93,773	(30,833)	1,916.2	1,904.3	0.049	(0.016)

(i) Potential Ordinary shares are not treated as dilutive when they would decrease a loss per share and as a result the weighted average number of Ordinary shares used as the denominator in the calculation of diluted EPS is the same as that used for calculating basic EPS in 2023

8. Distributions paid and proposed

The Company paid no dividends during the year ended 31 December 2024 (2023: none). At 31 December 2024, there were no proposed dividends (2023: none). During 2024, a share buy-back programme was executed with a total of 55,894,836 shares ($9.0 million) repurchased as at 31 December 2024.

Having continued to reduce EnQuest net debt and optimise the debt structure, EnQuest is now positioned to balance deploying capital for growth and returns to shareholders. As such, the Board is pleased to propose a final ordinary dividend of 0.616 pence per share (equivalent to c.$15 million). This final dividend is subject to approval by shareholders at the Annual General Meeting on 27 May 2025 and so not recognised as a liability as at 31 December 2024. If approved, the dividend will be paid on 6 June 2025 to shareholders on the register at 2 May 2025. Shares will trade ex-dividend from 1 May 2025.

9. Property, plant and equipment

Accounting policy

Property, plant and equipment is stated at cost less accumulated dep

Cost

Cost comprises the purchase price or cost relating to development, in infrastructure facilities such as platforms, pipelines and development capable of operating as intended by management. The purchase pric value of any other consideration given to acquire the asset.

The carrying amount of an item of property, plant and equipment is d expected from its use. The gain or loss arising from the derecognition operating income or expense line item in the Group income statemen

Development assets

Expenditure relating to development of assets, including the construct platforms, pipelines and development wells, is capitalised within prop

Carry arrangements

Where amounts are paid on behalf of a carried party, these are capita a carried party and the timing and amount are uncertain, a provision financial liability is recognised.

Borrowing costs

Borrowing costs directly attributable to the construction of qualifying of time to prepare for their intended use, are capitalised during the de substantially ready for their intended use.

Depletion and depreciation

Oil and gas assets are depleted, on a field-by-field basis, using the un probable reserves, taking account of estimated future development e affect unit of production calculations are dealt with prospectively. Dep

Depreciation on other elements of property, plant and equipment is p administration expenses, at the following rates:

Office furniture and equipment	Five years
Fixtures and fittings	Ten years
Right-of-use assets[(i)]	Lease term

(i) Excludes Kraken FPSO which is depleted using the unit of production method in accorda

Each asset's estimated useful life, residual value and method of depre year end. Any changes in estimate are accounted for on a prospectiv

Impairment of tangible (excluding goodwill)

At each balance sheet date, discounted cash flow models comprising using Level 3 inputs (based on IFRS 13 fair value hierarchy), have been a field depends on the interaction of a number of variables; see note 2 to the date of cessation of production on a field-by-field basis, includi business plan. Oil price assumptions and discount rate assumptions u asset (or CGU) is estimated to be less than its carrying amount, the ca amount. An impairment loss is recognised immediately in the Group i

Where an impairment loss subsequently reverses, the carrying amou its recoverable amount, but only so that the increased carrying amou determined had no impairment loss been recognised for the asset (o immediately in the Group income statement.

9. Property, plant and equipment continued

	Oil and gas assets $'000	Office furniture, fixtures and fittings $'000	Right-of-use assets (note 23) $'000	Total $'000
Cost:				
At 1 January 2023	9,037,851	67,321	876,859	9,982,031
Additions	120,820	1,257	28,378	150,455
Change in decommissioning provision	53,333	–	–	53,333
Disposal	–	–	(243)	(243)
Reclassification from intangible assets (note 11)	31,803	–	–	31,803
At 1 January 2024	9,243,807	68,578	904,994	10,217,379
Additions	325,813	394	16,453	342,660
Change in decommissioning provision (note 22)	(741)	–	–	(741)
At 31 December 2024	9,568,879	68,972	921,447	10,559,298
Accumulated depreciation, depletion and impairment:				
At 1 January 2023	7,000,950	56,625	447,481	7,505,056
Charge for the year	239,640	2,689	55,979	298,308
Net impairment charge/(reversal) for the year	123,473	–	(6,077)	117,396
Disposal	–	–	(121)	(121)
At 1 January 2024	7,364,063	59,314	497,262	7,920,639
Charge for the year	211,873	2,683	54,735	269,291
Net impairment charge/(reversal) for the year	75,428	–	(4,014)	71,414
At 31 December 2024	7,651,364	61,997	547,983	8,261,344
Net carrying amount:				
At 31 December 2024	1,917,515	6,975	373,464	2,297,954
At 31 December 2023	1,879,744	9,264	407,732	2,296,740
At 1 January 2023	2,036,901	10,696	429,378	2,476,975

The amount of borrowing costs capitalised during the year ended 31 December 2024 was nil (2023: nil), reflecting the short-term nature of the Group's capital expenditure programmes.

Impairments
Impairments to the Group's producing assets and reversals of impairments are set out in the table below:

	Impairment (charge)/reversal		Recoverable amount[i]	
	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000	31 December 2024 $'000	31 December 2023 $'000
North Sea	(71,414)	(117,396)	1,172,487	1,323,009
Net pre-tax impairment (charge)/reversal	(71,414)	(117,396)		

(i) Recoverable amount has been determined on a fair value less costs of disposal basis (see note 2 for further details of judgements, estimates and assumptions made in relation to impairments). The amounts disclosed above are in respect of assets where an impairment (or reversal) has been recorded. Assets which did not have any impairment or reversal are excluded from the amounts disclosed

For information on judgements, estimates and assumptions made in relation to impairments, along with sensitivity analysis, see Use of judgements, estimates and assumptions: recoverability of asset carrying values within note 2.

The 2024 net impairment charge of $71.4 million relates to producing assets in the UK North Sea (charges of $2.0 million for GKA and Scolty/Crathes CGU, $62.5 million for Golden Eagle and $20.1 million for Alba offset by an impairment reversal of $13.2 million at Kraken). Impairment charges/reversals were primarily driven by EPL revisions, lower near-term oil price assumptions and changes in production profiles, partially offset by a lower discount rate.

The 2023 net impairment charge of $117.4 million related to producing assets in the UK North Sea (charges of $17.2 million for GKA and Scolty/Crathes CGU, $122.5 million for Golden Eagle and $9.1 million for Alba offset by an impairment reversal of $31.4 million at Kraken). Impairment charges/reversals were primarily driven by changes in production and cost profile updates, partially offset by higher forecast oil prices.

10. Goodwill

Accounting policy
Cost
Goodwill arising on a business combination is initially measured at co
the net fair value of the identifiable assets, liabilities and contingent lia
net assets acquired is in excess of the aggregate consideration transf
of the assets acquired and all of the liabilities assumed and reviews th
the acquisition date. If the reassessment still results in an excess of the
transferred, the gain is recognised in profit or loss.

Impairment of goodwill
Following initial recognition, goodwill is stated at cost less any accumu
Assets, goodwill is reviewed for impairment annually or more frequent
amount of the CGU (or group of CGUs) to which the goodwill relates sh

For the purposes of impairment testing, goodwill acquired is allocated
synergies of the combination. Each unit or units to which goodwill is all
goodwill is monitored for internal management purposes. Impairmen
(or groups of CGUs) to which the goodwill relates. Where the recoverab
amount of the CGU (or group of CGUs) containing goodwill, an impairm
cannot be reversed in future periods. For information on significant est
of judgements, estimates and assumptions: recoverability of asset ca

A summary of goodwill is presented below:

Cost and net carrying amount	
At 1 January	
At 31 December	

The majority of the goodwill, relates to the 75% acquisition of the Magn
to the acquisition of the GKA and Scolty Crathes fields.

Impairment testing of goodwill
Goodwill, which has been acquired through business combinations, h
and this is therefore the lowest level at which goodwill is reviewed. The
within property, plant and equipment (note 9).

The recoverable amounts of the segment and fields have been deterr
9 for further details. An impairment charge of nil was taken in 2024 (20
North Sea segment grouping of CGUs, as described above.

Sensitivity to changes in assumptions
The Group's recoverable value of assets is highly sensitive, *inter alia*, to
run on the oil price assumptions, with a 10% change being considered
analysis (see note 2). A 10% reduction in oil price would result in an imp
in an impairment charge). A 17% reduction in oil price would fully impa
be a reasonable expectation.

11. Intangible assets

Accounting policy

Exploration and appraisal assets

Exploration and appraisal assets have indefinite useful lives and are accounted for using the successful efforts method of accounting. Pre-licence costs are expensed in the period in which they are incurred. Expenditure directly associated with exploration, evaluation or appraisal activities is initially capitalised as an intangible asset. Such costs include the costs of acquiring an interest, appraisal well drilling costs, payments to contractors and an appropriate share of directly attributable overheads incurred during the evaluation phase. For such appraisal activity, which may require drilling of further wells, costs continue to be carried as an asset, whilst related hydrocarbons are considered capable of commercial development. Such costs are subject to technical, commercial and management review to confirm the continued intent to develop, or otherwise extract value. When this is no longer the case, the costs are written off as exploration and evaluation expenses in the Group income statement. When exploration licences are relinquished without further development, any previous impairment loss is reversed and the carrying costs are written off through the Group income statement. When assets are declared part of a commercial development, related costs are transferred to property, plant and equipment. All intangible oil and gas assets are assessed for any impairment prior to transfer and any impairment loss is recognised in the Group income statement.

During the year ended 31 December 2024, there was no impairment of historical exploration and appraisal expenditures (2023: nil). During 2023, $31.8 million of intangible assets associated with the Kraken field were transferred to property, plant and equipment, reflecting updated drilling plans following assessment of previous seismic survey information. Also during 2023, Malaysia drilled an exploration well on the PM409 licence. The results indicated that there were no commercial prospects and as a result costs of $5.6 million were written off through the income statement during 2023 with an additional $0.2 million written off during 2024.

Other intangibles

UK emissions allowances ('UKAs') purchased to settle the Group's liability related to emissions are recognised on the balance sheet as an intangible asset at cost. The UKAs will be derecognised upon settling the liability with the respective regulator.

	Exploration and appraisal assets $'000	UK emissions allowances $'000	Total $'000
Cost:			
At 1 January 2023	154,937	1,199	156,136
Additions	10,467	876	11,343
Write-off of relinquished licences previously impaired	(485)	–	(485)
Write-off of unsuccessful exploration expenditure	(5,640)	–	(5,640)
Transfer to property, plant and equipment (note 9)	(31,803)	–	(31,803)
Disposal	–	(1,199)	(1,199)
At 1 January 2024	127,476	876	128,352
Additions	3,686	1,138	4,824
Write-off of unsuccessful exploration expenditure	(183)	–	(183)
Disposal	(1,263)	(876)	(2,139)
At 31 December 2024	129,716	1,138	130,854
Accumulated impairment:			
At 1 January 2023	(109,638)	–	(109,638)
Write-off of relinquished licences previously impaired	485	–	485
At 1 January 2024 and 31 December 2024	(109,153)	–	(109,153)
Net carrying amount:			
At 31 December 2024	20,563	1,138	21,701
At 31 December 2023	18,323	876	19,199
At 1 January 2023	45,299	1,199	46,498

12. Inventories

Accounting policy

Inventories of consumable well supplies and inventories of hydrocarbons are stated at the lower of cost and NRV, cost being determined on an average cost basis.

	2024 $'000	2023 $'000
Hydrocarbon inventories	22,544	21,189
Well supplies	26,432	63,608
	48,976	84,797

During 2024, a net gain of $6.9 million was recognised within cost of sales in the Group income statement relating to inventory (2023: net gain of $2.2 million). During the current year, following a review of the balance of well supplies held within inventory, it was concluded that some items met the definition of property, plant & equipment, and were reclassified during the current year end and presented as PP&E additions within PP&E (note 9).

The inventory valuation at 31 December 2024 is stated net of a provision of $28.5 million (2023: $36.3 million) to write-down well supplies to their estimated net realisable value.

13. Cash and cash equivalents

Accounting policy

Cash and cash equivalents includes cash at bank, cash in hand, cash

and highly liquid interest-bearing securities with original maturities of

Available cash	
Restricted cash	
Cash and cash equivalents	

The carrying value of the Group's cash and cash equivalents is consid

their short-term maturities.

Restricted cash

During 2024, additional security was required to be provided in accord

EnQuest renewed its surety bond facilities and added three new provi

(31 December 2023: nil). The remaining $0.5 million of restricted cash re

(31 December 2023: $0.5 million).

14. Financial instruments and fair value measurement

Accounting policy

A financial instrument is any contract that gives rise to a financial asse

entity. Financial instruments are recognised when the Group becomes

Financial assets and financial liabilities are offset and the net amount

enforceable legal right to offset the recognised amounts and there is

Financial assets

Financial assets are classified, at initial recognition, as amortised cost

value through profit or loss ('FVPL'). The classification of financial asset

cash flow characteristics and the Group's business model for managi

FVOCI, i.e. debt financial assets.

Financial assets are derecognised when the contractual rights to the

asset and substantially all the risks and rewards are transferred.

Financial assets at amortised cost

Trade receivables, other receivables and joint operation receivables a

amortised cost, using the effective interest rate ('EIR') method, and are

loss when the asset is derecognised, modified or impaired and EIR am

The Group measures financial assets at amortised cost if both of the f

- The financial asset is held in a business model with the objective to
- The contractual terms of the financial asset give rise on specified da

on the principal amount outstanding.

Prepayments, which are not financial assets, are measured at historic

14. Financial instruments and fair value measurement continued

Impairment of financial assets

The Group recognises a loss allowance for expected credit loss ('ECL'), where material, for all financial assets held at the balance sheet date. ECLs are based on the difference between the contractual cash flows due to the Group, and the discounted actual cash flows that are expected to be received. Where there has been no significant increase in credit risk since initial recognition, the loss allowance is equal to 12-month expected credit losses. Where the increase in credit risk is considered significant, lifetime credit losses are provided. For trade receivables, a lifetime credit loss is recognised on initial recognition where material.

The provision rates are based on days past due for groupings of customer segments with similar loss patterns (i.e. by geographical region, product type, customer type and rating) and are based on historical credit loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment. The Group evaluates the concentration of risk with respect to trade receivables and contract assets as low, as its customers are joint venture partners and there are no indications of change in risk. Generally, trade receivables are written off when they become past due for more than one year and are not subject to enforcement activity.

Financial liabilities

Financial liabilities are classified, at initial recognition, as amortised cost or at FVPL.

Financial liabilities are derecognised when they are extinguished, discharged, cancelled or they expire. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as the derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised in the Group income statement.

Financial liabilities at amortised cost

Loans and borrowings, trade payables and other creditors are measured initially at fair value net of directly attributable transaction costs and subsequently recorded at amortised cost, using the EIR method. Loans and borrowings are interest bearing. Gains and losses are recognised in profit or loss when the liability is derecognised and EIR amortisation is included within finance costs.

Financial instruments at FVPL

The Group holds derivative financial instruments classified as held for trading, not designated as effective hedging instruments. The derivative financial instruments include forward currency contracts and commodity contracts, to address the respective risks; see note 27. The Group also enters into forward contracts for the purchase of UKAs to manage its exposure to carbon emission credit prices. Derivatives are carried as financial assets when the fair value is positive and as financial liabilities when the fair value is negative.

Financial instruments at FVPL are carried in the Group balance sheet at fair value, with net changes in fair value recognised in the Group income statement.

Financial assets with cash flows that are not solely payments of principal and interest are classified and measured at FVPL, irrespective of the business model. All financial assets not classified as measured at amortised cost or FVOCI as described above are measured at FVPL. Financial instruments with embedded derivatives are considered in their entirety when determining whether their cash flows are solely payment of principal and interest.

The Group also holds contingent consideration (see note 21) and a listed equity investment (see note 18). The movements of both are recognised within the Group income statement.

14. Financial instruments and fair value measurement continu

Fair value measurement

The following table provides the fair values and fair value measureme

31 December 2024	
Financial assets measured at fair value:	
Derivative financial assets measured at FVPL	
Gas commodity contracts	
Other financial assets measured at FVPL	
Quoted equity shares	
Total financial assets measured at fair value	
Financial assets measured at amortised cost:	
Vendor financing facility	
Total financial assets measured at amortised cost[(i)]	
Liabilities measured at fair value:	
Derivative financial liabilities measured at FVPL	
Commodity derivative contracts	
Forward foreign currency contracts	
Forward UKA contracts	
Other financial liabilities measured at FVPL	
Contingent consideration	
Total liabilities measured at fair value	
Liabilities measured at amortised cost	
Interest-bearing loans and borrowings[(i)]	
Retail bond 9.00%[(ii)]	
High yield bond 11.625%[(ii)]	
Total liabilities measured at amortised cost[(iii)]	

(i) Amortised cost is a reasonable approximation of the fair value
(ii) Carrying value includes accrued interest
(iii) Excludes related fees

31 December 2023	
Financial assets measured at fair value:	
Derivative financial assets measured at FVPL	
Gas commodity contracts	
Other financial assets measured at FVPL	
Quoted equity shares	
Total financial assets measured at fair value	
Financial assets measured at amortised cost:	
Vendor financing facility	
Total financial assets measured at amortised cost[(i)]	
Liabilities measured at fair value:	
Derivative financial liabilities measured at FVPL	
Oil commodity derivative contracts	
Forward UKA contracts	
Other financial liabilities measured at FVPL	
Contingent consideration	
Total liabilities measured at fair value	
Liabilities measured at amortised cost	
Interest-bearing loans and borrowings[(i)]	
Retail bond 9.00%	
High yield bond 11.625%	
Total liabilities measured at amortised cost[(ii)]	

(i) Amortised cost is a reasonable approximation of the fair value
(ii) Excludes related fees

14. Financial instruments and fair value measurement continued

Fair value hierarchy

All financial instruments for which fair value is recognised or disclosed are categorised within the fair value hierarchy, based on the lowest level input that is significant to the fair value measurement as a whole, as follows:

Level 1: Quoted (unadjusted) market prices in active markets for identical assets or liabilities;

Level 2: Valuation techniques for which the lowest level input that is significant to the fair value measurement is directly (i.e. prices) or indirectly (i.e. derived from prices) observable; and

Level 3: Valuation techniques for which the lowest level input that is significant to the fair value measurement is unobservable.

Derivative financial instruments are valued by counterparties, with the valuations reviewed internally and corroborated with readily available market data (Level 2). Contingent consideration is measured at FVPL using the Level 3 valuation processes, details of which and a reconciliation of movements are disclosed in note 21. There have been no transfers between Level 1 and Level 2 during the period (2023: no transfers).

For the financial assets and liabilities measured at amortised cost but for which fair value disclosures are required, the fair value of the bonds classified as Level 1 was derived from quoted prices for that financial instrument, while interest-bearing loans and borrowings and the vendor financing facility were calculated at amortised cost using the effective interest method to capture the present value (Level 3). A reconciliation of movements is disclosed in note 29.

15. Trade and other receivables

	2024 $'000	2023 $'000
Current		
Trade receivables	20,151	31,905
Joint venture receivables	106,963	79,036
Under-lift position	16,806	22,309
VAT receivable	7,574	3,314
Other receivables	4,729	3,715
Prepayments	7,822	2,781
Accrued income	66,926	82,426
Total current	230,971	225,486
Non-current		
Other receivables	2,102	–
Total non-current	2,102	–

The carrying values of the Group's trade, joint venture and other receivables as stated above are considered to be a reasonable approximation to their fair value largely due to their short-term maturities. Under-lift is valued at the lower of cost or NRV at the prevailing balance sheet date (note 4(b)).

Trade receivables are non-interest-bearing and are generally on 15 to 30-day terms. Joint venture receivables relate to amounts billable to, or recoverable from, joint venture partners. Receivables are reported net of any ECL with no losses recognised as at 31 December 2024 or 2023.

Non-current trade and other receivables represents capitalised fees associated with the Group's Reserve Based Lending Facility that were reclassed to trade and other receivables to better reflect the variable nature of the facility following the repayment in full of the outstanding principal ($140.0 million) in February 2024.

16. Trade and other payables

Current	
Trade payables	
Accrued expenses	
Over-lift position	
Joint venture creditors	
Other payables	
Total current	
Non-current	
Joint venture creditors	
Total non-current	

The carrying value of the Group's current trade and other payables as to their fair value largely due to the short-term maturities. Certain trad reporting currency of the Group, mainly in Sterling. Trade payables are ten and 30 days.

Accrued expenses include accruals for capital and operating expendi

The carrying value of the Group's 2023 non-current trade and other pa approximation to their fair value as this represented a specific bi-later in full over time in accordance with the agreed schedule. The outstand trade and other payables.

17. Loans and borrowings

Loans	
Bonds	

The Group's borrowings are carried at amortised cost as follows:

RBL facility[i]	
Term loan facility	
SVT working capital facility	
High yield bond 11.625%	4
Retail bond 9.00%	
Accrued interest[ii]	
Total borrowings	
Due within one year	
Due after more than one year	
Total borrowings	

(i) Capitalised fees were reclassed in the current period to trade and other receivables to
(ii) Accrued interest on borrowings has been reclassed in the current period to better reflec not material). Accrued interest includes bond interest accruals of $9.4 million

See liquidity risk – note 27 for the timing of cash outflows relating to loa

17. Loans and borrowings continued

Reserve Based Lending facility ('RBL')

In October 2022, the Group agreed an amended and restated RBL facility with commitments of $500.0 million, reducing in accordance with an amortisation schedule, a sub-limit for drawings in the form of Letters of Credit of $75.0 million and a standard accordion facility which allowed the Group to increase commitments by an amount of up to $300.0 million on no more than three occasions. The maturity of the facility is April 2027. Funds can only be drawn under the RBL to a maximum amount of the lesser of (i) the total commitments and (ii) the borrowing base amount. Interest accrues at 4.00% until July 2025 when it increases to 4.50%, plus a combination of an agreed credit adjustment spread and the Secured Overnight Financing Rate ('SOFR'). The Group fully repaid the $140.0 million of its drawn Reserve Based Lending Facility in February 2024. At 31 December 2024, $176.4 million remained available for drawdown under the RBL (2023: $166.2 million). Effective from 1 January 2025, the amount available to drawdown increased to $237.1 million as a result of the annual redetermination process.

At 31 December 2024, the Letter of Credit utilisation was $54.1 million (2023: $43.5 million).

Term loan facility

In August 2023, the Group agreed a second lien US Dollar term loan facility of $150.0 million which was drawn down in full in September 2023 and incurred interest at SOFR +7.90%. In October 2024, the term loan, plus the early redemption fee of $4.7 million, was fully repaid utilising the proceeds from the high yield bond tap. The early redemption fee and the remaining unamortised costs of $2.9 million were expensed within finance costs.

SVT working capital facility

EnQuest has extended the £42.0 million revolving loan facility with a joint operations partner to fund the short-term working capital cash requirements of SVT and associated interests until April 2027. The facility is guaranteed by BP EOC Limited (joint operations partner) until the earlier of: a) the date on which production from Magnus permanently ceases; or b) if the operating agreements for both SVT and associated infrastructure are amended to allow for cash calling. The facility is able to be drawn down against, in instalments, and accrues interest at 2.05% per annum plus GBP Sterling Over Night Index Average ('SONIA').

Vendor Loan facility

In August 2024, the Group entered into a deferred payment facility agreement with a third-party vendor providing capacity for refinancing the payment of existing invoices up to an amount of £23.7 million, with interest payable monthly at a rate of 9.50% per annum. At 31 December 2024, nil was drawn down on the facility, with $20.7 million drawn by the end of February 2025.

High yield bond 11.625%

In October 2022, the Group concluded an offer of $305.0 million for a US Dollar high yield bond. In October 2024, the Group concluded a tap of an additional $160.0 million of the US Dollar high yield bond on the same terms and conditions as the existing bond. The notes accrue a fixed coupon of 11.625% payable semi-annually in arrears with a maturity date of November 2027. Associated fees of $3.4 million were capitalised and are being amortised over the period of the bond.

