This document (the "**Prospectus**") comprises a prospectus for the purposes of Article 6 of Regulation (EU) 2017/1129 which forms part of UK domestic law by virtue of the European Union (Withdrawal) Act 2018 ("**EUWA**") (the "**UK Prospectus Regulation**") relating to Harbour Energy plc (the "**Company**", and together with its subsidiaries and subsidiary undertakings from time to time, "**Harbour Energy**") and has been approved by the Financial Conduct Authority (the "**FCA**"), as competent authority under the UK Prospectus Regulation, in accordance with section 87A of the Financial Services and Markets Act 2000, as amended (the "**FSMA**"), and prepared and made available to the public in accordance with the Prospectus Regulation Rules of the FCA made under section 73A of the FSMA (the "**Prospectus Regulation Rules**"). The FCA only approves this Prospectus as meeting the standards of completeness, comprehensibility and consistency imposed by the UK Prospectus Regulation and such approval should not be considered as an endorsement of the Company or the quality of the securities that are the subject of this Prospectus. Investors should make their own assessment as to the suitability of investing in the securities. This Prospectus has been (i) filed with the FCA in accordance with paragraph 3.2.1 of the Prospectus Regulation Rules, and (ii) prepared to provide details of the BASF Consideration Shares (as defined below).

The Company and the Directors whose names appear in the section entitled "*Directors, Company Secretary, Registered Office and Advisers*" of this Prospectus, accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Company and the Directors, the information contained in this Prospectus is in accordance with the facts and this Prospectus makes no omission likely to affect its import.

YOU SHOULD READ THE WHOLE OF THIS PROSPECTUS AND ALL DOCUMENTS INCORPORATED INTO IT BY REFERENCE IN THEIR ENTIRETY. IN PARTICULAR, YOU SHOULD TAKE ACCOUNT OF THE PART ENTITLED "RISK FACTORS" OF THIS PROSPECTUS FOR A DISCUSSION OF THE RISKS THAT MIGHT AFFECT THE VALUE OF YOUR SHAREHOLDING IN THE COMPANY. YOU SHOULD NOT RELY SOLELY ON INFORMATION SUMMARISED IN THE SUMMARY.

Harbour Energy

HARBOUR ENERGY PLC

(a public limited company incorporated and registered in Scotland under number SC234781)

PROPOSED READMISSION OF EXISTING ORDINARY SHARES AND ISSUE AND APPLICATION FOR ADMISSION TO THE PREMIUM LISTING SEGMENT OF THE OFFICIAL LIST OF THE FINANCIAL CONDUCT AUTHORITY AND TO TRADING ON THE MAIN MARKET FOR LISTED SECURITIES OF THE LONDON STOCK EXCHANGE OF 669,714,027 BASF CONSIDERATION SHARES IN CONNECTION WITH THE PROPOSED ACQUISITION OF THE TARGET PORTFOLIO

Joint Financial Adviser and Sponsor
Barclays

Joint Financial Adviser
J.P. Morgan

The ordinary shares in the capital of the Company with a nominal value of 0.002 pence each (the "**Ordinary Shares**") are listed on the premium listing segment of the Official List of the FCA and traded on the main market for listed securities of London Stock Exchange plc (the "**London Stock Exchange**"). As the acquisition of the Target Portfolio (the "**Acquisition**") is classified as a reverse takeover under the Listing Rules, the listing of the Ordinary Shares will be cancelled and applications will be made to the FCA for the Ordinary Shares to be readmitted to the premium listing segment of the Official List (or the segment of the Official List for equity shares of commercial companies ("**ESCCs**"), if applicable at the time of application) and to the London Stock Exchange for the Ordinary Shares to be readmitted to trading on the London Stock Exchange's main market for listed securities (together, "**Readmission**"). Applications will also be made to the FCA for the new Ordinary

Shares to be issued to BASF pursuant to the Business Combination Agreement ("**BASF Consideration Shares**") to be admitted to the premium listing segment of the Official List of the FCA (or the segment of the Official List for ESCCs, if applicable at the time of application) and to the London Stock Exchange for the BASF Consideration Shares to be admitted to trading on the main market for listed securities of the London Stock Exchange (together "**Admission**"). It is expected that Readmission and Admission will become effective, and that dealings in the Ordinary Shares and the BASF Consideration Shares will commence, as soon as reasonably practicable once all the Conditions to Completion have been satisfied, which is currently expected to be in Q4 2024.

Neither the Ordinary Shares, the BASF Consideration Shares nor any other securities in the Company have been marketed to, nor are available for purchase, in whole or in part, by the public in the United Kingdom or elsewhere in connection with Readmission and Admission. **This Prospectus does not constitute or form part of any invitation to purchase, subscribe for, sell or issue, or any solicitation of any offer to purchase, subscribe for, sell or issue Ordinary Shares.**

Investors should only rely on the information contained in this Prospectus and contained in any documents incorporated into this Prospectus by reference. No person has been authorised to give any information or make any representations other than those contained in this Prospectus and any document incorporated by reference and, if given or made, such information or representation must not be relied upon as having been so authorised by the Company, the Directors, Barclays Bank PLC ("**Barclays**"), J.P. Morgan Securities plc (which conducts its UK investment banking activities under the marketing name J.P. Morgan Cazenove) ("**J.P. Morgan**") or any other person involved in the Acquisition or Admission. In particular, the contents of the Company's website, the contents of any website accessible from hyperlinks on such website or any other website referred to in this Prospectus do not form part of this Prospectus and prospective investors should not rely on them. Without prejudice to any legal or regulatory obligation on the Company to publish a supplementary prospectus pursuant to Article 23 of the UK Prospectus Regulation, neither the delivery of this Prospectus nor Admission shall, under any circumstances, create any implication that there has been no change in the business or affairs of the Company, Harbour Energy, the Target Company, and/or Harbour Energy following completion of the Acquisition (the "**Enlarged Group**") in accordance with the terms of the Business Combination Agreement ("**Completion**"), each taken as a whole since the date of this Prospectus or that the information in it is correct as at any time after the date of this Prospectus. The Company will comply with its obligation to publish supplementary prospectuses and other information containing further updated information as required by law or by a regulatory authority and, in particular, its obligations under the Prospectus Regulation Rules, the Listing Rules and the Disclosure Guidance and Transparency Rules (as appropriate) but assumes no further obligation to publish additional information.

Barclays, which is authorised by the Prudential Regulatory Authority ("**PRA**") and regulated by the FCA and the PRA in the United Kingdom, is acting exclusively as sole sponsor and joint financial adviser to the Company and no one else in connection with the Acquisition and/or Admission and will not be responsible to anyone other than the Company for providing the protections afforded to its clients or for providing any advice in connection with the Acquisition and/or Admission and will not regard any other person (whether or not a recipient of this Prospectus) as its client in relation to the Acquisition and/or Admission, the contents of this Prospectus or any matter or arrangement referred to in this Prospectus.

J.P. Morgan, which is authorised by the PRA and regulated by the FCA and the PRA in the United Kingdom, is acting exclusively as joint financial adviser to the Company and no one else in connection with the Acquisition and/or Admission and will not be responsible to anyone other than the Company for providing the protections afforded to its clients or for providing any advice in connection with the Acquisition and/or Admission and will not regard any other person (whether or not a recipient of this Prospectus) as its client in relation to the Acquisition and/or Admission, the contents of this Prospectus or any matter or arrangement referred to in this Prospectus.

Apart from the responsibilities and liabilities, if any, which may be imposed on Barclays and/or J.P. Morgan by the FSMA or the regulatory regime established thereunder, neither Barclays and/or J.P. Morgan nor any of their respective affiliates accept any responsibility or liability whatsoever and make no representations or warranties, express or implied, in relation to the contents of this Prospectus, including its accuracy, completeness or verification, or for any other statement made or purported to be made by the Company, or on the Company's behalf, in connection with Harbour Energy, the Enlarged Group, the Acquisition, Admission or the BASF Consideration Shares, and nothing contained in this Prospectus is, or shall be relied upon as, a promise or representation in this respect, whether or not as to the past or the future. Barclays and/or J.P. Morgan and their respective affiliates accordingly disclaim to the fullest extent permitted by applicable law all and any duty, liability or responsibility whatsoever (whether direct or indirect and whether arising in tort, contract, under statute or otherwise (save as referred to above)) which they might otherwise be found to have in respect of this Prospectus or any such statement.

THE CONTENTS OF THIS PROSPECTUS OR ANY SUBSEQUENT COMMUNICATION FROM THE COMPANY, BARCLAYS, J.P. MORGAN OR ANY OF THEIR RESPECTIVE AFFILIATES, OFFICERS, DIRECTORS, EMPLOYEES OR AGENTS ARE NOT TO BE CONSTRUED AS LEGAL, FINANCIAL OR TAX ADVICE. EACH PROSPECTIVE INVESTOR SHOULD CONSULT HIS, HER OR ITS OWN SOLICITOR, INDEPENDENT FINANCIAL ADVISER OR TAX ADVISER FOR LEGAL, FINANCIAL OR TAX ADVICE.