The above carrying value of the bond as at 31 December 2024 is $454.3 million (2023: $294.3 million). This includes bond principal of $465.0 million (2023: $305.0 million) and unamortised issue premium on the tap of $1.4 million less the unamortised original issue discount of $2.4 million (2023: $3.3 million) and unamortised fees of $9.7 million (2023: $7.4 million). The fair value of the high yield bond is disclosed in note 14.

Retail bond 9.00%

On 27 April 2022, the Group issued a new 9.00% retail bond following a successful partial exchange and cash offer. The principal of the retail bond 9.00% raised by the partial exchange and cash offer totalled £133.3 million. The notes accrue a fixed coupon of 9.00% payable semi-annually in arrears and are due to mature in October 2027.

The above carrying value of the bond as at 31 December 2024 is $167.1 million (2023: $169.7 million). All fees associated with this offer were recognised in the income statement in 2022. The fair value of the retail bond 9.00% is disclosed in note 14.

18. Other financial assets and financial liabilities

(a) Summary as at year end

Fair value through profit or loss:	
Derivative commodity contracts	
Forward foreign currency contracts	
Derivative UKA contracts	
Amortised cost:	
Other receivables (Vendor financing facility) (notes 18(f), 24)	
Total current	
Fair value through profit or loss:	
Quoted equity shares	
Amortised cost:	
Other receivables (Vendor financing facility) (notes 18(f), 24)	
Total non-current	
Total other financial assets and liabilities	

(b) Income statement impact

The income/(expense) recognised for derivatives are as follows:

Year ended 31 December 2024	
Commodity options	
Commodity swaps	
Commodity futures	
Foreign exchange contracts	
UKA contracts	

Year ended 31 December 2023	
Commodity options	
Commodity swaps	
Commodity futures	
Foreign exchange contracts	
UKA contracts	

(c) Commodity contracts

The Group uses derivative financial instruments to manage its exposu
and futures.

For the year ended 31 December 2024, losses totalling $9.8 million (202
contracts measured as FVPL. This included losses totalling $12.9 millio
during the year, and mark-to-market unrealised gains totalling $3.1 mi

The mark-to-market value of the Group's open commodity contracts
(2023: net liability of $13.9 million).

(d) Foreign currency contracts

The Group enters into a variety of foreign currency contracts, primarily
gains totalling $0.5 million (2023: gains of $5.7 million) were recognised
totalling $2.9 million (2023: gains of $5.7 million) on contracts that mat

The mark-to-market value of the Group's open contracts as at 31 Dece

18. Other financial assets and financial liabilities continued

(e) UK emissions allowance forward contracts

The Group enters into forward contracts for the purchase of UKAs to manage its exposure to carbon emission credit prices. During the year ended 31 December 2024, losses totalling $8.1 million (2023: losses of $6.7 million) were recognised in the Group income statement. This included realised losses totalling $7.6 million (2023: losses of $2.9 million) on contracts that matured in the year.

The mark-to-market value of the Group's open contracts as at 31 December 2024 was a net liability of $8.7 million (2023: $8.3 million).

(f) Other receivables

	Other receivables $'000	Equity shares $'000	Total $'000
At 1 January 2023	–	6	6
Additions[(i)]	145,103	–	145,103
At 31 December 2023	145,103	6	145,109
Interest	3,263	–	3,263
Repayments	(107,518)	–	(107,518)
Foreign exchange	(2,395)	–	(2,395)
At 31 December 2024	38,453	6	38,459
Current			–
Non-current			38,459
			38,459

(i) Additions in 2023 relate to a vendor financing facility entered into with RockRose Energy Limited on 29 December 2023 following the farm-down of a 15.0% share in the EnQuest Producer FPSO and capital items associated with the Bressay development. $107.5 million was repaid in the first quarter of 2024 with the remainder repayable through future net cash flows from the Bressay field. Interest on the outstanding amount accrues at 2.5% plus the Bank of England's Base Rate

19. Share capital and reserves

Accounting policy

Share capital and share premium

The balance classified as equity share capital includes the total net proceeds (both nominal value and share premium) on issue of registered share capital of the parent company. Share issue costs associated with the issuance of new equity are treated as a direct reduction of proceeds. The share capital comprises only one class of Ordinary share. Each Ordinary share carries an equal voting right and right to a dividend.

Treasury shares

Represents amounts transferred following purchase of the Company's own shares out of distributable profits, with those shares available for resale into the market, transfer to the Group's Employee Benefit Trust ('EBT') where they can be used to satisfy awards made under the Company's share-based incentive schemes, or cancelled.

Capital redemption reserve

Represents the par value of shares cancelled following the purchase of the Company's own shares out of distributable profits.

Retained earnings

Retained earnings contain the accumulated profits/(losses) of the Group.

Share-based payments reserve

Equity-settled share-based payment transactions are measured at the fair value of the services received, and the corresponding increase in equity is recorded. EnQuest PLC shares held by the Group in the EBT are recognised at cost and are deducted from the share-based payments reserve, as they are held to satisfy awards made under equity-settled share-based payment transactions. Consideration received for the sale of such shares is also recognised in equity, with any difference between the proceeds from the sale and the original cost being taken to reserves. No gain or loss is recognised in the Group income statement on the purchase, sale, issue or cancellation of equity shares.

Authorised, issued and fully paid	Ordinary shares of £0.05 each Number	Share capital $'000	Share premium $'000	Treasury shares $'000	Capital redemption reserve $'000	Total $'000
At 1 January 2024	1,912,304,113	133,285	260,546	–	–	393,831
Issue of new shares to EBT	3,620,226	229	–	–	–	229
Repurchase and cancellation of shares	(30,894,836)	(2,006)	–	(4,425)	2,006	(4,425)
At 31 December 2024	1,885,029,503	131,508	260,546	(4,425)	2,006	389,635

During 2024, a share buy-back programme was executed with a total of 55,894,836 Ordinary shares repurchased as at 31 December 2024. The first 25,000,000 Ordinary shares purchased under the Programme are held in Treasury for issue in due course to the Company's EBT to satisfy the anticipated future exercise of options and awards made to employees and Executive Directors of EnQuest PLC pursuant to certain of the Company's existing share plans. The remaining 30,894,836 Ordinary shares were cancelled.

At 31 December 2024, there were 972,269 shares held by the EBT (2023: 8,449,793) which are included within the share-based payment reserve. The movement in the year was 11,097,750 shares used to satisfy awards made under the Company's share-based incentive schemes offset by a subscription for 3,620,226 additional Ordinary shares.

At 1 January 2023, the number of Ordinary shares was 1,885,924,339. In December 2023, 26,379,774 shares were issued and subsequently transferred to the EBT.

20. Share-based payment plans

Accounting policy

Eligible employees (including Executive Directors) of the Group receive
whereby employees render services in exchange for shares or rights o

Information on these plans for Executive Directors is shown in the Direc

The cost of these equity-settled transactions is measured by referenc
value of awards is calculated in reference to the scheme rules at the
for the three immediately preceding dealing days as derived from the
dealing days do not fall within any period when dealings in shares are

The cost of equity-settled transactions is recognised over the vesting
award. The cumulative expense recognised for equity-settled transac
to which the vesting period has expired and the Group's best estimate
Group income statement charge or credit for a period represents the
and end of that period.

In valuing the transactions, no account is taken of any service or perfo
the shares of EnQuest PLC (market conditions) or 'non-vesting' conditi
not ultimately vest, except for awards where vesting is conditional upo
irrespective of whether or not the market or non-vesting condition is s
Equity awards cancelled are treated as vesting immediately on the da
the award at that date is recognised in the Group income statement.

The Group operates a number of equity-settled employee share plans
and certain other employees. These plans typically have a three-year
normally preclude the conversion of units into shares, but special arra

The share-based payment expense recognised for each scheme was

Performance Share Plan
Other performance share plans
Sharesave Plan

The following table shows the number of shares potentially issuable u
including the number of options outstanding and the number of optio

Share plans
Outstanding at 1 January
Granted during the year
Exercised during the year
Forfeited during the year
Outstanding at 31 December
Exercisable at 31 December

Within the Group's equity-settled employee share plans detailed abo
scheme (the 'Sharesave Plan'). The plan is based on eligible employee
Sharesave account with a nominated savings carrier and to save ove
the option is at the employee's discretion at the end of the period prev

20. Share-based payment plans continued

The following table shows the number of shares potentially issuable under equity-settled employee share option plans, including the number of options outstanding, the number of options exercisable at the end of each year and the corresponding weighted average exercise prices.

	2024		2023	
Sharesave options	Number	Weighted average exercise price $	Number	Weighted average exercise price $
Outstanding at 1 January	18,658,144	0.16	33,308,249	0.14
Granted during the year	–	–	10,268,853	0.14
Exercised during the year	(5,478,693)	0.13	(19,977,354)	0.13
Forfeited during the year	(3,223,434)	0.15	(4,941,604)	0.17
Outstanding at 31 December	9,956,017	0.15	18,658,144	0.16
Exercisable at 31 December	323,886	0.24	6,553,159	0.13

21. Contingent consideration

Accounting policy

When the consideration transferred by the Group in a business combination includes a contingent consideration arrangement, the contingent consideration is measured at its acquisition-date fair value and included as part of the consideration transferred in a business combination. 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 acquisition date) about facts and circumstances that existed at the acquisition date.

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 depicted below is remeasured to fair value at subsequent reporting dates with changes in fair value recognised in profit or loss. Contingent consideration that is classified as equity if any, is not remeasured at subsequent reporting dates and its subsequent settlement is accounted for within equity.

Contingent consideration is discounted at a risk-free rate combined with a risk premium, calculated in alignment with IFRS 13 and the unwinding of the discount is presented as part of the overall fair value change within other (expenses)/income.

Any contingent consideration included in the consideration payable for an asset acquisition is recorded at fair value at the date of acquisition and included in the initial measurement of cost.

Settlement of contingent consideration recorded at fair value through profit or loss is recorded as investing outflows in the cash flow statement to the extent 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 contingent consideration relating to an asset acquisition is recorded as an investing cash outflow.

	Magnus 75% $'000	Magnus decommissioning-linked liability $'000	Total $'000
At 31 December 2023	488,007	19,789	507,796
Unwinding of discount (see note 4(d))	55,144	2,301	57,445
Other changes in fair value (see note 4(d))	(43,353)	1,812	(41,541)
Utilisation	(48,465)	(1,941)	(50,406)
At 31 December 2024	451,333	21,961	473,294
Classified as:			
Current	18,905	1,498	20,403
Non-current	432,428	20,463	452,891
	451,333	21,961	473,294

21. Contingent consideration continued

75% Magnus acquisition contingent consideration

On 1 December 2018, EnQuest completed the acquisition of the additio
interests (collectively the 'Transaction assets') which was part funded
bp share the net cash flow generated by the 75% interest on a 50:50 b
consideration is a financial liability classified as measured at FVPL. The
calculating the present value of the future expected cash flows expec
value hierarchy. Future cash flows are estimated based on inputs inclu
Oil price assumptions and discount rate assumptions used were as di
note 2. The contingent consideration was fair valued at 31 December 2
of unwind of discount) of $43.4 million (2023: decrease of $69.8 million
term oil price assumptions and changes in the assets cost and produ
discount rate to 11.3% (2022: 10.0%) and changes in the asset cost profil
The overall fair value accounting effect including the unwinding of disc
on the contingent consideration were recognised in the Group income
arrangement cap of $1.0 billion was forecast to be met in the present v
met). Within the statement of cash flows, the profit share element of th
separately under investing activities. At 31 December 2024, the contin
$488.0 million).

Management has considered alternative scenarios to assess the valu
to, the key accounting estimates relating to the oil price, discount rate
arrangement. As described within note 2, oil price has been assessed
due to its material impact on revenue, which in turn results in changes
the timing of future cash flows and production profiles. As the profit-sh
calculations, sensitivity analysis has only been undertaken on a reduc
a reasonably possible change. This results in a reduction of $51.1 millio
A 1.0% reduction in the discount rate applied, which is considered a rea
conditions, would increase reported contingent consideration by $19.8
consideration by $18.6 million.

The payment of contingent consideration is limited to cash flows gene
payable if insufficient cash flows are generated over and above the re
existing at 31 December 2024, the maturity analysis of the contingent c
instruments: liquidity risk (note 27).

Magnus decommissioning-linked contingent consideration

As part of the Magnus and associated interests acquisition, bp retaine
infrastructure and EnQuest agreed to pay additional consideration in
of Magnus. At 31 December 2024, the amount due to bp calculated on
costs on Magnus was $22.0 million (2023: $19.8 million). Any reasonabl
on the provision.

Golden Eagle contingent consideration

Part of the Golden Eagle acquisition consideration included an amoun
and June 2023. Over the period July 2021 to June 2023, the average oil
consideration was valued at $50.0 million with settlement of this liabili
was nil (31 December 2023: nil).

22. Provisions

Accounting policy

Decommissioning

Provision for future decommissioning costs is made in full when the Group has an obligation: to dismantle and remove a facility or an item of plant; to restore the site on which it is located; and when a reasonable estimate of that liability can be made. The Group's provision primarily relates to the future decommissioning of production facilities and pipelines.

A decommissioning asset and liability are recognised, within property, plant and equipment and provisions, respectively, at the present value of the estimated future decommissioning costs. The decommissioning asset is amortised over the life of the underlying asset on a unit of production basis over proven and probable reserves, included within depletion in the Group income statement. Any change in the present value of estimated future decommissioning costs is reflected as an adjustment to the provision and the oil and gas asset for producing assets. For assets that have ceased production, the change in estimate is reflected as an adjustment to the provision and the Group income statement, via other income or expense. The unwinding of the decommissioning liability is included under finance costs in the Group income statement.

These provisions have been created based on internal and third-party estimates. Assumptions based on the current economic environment have been made which management believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required, which will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning liabilities is likely to depend on the dates when the fields cease to be economically viable. This in turn depends on future oil prices, which are inherently uncertain. See Use of judgements, estimates and assumptions: provisions within note 2.

Other

Provisions are recognised when the Group has a present legal or constructive obligation as a result of past events; it is probable that an outflow of resources will be required to settle the obligation; and a reliable estimate can be made of the amount of the obligation.

	Decommissioning provision $'000	Thistle decommissioning provision $'000	Other provisions $'000	Total $'000
At 31 December 2023	755,762	25,355	14,180	795,297
Additions during the year[(i)]	2,893	–	835	3,728
Changes in estimates[(i)]	3,032	412	–	3,444
Unwinding of discount	30,290	911	–	31,201
Utilisation	(50,412)	(8,319)	(9,063)	(67,794)
Foreign exchange	–	(11)	241	230
At 31 December 2024	741,565	18,348	6,193	766,106
Classified as:				
Current	42,030	7,700	5,400	55,130
Non-current	699,535	10,648	793	710,976
	741,565	18,348	6,193	766,106

(i) Includes $6.7 million relating to assets in decommissioning disclosed in note 4(d) and $(0.7) million related to producing assets disclosed in note 9

Decommissioning provision

The Group's total provision represents the present value of decommissioning costs which are expected to be incurred up to 2050, assuming no further development of the Group's assets. Additions during the year primarily relate to the decommissioning provision recognised due to drilling of new wells in Golden Eagle. Changes in estimates during the year primarily reflect the net effect of $78.0 million increase in the underlying cost estimates partly offset by $59.0 million impact from the increase in the discount rate and $12.4 million foreign exchange impact due to the weakening of Sterling to US Dollar exchange rates. At 31 December 2024, an estimated $281.1 million is expected to be utilised between one and five years (2023: $175.7 million), $280.0 million within six to ten years (2023: $355.6 million), and the remainder in later periods. For sensitivity analysis see Use of judgements, estimates and assumptions within note 2.

The Group enters into surety bonds principally to provide security for its decommissioning obligations (see note 13). The surety bond facilities, which expired in December 2023, were renewed for 12 months, subject to ongoing compliance with the terms of the Group's borrowings. At 31 December 2024, the Group held surety bonds totalling $277.0 million (2023: $250.4 million).

Thistle decommissioning provision

In 2018, EnQuest exercised the option to receive $50.0 million from bp in exchange for undertaking the management of the physical decommissioning activities for Thistle and Deveron and making payments by reference to 7.5% of bp's share of decommissioning costs of the Thistle and Deveron fields, with the liability recognised within provisions. At 31 December 2024, the amount due to bp by reference to 7.5% of bp's decommissioning costs on Thistle and Deveron was $18.3 million (2023: $25.4 million), with the reduction mainly reflecting the utilisation in the period. Change in estimates of $0.4 million are included within other expense (2023: $1.6 million) and unwinding of discount of $0.9 million is included within finance costs (2023: $1.1 million).

Other provisions

At 31 December 2023, the provision included a dispute with a third-party contractor of $9.1 million including legal costs and interest charges. In August 2024, the Malaysian Court of Appeal issued a judgement that funds held in escrow should be released to the third-party supplier pending resolution of the final arbitration decision. As such $8.6 million was released from escrow and hence deducted from the provision. Should the final arbitration decision find in the favour of EnQuest, EnQuest would seek reimbursement of any funds transferred. The Group expects the dispute to be settled in 2025.

23. Leases

Accounting policy

As a lessee

The Group recognises a right-of-use asset and a lease liability at the l

The lease liability is initially measured at the present value of the lease by using the rate implicit in the lease, or, if that rate cannot be readily d

The incremental borrowing rate is the rate that the Group would have an asset of similar value. The incremental borrowing rate is determine based on government bond rates and a credit risk adjustment based

Lease payments included in the measurement of the lease liability co

- fixed lease payments (including in-substance fixed payments), less
- variable lease payments that depend on an index or rate, initially m
- the exercise price of purchase options, if the lessee is reasonably ce
- payments of penalties for terminating the lease, if the lease term re

The lease liability is subsequently recorded at amortised cost, using th there is a change in future lease payments arising from a change in a will exercise a purchase, extension or termination option. When the lea made to the carrying amount of the right-of-use asset, or is recorded been reduced to zero. The Group did not make any such adjustments

The right-of-use asset is measured at cost, which comprises the initia made at or before the commencement date, plus any initial direct cos the underlying asset or to restore the underlying asset or the site on wh assets are depreciated over the shorter period of lease term and usef underlying asset or the cost of the right-of-use asset reflects that the use asset is depreciated over the useful life of the underlying asset. Th

The Group applies the short-term lease recognition exemption to thos commencement date. It also applies the low-value assets recognition short-term leases and leases of low-value assets are recognised as a

The Group applies IAS 36 Impairment of Assets to determine whether impairment loss as described in the 'property, plant and equipment' p

Variable rents that do not depend on an index or rate are not included The related payments are recognised as an expense in the period in w and are included within 'cost of sales' or 'general and administration e

For leases within joint ventures, the Group assesses on a lease-by-lea of vessels. Where all parties to a joint operation jointly have the right to legal obligation to make lease payments to the lessor, the Group's sha be recognised on the Group balance sheet. This may arise in cases wh joint operation partners are named within the lease. However, in cases lease payments to the lessor, the full lease liability and right-of-use as the case if, for example, EnQuest, as operator of the joint operation, is t performance of the joint operation agreement, EnQuest will recharge

As a lessor

When the Group acts as a lessor, it determines at lease inception whe the terms of the lease transfer substantially all the risks and rewards o lease. All other leases are classified as operating leases.

When the Group is an intermediate lessor, it accounts for the head-lea classified as a finance or operating lease by reference to the right-of-

Rental income from operating leases is recognised on a straight-line b in negotiating and arranging an operating lease are added to the car basis over the lease term.

Amounts due from lessees under finance leases are recognised as re Finance lease income is allocated to reporting periods so as to reflect outstanding in respect of the leases.

When a contract includes lease and non-lease components, the Grou each component.

23. Leases continued

Right-of-use assets and lease liabilities

Set out below are the carrying amounts of the Group's right-of-use assets and lease liabilities and the movements during the period:

	Right-of-use assets $'000	Lease liabilities $'000
As at 31 December 2022	429,378	482,066
Additions in the period	28,378	28,378
Depreciation expense	(55,979)	–
Impairment reversal	6,077	–
Disposal	(122)	–
Interest expense	–	43,801
Payments	–	(135,675)
Foreign exchange movements	–	3,604
As at 31 December 2023	407,732	422,174
Additions in the period (see note 9)	16,453	16,453
Depreciation expense (see note 9)	(54,735)	–
Impairment reversal (see note 9)	4,014	–
Interest expense	–	27,673
Payments	–	(130,065)
Foreign exchange movements	–	(979)
As at 31 December 2024	373,464	335,256
Current		46,994
Non-current		288,262
		335,256

The carrying value of the right-of-use assets include $340.9 million (2023: $372.6 million) of oil and gas assets and $32.6 million (2023: $35.1 million) of buildings.

The Group leases assets, including the Kraken FPSO, property, and oil and gas vessels, with a weighted average lease term of four years. The maturity analysis of lease liabilities is disclosed in note 27.

Amounts recognised in profit or loss

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Depreciation expense of right-of-use assets	54,735	55,979
Impairment reversal of right-of-use assets	(4,014)	(6,077)
Interest expense on lease liabilities	27,673	43,801
Rent expense – short-term leases	13,860	5,153
Rent expense – leases of low-value assets	33	113
Total amounts recognised in profit or loss	92,287	98,969

Amounts recognised in statement of cash flows

	Year ended 31 December 2024 $'000	Year ended 31 December 2023 $'000
Total cash outflow for leases	130,065	135,675

23. Leases continued

Leases as lessor

The Group sub-leases part of Annan House, the Aberdeen office. The s
rewards incidental to the ownership of the right-of-use asset are not c
by the Group during 2024 was $2.2 million (2023: $2.3 million).

The following table sets out a maturity analysis of lease payments, sh
reporting date:

Less than one year
One to two years
Two to three years
Three to four years
Four to five years
More than five years
Total undiscounted lease payments

24. Deferred income

Accounting policy

Income is not recognised in the income statement until it is highly prob

Deferred income

In December 2023 a farm-down of an equity interest in the EnQuest Pr
development was completed and cash received of $141.3 million. The s
vendor financing (see note 18(f)). Proceeds from the farm-down are re
Bressay development project achieving regulatory approval. Both par
the project not achieve regulatory approval there remains the option t

25. Commitments and contingencies

Capital commitments

At 31 December 2024, the Group had commitments for future capital e
components of this relate to commitments for the new stabilisation fa
Where the commitment relates to a joint venture, the amount represe
not the operator of the joint venture then the amounts are based on th

Other commitments

In the normal course of business, the Group will obtain surety bonds, L
held surety bonds totalling $277.0 million (2023: $250.4 million) to provi
further details.

Contingencies

The Group becomes involved from time to time in various claims and
those already provided, the Group is not, nor has been during the past
proceedings which, either individually or in the aggregate, have had, c
balance sheet or profitability. Nor, so far as the Group is aware, are any

A contingent payment of $15.0 million to Equinor is due upon regulator

26. Related party transactions

The Group financial statements include the financial statements of EnQuest PLC and its subsidiaries. A list of the Group's principal subsidiaries is contained in note 28 to these Group financial statements.

Balances and transactions between the Company and its subsidiaries, which are related parties, have been eliminated on consolidation and are not disclosed in this note.

All sales to and purchases from related parties are made at normal market prices and the pricing policies and terms of these transactions are approved by the Group's management. With the exception of the transactions disclosed below, there have been no transactions with related parties who are not members of the Group during the year ended 31 December 2024 (2023: none).

Within the $150.0 million term loan, which was fully repaid in October 2024, Double A Limited, a company beneficially owned by the extended family of Amjad Bseisu, lent $9.0 million on the same terms and conditions as all other lending parties. This was considered a smaller related party transaction under Listing Rule 11.1.10 which ended on repayment of the term loan. Double A Limited's share of the early repayment fee was $0.3 million.

Compensation of key management personnel

The following table details remuneration of key management personnel of the Group. Key management personnel comprise Executive and Non-Executive Directors of the Company and the Executive Committee.