THIS PROSPECTUS DOES NOT CONSTITUTE OR FORM PART OF AN OFFER OF AND MAY NOT BE USED FOR THE PURPOSES OF, AN OFFER TO SELL OR AN INVITATION, OR THE SOLICITATION OF AN OFFER TO SUBSCRIBE FOR OR BUY, ANY SECURITIES. NONE OF THE SECURITIES REFERRED TO IN THIS PROSPECTUS SHALL BE SOLD, ISSUED OR TRANSFERRED IN ANY JURISDICTION IN CONTRAVENTION OF APPLICABLE LAW.

The release, publication or distribution of this Prospectus in jurisdictions other than the United Kingdom may be restricted by law. This Prospectus has been prepared to comply with requirements of English law, the Listing Rules, the Prospectus Regulation Rules and the rules of the London Stock Exchange and information disclosed may not be the same as that which would have been disclosed if this Prospectus had been prepared in accordance with the laws of jurisdictions outside of the United Kingdom. No action has been taken by the Company, Barclays or J.P. Morgan to permit the release, publication or distribution of this Prospectus in any jurisdiction (other than the United Kingdom) where action for that purpose may be required or doing so is restricted by law. Accordingly, neither this Prospectus nor any advertisement may be released, published or distributed in any other jurisdiction except under circumstances that will result in compliance with any applicable laws and regulations. Persons into whose possession this Prospectus comes should inform themselves about and observe any such restrictions. Any failure to comply with such restrictions may constitute a violation of the securities laws of any such jurisdiction. No public offering of the BASF Consideration Shares or the Ordinary Shares is being made in the United Kingdom, the United States or elsewhere.

This Prospectus is not for release, publication or distribution, directly or indirectly, in whole or in part, in, into or from any jurisdiction in which the same would be restricted, unlawful or unauthorised (each a "**Restricted Territory**"). This Prospectus does not constitute an offer to purchase, subscribe for, sell or issue or the solicitation of an offer to purchase, subscribe for, sell or issue shares in the capital of the Company in any Restricted Territory or to any person to whom it is unlawful to make such offer or solicitation. Any failure to comply with these restrictions may constitute a violation of the securities laws of such jurisdictions. Subject to certain exemptions, the securities referred to herein may not be offered or sold in any Restricted Territory or for the account or benefit of any national resident or citizen of any Restricted Territory.

The securities referred to in this Prospectus have not been and will not be registered under the US Securities Act of 1933, as amended (the "**US Securities Act**"), or under the securities laws of any state or other jurisdiction of the United States, and may not be offered or sold, directly or indirectly, in the United States absent registration under the US Securities Act or an available exemption from the registration requirements of the US Securities Act and in compliance with any applicable securities laws of any state or other jurisdiction of the United States. The securities referred to in this Prospectus have not been approved by the US Securities and Exchange Commission, any state securities commission or any other regulatory authority in the United States, nor have any of the foregoing authorities passed upon, determined or endorsed the merits of the Acquisition or the accuracy or adequacy of the information contained in this Prospectus. Any representation to the contrary is a criminal offence in the United States. No public offering of the Shares is being made in the United States or any other Restricted Territory.

Capitalised terms have the meanings ascribed to them in Part XV (*Definitions and Interpretation*) of this Prospectus.

This Prospectus is dated 12 June 2024.

CONTENTS

	Page
SUMMARY INFORMATION	2
RISK FACTORS	9
IMPORTANT INFORMATION	43
INFORMATION INCORPORATED BY REFERENCE	46
EXPECTED TIMETABLE OF PRINCIPAL EVENTS	49
ACQUISITION STATISTICS	50
DIRECTORS, COMPANY SECRETARY, REGISTERED OFFICE AND ADVISERS	51
PART I INFORMATION ABOUT THE ACQUISITION	52
PART II INFORMATION ON HARBOUR ENERGY	62
PART III INFORMATION ON THE TARGET PORTFOLIO	84
PART IV REGULATORY OVERVIEW	105
PART V CAPITALISATION AND INDEBTEDNESS STATEMENT	123
PART VI OPERATING AND FINANCIAL REVIEW RELATING TO HARBOUR ENERGY	126
PART VII OPERATING AND FINANCIAL REVIEW RELATING TO THE TARGET PORTFOLIO	148
PART VIII HISTORICAL FINANCIAL INFORMATION RELATING TO HARBOUR ENERGY	164
PART IX HISTORICAL FINANCIAL INFORMATION RELATING TO THE TARGET PORTFOLIO	165
PART X UNAUDITED PRO FORMA FINANCIAL INFORMATION	221
PART XI COMPETENT PERSON'S REPORT ON THE TARGET COMPANY'S PORTFOLIO	227
PART XII UNITED KINGDOM TAXATION	355
PART XIII DIRECTORS, SENIOR MANAGERS AND CORPORATE GOVERNANCE	359
PART XIV ADDITIONAL INFORMATION	368
PART XV DEFINITIONS AND INTERPRETATION	410

SUMMARY INFORMATION

1. INTRODUCTION AND WARNINGS

1.1 Name and ISIN of the securities

Name: Ordinary Shares. ISIN: GB00BMBVGQ36. Ticker: HBR.

Name: BASF Consideration Shares. ISIN: GB00BMBVGQ36. Ticker: HBR.

1.2 Identity and contact details of the issuer

Harbour Energy plc (the "**Company**", and together with its subsidiaries and subsidiary undertakings, "**Harbour Energy**"). Address: 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh EH1 2EN, United Kingdom. Telephone: +44 20 7730 1111. LEI: 213800YPC42DYBKVPF97.

1.3 Identity and contact details of the competent authority

Name: Financial Conduct Authority.

Address: 12 Endeavour Square, London E20 1JN, United Kingdom.

Telephone: +44 20 7066 1000.

1.4 Date of approval of the Prospectus

12 June 2024.

1.5 Warnings

This summary should be read as an introduction to this Prospectus. Any decision to invest in the securities should be based on consideration of this Prospectus as a whole by the investor. The investor could lose all or part of the invested capital. Civil liability attaches only to those persons who have tabled the summary including any translation thereof, but only where the summary is misleading, inaccurate or inconsistent when read together with the other parts of this Prospectus, or where it does not provide, when read together with the other parts of this Prospectus, key information in order to aid investors when considering whether to invest in the securities.

2. KEY INFORMATION ON THE ISSUER

2.1 Who is the issuer of the securities?

Domicile and legal form, LEI, applicable legislation and country of incorporation

The Company is incorporated under the laws of Scotland with its registered office in United Kingdom and its legal entity identifier (LEI) is 213800YPC42DYBKVPF97. The Company was incorporated and registered in Scotland on 31 July 2002 with registered number SC234781 as a private limited company under the Companies Act 1985 with the name Dalgen (No.836) Limited. On 10 March 2003, the Company was re-registered as a public company and changed its name to Premier Oil Group plc. Premier Oil Group plc changed its name to Premier Oil plc on 15 July 2003. On 31 March 2021, the Company changed its name to Harbour Energy plc.

Principal activity

The principal activity of the Company is to act as the ultimate holding company of Harbour Energy. The principal legislation under which the company operates is the Companies Act 2006 and the regulations made thereunder.

Major shareholders

As at 7 June 2024 (the "**Latest Practicable Date**"), the Company had been notified in accordance with Chapter 5 of the Disclosure Guidance and Transparency Rules that the following persons are directly or indirectly interested (within the meaning of the Companies Act) in the Ordinary Shares:

Name	Number of Ordinary Shares as at the Latest Practicable Date	Percentage of Ordinary Shares as at the Latest Practicable Date	Number of Ordinary Shares as at Admission(1)	Percentage of Ordinary Shares capital as at Admission(1)	Number of Ordinary Shares upon conversion of all Non-Voting Shares(2)	Percentage of Ordinary Shares upon conversion of all Non-Voting Shares(2)
EIG Asset Management, LLC	134,281,887	16.74	134,281,887	9.32	134,281,887	7.94
Control Empresarial de Capitales	54,901,500	7.13	54,901,500	3.81	54,901,500	3.25
Bank of America Corporation	26,720,962	3.47	26,720,962	1.86	26,720,962	1.58

Notes

(1) This assumes that no further issues of Ordinary Shares occur between the Latest Practicable Date and Admission.

(2) Assuming conversion of all Non-Voting Shares and no further issues of Ordinary Shares having occurred between Admission and the date of conversion of the Non-Voting Shares.

Key managing directors

Linda Z. Cook is the Chief Executive Officer and Alexander Krane is Chief Financial Officer.

Statutory auditor

Ernst & Young LLP, whose registered address is at 1 More London Place, London SE1 2AF, United Kingdom.

2.2 **What is the key financial information?**

Harbour Energy

Income Statement Information	For the year ended 31 December 2021	For the year ended 31 December 2022	For the year ended 31 December 2023
		($ million)	
Revenue	3,479	5,390	3,715
Operating profit/loss	640	2,541	913
Profit for the year	101	8	32
Earnings per Ordinary Share—basic	11.6¢	0.9¢	4¢
Earnings per Ordinary Share—diluted	11.6¢	0.9¢	4¢

Balance Sheet Information	As at 31 December 2021	As at 31 December 2022	As at 31 December 2023
		($ million)	
Total assets	14,505	12,566	9,897
Total equity	473	1,021	1,540
Total liabilities	14,031	11,544	8,357

Cash Flow Statement Information	For the year ended 31 December 2021	For the year ended 31 December 2022	For the year ended 31 December 2023
		($ million)	
Net cash inflow from operating activities	1,614	3,130	2,144
Net cash outflow from investing activities	(571)	(629)	(693)
Net cash outflow from financing activities	(787)	(2,675)	(1,667)

There are no qualifications to Ernst & Young LLP's audit report on the consolidated financial statements of Harbour Energy for the years ended 31 December 2021, 2022 and 2023.

Target Portfolio

Income Statement Information	For the year ended 31 December 2021	For the year ended 31 December 2022	For the year ended 31 December 2023
		($ million)	
Revenue	4,892	7,984	6,337
Operating profit/(loss)	1,475	4,332	2,791
Profit/(loss) for the year	(55)	781	547

Balance Sheet Information	As at 31 December 2021	As at 31 December 2022	As at 31 December 2023
		($ million)	
Total assets	25,714	25,800	16,534
Total invested capital attributable to the Target Portfolio investors	6,651	6,690	792
Total liabilities	19,063	19,110	15,742

Cash Flow Statement Information	For the year ended 31 December 2021	For the year ended 31 December 2022	For the year ended 31 December 2023
		($ million)	
Net cash inflow from operating activities	3,108	3,655	1,597
Net cash outflow from investing activities	(3,871)	(3,147)	(164)
Net cash inflow / (outflow) from financing activities	802	(305)	(1,212)

Reporting accountants in respect of the historical financial information on the Target Portfolio

There are no qualifications to KPMG's accountant's report on the combined financial information of the Target Portfolio for the years ended 31 December 2021, 31 December 2022 and 31 December 2023.

Pro forma financial information

The unaudited pro forma financial information has been prepared to illustrate the effect of the Acquisition on: (i) the consolidated earnings of Harbour Energy for the year ended 31 December 2023 as if the Acquisition had taken place on 1 January 2023 and (ii) the consolidated net assets of Harbour Energy as at 31 December 2023 as if the Acquisition had occurred on 31 December 2023. The unaudited pro forma financial information, which has been produced for illustrative purposes only, by its nature addresses a hypothetical situation and, therefore, does not represent Harbour Energy's or the Enlarged Group's actual financial position or results.

The unaudited pro forma financial information has been compiled on a basis consistent with the accounting policies of Harbour Energy used to prepare its audited consolidated financial statements for the year ended 31 December 2023 and in accordance with Annex 20 to the UK Prospectus Regulation.

Unaudited Pro Forma Income Statement	Harbour Energy for the year ended 31 December 2023	The Target Portfolio for the year ended 31 December 2023	Transaction costs	Financing adjustments	Subordinated notes	Pro forma income statement of the Enlarged Group
			$ million			
Revenue	3,715	6,337	—	—	—	10,052
Operating profit/(loss)	913	2,791	(61)	—	—	3,643
Profit/(loss) for the year attributable to equity holders of the company	32	547	(61)	(32)	59	545

Unaudited Pro Forma Statement of Net Assets	Harbour Energy as at 31 December 2023	The Target Portfolio as at 31 December 2023	Transaction costs	Combination accounting adjustments	Financing adjustments	Subordinated notes	Pro forma statement of net assets of the Enlarged Group
				$ million			
Total assets . . .	9,897	16,534	(71)	1,086	1,618	(213)	28,851
Total liabilities .	8,357	15,742	(10)	39	1,687	(1,694)	24,121
Net assets	1,540	792	(61)	1,047	(69)	1,481	4,730

The unaudited consolidated pro forma profit before taxation for the year ended 31 December 2023 was $3,085 million. The unaudited consolidated pro forma net assets as at 31 December 2023 was $4,730 million.

2.3 **What are the key risks that are specific to the issuer?**

Risks relating to the Acquisition

- The Acquisition is conditional upon certain conditions which may take longer to satisfy than expected or may not be satisfied, as a result of which the Acquisition may not be implemented on its current terms, in a timely manner or possibly at all.
- The anticipated benefits from the Acquisition will depend on the Enlarged Group's ability to ensure operational performance and business continuity on transfer of the Target Portfolio's assets and to successfully integrate the Target Portfolio into Harbour Energy.
- Acquisition-related costs may exceed the Company's expectations and may affect the Company's ability to realise the anticipated benefits of the Acquisition in a timely manner or possibly at all.

Risks relating to Harbour Energy and, following Completion, the Enlarged Group as a result of the Acquisition

- Harbour Energy's production is currently concentrated in the United Kingdom exposing it to adverse or uncertain political, regulatory or fiscal developments and other risks associated with having the substantial majority of its production in one region.
- Harbour Energy may be exposed to adverse or uncertain political, security, economic, legal, regulatory and social developments in the territories where it operates or maintains interests and, following Completion, where the Enlarged Group will operate or maintain interests which may affect its existing business or reduce the attractiveness of potential new investments in the territory.
- Harbour Energy and, following Completion, the Enlarged Group may be adversely affected by changes to tax legislation or its interpretation or increases in effective tax rates in the jurisdictions in which it conducts its business.
- Harbour Energy and, following Completion, the Enlarged Group may be unable to replace its proved plus probable reserves as they are produced which could lead to a decline in its reserves, production and revenue.
- Harbour Energy has and, following Completion, the Enlarged Group may have limited influence on its joint venture partners. Operating joint venture partners may not manage assets in line with the values and business objectives of Harbour Energy and, following Completion, the Enlarged Group. This may result in a failure to maximise growth opportunities, loss of value or increased risk exposure.
- Harbour Energy and, following Completion, the Enlarged Group may fail to maintain a robust balance sheet by ensuring sufficient access to capital on satisfactory terms through the commodity price cycle to implement its strategy.
- Harbour Energy's and, following Completion, the Enlarged Group's failure to deliver on its stated climate change commitments and to adapt its strategy in the context of evolving external requirements and expectations, coupled with the effects of climate change and political and societal perception of the production and use of fossil fuels, may have a material adverse effect on the hydrocarbon industry, Harbour Energy and, following Completion, the Enlarged Group.

Risks relating to the oil and gas industry

- Harbour Energy and, following Completion, the Enlarged Group may face a major health, safety, environmental or physical security incident resulting in personal injury, physical property damage and/or environmental harm.
- Harbour Energy is and, following Completion, the Enlarged Group will be exposed to volatility in prevailing hydrocarbon prices and failure to manage the impact of commodity price fluctuations on the business may have a material adverse impact on its business, operating results, financial condition and prospects.

Risks relating to Readmission and Admission and an investment in the Ordinary Shares

- The market price of the Ordinary Shares could be negatively affected by sales of substantial amounts of Ordinary Shares by BASF and, in the event Non-Voting Shares are converted into Ordinary Shares, LetterOne in the public markets (or the perception that these sales could occur) following the expiry of lock-up agreements and/or the fact that the Enlarged Group will have a more concentrated shareholder base following Completion.

3. KEY INFORMATION ON THE SECURITIES

3.1 What are the main features of the securities?

Type, class and ISIN of the securities

The Company is proposing to issue 669,714,027 new ordinary shares to BASF ("**BASF Consideration Shares**") pursuant to the acquisition by the Company of substantially all of Wintershall Dea AG's upstream oil and gas assets (the "**Target Portfolio**") (the "**Acquisition**"). In addition, the Company is proposing to issue 251,488,211 Non-Voting Shares to LetterOne as part of the consideration for the Acquisition. Since the Acquisition is classified as a reverse takeover under the Listing Rules, the listing of the Ordinary Shares will be cancelled and applications will be made to the FCA for the Ordinary Shares to be readmitted to the premium listing segment of the Official List (or the segment of the Official List for equity shares of commercial companies ("**ESCCs**"), if applicable at the time of application) and to the London Stock Exchange plc (the "**London Stock Exchange**") for the Ordinary Shares to be readmitted to trading on the London Stock Exchange's main market for listed securities (together, "**Readmission**"). Applications will also be made to the FCA for the BASF Consideration Shares to be admitted to the premium listing segment of the Official List of the FCA (or the segment of the Official List for ESCCs, if applicable at the time of application) and to the London Stock Exchange for the BASF Consideration Shares to be admitted to trading on the main market for listed securities of the London Stock Exchange (together "**Admission**"). In connection with the Acquisition, the Company will issue 251,488,211 non-voting, non-listed convertible ordinary shares with preferential rights to LetterOne (the "**Non-Voting Shares**"). The Non-Voting Shares will not be admitted to listing therefore no application will be made in respect of the Non-Voting Shares to the FCA or the London Stock Exchange. The BASF Consideration Shares and the Non-Voting Shares (if converted into Ordinary Shares) will constitute approximately 39.6 per cent. and 14.9 per cent., respectively, of the enlarged issued share capital of the Company following Admission. The BASF Consideration Shares and the Ordinary Shares will be registered with ISIN GB00BMBVGQ36.