	2024 $'000	2023 $'000
Short-term employee benefits	5,138	5,360
Share-based payments	124	144
Post-employment pension benefits	226	241
Termination payments	947	367
	6,435	6,112

27. Risk management and financial instruments

Risk management objectives and policies

The Group's principal financial assets and liabilities comprise trade and other receivables, cash and cash equivalents, interest-bearing loans, borrowings and leases, derivative financial instruments and trade and other payables. The main purpose of the financial instruments is to manage cash flow and to provide liquidity for organic and inorganic growth initiatives.

The Group's activities expose it to various financial risks particularly associated with fluctuations in oil price, foreign currency risk, liquidity risk and credit risk. The Group is also exposed to interest rate risks related to SOFR on cash balances and the RBL. As the RBL was undrawn at 31 December 2024, no sensitivities have been provided. Management reviews and agrees policies for managing each of these risks, which are summarised below. Also presented below is a sensitivity analysis to indicate sensitivity to changes in market variables on the Group's financial instruments and to show the impact on profit and shareholders' equity, where applicable. The sensitivity has been prepared for periods ended 31 December 2024 and 2023, using the amounts of debt and other financial assets and liabilities held at those reporting dates.

Commodity price risk – oil prices

The Group is exposed to the impact of changes in Brent oil prices on its revenues and profits generated from sales of crude oil.

The Group's policy is to have the ability to hedge oil prices up to a maximum of 75% of the next 12 months' production on a rolling annual basis, up to 60% in the following 12-month period and 50% in the subsequent 12-month period. On a rolling quarterly basis, under the RBL facility, the Group is required to hedge a minimum of 45% of volumes of net entitlement production expected to be produced in the next 12 months, and between 35% and 15% of volumes of net entitlement production expected for the following 12 months dependent on the proportion of the facility that is utilised. This requirement ceases at the end date of the facility.

Details of the commodity derivative contracts entered into during and open at the end of 2024 are disclosed in note 18. As of 31 December 2024, the Group held financial instruments (options and swaps) related to crude oil that covered 4.4 MMbbls of 2025 production and 1.3 MMbbls of 2026 production. The instruments have an effective average floor price of around $69/bbl in both 2025 and 2026. The Group utilises multiple benchmarks when hedging production to achieve optimal results for the Group. No derivatives were designated in hedging relationships at 31 December 2024.

The following table summarises the impact on the Group's pre-tax profit of a reasonably possible change in the Brent oil price on the fair value of derivative financial instruments, with all other variables held constant. The impact in equity is the same as the impact on profit before tax.

	Pre-tax profit	
	+$10/bbl increase $'000	-$10/bbl decrease $'000
31 December 2024	(47,600)	47,200
31 December 2023	(4,000)	7,400

27. Risk management and financial instruments continued

Foreign exchange risk

The Group is exposed to foreign exchange risk arising from movement
purchases in currencies other than the Group's functional currency ar
is denominated in Sterling. To mitigate the risks of large fluctuations in
allows for up to 70% of the non-US Dollar portion of the Group's annual
specific contracted capital expenditure projects, up to 100% can be he
(2023: 95%) of costs (including operating and capital expenditure and
other than the functional currency.

The Group also enters into foreign currency swap contracts from time
summarise the Group's financial assets and liabilities exposure to fore

Year ended 31 December 2024
Total financial assets
Total financial liabilities

Year ended 31 December 2023
Total financial assets
Total financial liabilities

The following table summarises the sensitivity to a reasonably possibl
other variables held constant, of the Group's profit before tax due to ch
reporting date. The impact in equity is the same as the impact on prof
all other currencies is not material:

31 December 2024
31 December 2023

Credit risk

Credit risk is managed on a Group basis. Credit risk in financial instrun
financial instruments where the Group's exposure arises from default
amount of these instruments. For banks and financial institutions only
balances can be invested in short-term bank deposits and AAA-rated
minimising counterparty credit risks.

In addition, there are credit risks of commercial counterparties, includi
trades only with recognised international oil and gas companies, com
there were no trade receivables past due but not impaired (2023: nil) a
Receivable balances are monitored on an ongoing basis with approp
is disclosed in note 15.

Ageing of past due but not impaired receivables
Less than 30 days
30–60 days
60–90 days
90–120 days
120+ days

At 31 December 2024, the Group had two customers accounting for 91
four joint venture partners accounting for over 70% of outstanding join

27. Risk management and financial instruments continued

Liquidity risk

The Group monitors its risk of a shortage of funds by reviewing its cash flow requirements on a regular basis relative to its existing bank facilities and the maturity profile of its borrowings. Specifically, the Group's policy is to ensure that sufficient liquidity or committed facilities exist within the Group to meet its operational funding requirements and to ensure the Group can service its debt and adhere to its financial covenants. At 31 December 2024, $194.3 million (2023: $166.2 million) was available for drawdown under the Group's facilities (see note 17).

The following tables detail the maturity profiles of the Group's non-derivative financial liabilities, including projected interest thereon. The amounts in these tables are different from the balance sheet as the table is prepared on a contractual undiscounted cash flow basis and includes future interest payments.

The payment of contingent consideration is limited to cash flows generated from Magnus (see note 21). Therefore, no contingent consideration is payable if insufficient cash flows are generated over and above the requirements to operate the asset and there is no exposure to liquidity risk. By reference to the conditions existing at the reporting period end, the maturity analysis of the contingent consideration is disclosed below. All of the Group's liabilities, except for the RBL, are unsecured.

Year ended 31 December 2024	On demand $'000	Up to 1 year $'000	1 to 2 years $'000	2 to 5 years $'000	Over 5 years $'000	Total $'000
Loans	–	34,168	–	–	–	34,168
Bonds	–	69,095	69,095	701,197	–	839,387
Contingent consideration	–	20,675	64,877	265,854	425,027	776,433
Obligations under lease liabilities	–	66,092	71,600	222,093	31,696	391,481
Trade and other payables	–	414,390	–	–	–	414,390
	–	604,420	205,572	1,189,144	456,723	2,455,859

Year ended 31 December 2023	On demand $'000	Up to 1 year $'000	1 to 2 years $'000	2 to 5 years $'000	Over 5 years $'000	Total $'000
Loans	–	64,518	131,081	221,311	–	416,910
Bonds	–	50,749	50,749	576,415	–	677,913
Contingent consideration	–	46,555	95,335	289,823	393,187	824,900
Obligations under lease liabilities	–	160,341	70,062	229,310	36,322	496,035
Trade and other payables	–	347,408	13,167	19,750	–	380,325
	–	669,571	360,394	1,336,609	429,509	2,796,083

The following tables detail the Group's expected maturity of payables for its derivative financial instruments. The amounts in these tables are different from the balance sheet as the table is prepared on a contractual undiscounted cash flow basis. When the amount receivable or payable is not fixed, the amount disclosed has been determined by reference to a projected forward curve at the reporting date.

Year ended 31 December 2024	On demand $'000	Less than 3 months $'000	3 to 12 months $'000	1 to 2 years $'000	Over 2 years $'000	Total $'000
Commodity derivative contracts	–	546	8,908	999	–	10,453
Foreign exchange derivative contracts	–	1,105	1,249	–	–	2,354
Other derivative contracts	–	23,902	3,802	1,928	–	29,632
	–	25,553	13,959	2,927	–	42,439

Year ended 31 December 2023	On demand $'000	Less than 3 months $'000	3 to 12 Months $'000	1 to 2 years $'000	Over 2 years $'000	Total $'000
Commodity derivative contracts	414	3,111	17,264	1,000	–	21,789
Other derivative contracts	–	8,261	–	–	–	8,261
	414	11,372	17,264	1,000	–	30,050

27. Risk management and financial instruments continued

Capital management

The capital structure of the Group consists of debt, which includes the equity attributable to the equity holders of the parent company, comp statement of changes in equity.

The primary objective of the Group's capital management is to optimi achieve capital efficiency whilst also maintaining flexibility for downsi the capital requirements of the business over the short, medium and l will be required.

The Group has approval from the Board to hedge external risks, see Co designed to reduce the risk of adverse movements in exchange rates and operations.

The Board regularly reassesses the existing dividend policy to ensure t distributions are expected to depend on the earnings and financial co considers appropriate.

The Group monitors capital using the gearing ratio and return on shar movement year-on-year is provided within the relevant notes and wit

Loans, borrowings and bond[i] (A) (see note 17)	
Cash and cash equivalents (see note 13)	
EnQuest net debt (B)[ii]	
Equity attributable to EnQuest PLC shareholders (C)	
Profit/(loss) for the year attributable to EnQuest PLC shareholders (D	
Adjusted EBITDA (F)[ii]	
Gross gearing ratio (A/C)	
Net gearing ratio (B/C)	
EnQuest net debt/adjusted EBITDA (B/F)[ii]	
Shareholders' return on investment (D/C)	

(i) Principal amounts drawn, excludes netting off of fees and accrued interest (see note 17)
(ii) See Glossary – non GAAP measures on pages 189 to 192

28. Subsidiaries

At 31 December 2024, EnQuest PLC had investments in the following subsidiaries:

Name of company	Principal activity	Country of incorporation	Proportion of nominal value of issued Ordinary shares controlled by the Group
EnQuest Britain Limited	Intermediate holding company and provision of Group manpower and contracting/procurement services	England	100%
EnQuest Heather Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Thistle Limited(i) 4	Exploration, extraction and production of hydrocarbons	England	100%
Stratic UK (Holdings) Limited(i) 4	Intermediate holding company	England	100%
EnQuest ENS Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest UKCS Limited(i) 4	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Heather Leasing Limited(i)	Leasing	England	100%
EQ Petroleum Sabah Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Dons Leasing Limited(i)	Leasing	England	100%
EnQuest Energy Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Production Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Global Limited	Intermediate holding company	England	100%
EnQuest NWO Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EQ Petroleum Production Malaysia Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
NSIP (GKA) Limited1	Dormant	Scotland	100%
EnQuest Global Services Limited(i) 2	Provision of Group manpower and contracting/procurement services for the international business	Jersey	100%
EnQuest Marketing and Trading Limited	Marketing and trading of crude oil	England	100%
NorthWestOctober Limited(i) 4	Dormant	England	100%
EnQuest UK Limited(i) 4	Dormant	England	100%
EnQuest Petroleum Developments Malaysia SDN. BHD(i) 3	Exploration, extraction and production of hydrocarbons	Malaysia	100%
EnQuest NNS Holdings Limited(i) 4	Intermediate holding company	England	100%
EnQuest NNS Limited(i) 4	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Advance Holdings Limited(i)	Intermediate holding company	England	100%
EnQuest Advance Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Forward Holdings Limited(i) 4	Intermediate holding company	England	100%
EnQuest Forward Limited(i) 4	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Progress Limited(i)	Exploration, extraction and production of hydrocarbons	England	100%
North Sea (Golden Eagle) Resources Ltd(i)	Exploration, extraction and production of hydrocarbons	England	100%
Veri Energy (CCS) Limited(i)	Assessment and development of new energy and decarbonisation opportunities	England	100%
Veri Energy (Hydrogen) Limited(i)	Assessment and development of new energy and decarbonisation opportunities	England	100%
Veri Energy Holdings Limited	Intermediate holding company	England	100%
Veri Energy Limited(i)	Assessment and development of new energy and decarbonisation opportunities	England	100%

(i) Held by subsidiary undertaking

The Group has two branches outside the UK (all held by subsidiary undertakings): EnQuest Global Services Limited (Dubai) and EnQuest Petroleum Production Malaysia Limited (Malaysia).

Other than those listed below, all entities have a Registered office address as Charles House, 2nd Floor, 5-11 Regent Street, London, SW1Y 4LR, United Kingdom.

1 Annan House, Palmerston Road, Aberdeen, Scotland, AB11 5QP, United Kingdom
2 Ground Floor, Colomberie House, St Helier, JE4 0RX, Jersey
3 c/o TMF, 10th Floor, Menara Hap Seng, No. 1 & 3, Jalan P. Ramlee 50250 Kuala Lumpur, Malaysia
4 c/o BDO LLP, Temple Square, Temple Street, Liverpool L2 5RH – indicates those legal entities that formally entered into the liquidation process during October 2024

29. Cash flow information

Cash generated from operations

Profit/(loss) before tax	
Depreciation	
Depletion	
Exploration and appraisal expense	
Net impairment charge to oil and gas assets	
Net (write back)/disposal of inventory	
Share-based payment charge	
Change in Magnus related contingent consideration	
Change in provisions	
Other non-cash income	
Change in Golden Eagle related contingent consideration	
Unrealised (gain)/loss on commodity financial instruments	
Unrealised loss/(gain) on other financial instruments	
Unrealised exchange (gain)/loss	
Net finance expense	
Operating cash flow before working capital changes	
(Increase)/decrease in trade and other receivables	
(Increase)/decrease in inventories	
Increase/(decrease) in trade and other payables	
Cash generated from operations	

Changes in liabilities arising from financing activities

At 1 January 2023	
Cash movements:	
Repayments of loans and borrowings	
Proceeds from loans and borrowings	
Payment of lease liabilities	
Cash interest paid in year	
Non-cash movements:	
Additions	
Interest/finance charge payable	
Fee amortisation	
Foreign exchange and other non-cash movements	
At 31 December 2023	
Cash movements:	
Repayments of loans and borrowings(i)	
Proceeds from loans and borrowings(ii)	
Payment of lease liabilities	
Cash interest paid in year(iii)	
Non-cash movements:	
Additions	
Interest/finance charge payable	
Fee amortisation	
Foreign exchange and other non-cash movements	
At 31 December 2024	

(i) Repayments of loans and borrowings include $140.0 million repaid under the RBL facility capital facility (note 17). In the Group Cash Flow Statement, the repayment of loans and the proceeds from the high yield bond tap and as such netted against the proceeds of and borrowings line

(ii) Proceeds from loans and borrowing include $26.9 million draw-downs under the SVT w Statement, proceeds from loans and borrowings of $31.7 million includes amounts outli termination $4.7 million and $0.4 million relating to the high yield bond issue premium r

(iii) The cashflow statement includes interest on decommissioning bonds and Letters of Cr

29. Cash flow information continued

Reconciliation of carrying value

	Loans (see note 17) $'000	Bonds (see note 17) $'000	Lease liabilities (see note 23) $'000	Total $'000
Principal	(319,784)	(474,669)	(422,174)	(1,216,627)
Unamortised fees	8,553	10,724	–	19,277
Accrued interest	21	(7,074)	–	(7,053)
At 31 December 2023	(311,210)	(471,019)	(422,174)	(1,204,403)
Principal	(33,972)	(632,101)	(335,255)	(1,001,328)
Unamortised fees	–	10,661	–	10,661
Accrued interest	–	(9,445)	–	(9,445)
At 31 December 2024	(33,972)	(630,885)	(335,255)	(1,000,112)

30. Subsequent events

In January 2025, EnQuest announced that it had signed a Sale and Purchase Agreement to acquire Harbour Energy's business in Vietnam, which includes the 53.125% equity interest in the Chim Sáo and Dua production fields. These fields are governed by the Block 12W Production Sharing Contract, which runs to November 2030 with an opportunity to extend. The transaction has an effective date of 1 January 2024 and is scheduled to complete during the second quarter of 2025. The headline value of the transaction is $84.0 million and, net of interim period cash flows, the consideration to be paid by EnQuest on completion is expected to equal c.$35 million. As at 1 January 2025, net 2P reserves and 2C resources across the fields total 7.5 million Boe and 4.9 million Boe, respectively.

Statement of Directors' Responsibilities
for the Parent Company Financial Statements

The Directors are responsible for preparing the Parent Company finan

Company law requires the Directors to prepare financial statements f to prepare the financial statements in accordance with United Kingdo Accounting Standards and applicable law) including FRS 101 'Reduced approve the financial statements unless they are satisfied that they gi the profit or loss of the Company for that period. In preparing the pare

- Select suitable accounting policies and then apply them consistent
- Make judgements and estimates that are reasonable and prudent;
- State whether applicable UK Accounting Standards have been follo in the financial statements; and
- Prepare the financial statements on the going concern basis unless in business.

The Directors are responsible for keeping adequate accounting recor transactions and disclose with reasonable accuracy at any time the fi the Company financial statements comply with the Companies Act 2 Company and hence for taking reasonable steps for the prevention a

The Directors are responsible for the maintenance and integrity of the on the Group's website. Legislation in the United Kingdom governing th from legislation in other jurisdictions.

Independent auditor's report
to the members of EnQuest PLC

Report on the audit of the financial statements

1. Opinion

In our opinion:
- the financial statements of EnQuest PLC (the 'parent company') and its subsidiaries (the 'group') give a true and fair view of the state of the group's and of the parent company's affairs as at 31 December 2023 and of the group's profit for the year then ended;
- the group financial statements have been properly prepared in accordance with United Kingdom adopted International Financial Reporting Standards;
- the parent company financial statements have been properly prepared in accordance with United Kingdom Generally Accepted Accounting Practice, including Financial Reporting Standard 101 "Reduced Disclosure Framework"; and
- the financial statements have been prepared in accordance with the requirements of the Companies Act 2006.

We have audited the financial statements which comprise:
- the Group Income Statement;
- the Group Balance Sheet;
- the Group Statement of Changes in Equity;
- the Group Statement of Cash Flows;
- the related notes 1 to 31 to the Group Financial Statements;
- the Company Balance Sheet;
- the Company Statement of Changes in Equity; and
- the related notes 1 to 14 to the Company Financial Statements.

The financial reporting framework that has been applied in the preparation of the group financial statements is applicable law and United Kingdom adopted International Financial Reporting Standards. The financial reporting framework that has been applied in the preparation of the parent company financial statements is applicable law and United Kingdom Accounting Standards, including FRS 101 "Reduced Disclosure Framework" (United Kingdom Generally Accepted Accounting Practice).

2. Basis for opinion

We conducted our audit in accordance with International Standards on Auditing (UK) (ISAs (UK)) and applicable law. Our responsibilities under those standards are further described in the auditor's responsibilities for the audit of the financial statements section of our report.

We are independent of the group and the parent company in accordance with the ethical requirements that are relevant to our audit of the financial statements in the UK, including the Financial Reporting Council's (the 'FRC's') Ethical Standard as applied to listed public interest entities, and we have fulfilled our other ethical responsibilities in accordance with these requirements. The non-audit services provided to the group and parent company for the year are disclosed in note 5g to the group financial statements. We confirm that we have not provided any non-audit services prohibited by the FRC's Ethical Standard to the group or the parent company.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

3. Summary of our audit approach

Key audit matters	The key audit matters that we identified in the current year were: • Valuation of oil and gas related assets and liabilities • Valuation of decommissioning liability Within this report, key audit matters are identified as follows: Newly identified Increased level of risk Similar level of risk Decreased level of risk
Materiality	The materiality that we used for the group financial statements was $23m which was determined on the basis of 2.8% of adjusted EBITDA (earnings before interest, tax, depreciation, amortisation, remeasurements and exceptional items).
Scoping	EnQuest PLC has two components, being the North Sea and Malaysia. They account for 100% of the group's revenue, 100% of its adjusted EBITDA and 100% of its net assets.
Significant changes in our approach	There were no significant changes in our approach compared to the prior year.

4. Conclusions relating to going concern

In auditing the financial statements, we have concluded that th
the preparation of the financial statements is appropriate.

Our evaluation of the directors' assessment of the group's and
concern basis of accounting included:
- assessing the reasonableness of the assumptions used in th
  production levels and cash costs;
- assessing the historical accuracy of forecasts prepared by m
- assessing the financing facilities throughout the going concer
- considering the levels of cash and covenant headroom throu
  and reverse stress testing;
- assessing the mathematical accuracy of the forecasts and t
  and
- assessing the appropriateness of the group's and parent com

Based on the work we have performed, we have not identified
individually or collectively, may cast significant doubt on the gr
concern for a period of at least twelve months from when the fi

In relation to the reporting on how the group has applied the UK
add or draw attention to in relation to the directors' statement
considered it appropriate to adopt the going concern basis of

Our responsibilities and the responsibilities of the directors with
sections of this report.

5. Key audit matters

Key audit matters are those matters that, in our professional ju
financial statements of the current period and include the mos
or not due to fraud) that we identified. These matters included
strategy, the allocation of resources in the audit and directing t

These matters were addressed in the context of our audit of the
thereon, and we do not provide a separate opinion on these m

Independent auditor's report
to the members of EnQuest PLC continued

5.1. Valuation of oil and gas related assets and liabilities

Key audit matter description

Management is required to assess the carrying value of oil and gas related assets and liabilities, in line with the relevant accounting standard, at each balance sheet date. In order to appropriately value these assets and liabilities, management is required to forecast future cash flows. These forecast cash flows are used consistently across the:

- Impairment assessment of oil and gas assets;
- Impairment assessment of goodwill;
- Impairment assessment of the parent company investments;
- Valuation of Magnus contingent consideration; and
- Valuation of the deferred tax asset.

The forecast future cash flows contain a high level of management judgment and estimation, particularly in relation to the following significant assumptions:

- Forecast commodity prices;
- Discount rate applied; and
- Reserve estimates and production profiles.

In addition to the above, the assumed cost savings on the Kraken CGU as a result of alternative fuel sources was a key judgment during the year.

Commodity prices, reserve estimates and production profiles are also impacted by climate-related risks, which increases the level of estimation uncertainty.

Given the level of management judgment and estimation applied in determining the recoverable value of the oil and gas related assets and liabilities, including estimation uncertainty within the significant assumptions outlined above, we consider this to be a key audit matter related to the potential risk of fraud.

Impairment assessment of oil and gas assets, goodwill and parent company investments
Management performed an impairment assessment for oil and gas assets and goodwill carrying value, by reference to IAS 36 Impairment of Assets. As at 31 December 2023, the net book value of oil and gas assets was $1,880 million (2022: $2,037 million) and management have recorded a pre-tax impairment of $117 million (2022: $81 million) against certain oil and gas assets, including related right of use assets, as disclosed in note 10.

As at 31 December 2023, the net book value of goodwill was $134 million (2022: $134 million). No goodwill impairment charge has been recorded in 2023 (2022: nil), as disclosed in note 11.

Management also performed an assessment of the carrying values of the parent company's investment in subsidiaries by reference to IAS36 Impairment of Assets and IFRS9 Financial Instruments. As at 31 December 2023, the net book value of investments recognised in the parent company balance sheet was $300 million (2022: $370 million) and management have recorded an impairment of $74 million (2022: $31 million impairment), as disclosed in note 3 to the parent company financial statements.

Valuation of Magnus contingent consideration
The valuation of Magnus contingent consideration was $488 million (2022: $567 million) as at 31 December 2023, based on the estimated future cash flows for the Magnus oil and gas asset, as disclosed in note 22.

Valuation of the deferred tax asset
As at 31 December 2023, a deferred tax asset of $540m (2022: $706m) was recognised, based on the expected utilisation of historical tax losses, underpinned by forecasts of future profitability. The forecast cash flows used to value the deferred tax asset are consistent with the cash flows used for impairment purposes. Further details on the deferred tax asset are disclosed in note 7(c).

Given the interrelated nature of the key areas noted above, management have applied consistent assumptions across all of these valuations where appropriate. Further details on this matter have been disclosed in the audit committee report on page 95 and 96.

5.1. Valuation of oil and gas related assets and liabilities c

How the scope of our audit responded to the key audit matter

Our procedures comprised the following:

Procedures on internal controls and valu
- obtaining an understanding of relevant indicators of impairment and for perfor
- assessing management's forecasting a
- assessing whether forecast cash flows and forecasts used elsewhere, includin
- challenging the reasonableness of the
- assessing, with input from our tax speci flows, including the Energy Profits Levy;
- working with our modelling specialists t
- challenging management's determina purposes, in comparison to the require
- assessing the reasonableness of the va stand-back procedures;
- evaluating compliance with the relevan Impairment of assets and IFRS13 Fair Va
- evaluating the adequacy of managem valuations, including related sensitivity

Procedures related to the key assumptio
Our procedures related to the key assump

Forecast commodity prices
- assessing the appropriateness of mana against forward curves, peer informatio
- performing sensitivity analysis on the p conclusions of reasonably possible cha
- evaluating whether management's pric lower oil and gas demand due to clima

Discount rate
- evaluating, with input from our valuatio tests and valuations; and
- assessing whether country risks and ta discount rate.