Currency, denomination, par value, number of securities issued and term of the securities

Currency: pounds sterling;

Par value: ordinary shares with a nominal value of 0.002 pence each;

Number of securities: 669,714,027 BASF Consideration Shares will be issued for Admission; as at the Latest Practicable Date, there were 770,377,712 Ordinary Shares in issue (none of which are held in treasury);

Term: Indefinite

Rights attached to the securities

The BASF Consideration Shares will, following Admission, rank *pari passu* in all respects with the Ordinary Shares, including in relation to dividends or other distributions. The BASF Consideration Shares and the Ordinary Shares will have equal rights to participate in capital, dividend and distributions. In the event of insolvency, the BASF Consideration Shares and Ordinary Shares will rank behind any creditors or prior ranking capital of the Company and therefore any return for Shareholders will depend on the Company's assets being sufficient to meet prior entitlements of creditors. On a show of hands at the Company's general meetings every Shareholder who is present and every person holding a valid proxy shall have one vote and on a poll every Shareholder present in person or by proxy shall have one vote per BASF Consideration Share or Ordinary Share.

Restrictions on free transferability of the securities

The BASF Consideration Shares and the Ordinary Shares are free from any restriction on transfer, subject to the articles of association of the Company and the Companies Act 2006.

Dividends and Dividend policy

On 9 December 2021, the Company introduced a dividend policy of $200 million annually to be paid in two equal instalments. On 21 December 2023, as part of the Company's announcement of the Acquisition, the Company announced that it expects the Acquisition to support an increase in the Company's annual dividend from $200 million to c.$455 million, of which c.$380 million will be paid to holders of Ordinary Shares. This will reflect a 5 per cent. increase in dividend per Ordinary Share to 26.25 cents (based on a total expected dividend for 2023 of 25 cents/share (12 cents interim and expected 13 cents final) and 1,440.1 million Ordinary Shares post-completion).

3.2 Where will the securities be traded?

Applications will be made to the FCA for the Ordinary Shares to be readmitted and for the BASF Consideration Shares to be admitted to the premium listing segment of the Official List of the FCA (or the segment of the Official List for ESCCs, if applicable at the time of application) and to trading on the main market for listed securities of the London Stock Exchange. The Non-Voting Shares will not be admitted to listing therefore no application will be made in respect of the Non-Voting Shares to the FCA or the London Stock Exchange. It is expected that Readmission and Admission will become effective, and that dealings in the Ordinary Shares and the BASF Consideration Shares will commence, as soon as reasonably practicable once all the conditions to completion of the Acquisition have been satisfied, which is currently expected to be in Q4 2024.

3.3 What are the key risks that are specific to the securities?

- The price of the Ordinary Shares may fluctuate.
- There is no guarantee that there will be an active trading market in the Ordinary Shares.

4. KEY INFORMATION ON ADMISSION

4.1 Under which conditions and timetable can I invest in this security?

General terms and conditions

Not applicable. This Prospectus does not constitute an offer or an invitation to any person to subscribe for or purchase any securities in the Company. The BASF Consideration Shares are being issued to BASF as part of the consideration for the Acquisition. The BASF Consideration Shares and the Ordinary Shares are not being offered to the public.

Expected Timetable[1]

Announcement of the Acquisition	21 December 2023
Publication of the Circular	12 June 2024
Publication of this Prospectus	12 June 2024
General Meeting	5 July 2024
BASF Consideration Shares issued in connection with the Acquisition	On completion of the Acquisition
Readmission and Admission and commencement of dealings in the Ordinary Shares and the BASF Consideration Shares on the London Stock Exchange . . .	Following completion of the Acquisition[2]

Notes

(1) The above dates and times may be brought forward or extended and any changes will be notified via a RIS announcement. References to times are to London time unless otherwise stated.

(2) As soon as reasonably practicable once all the conditions to completion of the Acquisition have been satisfied, which is currently expected to be in Q4 2024.

Details of admission to trading on a regulated market

Applications will be made to the FCA for the Ordinary Shares to be readmitted and for the BASF Consideration Shares to be admitted to the premium listing segment of the Official List of the FCA (or the segment of the Official List for ESCCs, if applicable at the time of application) and to trading on the main market for listed securities of the London Stock Exchange. It is expected that Readmission and Admission will become effective, and that dealings in the BASF Consideration Shares will commence, as soon as reasonably practicable once all the conditions to completion of the Acquisition have been satisfied, which is currently expected to be in Q4 2024.

Amount and percentage of immediate dilution resulting from the issue

Immediately following Admission it is expected that the Company will have 1,440,091,739 fully paid Ordinary Shares in issue (none of which will be held in treasury).

If Admission occurs, it will result in the allotment and issue of 669,714,027 BASF Consideration Shares and 251,488,211 Non-Voting Shares. Existing Shareholders will suffer an immediate dilution as a result of Admission, following which they will hold approximately 53.5 per cent. of the enlarged ordinary share capital of the Company. If the Non-Voting Shares were to be converted into Ordinary Shares, the Company's current shareholders would own 45.5 per cent. of the Company; BASF and LetterOne would own 39.6 per cent. and 14.9 per cent., respectively.

Estimate of the total expenses of the issue

The aggregate costs and expenses of the Acquisition and Admission (including the listing fees of the FCA and the London Stock Exchange, professional fees and expenses and the costs of printing and distribution of documents), payable by the Company are estimated to be $150 million. Investors will not be charged any expenses by the Company.

4.2 Why is this Prospectus being produced?

This Prospectus has been prepared in connection with the proposed Readmission of the Ordinary Shares and the Admission of the BASF Consideration Shares which are proposed to be issued to BASF in connection with the Acquisition. There are no conflicting interests that are material to the Readmission and the Admission.

RISK FACTORS

Any investment in Ordinary Shares (including the BASF Consideration Shares) is subject to a number of risks and uncertainties. Each of these risks is expected to continue to be relevant to the Enlarged Group (and any investment in the Ordinary Shares) following Completion.

Before making any investment, prospective investors should carefully consider the factors, risks and uncertainties associated with any such investment and Harbour Energy's and, following Completion, the Enlarged Group's business, strategy and the industry and macroeconomic environment in which they operate, together with all other information in this document and the information incorporated into this document by reference, including, in particular, the risk factors discussed below.

Prospective investors should note that the risks and uncertainties identified in the section of this document headed "Summary" are the risks and uncertainties that the Directors believe to be most essential to an assessment by a prospective investor of whether to consider an investment in Ordinary Shares. However, these should not be regarded as a complete and comprehensive statement of all potential risks and uncertainties. Additional risks and uncertainties that are not presently known to the Directors, or which the Directors would deem immaterial, may (individually or cumulatively) also have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's business, operating results, financial condition or prospects. If any such risks were to materialise, the price of the Ordinary Shares could decline as a consequence and investors could lose all or part of their investment.

SECTION A: RISKS RELATING TO THE ACQUISITION

1. ***The Acquisition is conditional upon certain conditions which may take longer to satisfy than expected or may not be satisfied, as a result of which the Acquisition may not be implemented on its current terms, in a timely manner or possibly at all***

   The Acquisition is subject to the satisfaction (or waiver, where applicable) of certain conditions contained in the Business Combination Agreement (which is summarised in more detail in paragraph 15.1 (Business Combination Agreement) of Part XIV (*Additional Information*)), including, among other things: (i) the approval of the Resolutions by Shareholders at the General Meeting; (ii) the Spin-off having been registered with the commercial register of Wintershall Dea and thereby having become effective; (iii) consent having been obtained from the relevant regulatory authorities, including amongst others in the United Kingdom, Mexico, Denmark and Algeria; (iv) merger control clearances or non-objections having been obtained from, amongst others, the relevant competition authorities in COMESA, Mexico and Ukraine; (v) foreign direct investment clearance having been obtained from the relevant authority in the United Kingdom; (vi) a clearance having been obtained from the European Commission under the Foreign Subsidies Regulation (Regulation (EU) 2022/2560); (vii) none of the parties to the Business Combination Agreement being subject to sanctions restrictions and Completion not causing any such party to be in violation of certain sanctions laws; and (viii) Completion having occurred by no later than 21 June 2025. While the merger control conditions in the United Kingdom and the European Union, the foreign direct investment condition in Denmark and Germany, the regulatory consent conditions in Norway and Egypt and the registration of Harbour Argentina with the Federal Oil Companies Registry in Argentina have been satisfied, there is no guarantee that the remaining outstanding conditions will be satisfied (or waived, if applicable), in which case the Acquisition would not be implemented on its current terms or possibly at all.

   Whilst it is currently anticipated that Completion will occur in Q4 2024, no assurance can be given that all of the conditions to Completion will have been satisfied (or waived, if applicable) by such time. In the event that the conditions to Completion have not been satisfied (or waived, if applicable) by 17.00 CET on 21 June 2025, being the long stop date for Completion in the Business Combination Agreement, then absent agreement being reached between the parties to the Business Combination Agreement to extend the long-stop date, the Business Combination Agreement will terminate.

   If the Acquisition does not proceed to Completion as a result of any of the above conditions not being satisfied (or waived, if applicable), the benefits expected to result from the Acquisition will not materialise either at all or in part. The market price of the Ordinary Shares may decline if, among other reasons, the Acquisition does not proceed to Completion.

2. ***The anticipated benefits from the Acquisition will depend on the Enlarged Group's ability to ensure operational performance and business continuity on transfer of the Target Portfolio's assets and to successfully integrate the Target Portfolio into Harbour Energy***

The Enlarged Group may fail to adequately ensure the continued safe operational performance and business continuity on transfer of the assets included in the Target Portfolio. The Enlarged Group may also encounter transition and integration challenges in connection with the Acquisition, including challenges which are not currently foreseeable.

Successful execution of the Acquisition will include properly planning and executing the transition of the acquired businesses, operating assets, organisational structures (including the appropriate resourcing of that organisation) and processes, controls and systems of the Target Portfolio, and ensuring that Harbour Energy and the Target Portfolio continue to operate safely and without interruptions on Completion. The consequences of the transition process may, at least initially, lead to increased complexity, job security concerns, increased workloads, disengagement or loss of key staff which in turn may have an adverse impact on business continuity and/or the safe operational performance of the business.

Furthermore, integrating the acquired businesses, operating assets, organisational structures and processes, controls and systems of the Target Portfolio post Completion may prove more difficult, be more expensive or take longer than anticipated. Integration may, at least initially, lead to increased complexity, job security concerns, increased workloads, disengagement or loss of key staff which in turn may have an adverse impact on business continuity and/or the safe operational performance of the business. Integration of the Target portfolio into the Enlarged Group may initially disrupt the Enlarged Group's business for reasons including differences in operational and business culture, cost saving measures, difficulty preserving existing supplier or other important commercial relationships, unforeseen legal, fiscal, regulatory, labour or contractual issues arising from the Acquisition, or difficulty maintaining effective internal controls over cash flows and expenditures. The integration process may take longer than expected, or difficulties relating to the integration, of which the Directors are not yet aware, including unforeseen operating difficulties or fiscal uncertainties, may arise and pose management, administrative and financial challenges. Unexpected difficulties during the integration process may result in the need for senior management to devote more of their time and focus on the integration process which may have an adverse impact on other aspects of the business. The actual costs of the transition, integration and post-Completion process may exceed those estimated and there may be further additional and unforeseen expenses incurred in connection with the Acquisition. The occurrence of any of the above could adversely affect the delivery of the anticipated benefits from the Acquisition or result in greater costs and the Enlarged Group may not be successful in addressing risks or problems encountered in connection with the integration and failure to do so may adversely affect its business or financial condition.

The Enlarged Group may also be subject to personnel-related risks arising from the Acquisition. Members of the Target Portfolio workforce or existing employees of Harbour Energy may become distracted or disengaged from maintaining the performance of the Target Portfolio or Harbour Energy as a result of uncertainty associated with the Acquisition. In particular, a number of employees who are considered to be instrumental in ensuring a smooth transition and/or successful integration of the Target Portfolio into Harbour Energy may resign as a result of the Acquisition. In addition, the ability to achieve the anticipated benefits of the Acquisition is dependent upon a number of personnel-related factors, some of which may be beyond the control of the Enlarged Group including, for example, the ability of Harbour Energy personnel and the Target Portfolio personnel to work together effectively and efficiently in the new organisation.

The market price of the Ordinary Shares may decline as a result of the Acquisition if, among other reasons, the integration of Harbour Energy and the Target Portfolio is delayed or unsuccessful or the Enlarged Group fails to ensure the continued safe operational performance and business continuity on transfer of the Target Portfolio assets.

3. ***Acquisition-related costs may exceed the Company's expectations and may affect the Company's ability to realise the anticipated benefits of the Acquisition in a timely manner or possibly at all***

Harbour Energy expects to incur costs in relation to the Acquisition, including transition, integration and post-completion costs in order to integrate Harbour Energy and the Target Portfolio. To assist the integration process, a transitional services agreement (the "**TSA**") was entered into on 19 April 2024 in connection with the Acquisition pursuant to which certain transitional services are to be provided by Wintershall Dea to the Company to facilitate business continuity and migration planning and implementation. If the TSA fails to deliver the anticipated benefits, the actual costs of the transition and integration process may exceed those estimated and there may be further additional and unforeseen expenses incurred in connection with the Acquisition. In addition, Harbour Energy will incur legal, accounting and transaction fees and other costs relating to the Acquisition, some of which are payable whether or not the Acquisition is completed. Further details of the TSA are set out in paragraph 15.7 (Transitional Services Agreement) of Part XIV (*Additional Information*).

The market price of the Ordinary Shares may decline as a result of the Acquisition if, among other reasons, the effect of the Acquisition on the Company's financial results, including the actual costs of the transition and integration process (for example, in connection with ensuring effective workforce integration) and Acquisition-related costs, is not consistent with the expectations of investors. The market price of the Ordinary Shares may also decline as a result of the Acquisition if the integration of Harbour Energy and the Target Portfolio is delayed or unsuccessful or the anticipated benefits of the Acquisition fail to materialise.

4. ***Harbour Energy and, following Completion, the Enlarged Group may be subject to unforeseen liabilities and risks arising from liabilities or third party rights related to the Target Portfolio of which Harbour Energy is unaware or from Harbour Energy's and, following Completion, the Enlarged Group's inability to enforce its contractual or other rights in connection with the Acquisition***

Whilst Harbour Energy has had access to certain available information on the Target Portfolio and has reviewed information disclosed by BASF and LetterOne during the sale process, there can be no assurance that material assets held by members of the Target Portfolio are not subject to third party rights and liabilities of which Harbour Energy is unaware. Whilst some limited warranty protection in respect of fundamental warranties is provided for by BASF and LetterOne under the Business Combination Agreement, these warranties are subject to limitations and there is no certainty that Harbour Energy would be able to enforce its contractual or other rights against BASF and LetterOne. The market price of Ordinary Shares may decline as a result of the Acquisition if, among other reasons, material assets held by subsidiaries of the Target Company are subject to liabilities or third party rights of which Harbour Energy is unaware or if Harbour Energy is unable to enforce its contractual or other rights against BASF and LetterOne as and when expected, or at all. Further details of the Business Combination Agreement are set out in paragraph 15.1 (Harbour Energy Material Contracts) of Part XIV (*Additional Information*).

5. ***The Business Combination Agreement contains covenants and warranties in favour of BASF and LetterOne and potential liabilities arising from any breaches could have an adverse effect on Harbour Energy and, following Completion, the Enlarged Group's, cash flow and financial condition***

Under the Business Combination Agreement, Harbour Energy has given covenants and certain fundamental warranties to BASF and LetterOne, which are customary for a transaction of this nature. Further details of the Business Combination Agreement are set out in paragraph 15.1 (Harbour Energy Material Contracts) of Part XIV (*Additional Information*). If Harbour Energy were to breach any of the covenants or fundamental warranties and be required to make payments under any of the provisions described above, this could have an adverse effect on its and, following Completion, the Enlarged Group's cash flow and financial condition. The market price of the Ordinary Shares may decline as a result of the Acquisition if, among other reasons, the effect of the Acquisition on the Company's financial results, including the effect on the Enlarged Group's cash flow and financial condition resulting from any of the payments described above, is not consistent with the expectations of investors.

6. ***Readmission and Admission may not occur when expected***

Completion is conditional upon (among other things) the FCA and the London Stock Exchange having confirmed to Harbour Energy that applications relating to Admission have been approved by no later than 21 June 2025, or such other date as BASF, LetterOne and Harbour Energy may agree in writing.