Reserves estimates and production prof
- comparing management's reserves es independent reserves expert;
- assessing the technical competence, c external experts;
- evaluating, with involvement from our c estimates and production profiles; and
- working with our oil and gas reserves sp the reserves estimates and production

Kraken cost savings
- We challenged management on the in alternative fuel sources, with reference

Key observations

We are satisfied with management's con assets and liabilities, including the related

In reaching this conclusion, we observed
- Future commodity price assumptions a
- Impairment discount rates were within
- Reserves estimates and production pro management's reserves expert;
- The carrying value of the oil and gas as is reasonable;
- The carrying value of the investment in is reasonable;
- The carrying value of the Magnus conti
- The deferred tax asset recognition is ap

Independent auditor's report
to the members of EnQuest PLC continued

5.2. Valuation of decommissioning liability

Key audit matter description	The group is required by law to decommission the oil and gas assets and associated infrastructure at the end of their operating life. An estimate of the future cost of decommissioning is required to be provided for in accordance with IAS37 Provisions, Contingent Liabilities and Contingent Assets. The decommissioning provision at 31December 2023 is $781million (2022:$724 million). The provision represents the present value of decommissioning costs which are expected to be incurred during the decommissioning period, which is assumed to run to 2048, assuming no further development of the group's assets. Further details on the key sources of estimation uncertainty underpinning the valuation of decommissioning provisions can be found in note 2. This key audit matter is considered to be a risk due to fraud. Decommissioning liabilities are inherently judgemental areas, particularly in relation to cost estimates and the related assumptions. The key management estimates containing the most estimation uncertainty, and therefore the focus of our key audit matter, are: • internal well cost estimates included in the decommissioning model; and • internal cost reduction factors applied to the gross decommissioning cost estimates to reflect anticipated cost savings. The Group's Audit Committee has considered this key audit matter in their Audit Committee Report for the year ended 31December 2023 on page 96. Further detail on decommissioning provisions is included in note 23.
How the scope of our audit responded to the key audit matter	Our procedures comprised the following: Procedures on internal controls and the decommissioning model • obtaining an understanding of the relevant controls relating to the decommissioning provision; • assessing the technical competence, capabilities and objectivity of management's internal and external experts; • assessing the decommissioning provision for compliance with IAS37 Provisions, Contingent Liabilities and Contingent Assets; • working with our modelling specialists to evaluate the arithmetical accuracy of the decommissioning model; • assessing available benchmarking reports for indications of developments in industry practice in light of climate change goals; • testing a sample of actual decommissioning spend incurred during the period, by agreeing to invoices and payments from bank statements; • assessing the historical forecasting accuracy of management for decommissioning expenditure, by comparing actual spend with historical estimates; • re-calculating the closing decommissioning provision from the gross decommissioning cost estimate, and agreeing this to the group's financial records; and • evaluating the adequacy of management's disclosures, including the key sources of estimation uncertainty and associated sensitivity analysis of decommissioning assumptions. Procedures on cost estimates and related assumptions *Internal well cost estimates* • challenging the group's assumptions within the cost estimate by referencing to available third-party data and benchmarking to peer and market rates; and • assessing the assumed durations for plug and abandonment of wells, by comparison to available benchmarking data and potential contradictory evidence available from active decommissioning projects or operator estimates. *Internal cost reduction factors* • challenging the group's cost reduction factors applied to the decommissioning model, through comparison with available evidence for the factors applied; • benchmarking cost reduction factors to peers and other applicable sources; and • considering potentially contradictory evidence from actual decommissioning spend, changes in market rates and industry publications.
Key observations	• The key assumptions within the well cost estimates are reasonable; • Cost reduction factors are reasonable, albeit considered to be towards the optimistic end of an acceptable range; • We are satisfied that the group's decommissioning provision is prepared in accordance with the requirements of IAS37 Provisions, Contingent Liabilities and Contingent Assets; and • We are satisfied the disclosures in the financial statements are adequate.

6. Our application of materiality

6.1. Materiality

We define materiality as the magnitude of misstatement in the economic decisions of a reasonably knowledgeable person w planning the scope of our audit work and in evaluating the resu

Based on our professional judgement, we determined materia

	Group financial statements
Materiality	$23 million (2022:$30 million)
Basis for determining materiality	2.8%of adjusted EBITDA (earnings before interest, tax, depreciation, amortisation, remeasurements and exceptional items) (2022:3%of adjusted EBITDA). Management have presented a reconcili of $825 million adjusted EBITDA to profit fr operations before tax and interest in the g to the financial statements on page 193.
Rationale for the benchmark applied	Adjusted EBITDA was considered to be the relevant benchmark as it is a key perform measure used by the group and by inves represents a consistent profit measure us widely by stakeholders.



6.2. Performance materiality

We set performance materiality at a level lower than materialit and undetected misstatements exceed the materiality for the

	Group financial statements
Performance materiality	70% (2022: 70%) of group materiality
Basis and rationale for determining performance materiality	In determining performance materiality, • the quality of the control environment a • the nature, volume and size of correcte previous audit; • macro-economic factors such as com • management's willingness to correct e

6.3. Error reporting threshold

We agreed with the Audit Committee that we would report to th (2022:$1.5m), as well as differences below that threshold that, i We also report to the Audit Committee on disclosure matters th of the financial statements.

Independent auditor's report
to the members of EnQuest PLC continued

7. An overview of the scope of our audit

7.1. Identification and scoping of components

Our audit was scoped by obtaining an understanding of the group and its environment, including group-wide controls, and assessing the risks of material misstatement at the group level. In the current year we performed full scope audit procedures on the North Sea and Malaysia components. Audit procedures were performed by the group audit team for the North Sea component and by the Malaysia component team for the Malaysia component.

The materiality applied for the Malaysia component was $11.5 million (2022: $15.0 million). The materiality applied for the North Sea component was $20.6 million (2022: $27.0 million).

The North Sea and Malaysia components, where we performed full scope audit procedures, accounted for 100% of the group's revenue, 100% of the group's adjusted EBITDA and 100% of the group's net assets, consistent with the prior year.

7.2. Our consideration of the control environment

We obtained an understanding of the relevant controls in relation to key business processes as well as IT systems that were relevant to the audit, being the financial reporting system. We worked with our IT specialists to test the operating effectiveness of the general IT control environment. Weaknesses were identified and as a result of this we were unable to place reliance on the general IT controls. Where appropriate, we adapted our audit procedures in response.

7.3. Our consideration of climate-related risks

We performed enquiries of management to understand the impact of climate-related risks and controls relevant to the group. We performed a review of the climate change risk assessment and related documentation prepared by management and considered the completeness and accuracy of the climate-related risks identified and summarised in the Task Force on Climate-related Financial Disclosures report on page 66 and 75.

As disclosed in note 2, management identified key judgements and estimates with elevated climate-related risk, relating to impairment of oil and gas assets, valuation of contingent consideration, valuation of the decommissioning provision, valuation of deferred tax assets, and estimation of oil and gas reserves.

We considered whether the risks identified by management within their climate change risk assessment and related documentation are complete and challenged assumptions impacting the financial statements. The key piece of climate-related regulation enacted to date and impacting the group continues to relate to carbon costs and emission allowances. The key market-related matter which could have a material impact on the valuation of the items noted above is in respect of future demand for, and pricing of, oil and gas as the energy mix evolves in response to climate change risk and other matters. There continues to be a physical climate-related risk relating to the early cessation of production of oil and gas assets, which would impact all of the judgments and estimates outlined above. This is disclosed in the annual report on page 69.

We performed a review of the climate disclosures within the Annual Report, including the climate-related financial disclosures referred to on page 66 to 75, with the involvement of our climate specialists. We considered whether these were materially consistent with the financial disclosures and consistent with our understanding of the climate-related risks, assumptions and judgements during the year. Both of our key audit matters are considered to contain climate-related risks, being the risks to commodity prices and cessation of production, which could have a material impact on the valuation of oil and gas related assets and liabilities and valuation of the decommissioning provision. The procedures performed for these key audit matters are discussed in detail in the key audit matters section above.

7.4. Working with other auditors

We engaged Deloitte Malaysia as our component auditor, directed and supervised by the group engagement team in the UK. Detailed referral instructions were sent to the component audit team as part of planning procedures.

The group engagement team directed and supervised the component team throughout the year via attendance at planning meetings, regular communication between the teams and attendance at closing meetings. The group engagement team reviewed and challenged the reporting deliverables and audit file as part of concluding procedures.

We are satisfied that the level of involvement of the lead audit partner and team in the component audit has been appropriate and has enabled us to conclude that sufficient appropriate audit evidence has been obtained in support of our opinion on the group financial statements as a whole.

8. Other information

The other information comprises the information included in th
auditor's report thereon. The directors are responsible for the o

Our opinion on the financial statements does not cover the oth
stated in our report, we do not express any form of assurance c

Our responsibility is to read the other information and, in doing
inconsistent with the financial statements or our knowledge ob
materially misstated.

If we identify such material inconsistencies or apparent materi
gives rise to a material misstatement in the financial statemen
conclude that there is a material misstatement of this other inf

We have nothing to report in this regard.

9. Responsibilities of directors

As explained more fully in the Statement of Directors' responsib
financial statements and for being satisfied that they give a tru
determine is necessary to enable the preparation of financial s
due to fraud or error.

In preparing the financial statements, the directors are respons
ability to continue as a going concern, disclosing as applicable
concern basis of accounting unless the directors either intend
operations, or have no realistic alternative but to do so.

10. Auditor's responsibilities for the audit of the financial stat

Our objectives are to obtain reasonable assurance about whet
misstatement, whether due to fraud or error, and to issue an au
assurance is a high level of assurance, but is not a guarantee t
always detect a material misstatement when it exists. Misstate
material if, individually or in the aggregate, they could reasona
taken on the basis of these financial statements.

A further description of our responsibilities for the audit of the fi
www.frc.org.uk/auditorsresponsibilities. This description forms

11. Extent to which the audit was considered capable of detecting irregularities, including fraud

Irregularities, including fraud, are instances of non-compliance with laws and regulations. We design procedures in line with our responsibilities, outlined above, to detect material misstatements in respect of irregularities, including fraud. The extent to which our procedures are capable of detecting irregularities, including fraud is detailed below.

11.1. Identifying and assessing potential risks related to irregularities

In identifying and assessing risks of material misstatement in respect of irregularities, including fraud and non-compliance with laws and regulations, we considered the following:

- the nature of the industry and sector, control environment and business performance including the design of the group's remuneration policies, key drivers for directors' remuneration, bonus levels and performance targets;
- the group's own assessment of the risks that irregularities may occur, either as a result of fraud or error, that was approved by the board;
- results of our enquiries of management, internal audit, the directors and the Audit Committee about their own identification and assessment of the risks of irregularities, including those that are specific to the group's sector;
- any matters we identified having obtained and reviewed the group's documentation of their policies and procedures relating to:
  - identifying, evaluating and complying with laws and regulations and whether they were aware of any instances of non-compliance;
  - detecting and responding to the risks of fraud and whether they have knowledge of any actual, suspected or alleged fraud; and
  - the internal controls established to mitigate risks of fraud or non-compliance with laws and regulations.
- the matters discussed among the audit engagement team including the component audit team and relevant internal specialists, including tax, valuations, IT, modelling and oil and gas reserves specialists, regarding how and where fraud might occur in the financial statements and any potential indicators of fraud.

As a result of these procedures, we considered the opportunities and incentives that may exist within the organisation for fraud and identified the greatest potential for fraud in the following areas:

- valuation of oil and gas related assets and liabilities;
- valuation of decommissioning provision; and
- crude oil revenue recognition.

In common with all audits under ISAs (UK), we are also required to perform specific procedures to respond to the risk of management override.

We also obtained an understanding of the legal and regulatory framework that the group operates in, focusing on provisions of those laws and regulations that had a direct effect on the determination of material amounts and disclosures in the financial statements. The key laws and regulations we considered in this context included the UK Companies Act 2006 and the Listing Rules of the UK Listing Authority and the relevant tax compliance regulations in the jurisdictions in which the group operates.

In addition, we considered provisions of other laws and regulations that do not have a direct effect on the financial statements, but compliance with which may be fundamental to the group's ability to operate or to avoid a material penalty. These included environmental laws and regulations in the countries in which the group operates.

11.2. Audit response to risks identified

As a result of performing the above, we identified the valuation of the decommissioning provision as key audit matters related our report explains the matters in more detail and also describ key audit matters.

In addition to the above, our procedures to respond to risks id

- reviewing the financial statement disclosures and testing to provisions of relevant laws and regulations described as hav
- enquiring of management, the Audit Committee and in-hou and claims;
- performing analytical procedures to identify any unusual or misstatement due to fraud;
- reading minutes of meetings of those charged with governa correspondence with relevant authorities;
- in addressing the risk of fraud in revenue recognition associa invoices from a population of December 2023 and January 2
- in addressing the risk of fraud through management overrid other adjustments; assessing whether the judgements mad bias; and evaluating the business rationale of any significan of business.

We also communicated relevant identified laws and regulation members, including internal specialists and the component au or non-compliance with laws and regulations throughout the a

Independent auditor's report
to the members of EnQuest PLC continued

Report on other legal and regulatory requirements

12. Opinions on other matters prescribed by the Companies Act 2006

In our opinion the part of the directors' remuneration report to be audited has been properly prepared in accordance with the Companies Act 2006.

In our opinion, based on the work undertaken in the course of the audit:
- the information given in the strategic report and the directors' report for the financial year for which the financial statements are prepared is consistent with the financial statements; and
- the strategic report and the directors' report have been prepared in accordance with applicable legal requirements.

In the light of the knowledge and understanding of the group and the parent company and their environment obtained in the course of the audit, we have not identified any material misstatements in the strategic report or the directors' report.

13. Corporate Governance Statement

The Listing Rules require us to review the directors' statement in relation to going concern, longer-term viability and that part of the Corporate Governance Statement relating to the group's compliance with the provisions of the UK Corporate Governance Code specified for our review.

Based on the work undertaken as part of our audit, we have concluded that each of the following elements of the Corporate Governance Statement is materially consistent with the financial statements and our knowledge obtained during the audit: :
- the directors' statement with regards to the appropriateness of adopting the going concern basis of accounting and any material uncertainties identified set out on pages 29 and 30;
- the directors' explanation as to its assessment of the group's prospects, the period this assessment covers and why the period is appropriate set out on page 29 and 30;
- the directors' statement on fair, balanced and understandable set out on page 93;
- the board's confirmation that it has carried out a robust assessment of the emerging and principal risks set out on pages 46 to 64;
- the section of the annual report that describes the review of effectiveness of risk management and internal control systems set out on page 97; and
- the section describing the work of the audit committee set out on pages 92 and 93.

14. Matters on which we are required to report by exception

14.1. Adequacy of explanations received and accounting records

Under the Companies Act 2006 we are required to report to you if, in our opinion:
- we have not received all the information and explanations we require for our audit; or
- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or
- the parent company financial statements are not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

14.2. Directors' remuneration

Under the Companies Act 2006 we are also required to report if in our opinion certain disclosures of directors' remuneration have not been made or the part of the directors' remuneration report to be audited is not in agreement with the accounting records and returns.

We have nothing to report in respect of these matters.

15. Other matters which we are required to address

15.1. Auditor tenure

Following the recommendation of the Audit Committee, we we financial statements for the year ending 31 December 2020 an uninterrupted engagement including previous renewals and re ended 31 December 2020 to 31 December 2023.

15.2. Consistency of the audit report with the additional repor Our audit opinion is consistent with the additional report to the with ISAs (UK).

16. Use of our report

This report is made solely to the company's members, as a bo Act 2006. Our audit work has been undertaken so that we migh required to state to them in an auditor's report and for no other accept or assume responsibility to anyone other than the com work, for this report, or for the opinions we have formed.

As required by the Financial Conduct Authority (FCA) Disclosure these financial statements form part of the Electronic Format A Mechanism of the FCA in accordance with DTR 4.1.15R – DTR 4.1 the Electronic Format Annual Financial Report has been prepar

James Leigh FCA (Senior statutory auditor)
For and on behalf of Deloitte LLP
Statutory Auditor

London, United Kingdom

27 March 2024

Group Income Statement
For the year ended 31 December 2023

	Notes	2023 Business performance $'000	2023 Remeasurements and exceptional items (note 4) $'000	2023 Reported in year $'000	2022 Business performance $'000	2022 Remeasurements and exceptional items (note 4) $'000	2022 Reported in year $'000
Revenue and other operating income	5(a)	1,458,956	28,463	1,487,419	1,839,147	14,475	1,853,622
Cost of sales	5(b)	(941,102)	(5,650)	(946,752)	(1,195,806)	(4,900)	(1,200,706)
Gross profit/(loss)		517,854	22,813	540,667	643,341	9,575	652,916
Net impairment (charge)/ reversal to oil and gas assets	4,10	–	(117,396)	(117,396)	–	(81,049)	(81,049)
General and administration expenses	5(c)	(6,348)	–	(6,348)	(7,553)	–	(7,553)
Other income	5(d)	17,897	78,984	96,881	76,247	7,706	83,953
Other expenses	5(e)	(46,846)	(10,731)	(57,577)	(2,810)	(233,570)	(236,380)
Profit/(loss) from operations before tax and finance income/ (costs)		482,557	(26,330)	456,227	709,225	(297,338)	411,887
Finance costs	6	(172,087)	(58,854)	(230,941)	(176,227)	(36,410)	(212,637)
Finance income	6	6,493	–	6,493	1,816	2,148	3,964
Profit/(loss) before tax		316,963	(85,184)	231,779	534,814	(331,600)	203,214
Income tax	7	(287,750)	25,138	(262,612)	(322,468)	78,020	(244,448)
Profit/(loss) for the year attributable to owners of the parent		29,213	(60,046)	(30,833)	212,346	(253,580)	(41,234)
Total comprehensive profit/ (loss) for the year, attributable to owners of the parent				(30,833)			(41,234)

There is no comprehensive income attributable to the shareholders of the Group other than the profit/(loss) for the period. Revenue and operating profit/(loss) are all derived from continuing operations.

Earnings per share	8	$	$	$	$
Basic		0.016	(0.016)	0.114	(0.022)
Diluted		0.016	(0.016)	0.112	(0.022)

The attached notes 1 to 31 form part of these Group financial statements.

Group Balance Sheet
At 31 December 2023

ASSETS
Non-current assets
Property, plant and equipment
Goodwill
Intangible assets
Deferred tax assets
Other financial assets
Current assets
Intangible assets
Inventories
Trade and other receivables
Current tax receivable
Cash and cash equivalents
Other financial assets
TOTAL ASSETS
EQUITY AND LIABILITIES
Equity
Share capital and premium
Share-based payments reserve
Retained earnings
TOTAL EQUITY
Non-current liabilities
Borrowings
Bonds
Lease liabilities
Contingent consideration
Provisions
Deferred income
Trade and other payables
Deferred tax liabilities
Current liabilities
Borrowings
Bonds
Lease liabilities
Contingent consideration
Provisions
Trade and other payables
Other financial liabilities
Current tax payable
TOTAL LIABILITIES
TOTAL EQUITY AND LIABILITIES

The attached notes 1 to 31 form part of these Group financial st

The financial statements were approved by the Board of Direct its behalf by:

Amjad Bseisu
Chief Executive Officer

Group Statement of Changes in Equity
For the year ended 31 December 2023

	Notes	Share capital and share premium $'000	Share–based payments reserve $'000	Retained earnings $'000	Total $'000
Balance at 1 January 2022		392,196	6,791	121,769	520,756
Loss for the year		–	–	(41,234)	(41,234)
Total comprehensive expense for the year		–	–	(41,234)	(41,234)
Share-based payment		–	4,719	–	4,719
Balance at 31 December 2022		392,196	11,510	80,535	484,241
Loss for the year		–	–	(30,833)	(30,833)
Total comprehensive expense for the year		–	–	(30,833)	(30,833)
Issue of shares to Employee Benefit Trust	20	1,635	(1,635)	–	–
Share-based payment	21	–	3,320	–	3,320
Balance at 31 December 2023		393,831	13,195	49,702	456,728

The attached notes 1 to 31 form part of these Group financial statements.

Group Statement of Cash Flo
For the year ended 31 December 202

CASH FLOW FROM OPERATING ACTIVITIES
Cash generated from operations
Cash received from insurance
Cash (paid)/received on purchase of financial instruments
Decommissioning spend
Income taxes paid
Net cash flows from/(used in) operating activities
INVESTING ACTIVITIES
Purchase of property, plant and equipment
Proceeds from farm-down
Vendor financing facility
Purchase of intangible oil and gas assets
Purchase of other intangible assets
Payment of Magnus contingent consideration – Profit share
Payment of Golden Eagle contingent consideration – Acquisit
Interest received
Net cash flows (used in)/from investing activities
FINANCING ACTIVITIES
Proceeds from loans and borrowings
Repayment of loans and borrowings
Payment of obligations under financing leases
Interest paid
Net cash flows (used in)/from financing activities
NET INCREASE/(DECREASE) IN CASH AND CASH EQUIVALENTS
Net foreign exchange on cash and cash equivalents
Cash and cash equivalents at 1 January
CASH AND CASH EQUIVALENTS AT 31 DECEMBER
Reconciliation of cash and cash equivalents
Total cash at bank and in hand
Restricted cash
Cash and cash equivalents per balance sheet

The attached notes 1 to 31 form part of these Group financial st

Notes to the Group Financial Statements
For the year ended 31 December 2023

1. Corporate information
EnQuest PLC ('EnQuest' or the 'Company') is a public company limited by shares incorporated in the United Kingdom under the Companies Act and is registered in England and Wales and listed on the London Stock Exchange. The address of the Company's registered office is shown on the inside back cover.

EnQuest PLC is the ultimate controlling party. The principal activities of the Company and its subsidiaries (together the 'Group') are to responsibly optimise production, leverage existing infrastructure, deliver a strong decommissioning performance and explore new energy and decarbonisation opportunities.

The Group's financial statements for the year ended 31 December 2023 were authorised for issue in accordance with a resolution of the Board of Directors on 27 March 2024.

A listing of the Group's companies is contained in note 29 to these Group financial statements.

2. Basis of preparation
The consolidated financial statements have been prepared in accordance with UK-adopted International Financial Reporting Standards ('IFRS') in conformity with the requirements of the Companies Act 2006. The accounting policies which follow set out those policies which apply in preparing the financial statements for the year ended 31 December 2023.

The Group financial information has been prepared on a historical cost basis, except for the fair value remeasurement of certain financial instruments, including derivatives and contingent consideration, as set out in the accounting policies. The presentation currency of the Group financial information is US Dollars ('$') and all values in the Group financial information are rounded to the nearest thousand ($'000) except where otherwise stated.

The Group's results on a UK-adopted International Financial Reporting Standards ('IFRS') basis are shown on the Group Income Statement as 'Reported in the year', being the sum of its Business performance results and its Remeasurements and exceptional items as permitted by IAS 1 (Revised) Presentation of Financial Statements. Remeasurements and exceptional items are items that management considers not to be part of underlying business performance and are disclosed separately in order to enable shareholders to understand better and evaluate the Group's reported financial performance. For further information see note 4.

Going concern
The financial statements have been prepared on the going concern basis.

In recent years, given the prevailing macroeconomic and fiscal environment, the Group has prioritised deleverage - reducing gross debt (excluding leases) by c.$1.4 billion since 2017 to $794.5 million at 31 December 2023. During 2023, EnQuest net debt was reduced by $236.2 million (to $480.9 million) and the Group strengthened its net debt to adjusted EBITDA ratio to 0.6x, close to EnQuest's target of 0.5x. In this 12-month period, cash and available facilities increased by $149.9 million, to $498.8 million at 31 December 2023, and medium-term liquidity is secured, with all the Group's debt maturities now in 2027.

Against this robust backdrop, EnQuest continues to closely monitor and manage its funding position and liquidity risk throughout the year, including monitoring forecast covenant results, to ensure that it has access to sufficient funds to meet forecast cash requirements. Cash forecasts are regularly produced and sensitivities considered for, but not limited to, changes in crude oil prices (adjusted for hedging undertaken by the Group), production rates and costs. These forecasts and sensitivity analyses allow management to mitigate liquidity or covenant compliance risks in a timely manner.

The Group's latest approved business plan underpins management's base case ('Base Case') and is in line with the Group's production guidance using oil price assumptions of $80.0/bbl for 2024 and $75.0/bbl for 2025.

A reverse stress test has been performed on the Base Case indicating that an average oil price of c.$63.0/bbl over the going concern period maintains covenant compliance, reflecting the Group's strong liquidity position.

The Base Case has also been subjected to further testing through a scenario reflecting the impact of the following plausible downside risks (the 'Downside Case'):
- 10% discount to Base Case prices resulting in Downside Case prices of $72.0/bbl for 2024 and $67.5/bbl for 2025;
- Production risking of 5.0%; and
- 2.5% increase in operating, capital and decommissioning expenditure.

The Base Case and Downside Case indicate that the Group is able to operate as a going concern and remain covenant compliant for 12 months from the date of publication of its full-year results.

After making appropriate enquiries and assessing the progress against the forecast and projections, the Directors have a reasonable expectation that the Group will continue in operation and meet its commitments as they fall due over the going concern period. Accordingly, the Directors continue to adopt the going concern basis in preparing these financial statements.

2. Basis of preparation continued
New standards and interpretations
The following new standards became applicable for the curre
upon application:
- Insurance contracts (IFRS 17)
- Disclosure of Accounting Policies (Amendments to IAS 1 and
- Definition of Accounting Estimates (Amendments to IAS 8)
- Deferred Tax related to Assets and Liabilities arising from a Si
- International Tax reform – Pillar Two Model Rules (Amendmen

Standards issued but not yet effective
At the date of authorisation of these financial statements, the G
Standards that have been issued but are not yet effective:

IFRS 10 and IAS 28 (amendments)	Sale or Contribution of As
Amendments to IAS 1	Classification of Liabilities
Amendments to IAS 1	Non-current Liabilities wit
Amendments to IAS 7 and IFRS 7	Supplier Finance Arrange
Amendments to IFRS 16	Lease Liability in a Sale ar

The Directors do not expect that the adoption of the Standards
statements of the Group in future periods.

Basis of consolidation
The consolidated financial statements incorporate the financ
Company (its subsidiaries) made up to 31 December each ye
- has power over the investee;
- is exposed, or has rights, to variable returns from its involvem
- has the ability to use its power to affect its returns.

The Company reassesses whether or not it controls an investee
one or more of the three elements of control listed above. Cons
control over the subsidiary and ceases when the Company los
subsidiaries acquired or disposed of during the year are includ
until the date the Company ceases to control the subsidiary.

Where necessary, adjustments are made to the financial state
into line with the Group's accounting policies. All intra-Group a
relating to transactions between the members of the Group ar

Joint arrangements
Oil and gas operations are usually conducted by the Group as
companies. Joint control is the contractually agreed sharing of
about the relevant activities require the consent of the relevant
underlying contractual framework to the joint arrangement, wh
Report and Accounts therefore refers to 'joint ventures' as a sta
interchangeably with joint operations.

Most of the Group's activities are conducted through joint oper
arrangement have the rights to the assets, and obligations for
recognises its share of assets, liabilities, income and expenses
on a line-by-line basis. During 2023, the Group did not have an
in IAS 28.

2. Basis of preparation continued

Foreign currencies

Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates ('functional currency'). The Group's financial statements are presented in US Dollars, the currency which the Group has elected to use as its presentation currency.

In the financial statements of the Company and its individual subsidiaries, transactions in currencies other than a company's functional currency are recorded at the prevailing rate of exchange on the date of the transaction. At the year end, monetary assets and liabilities denominated in foreign currencies are retranslated at the rates of exchange prevailing at the balance sheet date. Non-monetary assets and liabilities that are measured at historical cost in a foreign currency are translated using the rate of exchange at the dates of the initial transactions. Non-monetary assets and liabilities measured at fair value in a foreign currency are translated using the rate of exchange at the date the fair value was determined. All foreign exchange gains and losses are taken to profit and loss in the Group income statement.

Emissions liabilities

The Group operates in an energy intensive industry and is therefore required to partake in emission trading schemes ('ETS'). The Group recognises an emission liability in line with the production of emissions that give rise to the obligation. To the extent the liability is covered by allowances held, the liability is recognised at the cost of these allowances held and if insufficient allowances are held, the remaining uncovered portion is measured at the spot market price of allowances at the balance sheet date. The expense is presented within 'production costs' under 'cost of sales' and the accrual is presented in 'trade and other payables'. Any allowance purchased to settle the Group's liability is recognised on the balance sheet as an intangible asset. Both the emission allowances and the emission liability are derecognised upon settling the liability with the respective regulator.

Use of judgements, estimates and assumptions

The preparation of the Group's consolidated financial statements requires management to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the accompanying disclosures, at the date of the consolidated financial statements. Estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

The accounting judgements and estimates that have a significant impact on the results of the Group are set out below and should be read in conjunction with the information provided in the Notes to the financial statements. The Group does not consider contingent consideration and deferred taxation (including EPL) to represent a significant estimate or judgement as the estimates and assumptions relating to projected earnings and cash flows used to assess contingent consideration and deferred taxation are the same as those applied in the Group impairment process as described below in *e era ilit a et arr in al e*. Judgements and estimates, not all of which are significant, made in assessing the impact of climate change and the transition to a lower carbon economy on the consolidated financial statements are also set out below. Where an estimate has a significant risk of resulting in a material adjustment to the carrying amounts of assets and liabilities within the next financial year, this is specifically noted.

Climate change and energy transition

As covered in the Group's principal risks on oil and gas prices on page 52, the Group recognises that the energy transition is likely to impact the demand, and hence the future prices, of commodities such as oil and natural gas. This in turn may affect the recoverable amount of property, plant and equipment, and goodwill in the oil and gas industry. The Group acknowledges that there are a range of possible energy transition scenarios that may indicate different outcomes for oil prices. There are inherent limitations with scenario analysis and it is difficult to predict which, if any, of the scenarios might eventuate.

The Group has assessed the potential impacts of climate change and the transition to a lower carbon economy in preparing the consolidated financial statements, including the Group's current assumptions relating to demand for oil and natural gas and their impact on the Group's long-term price assumptions. See *e era ilit a et arr in al e: il rie*.

While the pace of transition to a lower carbon economy is uncertain, oil and natural 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 useful lives of the Group's current portfolio of oil and gas assets, a material adverse change is not expected to the carrying values of EnQuest's assets and liabilities within the next financial year as a result of climate change and the transition to a lower carbon economy.

Management will continue to review price assumptions as the energy transition progresses and this may result in impairment charges or reversals in the future.

2. Basis of preparation continued

Critical accounting judgements and key sources of estimatio

The Group has considered its critical accounting judgements a
out below.

Recoverability of asset carrying values

Judgements: The Group assesses each asset or cash-generat
annually regardless of indicators) in each reporting period to d
Assessment of indicators of impairment or impairment reversa
into a CGU or the appropriate grouping of CGUs for impairmen
For example, individual oil and gas properties may form separa
infrastructure may be grouped together to form a single CGU. A
different outcome from impairment testing. See note 11 for deta
to the impairment testing of goodwill.

Estimates: Where an indicator of impairment exists, a formal est
to be the higher of the fair value less costs to dispose ('FVLCD') a
estimates and assumptions, such as the effects of inflation and
those related to emission reduction initiatives such as alternativ
production profiles, reserves and resources, and future commod
supply-and-demand conditions for crude oil and natural gas. S
related cash flows based on management's plans for the assets

As described above, the recoverable amount of an asset is the
is measured by reference to FVLCD, in the absence of quoted m
regarding the present value of future post-tax cash flows. Thes
participant and include prices, life of field production profiles, c
tax attributes, risking factors applied to cash flows, and discoun
assessment of FVLCD to the extent that it is considered probab
Details of impairment charges and reversals recognised in the
assets are shown in note 10, note 11 and note 12.

The estimates for assumptions made in impairment tests in 20
below. Changes in the economic environment or other facts ar
assumptions and could result in a material change to the carry

Discount rates

For discounted cash flow calculations, future cash flows are ad
calculations use the post-tax discount rate. The discount rate is
methodology. The discount rates applied in impairment tests a
rate was estimated at 11.0% (2022: 11.0%) with the effect of the G
general increase in interest rates.

Oil prices

The price assumptions used for FVLCD impairment testing were
which assume short-term market prices will revert to the Group
EnQuest's long-term views of global supply and demand, inclu
change and the transition to a low carbon economy as outline
external sources of information such as analyst forecasts. The
management, the Audit Committee and the Board of Directors

EnQuest revised its oil price assumptions for FVLCD impairment t
price assumption was increased to better align with external for
provided below. These assumptions, which represent managem
external forecasts. They do not correspond to any specific Paris-
Energy Agency's ('IEA') forecast prices under its Announced Pled
achieving an emissions trajectory consistent with keeping the te
considered to be broadly in line with a Paris-consistent scenario
those assumed under the APS, while its longer-term prices are s
under the APS are discussed in EnQuest's Task Force on Climate-
Discounts or premiums are applied to price assumptions based
of the relevant sales contracts.

An inflation rate of 2% (2022: 2%) is applied from 2027 onwards t
table below). The price assumptions used in 2022 were $84.0/b
thereafter, inflated at 2.0% per annum from 2026.

Brent oil ($/bbl)

* Inflated at 2% from 2027

2. Basis of preparation continued

Oil and natural gas reserves

Hydrocarbon reserves are estimates of the amount of hydrocarbons that can be economically and legally extracted from the Group's oil and gas properties. The business of the Group is to responsibly optimise production, leverage existing infrastructure, deliver a strong decommissioning performance and explore new energy and decarbonisation opportunities. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity, and drilling of new wells all impact on the determination of the Group's estimates of its oil and gas reserves and result in different future production profiles affecting prospectively the discounted cash flows used in impairment testing and the calculation of contingent consideration, the anticipated date of decommissioning and the depletion charges in accordance with the unit of production method, as well as the going concern assessment. Economic assumptions used to estimate reserves change from period to period as additional technical and operational data is generated. This process may require complex and difficult geological judgements to interpret the data.

The Group uses proven and probable ('2P') reserves (see page 24) as the basis for calculations of expected future cash flows from underlying assets because this represents the reserves management intends to develop and it is probable that a market participant would attribute value to them. Third-party audits of EnQuest's reserves and resources are conducted annually.

Sensitivity analyses

Management tested the impact of a change in cash flows in FVLCD impairment testing arising from a 10% reduction in price assumptions, which it believes to be a reasonably possible change given the prevailing macroeconomic environment.

Price reductions of this magnitude in isolation could indicatively lead to a further reduction in the carrying amount of EnQuest's oil and gas properties by approximately $224.1 million, which is approximately 10% of the net book value of property, plant and equipment as at 31 December 2023.

The oil price sensitivity analysis above does not, however, represent management's best estimate of any impairments that might be recognised as it does not fully incorporate consequential changes that may arise, such as reductions in costs and changes to business plans, phasing of development, levels of reserves and resources, and production volumes. As the extent of a price reduction increases, the more likely it is that costs would decrease across the industry. The oil price sensitivity analysis therefore does not reflect a linear relationship between price and value that can be extrapolated.

Management also tested the impact of a one percentage point change in the discount rate of 11% used for FVLCD impairment testing of oil and gas properties, which is considered a reasonably possible change given the prevailing macroeconomic environment. If the discount rate was one percentage point higher across all tests performed, the net impairment charge in 2023 would have been approximately $51.3 million higher. If the discount rate was one percentage point lower, the net impairment charge would have been approximately $56.0 million lower.

Goodwill

Irrespective of whether there is any indication of impairment, EnQuest is required to test annually for impairment of goodwill acquired in business combinations. The Group carries goodwill of approximately $134.4 million on its balance sheet (2022: $134.4 million), principally relating to the acquistion of Magnus oil field. Sensitivities and additional information relating to impairment testing of goodwill are provided in note 11.

Deferred tax

The Group assesses the recoverability of its deferred tax assets at each period end. Sensitivities and additional information relating to deferred tax assets/liabilities are provided in note 7(d).

75% Magnus acquisition contingent consideration

Estimates: Following the rising interest rate environment seen in 2023, the Group reassessed the fair value discount rate associated with the Magnus contingent consideration. This was estimated to be 11.3% as at the end of 2023 (2022: 10.0%), as calculated in line with IFRS 13. Sensitivities and additional information relating to the 75% Magnus acquisition contingent consideration are provided in note 22.

2. Basis of preparation continued

Provisions

Estimates: Decommissioning costs will be incurred by the Grou
and gas production facilities and pipelines. The Group assesse
ultimate decommissioning costs are uncertain and cost estim
to relevant legal requirements, estimates of the extent and cos
restoration techniques and experience at other production site
may also change, for example, in response to changes in oil an
interpretation. Therefore, significant estimates and assumption
As a result, there could be significant adjustments to the provis
although this is not expected within the next year.

The timing and amount of future expenditures relating to decom
The rate used in discounting the cash flows is reviewed half-yea
sheet obligations at the end of 2023 was 3.5% (2022: 3.5%), reflec
period over which decommissioning costs are generally expecte
Costs at future prices are determined by applying inflation rates
(2022: 4% (2023), 3% (2024) and a long-term inflation rate of 2% th

Further information about the Group's provisions is provided in
factors in relation to the Group's provisions, could result in a ma
financial year. A one percentage point decrease in the nomina
possible change given the prevailing macroeconomic environ
approximately $68.0 million (2022: $54.0 million). The pre-tax im
approximately $67.1 million.

Intangible oil and gas assets

Judgements: The application of the Group's accounting policy f
to determine whether future economic benefits are likely from e
a stage which permits a reasonable assessment of the existenc

3. Segment information

The Group's organisational structure reflects the various activities in which EnQuest is engaged. Management has considered the requirements of IFRS 8 Operating Segments in regard to the determination of operating segments and concluded that at 31 December 2023, the Group had two significant operating segments: the North Sea and Malaysia. Operations are managed by location and all information is presented per geographical segment. The Group's segmental reporting structure remained in place throughout 2023. The North Sea's activities include Upstream, Midstream, Decommissioning and Veri Energy. Veri Energy is not considered a separate operating segment as it does not yet earn revenues and does not yet have material capital and resources. Malaysia's activities include Upstream and Decommissioning. The Group's reportable segments may change in the future depending on the way that resources may be allocated and performance assessed by the Chief Operating Decision Maker, who for EnQuest is the Chief Executive. The information reported to the Chief Operating Decision Maker does not include an analysis of assets and liabilities, and accordingly this information is not presented, in line with IFRS 8 paragraph 23.

Year ended 31 December 2023 $'000	North Sea	Malaysia	All other segments	Total segments	Adjustments and eliminations[i, ii]	Consolidated
Revenue and other operating income:						
Revenue from contracts with customers	1,325,200	142,510	–	1,467,710	–	1,467,710
Other operating income/(expense)	2,229	–	281	2,510	17,199	19,709
Total revenue and other operating income/(expense)	1,327,429	142,510	281	1,470,220	17,199	1,487,419
Income/(expenses) line items:						
Depreciation and depletion	(278,280)	(19,923)	(105)	(298,308)	–	(298,308)
Net impairment (charge)/reversal to oil and gas assets	(117,396)	–	–	(117,396)	–	(117,396)
Exploration write-off and impairments	–	(5,640)	–	(5,640)	–	(5,640)
Segment profit/(loss)[ii]	389,355	46,192	4,474	440,021	16,206	456,227
Other disclosures:						
Capital expenditure[iii]	149,093	11,817	12	160,922	–	160,922

Year ended 31 December 2022 $'000	North Sea	Malaysia	All other segments	Total segments	Adjustments and eliminations[i, ii]	Consolidated
Revenue and other operating income:						
Revenue from contracts with customers	1,873,214	159,578	–	2,032,792	–	2,032,792
Other operating income/(expense)	9,832	–	264	10,096	(189,266)	(179,170)
Total revenue and other operating income/(expense)	1,883,046	159,578	264	2,042,888	(189,266)	1,853,622
Income/(expenses) line items:						
Depreciation and depletion	(319,025)	(14,116)	(107)	(333,248)	–	(333,248)
Net impairment (charge)/reversal to oil and gas assets	(81,049)	–	–	(81,049)	–	(81,049)
Segment profit/(loss)[ii]	546,199	65,160	112	611,471	(199,584)	411,887
Other disclosures:						
Capital expenditure[iii]	115,853	39,030	30	154,913	–	154,913

(i) Finance income and costs and gains and losses on derivatives are not allocated to individual segments as the underlying instruments are managed on a Group basis
(ii) Inter-segment revenues are eliminated on consolidation. All other adjustments are part of the reconciliations presented further below
(iii) Capital expenditure consists of property, plant and equipment and intangible exploration and appraisal assets

3. Segment information continued

Reconciliation of profit/(loss):

Segment profit/(loss) before tax and finance income/(costs)
Finance costs
Finance income
Gain/(loss) on oil and foreign exchange derivatives[i]
Profit/(loss) before tax

(i) Includes $8.4 million realised losses on derivatives (2022: $209.2 million) and $24

Revenue from two customers relating to the North Sea operatin revenue arising from sales of crude oil, with amounts of $491.2 m (2022: two customers; $365.1 million and $321.7 million per each

4. Remeasurements and exceptional items

Accounting policy

As permitted by IAS 1 (Revised) Presentation of Financial Statem are presented separately. Additional line items, headings, sub- presented to provide relevant understanding of the Group's fin

Remeasurements and exceptional items are items that manag performance and are disclosed in order to enable shareholder financial performance. The items that the Group separately pr statement are those material items of income and expense wh events giving rise to them, merit separate presentation to allow performance in the year, so as to facilitate comparison with pri performance. Remeasurements relate to those items which ar year-on-year. If an item is assessed as a remeasurement or ex the item is also taken through remeasurement and exceptiona the relevant material items disclosed as exceptional.

The following items are classified as remeasurements and ex

- Unrealised mark-to-market changes in the remeasurement recognised within remeasurements, with the recycling of rea performance income when a derivative instrument matures
- Impairments on assets, including other non-routine write-of and are deemed to be exceptional in nature;
- Fair value accounting arising in relation to business combina transactions do not relate to the principal activities and day- remeasurements of contingent assets and liabilities arising presented within remeasurements and are presented consis
- Other items that arise from time to time that are reviewed by disclosed further below.

Year ended 31 December 2023 $'000
Revenue and other operating income
Cost of sales
Net impairment (charge)/reversal on oil and gas assets
Other income
Other expense
Finance costs
Corporation tax on items above
UK Energy Profits Levy[v]

4. Remeasurements and exceptional items continued

Year ended 31 December 2022 $'000	Fair value remeasurement[i]	Impairments and write-offs[ii]	Other[iii]	Total
Revenue and other operating income	14,475	–	–	14,475
Cost of sales	(4,900)	–	–	(4,900)
Net impairment (charge)/reversal on oil and gas assets	–	(81,049)	–	(81,049)
Other income	1,070	–	6,636	7,706
Other expenses	(233,570)	–	–	(233,570)
Finance costs	–	–	(36,410)	(36,410)
Finance income	–	–	2,148	2,148
	(222,925)	(81,049)	(27,626)	(331,600)
Corporation tax on items above	89,599	32,420	7,817	129,836
Recognition of undiscounted deferred tax asset[iv]	–	127,024	–	127,024
UK Energy Profits Levy[v]	–	–	(178,840)	(178,840)
	(133,326)	78,395	(198,649)	(253,581)

(i) Fair value remeasurements include unrealised mark-to-market movements on derivative contracts and other financial instruments, and the impact of recycled realised gains and losses out of 'Remeasurements and exceptional items' and into Business performance profit or loss of $24.6 million (2022: $9.6 million). Other income relates to the fair value remeasurement of contingent consideration relating to the acquisition of Magnus and associated infrastructure of $69.7 million (note 22) (2022: net other expense of $232.5 million)

(ii) Impairments and write-offs include a net impairment charge of tangible oil and gas assets and right-of-use assets totalling $117.4 million (note 10) (2022: charge of $81.0 million) and write-off of exploration costs in Malaysia of $5.6 million (2022: nil)

(iii) Other items are made up of the following: other costs of sales includes $1.8 million related to an increase in a provision for a dispute with a third-party contractor (2022: nil). Other net income primarily includes $4.1 million recognition of insurance income related to the PM8/Seligi riser incident (2022: $6.6 million) and $0.1 million movement in other provisions (2022: nil). Finance costs relates to the finance cost element of the 75% acquisition of Magnus and associated infrastructure of $58.9 million (note 22) (2022: $36.4 million). In 2022, finance income of $2.1 million represents a realised gain on the partial buy back of the Group's 7.00% high yield bond

(iv) Non-cash deferred tax recognition in 2022 is due to the Group's higher oil price assumptions

(v) In 2022, UK Energy Profits Levy ('EPL') represented the charge on initial recognition. In 2023, the related assumptions were refined, resulting in a credit of $32.7 million in other items. The remaining EPL items relate to the EPL charges and credits on the items above

5. Revenue and expenses

(a) Revenue and other operating income

Accounting policy

Revenue from contracts with customers

The Group generates revenue through the sale of crude oil, gas and condensate to third parties, and through the provision of infrastructure to its customers for tariff income. Revenue from contracts with customers is recognised when control of the goods or services is transferred to the customer at an amount that reflects the consideration to which the Group expects to be entitled to in exchange for those goods or services. The Group has concluded that it is the principal in its revenue arrangements because it typically controls the goods or services before transferring them to the customer. The normal credit term is 30 days or less upon performance of the obligation.

Sale of crude oil, gas and condensate

The Group sells crude oil, gas and condensate directly to customers. The sale represents a single performance obligation, being the sale of barrels equivalent to the customer on taking physical possession or on delivery of the commodity into an infrastructure. At this point the title passes to the customer and revenue is recognised. The Group principally satisfies its performance obligations at a point in time; the amounts of revenue recognised relating to performance obligations satisfied over time are not significant. Transaction prices are referenced to quoted prices, plus or minus an agreed fixed discount rate to an appropriate benchmark, if applicable.

Tariff revenue for the use of Group infrastructure

Tariffs are charged to customers for the use of infrastructure owned by the Group. The revenue represents the performance of an obligation for the use of Group assets over the life of the contract. The use of the assets is not separable as they are interdependent in order to fulfil the contract and no one item of infrastructure can be individually isolated. Revenue is recognised as the performance obligations are satisfied over the period of the contract, generally a period of 12 months or less, on a monthly basis based on throughput at the agreed contracted rates.

Other operating income

Other operating revenue is recognised to the extent that it is probable economic benefits will flow to the Group and the revenue can be reliably measured.

The Group enters into oil derivative trading transactions which can be settled net in cash. Accordingly, any gains or losses are not considered to constitute revenue from contracts with customers in accordance with the requirements of IFRS 15, rather are accounted for in line with IFRS 9 and included within other operating income (see note 19).