Readmission of the Ordinary Shares and Admission of the BASF Consideration Shares, to trading on the London Stock Exchange's main market for listed securities will become effective as soon as a dealing notice has been issued by the FCA and the London Stock Exchange has acknowledged that the Ordinary Shares and the BASF Consideration Shares will be admitted to trading. There can be no guarantee that any conditions to which the Readmission and the Admission are subject will be met or that the FCA will issue a dealing notice.

SECTION B: RISKS RELATING TO HARBOUR ENERGY AND, FOLLOWING COMPLETION, THE ENLARGED GROUP AS A RESULT OF THE ACQUISITION

Host Government Political and Fiscal Risks

1. ***Harbour Energy's production is currently concentrated in the United Kingdom exposing it to adverse or uncertain political, regulatory or fiscal developments and other risks associated with having the substantial majority of its production in one region***

   As of 31 December 2023, over 90 per cent. of Harbour Energy's production came from the UKCS offshore fields. From 1 January 2023 to 31 December 2023, Harbour Energy's net average daily production was 175 kboepd from the producing assets in the UK.

   As Harbour Energy's current production is substantially UK focused, significant changes to UK governmental regulation of oil and gas production could have a material impact on Harbour Energy and, following Completion, the Enlarged Group. During 2022, the UK Government enacted, and subsequently expanded, an EPL on oil and gas producers in the country. The EPL has increased the tax paid by Harbour Energy and, following Completion, which will be payable by the Enlarged Group and has thereby impacted and will impact profits and cash flow, reducing the debt capacity of the Company and, following Completion, the Enlarged Group and created uncertainty regarding the attractiveness of existing and prospective investments in the UK, and those of Harbour Energy's joint venture partners in the region. More specifically, the EPL initially applied at a rate of 25 per cent. but was then increased to 35 per cent. from January 2023 to March 2028. This tax has resulted in Harbour Energy's headline UK tax rate being 75 per cent., which reduces both profits and cash flows. On 9 June 2023, the UK government proposed the introduction of the Energy Security Investment Mechanism (the "**ESIM**") which would end the imposition of EPL earlier than 31 March 2028 where certain conditions are met. Under the proposed ESIM, 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, then EPL will be repealed and the headline tax rate on UK oil and gas profits will return to 40 per cent. Whilst the measure is expected to be legislated for during the 2023-24 session of Parliament, oil and gas prices are not expected to fall to, or below, the quoted triggers before the existing EPL end date of 31 March 2029. The change as currently proposed is therefore not expected to materially alleviate the impact of the EPL on Harbour Energy or, following Completion, the Enlarged Group. In addition, a UK general election is currently expected to take place in late 2024 and the outcomes of this could result in further fiscal and regulatory developments which might adversely impact Harbour Energy and, following Completion, the Enlarged Group.

   A significant proportion of Harbour Energy's existing production is in the UKCS and, following Completion, the Enlarged Group's production will be in UKCS and the Norwegian Continental Shelf (the "**NCS**"). These areas, like other oil producing regions, are prone to difficult weather conditions that can in some cases prevent Harbour Energy and, following Completion, the Enlarged Group from transporting supplies, personnel and fuel to its facilities, each of which can cause production shut-downs or slow-downs. If mechanical problems, storms or other events curtail a substantial portion of Harbour Energy and, following Completion, the Enlarged Group production or cause damage to any of its facilities, it may have unpredictable and materially adverse impacts on its results of operations and financial condition.

   As a result of a significant proportion of Harbour Energy's existing production being in the UKCS and, following Completion, the Enlarged Group's production being in the UKCS and the NCS, it may be disproportionately exposed to the effect of regional supply and demand factors, delays or interruptions of production from wells in this area caused by processing or transportation capacity constraints, availability of equipment, equipment failure, facilities, personnel or services market limitations, weather events, interruption of the processing or transportation of oil or governmental regulation. Failure to engage constructively with the UK, Scottish and Norwegian governments and regulators, including for example, the North Sea Transition Authority (the "**NSTA**"), the UK Department for Energy Security and Net Zero (the "**DESNZ**"), HM Treasury and the Norwegian Offshore Directorate or to comply with the requirements of these and other regulatory bodies could result in penalties, a negative reputational impact and/or other impediments to Harbour Energy's and, following Completion, the Enlarged Group's UK and Norway operations.

2. ***Harbour Energy may be exposed to adverse or uncertain political, security, economic, legal, regulatory and social developments in the territories where it operates or maintains interests and, following Completion, where the Enlarged Group will operate or maintain interests which may affect its existing business or reduce the attractiveness of potential new investments in the territory***

Harbour Energy operates or maintains interests and, in the future the Enlarged Group will operate or maintain interests, in some countries where political, security, public health, economic, legal, regulatory and social transition is taking place or where there are sovereignty disputes. In addition, changes or uncertainty regarding future changes in politics, security, laws and regulations in the countries in which Harbour Energy operates or maintains interests and, following Completion, in which the Enlarged Group will operate or maintain interests, or which affect third parties with whom Harbour Energy does business and with whom the Enlarged Group will do business, could affect operations and earnings and reduce the attractiveness of prospective investments in such countries. Such circumstances could include:

- forced divestment of assets, including expropriation and nationalisation of property;
- Failure to receive the necessary governmental or corporate approvals for projects, the withdrawal of any required approvals, the suspension of projects or the renegotiation or nullification of existing concession contracts;
- limits on production or cost recovery;
- import and export restrictions;
- legal or practical restrictions on the free convertibility of local currencies;
- imposition of sanctions or similar measures in respect of countries of operation or interest or in respect of partners, suppliers or customers of Harbour Energy and the Enlarged Group;
- changes to legislation due to climate change and other environmental regulations, such as carbon takeback obligations;
- international conflicts including war;
- civil unrest and local security concerns that threaten the operation of Harbour Energy's and, following Completion, the Enlarged Group's facilities;
- independence movements seeking to gain national sovereignty, for example a future Scottish referendum on independence;
- price controls;
- lack of predictability or adverse changes to the operational, regulatory, legal or fiscal regime, including changes in oil or gas pricing or taxation policy;
- uncertain implementation of legislation and difficulties in ascertaining (or enforcing) Harbour Energy's and, following Completion, the Enlarged Group's legal obligations and rights, including adverse retrospective amendment and/or cancellation of contractual rights;
- excessive local content requirements; and
- outbreak of severe communicable diseases, such as COVID-19, which may be widespread and uncontrolled.

It is difficult to predict the timing or severity of these occurrences or their potential effect. However, if any of these events were to occur, they could have a material adverse effect on the employees, reputation, business, operating results, financial condition or prospects of Harbour Energy and, following Completion, the Enlarged Group.

Certain countries in which Harbour Energy has and, following Completion, the Enlarged Group will have operations also have potential issues relating to transportation, telecommunications and financial services infrastructures that may present logistical challenges not usually present whilst doing business in more developed countries. Countries in which Harbour Energy operates, or in which the Enlarged Group may operate following Completion, and third parties such as partners, customers and suppliers with whom Harbour Energy does business or with whom the Enlarged Group may do business following Completion, could become subject to trade, economic or other sanctions or similar measures affecting the ability of Harbour Energy or the Enlarged Group to carry on business in relevant countries or with relevant third parties or otherwise disrupting the operations of Harbour Energy or the Enlarged Group.

Harbour Energy may have less significant or no previous experience in these countries and failure to comply with applicable laws or regulations or a lack of familiarity with governments or key stakeholders may lead to delays, a temporary disruption in operations or shut down of production.

3. ***Harbour Energy and, following Completion, the Enlarged Group may be adversely affected by changes to tax legislation or its interpretation or increases in effective tax rates in the jurisdictions in which it conducts its business***

Harbour Energy does, and following Completion, the Enlarged Group will do, business in more than one jurisdiction and its profits are and will be taxed according to the tax laws of such jurisdictions. Jurisdiction by jurisdiction fluctuations in tax rates can have an impact on projects and make certain projects less economically viable. Harbour Energy's, and following Completion, the Enlarged Group's, tax position, including their effective tax rate, may be affected by changes in tax laws, uncertain tax positions or interpretations of tax laws in any jurisdiction and in any financial year will reflect a variety of factors that may not be present in succeeding financial years. As a result, Harbour Energy's, and following Completion, the Enlarged Group's tax position may increase in future periods, which could have a material adverse effect on Harbour Energy's, and following Completion, the Enlarged Group's, financial results and, specifically, its 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 Harbour Energy's, and following Completion, the Enlarged Group's, 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 Harbour Energy's, and following Completion, the Enlarged Group's, profits from activities in those jurisdictions may be subject to additional tax or additional unexpected transactional taxes (e.g. stamp duty, value added tax or capital gains tax) may arise, which, in each case, could result in significant legal proceedings and additional taxes, penalties and interest, any of which could have a material adverse impact on Harbour Energy's, and following Completion, the Enlarged Group's, business, prospects, financial condition or results of operations.