5. Revenue and expenses continued

Revenue from contracts with customers:	
Revenue from crude oil sales	
Revenue from gas and condensate sales[i]	
Tariff revenue	
Total revenue from contracts with customers	
Realised gains/(losses) on oil derivative contracts (see note 19	
Other	
Business performance revenue and other operating income	
Unrealised gains/(losses) on oil derivative contracts[ii] (see no	
Total revenue and other operating income	

(i) Includes onward sale of third-party gas purchases not required for injection act

(ii) Unrealised gains and losses on oil derivative contracts are disclosed as fair valu

Disaggregation of revenue from contracts with customers

	Nort
Revenue from contracts with customers:	
Revenue from crude oil sales	987
Revenue from gas and condensate sales[i]	336
Tariff revenue	
Total revenue from contracts with customers	1,325

(i) Includes onward sale of third-party gas purchases not required for injection act

(b) Cost of sales

Accounting policy

Production imbalances, movements in under/over-lift and mov
liability is recorded at the cost of the production imbalance to
volumes sold in excess of entitlement. The under-lift asset is re
consistent with IAS 2, to represent a right to additional physical
current receivables and an over-lift of production from a field is

Production costs	
Tariff and transportation expenses	
Realised (gain)/loss on derivative contracts related to operati	
Change in lifting position	
Crude oil inventory movement	
Depletion of oil and gas assets[i]	
Other cost of operations[ii]	
Business performance cost of sales	
Unrealised losses/(gains) on derivative contracts related to op	
Movement in contractor dispute provision (see note 23)	
Total cost of sales	

(i) Includes $28.6 million (2022: $38.7 million) Kraken FPSO right-of-use asset depre
depreciation charge

(ii) Includes $294.0 million (2022: $452.8 million) of purchases and associated costs

(iii) Unrealised gains and losses on derivative contracts are disclosed as fa

5. Revenue and expenses continued
(c) General and administration expenses

	Year ended 31 December 2023 $'000	Year ended 31 December 2022 $'000
Staff costs (see note 5(f))	77,517	75,266
Depreciation[(i)]	6,109	6,222
Other general and administration costs	25,490	21,740
Recharge of costs to operations and joint venture partners	(102,768)	(95,675)
Total general and administration expenses	6,348	7,553

(i) Includes $3.4 million (2022: $3.4 million) right-of-use assets depreciation charge on buildings

(d) Other income

	Year ended 31 December 2023 $'000	Year ended 31 December 2022 $'000
Net foreign exchange gains	–	21,329
Change in decommissioning provisions (see note 23)	–	36,763
Change in Thistle decommissioning provisions (see note 23)	–	6,060
Rental income from office sublease	2,286	1,549
Other	15,611	10,546
Business performance other income	17,897	76,247
Fair value changes in contingent consideration (see note 22)	69,665	1,070
Other non-business performance (see note 4)	9,319	6,636
Total other income	96,881	83,953

(e) Other expenses

	Year ended 31 December 2023 $'000	Year ended 31 December 2022 $'000
Net foreign exchange losses	11,659	–
Change in decommissioning provisions (see note 23)	31,159	–
Change in Thistle decommissioning provisions (see note 23)	1,605	–
Other	2,423	2,810
Business performance other expenses	46,846	2,810
Fair value changes in contingent consideration (see note 22)	–	233,570
Other non-business performance (see note 4)	10,731	–
Total other expenses	57,577	236,380

5. Revenue and expenses continued
(f) Staff costs
Accounting policy
Short-term employee benefits, such as salaries, social premiun

The Group's pension obligations consist of defined contributior payment obligations once the contributions have been paid. T of pension costs reflects the contributions payable in the year. and contributions actually paid are shown as either accrued lia

Wages and salaries
Social security costs
Defined contribution pension costs
Expense of share-based payments (see note 21)
Other staff costs
Total employee costs
Contractor costs
Total staff costs
General and administration staff costs (see note 5(c))
Non-general and administration costs
Total staff costs

The monthly average number of persons, excluding contractor the general and administration staff costs and 354 directly attr administration and 380 directly attributable to assets). Compe and in the Directors' Remuneration Report on pages 99 to 117.

(g) Auditor's remuneration
The following amounts for the year ended 31 December 2023 ar payable by the Group to Deloitte:

Fees payable to the Company's auditor for the audit of the pa Group financial statements
The audit of the Company's subsidiaries
Total audit
Audit-related assurance services[(i)]
Total audit and audit-related assurance services
Total auditor's remuneration

(i) Audit-related assurance services in both years include the review of the Group's

6. Finance costs/income

Accounting policy
Borrowing costs are recognised as interest payable within finance costs at amortised cost using the effective interest method.

	Year ended 31 December 2023 $'000	Year ended 31 December 2022 $'000
Finance costs:		
Loan interest payable	30,708	14,906
Bond interest payable	58,999	62,260
Unwinding of discount on decommissioning provisions (see note 23)	24,236	16,995
Unwinding of discount on other provisions (see note 23)	1,145	777
Finance charges payable under leases (see note 24)	43,801	39,172
Amortisation of finance fees on loans and bonds	7,899	35,287
Other financial expenses[i]	5,299	6,830
Business performance finance expenses	172,087	176,227
Unwinding of discount on Magnus-related contingent consideration (see note 22)	58,854	36,410
Total finance costs	230,941	212,637
Finance income:		
Bank interest receivable	6,493	1,816
Business performance finance income	6,493	1,816
Other financial income (see note 4)	–	2,148
Total finance income	6,493	3,964

(i) Includes unwinding of discount on Golden Eagle contingent consideration of $1.7 million (2022: $3.2 million). See note 22

7. Income tax

(a) Income tax
Accounting policy
Current tax assets and liabilities are measured at the amount expected to be recovered from or paid to the taxation authorities, based on tax rates and laws that are enacted or substantively enacted by the balance sheet date.

The Group's operations are subject to a number of specific tax rules which apply to exploration, development and production. 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 estimates and judgements, including those required in calculating the effective tax rate. In considering the tax on exceptional items, the Group applies the appropriate statutory tax rate to each item to calculate the relevant tax charge on exceptional items.

Deferred tax is provided in full on temporary differences arising between the tax bases of assets and liabilities and their carrying amounts in the Group financial statements. However, deferred tax is not accounted for if a temporary difference arises from initial recognition of other assets or liabilities in a transaction other than a business combination that at the time of the transaction affects neither accounting nor taxable profit or loss. Deferred tax is measured on an undiscounted basis using tax rates (and laws) that have been enacted or substantively enacted by the balance sheet date and are expected to apply when the related deferred tax asset is realised or the deferred tax liability is settled. Deferred tax assets are recognised to the extent that it is probable that future taxable profits will be available against which the temporary differences can be utilised.

Deferred tax liabilities are recognised for taxable temporary differences arising on investments in subsidiaries, except where the Group is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

The carrying amount of deferred income tax assets is reviewed at each balance sheet date. Deferred income tax assets and liabilities are offset only if a legal right exists to offset current tax assets against current tax liabilities, the deferred income taxes relate to the same taxation authority and that authority permits the Group to make a single net payment.

Production taxes
In addition to corporate income taxes, the Group's financial statements also include and disclose production taxes on net income determined from oil and gas production.

Production tax relates to Petroleum Revenue Tax ('PRT') within the UK and is accounted for under IAS 12 Income Taxes since it has the characteristics of an income tax as it is imposed under government authority and the amount payable is based on taxable profits of the relevant fields. Current and deferred PRT is provided on the same basis as described above for income taxes.

7. Income tax continued

Investment allowance
The UK taxation regime provides for a reduction in ring-fence s
UK assets qualify for a relief known as investment allowance. In
production from the same field before it can be claimed. The G
allowances which could reduce future supplementary charge
recognised as a reduction in the charge to taxation in the years

Energy Profits Levy
The Energy (Oil & Gas) Profits Levy Act 2022 ('EPL') applies an ad
from the production of oil and gas on the United Kingdom Cont
31 March 2029). This is accounted for under IAS 12 Income Taxes
imposed under government authority and the amount payabl
Current and deferred tax is provided on the same basis as dese

The major components of income tax expense/(credit) are as f

Current UK income tax	
Current income tax charge	
Adjustments in respect of current income tax of previous year	
Current overseas income tax	
Current income tax charge	
Adjustments in respect of current income tax of previous year	
UK Energy Profits Levy	
Current year charge	
Adjustments in respect of current charge of previous years	
Total current income tax	
Deferred UK income tax	
Relating to origination and reversal of temporary differences	
Adjustments in respect of changes in tax rates	
Adjustments in respect of deferred income tax of previous yea	
Deferred overseas income tax	
Relating to origination and reversal of temporary differences	
Adjustments in respect of deferred income tax of previous yea	
Deferred UK Energy Profits Levy	
Relating to origination and reversal of temporary differences	
Adjustments in respect of deferred charge of previous years	
Total deferred income tax	
Income tax expense reported in profit or loss	

7. Income tax continued

(b) Reconciliation of total income tax charge

A reconciliation between the income tax charge and the product of accounting profit multiplied by the UK statutory tax rate is as follows:

	Year ended 31 December 2023 $'000	Year ended 31 December 2022 $'000
Profit/(loss) before tax	231,779	203,214
UK statutory tax rate applying to North Sea oil and gas activities of 40% (2022: 40%)	92,712	81,284
Supplementary corporation tax non-deductible expenditure	10,580	11,486
Non-deductible expenditure[i]	69,494	47,951
Petroleum revenue tax (net of income tax benefit)	(8,200)	–
Tax in respect of non-ring-fence trade	7,418	8,892
Deferred tax asset impairment in respect of non-ring-fence trade	11,696	8,563
Deferred tax asset recognition in respect of ring-fence trade	–	(127,022)
UK Energy Profits Levy[ii]	116,457	225,817
Adjustments in respect of prior years	(35,481)	(9,098)
Overseas tax rate differences	(1,114)	(1,264)
Share-based payments	(90)	(1,345)
Other differences	(860)	(816)
At the effective income tax rate of 113% (2022: 120%)	262,612	244,448

(i) Predominantly in relation to non-qualifying expenditure relating to the initial recognition exemption utilised under IAS 12 upon acquisition of Golden Eagle given that at the time of the transaction, it affected neither accounting profit nor taxable profit

(ii) Includes current EPL charge of $175.1 million (2022: $72.1 million charge) and deferred EPL credit of $58.7 million (2022: $153.7 million charge)

(c) Deferred income tax

Deferred income tax relates to the following:

	Group balance sheet		Charge/(credit) for the year recognised in profit or loss	
	2023 $'000	2022 $'000	2023 $'000	2022 $'000
Deferred tax liability				
Accelerated capital allowances	877,800	963,816	(86,015)	195,185
	877,800	963,816		
Deferred tax asset				
Losses	(695,888)	(902,101)	206,213	114,996
Decommissioning liability	(265,800)	(238,624)	(27,176)	47,421
Other temporary differences	(378,592)	(362,565)	(16,027)	(197,524)
	(1,340,280)	(1,503,290)	76,995	160,078
Net deferred tax (assets)	(462,479)	(539,474)		
Reflected in the balance sheet as follows:				
Deferred tax assets	(540,122)	(705,808)		
Deferred tax liabilities	77,643	166,334		
Net deferred tax (assets)	(462,479)	(539,474)		

Reconciliation of net deferred tax assets/(liabilities)

	2023 $'000	2022 $'000
At 1 January	539,474	699,552
Tax expense during the period recognised in profit or loss	(76,995)	(160,078)
At 31 December	462,479	539,474

7. Income tax continued

(d) Tax losses

The Group's deferred tax assets at 31 December 2023 are recogn
the future against which tax losses and allowances in the UK ca
assesses the recoverability of its deferred tax assets at each per
with a 10% change being considered a reasonable possible cha
reduction in oil price would result in a deferred tax asset derecog
result in any change as the Group is currently recognising all UK

The Group has unused UK mainstream corporation tax losses c
of $1,163.0 million (2022: $1,163.0 million) associated with the Ben
recognised at the balance sheet date as recovery of these loss
recognised a deferred tax asset for the adjustment to bond val
is taken over ten years, with a deduction of $2.2 million being to
million (2022: $10.7 million) remaining unrecognised.

The Group has unused Malaysian income tax losses of $14.3 mi
Baram FSC for which no deferred tax asset has been recognise
these losses.

No deferred tax has been provided on unremitted earnings of c
dividends from the scope of UK corporation tax where certain c

(e) Changes in legislation

Finance Act 2001 amended the mainstream corporation tax rat
current year as UK mainstream corporation tax losses are not r

In the Autumn Statement on 22 November 2023, the UK Governm
Security Investment Mechanism and has agreed to index link th
Government also announced that once the decarbonisation a
replace this with a new allowance at the same effective rate ag
Government announced that the sunset clause for EPL would b
current year financial statements would be an increase in the t
will continue to monitor developments and any potential relate

The UK has introduced legislation implementing the Organisati
proposals for a global minimum corporation tax rate (Pillar Two
31 December 2023. This legislation will ensure that profits earne
Group has performed an assessment of the potential exposure
only material overseas jurisdiction in which the Group operates
does not expect a material exposure to Pillar Two income taxes
exception to recognising and disclosing information about the
taxes in accordance with the amendments to IAS 12 published
23 May 2023.

8. Earnings per share

The calculation of earnings per share is based on the profit afte
in issue during the period. Diluted earnings per share is adjuste
based payment plans, which are held in the Employee Benefit
decreasing the loss attributable to each share.

Basic and diluted earnings per share are calculated as follows

	Year
Basic	(30
Dilutive potential of Ordinary shares granted under share-based incentive schemes	
Diluted[i]	(30
Basic (excluding remeasurements and exceptional items)	29
Diluted (excluding remeasurements and exceptional items)[i]	29

(i) Potential Ordinary shares are not treated as dilutive when they would decrease

9. Distributions paid and proposed

The Company paid no dividends during the year ended 31 December 2023 (2022: none). At 31 December 2023, there are no proposed dividends (2022: none). The Board of Directors of EnQuest PLC are proposing making a $15.0 million share buy back, to be executed during 2024. The distribution will be below the limit granted at the 2023 Annual General Meeting allowing the Company to purchase up to 10% of its issued Ordinary share capital in the market.

10. Property, plant and equipment

Accounting policy

Property, plant and equipment is stated at cost less accumulated depreciation and accumulated impairment charges.

Cost

Cost comprises the purchase price or cost relating to development, including the construction, installation and completion of infrastructure facilities such as platforms, pipelines and development wells and any other costs directly attributable to making that asset capable of operating as intended by management. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

The carrying amount of an item of property, plant and equipment is derecognised on disposal or when no future economic benefits are expected from its use. The gain or loss arising from the derecognition of an item of property, plant and equipment is included in the other operating income or expense line item in the Group income statement when the asset is derecognised.

Development assets

Expenditure relating to development of assets, including the construction, installation and completion of infrastructure facilities such as platforms, pipelines and development wells, is capitalised within property, plant and equipment.

Carry arrangements

Where amounts are paid on behalf of a carried party, these are capitalised. Where there is an obligation to make payments on behalf of a carried party and the timing and amount are uncertain, a provision is recognised. Where the payment is a fixed monetary amount, a financial liability is recognised.

Borrowing costs

Borrowing costs directly attributable to the construction of qualifying assets, which are assets that necessarily take a substantial period of time to prepare for their intended use, are capitalised during the development phase of the project until such time as the assets are substantially ready for their intended use.

Depletion and depreciation

Oil and gas assets are depleted, on a field-by-field basis, using the unit of production method based on entitlement to proven and probable reserves, taking account of estimated future development expenditure relating to those reserves. Changes in factors which affect unit of production calculations are dealt with prospectively. Depletion of oil and gas assets is taken through cost of sales.

Depreciation on other elements of property, plant and equipment is provided on a straight-line basis, and taken through general and administration expenses, at the following rates:

Office furniture and equipment	Five years
Fixtures and fittings	Ten years
Right-of-use assets*	Lease term

* Excludes Kraken FPSO which is depleted using the unit of production method in accordance with the related oil and gas assets

Each asset's estimated useful life, residual value and method of depreciation is reviewed and adjusted if appropriate at each financial year end. No depreciation is charged on assets under construction.

Impairment of tangible and intangible assets (excluding goodwill)

At each balance sheet date, discounted cash flow models comprising asset-by-asset life-of-field projections and risks specific to assets, using Level 3 inputs (based on IFRS 13 fair value hierarchy), have been used to determine the recoverable amounts for each CGU. The life of a field depends on the interaction of a number of variables; see note 2 for further details. Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis, including operating and capital expenditure, are derived from the Group's business plan. Oil price assumptions and discount rate assumptions used were as disclosed in note 2. 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 its recoverable amount. An impairment loss is recognised immediately in the Group income statement.

Where an impairment loss subsequently reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset in prior years. A reversal of an impairment loss is recognised immediately in the Group income statement.

10. Property, plant and equipment continued

Cost:	
At 1 January 2022	
Additions	
Change in decommissioning provision	
Disposal	
At 1 January 2023	
Additions	
Change in decommissioning provision (note 23)	
Disposal	
Reclassification from intangible assets (note 12)	
At 31 December 2023	
Accumulated depreciation, depletion and impairment:	
At 1 January 2022	
Charge for the year	
Net impairment charge for the year	
Disposal	
At 1 January 2023	
Charge for the year	
Net impairment charge/(reversal) for the year	
Disposal	
At 31 December 2023	
Net carrying amount:	
At 31 December 2023	
At 31 December 2022	
At 1 January 2022	

The amount of borrowing costs capitalised during the year end
short-term nature of the Group's capital expenditure programm

Impairments

Impairments to the Group's producing assets and reversals of

North Sea	
Net pre-tax impairment reversal/(charge)	

(i) Recoverable amount has been determined on a fair value less costs of disposal made in relation to impairments). The amounts disclosed above are in respect o not have any impairment or reversal are excluded from the amounts disclosed

For information on judgements, estimates and assumptions m
see Use of judgements, estimates and assumptions: recoverab

The 2023 net impairment charge of $117.4 million relates to prod
reversals were primarily driven by changes in production and c
higher forecast oil prices. The 2022 net impairment charge was
production profiles and an increased discount rate partially off

11. Goodwill

Accounting policy

Cost

Goodwill arising on a business combination is initially measured at cost, being the excess of the cost of the business combination over the net fair value of the identifiable assets, liabilities and contingent liabilities of the entity at the date of acquisition. If the fair value of the net assets acquired is in excess of the aggregate consideration transferred, the Group reassesses whether it has correctly identified all of the assets acquired and all of the liabilities assumed and reviews the procedures used to measure the amounts to be recognised at the acquisition date. If the reassessment still results in an excess of the fair value of net assets acquired over the aggregate consideration transferred, the gain is recognised in profit or loss.

Impairment of goodwill

Following initial recognition, goodwill is stated at cost less any accumulated impairment losses. In accordance with IAS 36 Impairment of Assets, goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the recoverable amount of the CGU to which the goodwill relates should be assessed.

For the purposes of impairment testing, goodwill acquired is allocated to the CGU that is expected to benefit from the synergies of the combination. Each unit or units to which goodwill is allocated represents the lowest level within the Group at which the goodwill is monitored for internal management purposes. Impairment is determined by assessing the recoverable amount of the CGU to which the goodwill relates. Where the recoverable amount of the CGU is less than the carrying amount of the CGU containing goodwill, an impairment loss is recognised. Impairment losses relating to goodwill cannot be reversed in future periods. For information on significant estimates and judgements made in relation to impairments, see Use of judgements, estimates and assumptions: recoverability of asset carrying values within note 2.

A summary of goodwill is presented below:

	2023 $'000	2022 $'000
Cost and net carrying amount		
At 1 January	134,400	134,400
At 31 December	134,400	134,400

The majority of the goodwill relates to the 75% acquisition of the Magnus oil field and associated interests. The remaining balance relates to the acquisition of the GKA and Scolty Crathes fields.

Impairment testing of goodwill

Goodwill, which has been acquired through business combinations, has been allocated to the UK North Sea segment CGU, and this is therefore the lowest level at which goodwill is reviewed. The UK North Sea is a combination of oil and gas assets, as detailed within property, plant and equipment (note 10).

The recoverable amounts of the CGU and fields have been determined on a fair value less costs of disposal basis. See notes 2 and 10 for further details. An impairment charge of nil was taken in 2023 (2022: nil) based on a fair value less costs to dispose valuation of the North Sea CGU, as described above.

Sensitivity to changes in assumptions

The Group's recoverable value of assets is highly sensitive, inter alia, to oil price achieved and production volumes. A sensitivity has been run on the oil price assumptions, with a 10% change being considered to be a reasonable possible change for the purposes of sensitivity analysis (see note 2). A 10% reduction in oil price would not result in an impairment charge (2022: 10% reduction would not result in an impairment charge). A 20% reduction in oil price would fully impair goodwill (2022: 25%).

12. Intangible assets

Accounting policy

Exploration and appraisal assets

Exploration and appraisal assets have indefinite useful lives an
accounting. Pre-licence costs are expensed in the period in wh
exploration, evaluation or appraisal activities is initially capitali
acquiring an interest, appraisal well drilling costs, payments to
overheads incurred during the evaluation phase. For such app
continue to be carried as an asset, whilst related hydrocarbons
costs are subject to technical, commercial and management
extract value. When this is no longer the case, the costs are wri
income statement. When exploration licences are relinquished
reversed and the carrying costs are written off through the Gro
commercial development, related costs are transferred to prop
are assessed for any impairment prior to transfer and any imp

During the year ended 31 December 2023, there was no impairm
(2022: nil), although $31.8 million of intangible assets associate
equipment, reflecting updated drilling plans following assessm
Malaysia drilled an exploration well on the PM409 licence. The
and as a result costs of $5.6 million have been written off throu

Other intangibles

UK emissions allowances ('UKAs') purchased to settle the Grou
sheet as an intangible asset at cost. The UKAs will be derecogn

Cost:
At 1 January 2022
Additions
Write-off of relinquished licences previously impaired
Disposal
At 1 January 2023
Additions
Write-off of relinquished licences previously impaired
Write-off of unsuccessful exploration expenditure
Transfer to property, plant and equipment (note 10)
Disposal
At 31 December 2023
Accumulated impairment:
At 1 January 2022
Write-off of relinquished licences previously impaired
At 1 January 2023
Write-off of relinquished licences previously impaired
At 31 December 2023
Net carrying amount:
At 31 December 2023
At 31 December 2022
At 1 January 2022

13. Inventories

Accounting policy

Inventories of consumable well supplies and inventories of hydrocarbons are stated at the lower of cost and NRV, cost being determined on an average cost basis.

	2023 $'000	2022 $'000
Hydrocarbon inventories	21,189	19,613
Well supplies	63,608	56,805
	84,797	76,418

During 2023, a net gain of $2.2 million was recognised within cost of sales in the Group income statement relating to inventory (2022: net loss of $4.0 million). The $8.4 million increase in well supplies was primarily driven by increased drilling activities.

The inventory valuation at 31 December 2023 is stated net of a provision of $36.3 million (2022: $38.9 million) to write-down well supplies to their estimated net realisable value.

Inventory with a net book value of $2.9 million was sold as part of the Bressay farm-down (note 25).

14. Cash and cash equivalents

Accounting policy

Cash and cash equivalents includes cash at bank, cash in hand, outstanding bank overdrafts and highly liquid interest-bearing securities with original maturities of three months or fewer.

	2023 $'000	2022 $'000
Available cash	313,028	293,866
Restricted cash	544	7,745
Cash and cash equivalents	313,572	301,611

The carrying value of the Group's cash and cash equivalents is considered to be a reasonable approximation to their fair value due to their short-term maturities.

Restricted cash

Included within the cash balance at 31 December 2023 is restricted cash of $0.5 million placed on deposit in relation to bank guarantees for the Group's Malaysian assets (31 December 2022: $7.7 million).

15. Financial instruments and fair value measurement

Accounting policy

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument of another entity. Financial instruments are recognised when the Group becomes a party to the contractual provisions of the financial instrument.

Financial assets and financial liabilities are offset and the net amount is reported in the Group balance sheet if there is a currently enforceable legal right to offset the recognised amounts and there is an intention to settle on a net basis.

Financial assets

Financial assets are classified, at initial recognition, as amortised cost, fair value through other comprehensive income ('FVOCI'), or fair value through profit or loss ('FVPL'). The classification of financial assets at initial recognition depends on the financial assets' contractual cash flow characteristics and the Group's business model for managing them. The Group does not currently hold any financial assets at FVOCI, i.e. debt financial assets.

Financial assets are derecognised when the contractual rights to the cash flows from the financial asset expire, or when the financial asset and substantially all the risks and rewards are transferred.

Financial assets at amortised cost

Trade receivables, other receivables and joint operation receivables are measured initially at fair value and subsequently recorded at amortised cost, using the effective interest rate ('EIR') method, and are subject to impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired and EIR amortisation is included within finance costs.

The Group measures financial assets at amortised cost if both of the following conditions are met:

- The financial asset is held within a business model with the objective to hold financial assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Prepayments, which are not financial assets, are measured at historical cost.

15. Financial instruments and fair value measurement continu

Impairment of financial assets

The Group recognises a loss allowance for expected credit loss balance sheet date. ECLs are based on the difference between discounted actual cash flows that are expected to be received since initial recognition, the loss allowance is equal to 12-month considered significant, lifetime credit losses are provided. For t recognition where material.

The provision rates are based on days past due for groupings o geographical region, product type, customer type and rating) forward-looking factors specific to the debtors and the econon with respect to trade receivables and contract assets as low, a indications of change in risk. Generally, trade receivables are w and are not subject to enforcement activity.

Financial liabilities

Financial liabilities are classified, at initial recognition, as amor

Financial liabilities are derecognised when they are extinguishe financial liability is replaced by another from the same lender liability are substantially modified, such an exchange or modifi and the recognition of a new liability. The difference in the resp statement.

Financial liabilities at amortised cost

Loans and borrowings, trade payables and other creditors are transaction costs and subsequently recorded at amortised co bearing. Gains and losses are recognised in profit or loss when within finance costs.

Financial instruments at FVPL

The Group holds derivative financial instruments classified as h instruments. The derivative financial instruments include forwa the respective risks; see note 28. Derivatives are carried as fina liabilities when the fair value is negative.

Financial instruments at FVPL are carried in the Group balance the Group income statement. Unrealised mark-to-market char each period end are recognised within remeasurements, with t Business performance income when a derivative instrument m

Financial assets with cash flows that are not solely payments o irrespective of the business model. All financial assets not class above are measured at FVPL. Financial instruments with embe determining whether their cash flows are solely payment of pri

The Group also holds contingent consideration (see note 22) a both are recognised within remeasurements in the Group inco

15. Financial instruments and fair value measurement continued

Fair value measurement

The following table provides the fair value measurement hierarchy of the Group's assets and liabilities:

31 December 2023	Notes	Total $'000	Amortised cost $'000	Quoted prices in active markets (Level 1) $'000	Significant observable inputs (Level 2) $'000	Significant unobservable inputs (Level 3) $'000
Financial assets measured at fair value:						
Derivative financial assets measured at FVPL						
Gas commodity contracts	19(a)	4,499	–	–	4,499	–
Other financial assets measured at FVPL						
Quoted equity shares		6	–	6	–	–
Total financial assets measured at fair value		4,505	–	6	4,499	–
Financial assets measured at amortised cost:						
Vendor financing facility	19(f)	145,103	145,103	–	–	–
Total financial assets measured at amortised cost[ii]		145,103	145,103	–	–	–
Liabilities measured at fair value:						
Derivative financial liabilities measured at FVPL						
Oil commodity derivative contracts	19(a)	18,418	–	–	18,418	–
Forward UKA contracts	19(a)	8,261	–	–	8,261	–
Other financial liabilities measured at FVPL						
Contingent consideration	22	507,796	–	–	–	507,796
Total liabilities measured at fair value		534,475	–	–	26,679	507,796
Liabilities measured at amortised cost:						
Interest-bearing loans and borrowings[ii]	18(a)	319,784	319,784	–	–	–
Retail bond 9.00%	18(b)	158,683	–	158,683	–	–
High yield bond 11.625%	18(b)	292,419	–	292,419	–	–
Total liabilities measured at amortised cost[i]		770,886	319,784	451,102	–	–

(i) Excludes related fees
(ii) Amortised cost is a reasonable approximation of the fair value

15. Financial instruments and fair value measurement contin

31 December 2022	Notes
Financial assets measured at fair value:	
Derivative financial assets measured at FVPL	
Gas commodity contracts	
Other financial assets measured at FVPL	
Quoted equity shares	
Total financial assets measured at fair value	
Liabilities measured at fair value:	
Derivative financial liabilities measured at FVPL	
Oil commodity derivative contracts	19(a)
Forward UKA contracts	19(a)
Other financial liabilities measured at FVPL	
Contingent consideration	22
Total liabilities measured at fair value	
Liabilities measured at amortised cost:	
Interest-bearing loans and borrowings[ii]	18(a)
Retail bond 7.00%	18(b)
Retail bond 9.00%	18(b)
High yield bond 11.625%	18(b)
Total liabilities measured at amortised cost[i]	

(i) Excludes related fees
(ii) Amortised cost is a reasonable approximation of the fair value

Fair value hierarchy

All financial instruments for which fair value is recognised or dis
on the lowest level input that is significant to the fair value mea

Level 1: Quoted (unadjusted) market prices in active markets fo

Level 2: Valuation techniques for which the lowest level input th
(i.e. prices) or indirectly (i.e. derived from prices) observable; ar

Level 3: Valuation techniques for which the lowest level input th

Derivative financial instruments are valued by counterparties,
readily available market data (Level 2). Contingent considerati
details of which and a reconciliation of movements are disclos
and Level 2 during the period (2022: no transfers).

For the financial assets and liabilities measured at amortised c
value of the bonds classified as Level 1 was derived from quote
loans and borrowings and the vendor financing facility were co
to capture the present value (Level 3). A reconciliation of move

16. Trade and other receivables

	2023 $'000	2022 $'000
Current		
Trade receivables	31,905	69,508
Joint venture receivables	79,036	95,854
Under-lift position	22,309	26,474
VAT receivable	3,314	–
Other receivables	3,715	4,141
Prepayments	2,781	1,271
Accrued income	82,426	79,115
	225,486	276,363

The carrying values of the Group's trade, joint venture and other receivables as stated above are considered to be a reasonable approximation to their fair value largely due to their short-term maturities. Under-lift is valued at the lower of cost or NRV at the prevailing balance sheet date (note 5(b)).

Trade receivables are non-interest-bearing and are generally on 15 to 30-day terms. Joint venture receivables relate to amounts billable to, or recoverable from, joint venture partners. Receivables are reported net of any ECL with no losses recognised as at 31 December 2023 or 2022.

17. Trade and other payables

	2023 $'000	2022 $'000
Current		
Trade payables	75,981	82,897
Accrued expenses	228,664	300,317
Over-lift position	18,824	25,658
Joint venture creditors	20,262	11,957
VAT payable	–	5,282
Other payables	3,678	536
Total Current	347,409	426,647
Non-current		
Joint venture creditors	32,917	–
Total Non-current	32,917	–

The carrying value of the Group's current trade and other payables as stated above is considered to be a reasonable approximation to their fair value largely due to the short-term maturities. Certain trade and other payables will be settled in currencies other than the reporting currency of the Group, mainly in Sterling. Trade payables are normally non-interest-bearing and settled on terms of between 10 and 30 days.

Accrued expenses include accruals for capital and operating expenditure in relation to the oil and gas assets and interest accruals.

The carrying value of the Group's non-current trade and other payables as stated above is considered to be a reasonable approximation to their fair value as this is a specific bi-lateral agreement between counterparties with the liability extinguished in full over time in accordance with the agreed schedule.

18. Loans and borrowings

Borrowings	
Bonds	

(a) Borrowings
The Group's borrowings are carried at amortised cost as follow

	Prin
RBL facility	140
Term Loan facility	150
SVT working capital facility	29
Vendor loan facility	
Total borrowings	319
Due within one year	
Due after more than one year	
Total borrowings	

See liquidity risk – note 28 for the timing of cash outflows relati

Reserve Based Lending ('RBL') facility
In October 2022, the Group agreed an amended and restated
accordance with an amortisation schedule, a sub limit for draw
standard accordion facility which allowed the Group to increas
more than three occasions. The maturity of the new facility is A
maximum amount of the lesser of (i) the total commitments ar
plus a combination of an agreed credit adjustment spread an

As at 31 December 2023, the carrying value of the facility was $
$140.0 million out of accessible commitments of $309.0 million
and unamortised fees of $4.9 million (2022: $4.6 million).

At 31 December 2023, $166.2 million (2022: $47.3 million) remain

At 31 December 2023, the Letter of Credit utilisation was $43.5 m

By the end of February 2024, the Group had fully repaid the out

Term Loan facility
In August 2023, the Group agreed a second lien US Dollar Term
down in full in September 2023, matures in July 2027 and incurs
amount of the facility was $146.4 million (2022: nil), comprising
million. See note 27.

SVT working capital facility
EnQuest has extended the £42.0 million revolving loan facility w
capital cash requirements of SVT and associated interests unti
replacement bank are expected to be executed in April 2024. T
a) the date on which production from Magnus permanently ce
associated infrastructure are amended to allow for cash callin
and accrues interest at 1.0% per annum plus GBP Sterling Over

Vendor loan facility
In June 2023, the Group agreed an amended and restated facil
the payment of existing invoices up to an amount of £15.0 millio
At 31 December 2023, nil was drawn down on the facility and so
terms of the facility.

In December 2022, the Group agreed a facility with a third-part
amount of £7.5 million. At 31 December 2022, £4.7 million was dr
was payable monthly at a rate of 8.00% per annum.

18. Loans and borrowings continued
(b) Bonds
The Group's bonds are carried at amortised cost as follows:

	2023			2022		
	Principal $'000	Fees and discount $'000	Total $'000	Principal $'000	Fees and discount $'000	Total $'000
High yield bond 11.625%	305,000	(10,724)	294,276	305,000	(13,815)	291,185
Retail bond 7.00%	–	–	–	134,544	–	134,544
Retail bond 9.00%	169,669	–	169,669	161,201	–	161,201
Total	474,669	(10,724)	463,945	600,745	(13,815)	586,930
Due within one year			–			134,544
Due after more than one year			463,945			452,386
Total			463,945			586,930

High yield bond 11.625%
In October 2022, the Group concluded an offer of $305.0 million for a US Dollar high yield bond. The notes accrue a fixed coupon of 11.625% payable semi-annually in arrears with a maturity date of November 2027.

The above carrying value of the bond as at 31 December 2023 is $294.3 million (2022: $291.2 million). This includes bond principal of $305.0 million (2022: $305.0 million) less the unamortised original issue discount ('OID') of $3.3 million (2022: $4.2 million) and unamortised fees of $7.4 million (2022: $9.6 million). The high yield bond does not include accrued interest of $5.8 million (2022: $6.5 million), which is reported within trade and other payables. The fair value of the high yield bond is disclosed in note 15.

Retail bond 7.00%
On 27 April 2022, following a successful partial exchange and cash offer, £79.3 million of the retail bond 7.00% were exchanged for the retail bond 9.00%. This resulted in an outstanding principal of £111.3 million. On 13 October 2023, the outstanding principal of £111.3 million was repaid in full.

Retail bond 9.00%
On 27 April 2022, the Group issued a new 9.00% retail bond following a successful partial exchange and cash offer. The principal of the retail bond 9.00% raised by the partial exchange and cash offer totalled £133.3 million. The notes accrue a fixed coupon of 9.00% payable semi-annually in arrears and are due to mature in October 2027.

The above carrying value of the bond as at 31 December 2023 is $169.7 million (2022: $161.2 million). All fees associated with this offer were recognised in the income statement in 2022. The retail bond 9.00% does not include accrued interest of $2.7 million (2022: $2.6 million), which is reported within trade and other payables. The fair value of the retail bond 9.00% is disclosed in note 15.

19. Other financial assets and financial liabilities
(a) Summary as at year end

Fair value through profit or loss:	
Derivative commodity contracts	
Derivative UKA contracts	
Amortised cost:	
Other receivables (Vendor financing facility)[(i)]	
Total current	
Fair value through profit or loss:	
Quoted equity shares	
Amortised cost:	
Other receivables (Vendor financing facility)	
Total non-current	
Total other financial assets and liabilities	

(i) Repayment of $108.8 million was received in the first quarter of 2024 in accordan

(b) Income statement impact
The income/(expense) recognised for derivatives are as follows

Year ended 31 December 2023	
Commodity options	
Commodity swaps	
Commodity futures	
Foreign exchange contracts	
UKA contracts	

Year ended 31 December 2022	
Commodity options	
Commodity swaps	
Commodity futures	
Foreign exchange contracts	
UKA contracts	

(c) Commodity contracts
The Group uses derivative financial instruments to manage its contracts and futures.

For the year ended 31 December 2023, gains totalling $17.2 milli commodity contracts designated as FVPL. This included losses contracts that matured during the year, and mark-to-market un

The mark-to-market value of the Group's open commodity co million (2022: net liability of $41.8 million).

19. Other financial assets and financial liabilities continued

(d) Foreign currency contracts

The Group enters into a variety of foreign currency contracts, primarily in relation to Sterling. During the year ended 31 December 2023, gains totalling $5.7 million (2022: losses of $5.4 million) were recognised in the Group income statement. This included realised gains totalling $5.7 million (2022: losses of $5.2 million) on contracts that matured in the year.

The mark-to-market value of the Group's open contracts as at 31 December 2023 was nil (2022: nil).

(e) UK emissions allowance forward contracts

The Group enters into forward contracts for the purchase of UKAs to manage its exposure to carbon emission credit prices.

The mark-to-market value of the Group's open contracts as at 31 December 2023 was $8.3 million (2022: $4.4 million).

(f) Other receivables

	Other receivables $'000	Equity shares $'000	Total $'000
At 1 January 2022 and 2023	–	6	6
Additions[i]	145,103	–	145,103
At 31 December 2023	145,103	6	145,109
Current			108,827
Non-current			36,282
			145,109

(i) Additions relate to a vendor financing facility entered into with RockRose Energy Limited on 29 December 2023 following the farm-down of a 15.0% share in the EnQuest Producer FPSO and capital items associated with the Bressay development. $108.8 million was repaid in the first quarter of 2024 with the remainder of $36.3 million repayable through future net cash flows from the Bressay field. Interest on the outstanding amount accrues at 2.5% plus the Bank of England's Base Rate

20. Share capital and premium

Accounting policy

Share capital and share premium

The balance classified as equity share capital includes the total net proceeds (both nominal value and share premium) on issue of registered share capital of the parent company. Share issue costs associated with the issuance of new equity are treated as a direct reduction of proceeds. The share capital comprises only one class of Ordinary share. Each Ordinary share carries an equal voting right and right to a dividend.

Retained earnings

Retained earnings contain the accumulated profits/(losses) of the Group.

Share-based payments reserve

Equity-settled share-based payment transactions are measured at the fair value of the services received, and the corresponding increase in equity is recorded. EnQuest PLC shares held by the Group in the Employee Benefit Trust ('EBT') are recognised at cost and are deducted from the share-based payments reserve. Consideration received for the sale of such shares is also recognised in equity, with any difference between the proceeds from the sale and the original cost being taken to reserves. No gain or loss is recognised in the Group income statement on the purchase, sale, issue or cancellation of equity shares.

Authorised, issued and fully paid	Ordinary shares of £0.05 each Number	Share capital $'000	Share premium $'000	Total $'000
At 1 January 2023	1,885,924,339	131,650	260,546	392,196
Issue of new shares to EBT	26,379,774	1,635	–	1,635
At 31 December 2023	1,912,304,113	133,285	260,546	393,831

At 31 December 2023, there were 8,449,793 shares held by the Employee Benefit Trust (2022: 21,663,181). The movement in the year was shares used to satisfy awards made under the Company's share-based incentive schemes offset by a subscription for additional Ordinary shares.

21. Share-based payment plans

Accounting policy

Eligible employees (including Executive Directors) of the Group

transactions, whereby employees render services in exchange

Information on these plans for Executive Directors is shown in th

The cost of these equity-settled transactions is measured by re

granted. The fair value of awards is calculated in reference to t

middle market quotation of a share for the three immediately p

the London Stock Exchange, provided such dealing days do no

because of any dealing restriction.

The cost of equity-settled transactions is recognised over the v

entitled to the award. The cumulative expense recognised for e

vesting date reflects the extent to which the vesting period has

instruments that will ultimately vest. The Group income statem

cumulative expense recognised as at the beginning and end o

In valuing the transactions, no account is taken of any service or p

of the shares of EnQuest PLC (market conditions) or 'non-vesting'

that do not ultimately vest, except for awards where vesting is con

treated as vesting irrespective of whether or not the market or no

performance conditions are satisfied. Equity awards cancelled ar

and any expense not previously recognised for the award at that

The Group operates a number of equity-settled employee sha

senior leaders and certain other employees. These plans typica

Leaving employment will normally preclude the conversion of u

participants that leave for qualifying reasons.

The share-based payment expense recognised for each scher

Performance Share Plan
Other performance share plans
Sharesave Plan

The following table shows the number of shares potentially issu

the number of options outstanding and the number of options

Share plans
Outstanding at 1 January
Granted during the year
Exercised during the year
Forfeited during the year
Outstanding at 31 December
Exercisable at 31 December

In addition, the Group operates an approved savings-related s

on eligible employees being granted options and their agreem

savings carrier and to save over a specified period, either three

employee's discretion at the end of the period previously chose

21. Share-based payment plans continued

The following table shows the number of shares potentially issuable under equity-settled employee share option plans, including the number of options outstanding, the number of options exercisable at the end of each year and the corresponding weighted average exercise prices.

	2023		2022	
Share options	Number	Weighted average exercise price $	Number	Weighted average exercise price $
Outstanding at 1 January	33,308,249	0.14	37,518,927	0.14
Granted during the year	10,268,853	0.14	1,292,788	0.32
Exercised during the year	(19,977,354)	0.13	(2,150,313)	0.17
Forfeited during the year	(4,941,604)	0.17	(3,353,153)	0.14
Outstanding at 31 December	18,658,144	0.16	33,308,249	0.14
Exercisable at 31 December	6,553,159	0.13	445,318	0.17

22. Contingent consideration

Accounting policy

When the consideration transferred by the Group in a business combination includes a contingent consideration arrangement, the contingent consideration is measured at its acquisition-date fair value and included as part of the consideration transferred in a business combination. 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 acquisition date) about facts and circumstances that existed at the acquisition date.

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 depicted below is remeasured to fair value at subsequent reporting dates with changes in fair value recognised in profit or loss. Contingent consideration that is classified as equity if any, is not remeasured at subsequent reporting dates and its subsequent settlement is accounted for within equity.

Contingent consideration is discounted at a risk-free rate combined with a risk premium, calculated in alignment with IFRS 13 and the unwinding of the discount is presented within finance costs.

Any contingent consideration included in the consideration payable for an asset acquisition is recorded at fair value at the date of acquisition and included in the initial measurement of cost. Subsequent measurement changes relating to the variable consideration are capitalised as part of the asset value if it is probable that future economic benefits associated with the asset will flow to the Group and can be measured reliably.

	Notes	Magnus 75% $'000	Magnus decommissioning-linked liability $'000	Golden Eagle $'000	Total $'000
At 31 December 2022		566,685	21,853	48,337	636,875
Change in fair value	5(d)	(69,840)	175	–	(69,665)
Unwinding of discount	6	56,668	2,186	1,663	60,517
Utilisation		(65,506)	(4,425)	(50,000)	(119,931)
At 31 December 2023		488,007	19,789	–	507,796
Classified as:					
Current		43,073	3,452	–	46,525
Non-current		444,934	16,337	–	461,271
		488,007	19,789	–	507,796

22. Contingent consideration continued

75% Magnus acquisition contingent consideration

On 1 December 2018, EnQuest completed the acquisition of the c
associated interests (collectively the 'Transaction assets') which
whereby EnQuest and bp share the net cash flow generated by
received by bp. This contingent consideration is a financial liabil
consideration has been determined by calculating the present
is considered a Level 3 valuation under the fair value hierarchy. F
future oil prices, production volumes and operating costs. Oil pri
disclosed in Use of judgements, estimates and assumptions wit
31 December 2023, which resulted in a decrease in fair value of $
fair value in 2023 reflects a 1.3% increase in the discount rate to 1
offset by the Group's increased oil price assumptions. The increa
assumptions and changes in asset profiles and cost assumptio
million (2022: $34.5 million) on the contingent consideration wer
in the Group income statement. At 31 December 2023, the contin
to be met in the present value calculations (31 December 2022: c
the profit share element of the repayment, $65.5 million (2022: $
31 December 2023, the contingent consideration for Magnus wa

Management has considered alternative scenarios to assess t
limited to, the key accounting estimate relating to discount rat
the profit-share arrangement. A 1.0% reduction in the discount
change given the prevailing macroeconomic conditions, woul
A 1.0% increase would decrease reported contingent considera
forecast to be met in the present value calculations, sensitivity
assumptions of 10%, which is considered to be a reasonably po
contingent consideration (2022: reduction of $73.6 million).

The payment of contingent consideration is limited to cash flo
consideration is payable if insufficient cash flows are generate
reference to the conditions existing at 31 December 2023, the m
Risk management and financial instruments: liquidity risk (note

Magnus decommissioning-linked contingent consideration
As part of the Magnus and associated interests acquisition, bp
existing wells and infrastructure and EnQuest agreed to pay ad
physical decommissioning costs of Magnus. At 31 December 20
reference to 30% of bp's decommissioning costs on Magnus wa
change in assumptions would not have a material impact on t

Golden Eagle contingent consideration
Part of the Golden Eagle acquisition consideration included an
July 2021 and June 2023. Over the period July 2021 to June 2023
the contingent consideration was valued at $50.0 million with s
of $48.3 million).

23. Provisions

Accounting policy

Decommissioning

Provision for future decommissioning costs is made in full when the Group has an obligation: to dismantle and remove a facility or an item of plant; to restore the site on which it is located; and when a reasonable estimate of that liability can be made. The Group's provision primarily relates to the future decommissioning of production facilities and pipelines.

A decommissioning asset and liability are recognised, within property, plant and equipment and provisions, respectively, at the present value of the estimated future decommissioning costs. The decommissioning asset is amortised over the life of the underlying asset on a unit of production basis over proven and probable reserves, included within depletion in the Group income statement. Any change in the present value of estimated future decommissioning costs is reflected as an adjustment to the provision and the oil and gas asset for producing assets. For assets that have ceased production, the change in estimate is reflected as an adjustment to the provision and the Group income statement, via other income or expense. The unwinding of the decommissioning liability is included under finance costs in the Group income statement.

These provisions have been created based on internal and third-party estimates. Assumptions based on the current economic environment have been made which management believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required, which will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning liabilities is likely to depend on the dates when the fields cease to be economically viable. This in turn depends on future oil prices, which are inherently uncertain. See Use of judgements, estimates and assumptions: provisions within note 2.

Other

Provisions are recognised when the Group has a present legal or constructive obligation as a result of past events; it is probable that an outflow of resources will be required to settle the obligation; and a reliable estimate can be made of the amount of the obligation.

	Decommissioning provision $'000	Thistle decommissioning provision $'000	Other provisions $'000	Total $'000
At 31 December 2022	691,584	32,720	13,366	737,670
Additions during the year[(i)]	6,245	–	7,017	13,262
Changes in estimates[(i)]	78,247	1,605	(5,192)	74,660
Unwinding of discount	24,236	1,145	–	25,381
Utilisation	(44,550)	(10,160)	(797)	(55,507)
Foreign exchange	–	45	(214)	(169)
At 31 December 2023	755,762	25,355	14,180	795,297
Classified as:				
Current	55,924	9,757	14,180	79,861
Non-current	699,838	15,598	–	715,436
	755,762	25,355	14,180	795,297

(i) Includes $31.2 million relating to assets in decommissioning disclosed in note 5(e) and $53.3 million related to producing assets disclosed in note 10

Decommissioning provision

The Group's total provision represents the present value of decommissioning costs which are expected to be incurred up to 2048, assuming no further development of the Group's assets. Additions during the year primarily relate to the decommissioning provision recognised due to drilling of new wells in Magnus and Golden Eagle. Changes in estimates during the year primarily reflect the net effect of $61.0 million increase in the underlying cost estimates and $35.0 million foreign exchange impact due to the strengthening Sterling to US Dollar exchange rates. At 31 December 2023, an estimated $175.7 million is expected to be utilised between one and five years (2022: $407.0 million), $355.6 million within six to ten years (2022: $67.6 million), and the remainder in later periods. For sensitivity analysis see Use of judgements, estimates and assumptions within note 2.