Harbour Energy's results of operations have also been materially affected by and, following Completion, the Enlarged Group's results of operations could be further materially affected by changes to UK tax legislation. For more information on the impact of the EPL on Harbour Energy, see "*Harbour Energy's production is currently concentrated in the United Kingdom exposing it to adverse or uncertain political, regulatory or fiscal developments and other risks associated with having the substantial majority of its production in one region*" in this "*Risk Factors*" section.

In addition, should Scotland become independent from the United Kingdom, tax law and regulations may change so that the tax regime in Scotland diverges further from the tax regime in the remaining parts of the United Kingdom. The Directors cannot assure investors that any changes to the tax regime in Scotland would not result in additional tax costs.

Capital Programme and Delivery Risks

4. ***Harbour Energy and, following Completion, the Enlarged Group may be unable to replace its proved plus probable reserves as they are produced which could lead to a decline in its reserves, production and revenue***

Harbour Energy depends and, following Completion, the Enlarged Group will depend on its ability to find, develop or acquire additional reserves that are economically recoverable, which is (among other factors) dependent on current and future oil and gas prices. Production from oil and natural gas reservoirs, particularly in the case of mature fields, is generally characterised by declining production rates that vary depending upon reservoir characteristics and other factors. Further, while well supervision and effective maintenance operations can contribute to sustaining production rates over time, the production from fields will naturally decline over time until it is no longer economic to continue production. Thus, Harbour Energy's and, following Completion, the Enlarged Group's future oil and natural gas reserves and production and, therefore, its cash flow and results of operations are highly dependent upon its ability to efficiently develop and produce from its current properties and its ability to economically select and acquire additional assets either through awards at licensing rounds or through acquisitions. Harbour Energy and, following Completion, the Enlarged Group may not be able to find, develop, or acquire sufficient additional reserves to replace its current reserves as they are produced. If Harbour Energy and, following Completion, the Enlarged Group is unable to replace its current reserves in a value accretive manner as they are produced, the amount and value of its reserves will decrease, and its business, financial condition and results of operations could be adversely affected.

Harbour Energy's and, following Completion, the Enlarged Group's reserves and levels of future production also depends on amongst other things, the success of its activities to find and appraise additional reserves that are economically viable. Exploration activities are dependent on being awarded licences at licensing rounds, entering into production sharing contracts or being successful in acquiring interests in licences held by third parties or negotiating farm-ins. Exploration and appraisal activities are capital intensive, subject to financing limitations and the results are inherently uncertain as there can be no assurance that future exploration expenditure, which is required to establish the extent of the oil and gas reserves through seismic and other surveys and drilling, will result in the discovery of commercially producible hydrocarbons. Significant expenditure is required, for example to establish the extent of oil and gas resources through seismic and other surveys and drilling. Such activities may involve unprofitable efforts, not only by drilling dry wells, but also by drilling wells that discover hydrocarbons but are of insufficient volume or in poor-quality reservoirs that cannot support commercial development. Therefore, there can be no certainty that further commercial quantities of oil and gas will be discovered, acquired or developed by Harbour Energy and, following Completion, the Enlarged Group. Harbour Energy and, following Completion, the Enlarged Group 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, a public health crisis, compliance with governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment or other factors which may result in drilling operations becoming uneconomic.

Estimates of economically recoverable oil and gas reserves and resources are based on a number of factors and assumptions made as of the date on which the reserves and resources estimates were determined, such as geological, geophysical and engineering estimates (which have inherent uncertainties), historical production from the properties or analogous reserves, 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. The quantity of underground accumulations of hydrocarbons cannot be measured in an exact manner and the estimation of this is a subjective process aimed at understanding the statistical probabilities of recovery. Reserve and resource estimates are subjective and not all underground accumulations are economically recoverable and estimates of the quantity of economically recoverable oil and gas reserves and resources and the costs, timing and rates of future production depend upon several variables and assumptions, including the following:

- quality and quantity of available data;
- interpretation of the available geological and geophysical data;
- analogue production history compared with other comparable producing areas;
- local laws and regulations;
- expectations of future oil and gas prices;
- availability of third party products and services required to develop and produce discovered hydrocarbons;
- estimates of costs required and taxes incurred to develop, produce, and ultimately decommission production facilities;
- extension of production licenses;
- the judgment of the persons preparing the estimate;
- the quantities and qualities that are ultimately recovered;
- the timing of the recovery;
- the amount and timing of development expenditures;
- the costs incurred to produce;
- future hydrocarbon sales prices; and
- costs and timing of decommissioning.

Many of the factors in respect of which assumptions are made when estimating reserves and resources are beyond Harbour Energy's and, following Completion, the Enlarged Group's control and therefore these estimates may prove to be incorrect over time. Evaluations of reserves necessarily involve multiple uncertainties. The accuracy of any reserves or resources evaluation depends on the quality of available information and oil and gas engineering and geological interpretation. If the assumptions upon which the estimates of Harbour Energy's and, following Completion, the Enlarged Group's oil and gas reserves have been based prove to be incorrect or if the actual reserves or recoverable resources available are otherwise less than the current estimates or of lesser quality than expected, Harbour Energy and, following Completion, the Enlarged Group may be unable to recover and produce the estimated levels or quality of oil, gas and other hydrocarbons.

Appraisal and development activities may also be subject to delays in obtaining governmental approvals or consents, agreeing development plans with joint venture partners, obtaining sufficient access to storage or transportation facilities or other constraints, which could materially adversely affect Harbour Energy's and, following Completion, the Enlarged Group's replacement of reserves and long-term oil and gas production. Even if Harbour Energy and, following Completion, the Enlarged Group is able to discover or acquire commercial quantities of oil and gas in the future, there can be no assurance that these will be commercially developed. Few prospects that are explored are ultimately developed into producing oil and gas fields.

Completion of Harbour Energy's and, following Completion, the Enlarged Group's 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 to be recovered. In addition, various field operating conditions may also adversely affect production from successful wells including delays in obtaining governmental approvals, permits, licences, authorisations or consents, shut ins of connected wells, or other unusual or unexpected geological, oceanographic and mechanical conditions.

Harbour Energy currently holds and, following Completion, the Enlarged Group will hold exploration licences or production sharing contracts for assets located in a number of countries and Harbour Energy maintains and, following Completion, the Enlarged Group will maintain an ongoing evaluation process to identify which exploration and appraisal opportunities to prioritise. For example, in Indonesia, Harbour Energy made significant gas discoveries at Tangkulo-1 (2024) and Layaran-1 (2023) on the South Andaman licence and at Timpan-1 on the Andaman II licence (2022). Recently, Harbour Energy drilled exploration wells targeting the Halwa and Gayo prospects on Andaman II. The Halwa-1 well encountered low gas saturations while a small gas discovery was made at Gayo.

In the future, Harbour Energy and, following Completion, the Enlarged Group will continue to manage its exploration portfolio in order to allocate capital to projects regarded as strategically important or which offer the potential to deliver higher returns, thereby not allocating capital to all its available opportunities. Even if Harbour Energy's and, following Completion, the Enlarged Group's licensing and exploration drilling campaigns are successful, it must then invest capital to appraise and develop the discoveries and there can be no certainty that further commercial quantities of oil and gas will be discovered. There is also the risk that exploration, appraisal and development activities may cost more than anticipated, take longer and may not realise the value that was anticipated.

In addition to participating in licencing rounds or entering into production sharing contracts, Harbour Energy and, following Completion, the Enlarged Group may seek to add or increase reserves through acquisitions. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, upside potential, downside risks, future oil and gas prices, operating and decommissioning costs and potential environmental and other liabilities. Such assessments are uncertain and cannot be made with a high degree of accuracy. Whilst Harbour Energy routinely performs and, following Completion, the Enlarged Group will routinely perform due diligence reviews of potential material acquisition targets, even in depth reviews of all properties and records will not necessarily reveal all existing or potential problems or liabilities. See "*Harbour Energy and, following Completion, the Enlarged Group may be exposed to risks inherent in any future acquisitions and disposals of oil and gas assets and businesses and may fail to properly integrate acquired assets and businesses and realise anticipated synergies in a timely manner*" in this "*Risk Factors*" section.