The Group enters into surety bonds principally to provide security for its decommissioning obligations. The surety bond facilities, which expired in December 2022, were renewed for 12 months, subject to ongoing compliance with the terms of the Group's borrowings. At 31 December 2023, the Group held surety bonds totalling $250.4 million (2022: $227.6 million).

23. Provisions continued

Thistle decommissioning provision

In 2018, EnQuest exercised the option to receive $50.0 million from
decommissioning activities for Thistle and Deveron and making p
costs of the Thistle and Deveron fields, with the liability recognised
bp by reference to 7.5% of bp's decommissioning costs on Thistle
reduction mainly reflecting the utilisation in the period. Change in
$6.1 million other income) and unwinding of discount of $1.1 million

Other provisions

During 2021, the Group recognised $8.2 million in relation to disput
for $0.5 million and the other dispute is ongoing. At 31 December 2
2022: $7.5 million) reflecting legal costs and interest charges. The

24. Leases

Accounting policy

As a lessee

The Group recognises a right-of-use asset and a lease liability

The lease liability is initially measured at the present value of th
date, discounted by using the rate implicit in the lease, or, if tha
incremental borrowing rate.

The incremental borrowing rate is the rate that the Group would
security, to obtain an asset of similar value. The incremental bor
the term, the risk-free rate based on government bond rates and

Lease payments included in the measurement of the lease lia
- fixed lease payments (including in-substance fixed paymen
- variable lease payments that depend on an index or rate, ini
  date;
- the exercise price of purchase options, if the lessee is reason
- payments of penalties for terminating the lease, if the lease t

The lease liability is subsequently recorded at amortised cost,
remeasured when there is a change in future lease payments
changes its assessment of whether it will exercise a purchase,
remeasured in this way, a corresponding adjustment is made t
in profit or loss if the carrying amount of the right-of-use asset
adjustments during the periods presented.

The right-of-use asset is measured at cost, which comprises th
payments made at or before the commencement date, plus a
dismantle and remove the underlying asset or to restore the un
incentives received. Right-of-use assets are depreciated over t
underlying asset. If a lease transfers ownership of the underlyin
Group expects to exercise a purchase option, the related right-
underlying asset. The depreciation starts at the commenceme

The Group applies the short-term lease recognition exemption
from the commencement date. It also applies the low-value as
Lease payments on short-term leases and leases of low-value
over the lease term.

The Group applies IAS 36 Impairment of Assets to determine wh
identified impairment loss as described in the 'property, plant

Variable rents that do not depend on an index or rate are not in
right-of-use asset. The related payments are recognised as an
triggers those payments occurs and are included within 'cost o
income statement.

24. Leases continued

For leases within joint ventures, the Group assesses on a lease-by-lease basis the facts and circumstances. This relates mainly to leases of vessels. Where all parties to a joint operation jointly have the right to control the use of the identified asset and all parties have a legal obligation to make lease payments to the lessor, the Group's share of the right-of-use asset and its share of the lease liability will be recognised on the Group balance sheet. This may arise in cases where the lease is signed by all parties to the joint operation or the joint operation partners are named within the lease. However, in cases where EnQuest is the only party with the legal obligation to make lease payments to the lessor, the full lease liability and right-of-use asset will be recognised on the Group balance sheet. This may be the case if, for example, EnQuest, as operator of the joint operation, is the sole signatory to the lease. If the underlying asset is used for the performance of the joint operation agreement, EnQuest will recharge the associated costs in line with the joint operating agreement.

As a lessor

When the Group acts as a lessor, it determines at lease inception whether each lease is a finance lease or an operating lease. Whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee, the contract is classified as a finance lease. All other leases are classified as operating leases.

When the Group is an intermediate lessor, it accounts for the head-lease and the sub-lease as two separate contracts. The sub-lease is classified as a finance or operating lease by reference to the right-of-use asset arising from the head-lease.

Rental income from operating leases is recognised on a straight-line basis over the term of the relevant lease. Initial direct costs incurred in negotiating and arranging an operating lease are added to the carrying amount of the leased asset and recognised on a straight-line basis over the lease term.

Amounts due from lessees under finance leases are recognised as receivables at the amount of the Group's net investment in the leases. Finance lease income is allocated to reporting periods so as to reflect a constant periodic rate of return on the Group's net investment outstanding in respect of the leases.

When a contract includes lease and non-lease components, the Group applies IFRS 15 to allocate the consideration under the contract to each component.

Right-of-use assets and lease liabilities

Set out below are the carrying amounts of the Group's right-of-use assets and lease liabilities and the movements during the period:

	Notes	Right-of-use assets $'000	Lease liabilities $'000
As at 31 December 2021		463,393	570,781
Additions in the period		28,394	28,130
Depreciation expense		(57,864)	–
Impairment charge		(2,991)	–
Disposal		(1,554)	(1,432)
Interest expense		–	39,172
Payments		–	(147,971)
Foreign exchange movements		–	(6,614)
As at 31 December 2022		429,378	482,066
Additions in the period	10	28,378	28,378
Depreciation expense	10	(55,979)	–
Impairment reversal	10	6,077	–
Disposal		(122)	–
Interest expense		–	43,801
Payments		–	(135,675)
Foreign exchange movements		–	3,604
As at 31 December 2023		407,732	422,174
Current			133,282
Non-current			288,892
			422,174

The Group leases assets, including the Kraken FPSO, property, and oil and gas vessels, with a weighted average lease term of four years. The maturity analysis of lease liabilities is disclosed in note 28.

24. Leases continued

Amounts recognised in profit or loss

Depreciation expense of right-of-use assets
Interest expense on lease liabilities
Rent expense – short-term leases
Rent expense – leases of low-value assets
Total amounts recognised in profit or loss

Amounts recognised in statement of cash flows

Total cash outflow for leases

Leases as lessor

The Group sub-leases part of Annan House, the Aberdeen offic
risks and rewards incidental to the ownership of the right-of-us
Rental income recognised by the Group during 2023 was $2.3 m

The following table sets out a maturity analysis of lease payme
after the reporting date:

Less than one year
One to two years
Two to three years
Three to four years
Four to five years
More than five years
Total undiscounted lease payments

25. Deferred income

Accounting policy

Income is not recognised in the income statement until it is hig
be met.

Deferred income

In December 2023 a farm-down of an equity interest in the EnQ
Bressay development was completed and cash received of $14
December 2023 as vendor financing (see note 19(f)). Proceeds f
these are contingent upon the Bressay development project ac
delivering the development, however should the project not ac
the assets on an alternative project.

26. Commitments and contingencies

Capital commitments

At 31 December 2023, the Group had commitments for future ca
The key components of this relate to drilling commitments for th
stabilisation facility at Sullom Voe Terminal. Where the commitm
Group's net share of the commitment. Where the Group is not th
the Group's net share of committed future work programmes.

Other commitments

In the normal course of business, the Group will obtain surety b
the Group held surety bonds totalling $250.4 million (2022: $227
obligations. See note 23 for further details.

26. Commitments and contingencies continued

Contingencies

The Group becomes involved from time to time in various claims and lawsuits arising in the ordinary course of its business. Outside of those already provided, the Group is not, nor has been during the past 12 months, involved in any governmental, legal or arbitration proceedings which, either individually or in the aggregate, have had, or are expected to have, a material adverse effect on the Group balance sheet or profitability. Nor, so far as the Group is aware, are any such proceedings pending or threatened.

A contingent payment of $15.0 million to Equinor is due upon regulatory approval of a Bressay field development plan.

27. Related party transactions

The Group financial statements include the financial statements of EnQuest PLC and its subsidiaries. A list of the Group's principal subsidiaries is contained in note 29 to these Group financial statements.

Balances and transactions between the Company and its subsidiaries, which are related parties, have been eliminated on consolidation and are not disclosed in this note.

All sales to and purchases from related parties are made at normal market prices and the pricing policies and terms of these transactions are approved by the Group's management. With the exception of the transactions disclosed below, there have been no transactions with related parties who are not members of the Group during the year ended 31 December 2023 (2022: none).

Within the $150.0 million Term Loan, Double A Limited, a company beneficially owned by the extended family of Amjad Bseisu, lent $9.0 million on the same terms and conditions as all other lending parties. This is considered a smaller related party transaction under Listing Rule 11.1.10.

Compensation of key management personnel

The following table details remuneration of key management personnel of the Group. Key management personnel comprise Executive and Non-Executive Directors of the Company and the Executive Committee.

	2023 $'000	2022 $'000
Short-term employee benefits	5,360	6,195
Share-based payments	144	3,049
Post-employment pension benefits	241	164
Termination payments	367	228
	6,112	9,636

28. Risk management and financial instruments

Risk management objectives and policies

The Group's principal financial assets and liabilities comprise trade and other receivables, cash and cash equivalents, interest-bearing loans, borrowings and finance leases, derivative financial instruments and trade and other payables. The main purpose of the financial instruments is to manage short-term cash flow.

The Group's activities expose it to various financial risks particularly associated with fluctuations in oil price, foreign currency risk, liquidity risk and credit risk. Management reviews and agrees policies for managing each of these risks, which are summarised below. Also presented below is a sensitivity analysis to indicate sensitivity to changes in market variables on the Group's financial instruments and to show the impact on profit and shareholders' equity, where applicable. The sensitivity has been prepared for periods ended 31 December 2023 and 2022, using the amounts of debt and other financial assets and liabilities held at those reporting dates.

Commodity price risk – oil prices

The Group is exposed to the impact of changes in Brent oil prices on its revenues and profits generated from sales of crude oil.

The Group's policy is to have the ability to hedge oil prices up to a maximum of 75% of the next 12 months' production on a rolling annual basis, up to 60% in the following 12-month period and 50% in the subsequent 12-month period. On a rolling quarterly basis, under the RBL facility, the Group is required to hedge a minimum of 45% of volumes of net entitlement production expected to be produced in the next 12 months, and between 35% and 15% of volumes of net entitlement production expected for the following 12 months dependent on the proportion of the facility that is utilised. This requirement ceases at the end date of the facility.

Details of the commodity derivative contracts entered into during and open at the end of 2023 are disclosed in note 19. As of 31 December 2023, the Group held financial instruments (options and swaps) related to crude oil that covered 5.2 MMbbls of 2024 production and 1.6 MMbbls of 2025 production. The instruments have an effective average floor price of around $60/bbl in both 2024 and 2025. The Group utilises multiple benchmarks when hedging production to achieve optimal results for the Group. No derivatives were designated in hedging relationships at 31 December 2023.

The following table summarises the impact on the Group's pre-tax profit of a reasonably possible change in the Brent oil price on the fair value of derivative financial instruments, with all other variables held constant. The impact in equity is the same as the impact on profit before tax.

31 December 2023
31 December 2022

Foreign exchange risk

The Group is exposed to foreign exchange risk arising from mo
from sales or purchases in currencies other than the Group's fu
denominated in Sterling. To mitigate the risks of large fluctuatio
Board allows for up to 70% of the non-US Dollar portion of the G
hedged. For specific contracted capital expenditure projects, u
the Group's sales and 95% (2022: 85%) of costs (including opera
costs) are denominated in currencies other than the functiona

The Group also enters into foreign currency swap contracts fro
tables summarise the Group's financial assets and liabilities ex

Year ended 31 December 2023
Total financial assets
Total financial liabilities

Year ended 31 December 2022
Total financial assets
Total financial liabilities

The following table summarises the sensitivity to a reasonably
rate, with all other variables held constant, of the Group's profit
assets and liabilities at the reporting date. The impact in equity
exposure to foreign currency changes for all other currencies is

31 December 2023
31 December 2022

Credit risk

Credit risk is managed on a Group basis. Credit risk in financial
derivative financial instruments where the Group's exposure ar
exposure equal to the carrying amount of these instruments. Fo
A3 credit rating or better are accepted. Cash balances can be
funds, subject to Board-approved limits and with a view to min

In addition, there are credit risks of commercial counterparties
The Group trades only with recognised international oil and ga
and at 31 December 2023, there were no trade receivables past
receivables past due (2022: $0.1 million) but not impaired. Rece
appropriate follow-up action taken where necessary. Any impa

Ageing of past due but not impaired receivables
Less than 30 days
30–60 days
60–90 days
90–120 days
120+ days

At 31 December 2023, the Group had one customer accounting for
and no joint venture partner accounting for over 10% of outstandin

28. Risk management and financial instruments continued

Liquidity risk

The Group monitors its risk of a shortage of funds by reviewing its cash flow requirements on a regular basis relative to its existing bank facilities and the maturity profile of its borrowings. Specifically, the Group's policy is to ensure that sufficient liquidity or committed facilities exist within the Group to meet its operational funding requirements and to ensure the Group can service its debt and adhere to its financial covenants. At 31 December 2023, $166.2 million (2022: $47.3 million) was available for drawdown under the Group's facilities (see note 18).

The following tables detail the maturity profiles of the Group's non-derivative financial liabilities, including projected interest thereon. The amounts in these tables are different from the balance sheet as the table is prepared on a contractual undiscounted cash flow basis and includes future interest payments.

The payment of contingent consideration is limited to cash flows generated from Magnus (see note 22). Therefore, no contingent consideration is payable if insufficient cash flows are generated over and above the requirements to operate the asset and there is no exposure to liquidity risk. By reference to the conditions existing at the reporting period end, the maturity analysis of the contingent consideration is disclosed below. All of the Group's liabilities, except for the RBL and Term Loan facilities, are unsecured.

Year ended 31 December 2023	On demand $'000	Up to 1 year $'000	1 to 2 years $'000	2 to 5 years $'000	Over 5 years $'000	Total $'000
Loans and borrowings	–	64,518	131,081	221,311	–	416,910
Bonds	–	50,749	50,749	576,415	–	677,913
Contingent consideration	–	46,555	95,335	289,823	393,187	824,900
Obligations under finance leases	–	160,341	70,062	229,310	36,322	496,035
Trade and other payables	–	347,408	13,167	19,750	–	380,325
	–	669,571	360,394	1,336,609	429,509	2,796,083

Year ended 31 December 2022	On demand $'000	Up to 1 year $'000	1 to 2 years $'000	2 to 5 years $'000	Over 5 years $'000	Total $'000
Loans and borrowings	–	163,223	175,400	152,000	–	490,623
Bonds	–	194,991	49,919	615,449	–	860,359
Contingent consideration	–	126,910	85,267	327,642	400,480	940,299
Obligations under finance leases	–	151,621	127,592	256,139	37,693	573,045
Trade and other payables	–	426,643	–	–	–	426,643
	–	1,063,388	438,178	1,351,230	438,173	3,290,969

The following tables detail the Group's expected maturity of payables for its derivative financial instruments. The amounts in these tables are different from the balance sheet as the table is prepared on a contractual undiscounted cash flow basis. When the amount receivable or payable is not fixed, the amount disclosed has been determined by reference to a projected forward curve at the reporting date.

Year ended 31 December 2023	On demand $'000	Less than 3 months $'000	3 to 12 months $'000	1 to 2 years $'000	Over 2 years $'000	Total $'000
Commodity derivative contracts	414	3,111	17,264	1,000	–	21,789
Other derivative contracts	–	8,261	–	–	–	8,261
	414	11,372	17,264	1,000	–	30,050

Year ended 31 December 2022	On demand $'000	Less than 3 months $'000	3 to 12 months $'000	1 to 2 years $'000	Over 2 years $'000	Total $'000
Commodity derivative contracts	9,549	27,496	15,553	–	–	52,598
Other derivative contracts	880	4,429	–	–	–	5,309
	10,429	31,925	15,553	–	–	57,907

28. Risk management and financial instruments continued

Capital management

The capital structure of the Group consists of debt, which inclu
equivalents and equity attributable to the equity holders of the
retained earnings as in the Group statement of changes in equ

The primary objective of the Group's capital management is to
structure to achieve capital efficiency whilst also maintaining f
requirements of the business over the short, medium and long
will be required.

The Group has approval from the Board to hedge external risks
risk. This is designed to reduce the risk of adverse movements i
Group's projects and operations.

The Board regularly reassesses the existing dividend policy to e
shareholder distributions are expected to depend on the earni
factors as the Board considers appropriate.

The Group monitors capital using the gearing ratio and return
to the movement year-on-year is provided within the relevant

Loans, borrowings and bond[i] (A)
Cash and short-term deposits
EnQuest net debt[ii] (B)
Equity attributable to EnQuest PLC shareholders (C)
Profit/(loss) for the year attributable to EnQuest PLC shareholo
Profit/(loss) for the year attributable to EnQuest PLC shareholo remeasurements and exceptionals (E)
Adjusted EBITDA[ii] (F)
Gross gearing ratio (A/C)
Net gearing ratio (B/C)
EnQuest net debt/adjusted EBITDA[ii] (B/F)
Shareholders' return on investment (D/C)
Shareholders' return on investment excluding exceptionals (E

(i) Principal amounts drawn, excludes netting off of fees (see note 18)
(ii) See Glossary – non GAAP measures on pages 193 to 196

29. Subsidiaries

At 31 December 2023, EnQuest PLC had investments in the following subsidiaries:

Name of company	Principal activity	Country of incorporation	Proportion of nominal value of issued Ordinary shares controlled by the Group
EnQuest Britain Limited	Intermediate holding company and provision of Group manpower and contracting/procurement services	England	100%
EnQuest Heather Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Thistle Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
Stratic UK (Holdings) Limited (i)	Intermediate holding company	England	100%
EnQuest ENS Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest UKCS Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Heather Leasing Limited (i)	Leasing	England	100%
EQ Petroleum Sabah Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Dons Leasing Limited (i)	Leasing	England	100%
EnQuest Energy Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Production Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Global Limited	Intermediate holding company	England	100%
EnQuest NWO Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
EQ Petroleum Production Malaysia Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
NSIP (GKA) Limited [1]	Construction, ownership and operation of an oil pipeline	Scotland	100%
EnQuest Global Services Limited (i) [2]	Provision of Group manpower and contracting/ procurement services for the international business	Jersey	100%
EnQuest Marketing and Trading Limited	Marketing and trading of crude oil	England	100%
NorthWestOctober Limited (i)	Dormant	England	100%
EnQuest UK Limited (i)	Dormant	England	100%
EnQuest Petroleum Developments Malaysia SDN. BHD (i) [3]	Exploration, extraction and production of hydrocarbons	Malaysia	100%
EnQuest NNS Holdings Limited (i)	Intermediate holding company	England	100%
EnQuest NNS Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Advance Holdings Limited (i)	Intermediate holding company	England	100%
EnQuest Advance Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Forward Holdings Limited (i)	Intermediate holding company	England	100%
EnQuest Forward Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
EnQuest Progress Limited (i)	Exploration, extraction and production of hydrocarbons	England	100%
North Sea (Golden Eagle) Resources Ltd	Exploration, extraction and production of hydrocarbons	England	100%
Veri Energy (CCS) Limited (i)	Assessment and development of new energy and decarbonisation opportunities	England	100%
Veri Energy (Hydrogen) Limited (i)	Assessment and development of new energy and decarbonisation opportunities	England	100%
Veri Energy Holdings Limited	Intermediate holding company	England	100%
Veri Energy Limited (i)	Assessment and development of new energy and decarbonisation opportunities	England	100%

(i) Held by subsidiary undertaking

The Group has two branches outside the UK (all held by subsidiary undertakings): EnQuest Global Services Limited (Dubai) and EnQuest Petroleum Production Malaysia Limited (Malaysia).

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2 Ground Floor, Colomberie House, St Helier, JE4 0RX, Jersey
3 c/o TMF, 10th Floor, Menara Hap Seng, No. 1 & 3, Jalan P. Ramlee 50250 Kuala Lumpur, Malaysia

30. Cash flow information

Cash generated from operations

Profit/(loss) before tax	
Depreciation	
Depletion	
Exploration and appraisal expense	
Net impairment charge to oil and gas assets	
Net (write back)/disposal of inventory	
Share-based payment charge	
Change in Magnus related contingent consideration	
Change in provisions	
Other non-cash income	
Change in Golden Eagle related contingent consideration	
Option premium recognition	
Unrealised (gain)/loss on commodity financial instruments	
Unrealised loss/(gain) on other financial instruments	
Unrealised exchange loss/(gain)	
Net finance expense	
Operating cash flow before working capital changes	
Decrease in trade and other receivables	
Increase in inventories	
(Decrease)/increase in trade and other payables	
Cash generated from operations	

30. Cash flow information continued

Changes in liabilities arising from financing activities

	Loans and borrowings $'000	Bonds $'000	Lease liabilities $'000	Total $'000
At 1 January 2022	(402,065)	(1,109,920)	(570,781)	(2,082,766)
Cash movements:				
Repayments of loans and borrowings	415,000	827,166	–	1,242,166
Proceeds from loans and borrowings	(409,180)	(376,163)	–	(785,343)
Payment of lease liabilities	–	–	147,971	147,971
Cash interest paid in year	14,771	80,189	–	94,960
Non-cash movements:				
Additions	4,038	14,323	(28,130)	(9,769)
Interest/finance charge payable	(14,490)	(62,262)	(39,172)	(115,924)
Fee amortisation	(22,679)	(2,652)	–	(25,331)
Disposal	–	–	1,432	1,432
Foreign exchange and other non-cash movements	1,077	32,036	6,614	39,727
At 31 December 2022	(413,528)	(597,283)	(482,066)	(1,492,877)
Cash movements:				
Repayments of loans and borrowings	265,809	138,052	–	403,861
Proceeds from loans and borrowings	(166,782)	–	–	(166,782)
Payment of lease liabilities	–	–	135,675	135,675
Cash interest paid in year	36,285	62,130	–	98,415
Non-cash movements:				
Additions	–	–	(28,377)	(28,377)
Interest/finance charge payable	(30,708)	(58,999)	(43,801)	(133,508)
Fee amortisation	(1,476)	(3,091)	–	(4,567)
Foreign exchange and other non-cash movements	(810)	(11,828)	(3,605)	(16,243)
At 31 December 2023	(311,210)	(471,019)	(422,174)	(1,204,403)

Reconciliation of carrying value

	Notes	Loans and borrowings (see note 18) $'000	Bonds (see note 18) $'000	Lease liabilities (see note 24) $'000	Total $'000
Principal		(417,967)	(600,745)	(482,066)	(1,500,778)
Unamortised fees		4,609	13,815	–	18,424
Accrued interest	17	(170)	(10,353)	–	(10,523)
At 31 December 2022		(413,528)	(597,283)	(482,066)	(1,492,877)
Principal		(319,784)	(474,669)	(422,174)	(1,216,627)
Unamortised fees		8,553	10,724	–	19,277
Accrued interest	17	21	(7,074)	–	(7,053)
At 31 December 2023		(311,210)	(471,019)	(422,174)	(1,204,403)

31. Subsequent events

In March 2024, the UK Government announced that the sunset clause for EPL would be extended by a year to 31 March 2029, although no date has yet been set for when this will be legislated. The Group estimates the impact of this one year extension to be an additional deferred tax liability of approximately $44.6 million, with a reduction in the carrying value of the Group's assets of approximately $22.3 million.

In February 2024, the regulator approved the 15.0% disposal of a share in the Bressay licence to RockRose.

By the end of February 2024, the Group had fully repaid the outstanding $140.0 million of its Reserve Based Lending Facility.

The Board of Directors of EnQuest PLC are proposing making a $15.0 million share buy back, to be executed during 2024. The distribution will be below the limit granted at the 2023 Annual General Meeting allowing the Company to purchase up to 10% of its issued Ordinary share capital in the market.

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