5. ***Harbour Energy and, following Completion, the Enlarged Group may fail to successfully define and deliver capital intensive projects (including decommissioning projects) that optimise value***

Harbour Energy undertakes and, following Completion, the Enlarged Group will undertake drilling operations and capital projects to find and develop oil and gas reserves and capital projects to decommission assets at the end of their economic life. For example, Harbour Energy has a number of development and pre-development projects, including Zama in Mexico and Tuna in Indonesia. Development and pre-development projects, as well as decommissioning projects, are often complex in nature and may face delays, cost overruns, unsatisfactory quality or poor health, safety, environmental or social performance. In the case of development and pre-development projects, the volume and productivity of the reserves targeted for development are inherently uncertain and may differ from those expected. Furthermore, following Completion, the Enlarged Group will have additional development and pre-development projects that are in various phases of development for future production, including the Target Portfolio's projects in Irpa, Maria Phase 2 and Dvalin North in Norway and Zama in Mexico. In addition, Harbour Energy has a number of decommissioning projects including Southern North Sea and East Irish Sea gas assets and the Balmoral Area in the Central North Sea. Harbour Energy's and the Enlarged Group's ability to sanction or execute capital development projects, including decommissioning projects, is subject to a number of factors, including the availability of financing on acceptable terms, the consent of its creditors and field partners and (in appropriate cases), the ability to share development costs and risk by farming down part of its interest, securing contractual access to third party infrastructure to transport produced volumes to market and ensuring that service providers are able to provide key products and services.

Failure to sanction development projects would mean that Harbour Energy and, following Completion, the Enlarged Group will be unable to realise value from their resources by converting them into production. Failure to execute development projects effectively may lead to delays or cost overruns that could result in them being less profitable than forecast, generating cash later than expected, requiring additional expenditure and ultimately leading to a failure in adding reserves in a value accretive manner. In the case of projects that are expected to result in significant production, delays in completing the project could have a material adverse effect on Harbour Energy's or the Enlarged Group's business, operating results, financial condition or prospects.

6. ***Harbour Energy and, following Completion, the Enlarged Group may fail to accurately estimate the cost and timing of projects including decommissioning which could lead to inaccurate or inadequate provision for future liabilities***

Harbour Energy has and, following Completion, the Enlarged Group will have obligations in respect of the decommissioning of some of the fields in which it has, or in the past has had, licence interests and related infrastructure. It is difficult to forecast accurately the costs and timing Harbour Energy and, following Completion, the Enlarged Group will incur in satisfying its decommissioning obligations especially in certain jurisdictions in which the Enlarged Group will operate and in which the oil and gas industry has limited experience of decommissioning petroleum, in particular outside the UKCS in territories currently with low levels of decommissioning activity.

In the UK, Harbour Energy is and, following Completion, the Enlarged Group will be obliged to dismantle and remove certain equipment, to cap or seal wells and generally to remediate production sites. Under the UK Petroleum Act 1998 (the "**Petroleum Act**"), a party incurs liabilities in respect of the decommissioning of installations and pipelines following the service by the DESNZ of a section 29 notice on that party under the Petroleum Act. At any time during the life of the relevant field, the DESNZ can issue a section 29 notice requiring that a costed decommissioning program be provided by, among others, the license holder, a parent company or associated companies of a license holder, or the field operator. In addition to the liable parties set out above, under section 34 of the Petroleum Act, DESNZ may use a "claw-back" discretionary 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 or was previously a recipient of a section 29 notice but has had such notice withdrawn, being former license holders and their affiliates. 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 DESNZ, it becomes a joint and several obligation upon the persons who submitted the decommissioning program to ensure that it is carried out. Although Harbour Energy typically aims to have contracted for limited decommissioning liabilities and assumes responsibility for the share of the costs in proportion to its working interest, it may retain or be liable to third parties under the Petroleum Act for these liabilities. However, once Harbour Energy and, following Completion, the Enlarged Group is required to submit a decommissioning plan, it will be jointly and severally liable for implementing that plan with former or current commercial partners. If Harbour Energy's and, following Completion, the Enlarged Group's commercial partners do not meet their obligations, Harbour Energy and, following Completion, the Enlarged Group will remain liable and its decommissioning liabilities could increase significantly through such default. Where the UK 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. For more information, see "*—United Kingdom—Summary of Regulatory Regime and Licence Terms in the UK*" in Part IV (*Regulatory Overview*).

Under the legal and regulatory regimes of the UK and other jurisdictions in which Harbour Energy currently has and, following Completion, the Enlarged Group will have an operating presence, it may be liable for up to 100 per cent. of decommissioning liabilities with respect to enhancements that it makes to assets after it acquires them. In connection with the sale or transfer of its assets, Harbour Energy and, following Completion, the Enlarged Group may retain or be liable for decommissioning liabilities, even if it has not contractually agreed to accept these liabilities.

In addition, Harbour Energy and, following Completion, the Enlarged Group may be liable for decommissioning costs associated with assets from which it has received limited or no commercial advantage. For UK assets that Harbour Energy or, following Completion, the Enlarged Group no longer holds (i.e. which have been disposed of by Harbour Energy or by affiliates whom Harbour Energy has subsequently acquired), it may be subject to significant costs related to any potential decommissioning if it is issued a notice under section 34 of the Petroleum Act as a result of it formerly holding interest in certain assets. These decommissioning costs could materially and adversely affect Harbour Energy's and, following Completion, the Enlarged Group's business, prospects, financial condition and results of operations.

Harbour Energy's financial statements as at 31 December 2023 include a provision for decommissioning liabilities that consists of internal and third party estimates based on factors including current legal and constructive requirements and current technology and price levels for the removal of facilities and plugging and abandoning of wells. These estimates include the application of annual inflation and discount rates. Harbour Energy's estimates are based on facts and circumstances known as of the date of such financial statements including the extent of its operations. As of 31 December 2023, Harbour Energy had a decommissioning liability of $4.0 billion calculated using a risk-free discount rate between 4.3 per cent. and 5.2 per cent. and long-term inflation rate of 2.5 per cent. over the varying lives of the assets to determine the pre-tax present value of the decommissioning liabilities. The ultimate costs of decommissioning wells and sites are difficult to predict accurately and may depend on a number of factors. For example, changes in interest rates and increases in inflation since 2022 have made estimation of the pre-tax present value of decommissioning liabilities challenging. Harbour Energy's and, following Completion, the Enlarged Group's decommissioning provisions may not be sufficient and it may be required to provide new or increased financial security to any of the governments in any of the jurisdictions in which Harbour Energy or, following Completion, the Enlarged Group has licence interests or related infrastructure, or to its counterparties. Harbour Energy and, following Completion, the Enlarged Group may also fail to provide adequate financial security or accurately estimate security provision requirements for future decommissioning costs due to the factors described above. Any increase in estimated decommissioning liability or in the amount of financial security Harbour Energy is and, following Completion, the Enlarged Group will be required to provide or failure to provide sufficient financial security for decommissioning costs could materially and adversely affect its business, prospects, financial condition and results of operations.

The costs of decommissioning may exceed the value of the long-term provision set aside to cover such decommissioning costs. This risk may also materialise from Harbour Energy's and following Completion, the Enlarged Group's assets in Asia if the payments it has made into escrow does not cover the committed decommissioning costs which may have a material adverse effect on its business, operating results, financial condition or prospects. Harbour Energy and, following Completion the Enlarged Group may have to draw on funds from other sources to fund such decommissioning costs.

Third Party Reliance Risks

7. ***Harbour Energy has and, following Completion, the Enlarged Group may have limited influence on its joint venture partners. Operating joint venture partners may not manage assets in line with the values and business objectives of Harbour Energy and, following Completion, the Enlarged Group. This may result in a failure to maximise growth opportunities, loss of value or increased risk exposure***

Some of Harbour Energy's major assets are operated, and some of the Enlarged Group's major assets will be operated, by a partner in the relevant joint venture. A majority of the assets included in the Target

Portfolio are non-operated and the percentage of non-operated assets in Harbour Energy will increase as a result of the Acquisition.

Harbour Energy requires and, following Completion, the Enlarged Group will require cooperation from its joint venture partners in obtaining approval of field development plans and in funding the development of and production from an asset. Where Harbour Energy or, following Completion, the Enlarged Group is not the operator of a licence, although it may have consultation rights or the right to withhold consent in relation to significant operational matters depending on the level of interest in such licence (as most operational decisions by the management committee only require a majority vote), Harbour Energy only has and, following Completion, the Enlarged Group will only have limited control over management of the assets and mismanagement by the operator or disagreements with the operator as to the most appropriate course of action may arise. There is also a risk that a joint venture partner with interests in Harbour Energy's and, following Completion, the Enlarged Group's operated properties may elect not to participate in certain activities relating to those properties that require that party's consent. In these circumstances, it may not be possible for such activities to be undertaken by Harbour Energy and, following Completion, the Enlarged Group alone or in conjunction with other joint venture partners at the desired time or at all or otherwise, to the extent permitted, such activities may be undertaken with the Enlarged Group bearing a greater proportion of the risks involved in the project. The terms of the operating agreements generally impose standards and requirements in relation to the operatorship of the oil or natural gas field, however there can be no assurance that the operator will observe such standards or requirements.

Where Harbour Energy is the operator, for example with respect of the J-Area fields, Greater Britannia Area (except for the Alder field), AELE Area (except for the Erskine field), Catcher Area fields, Tolmount, Solan, Johnston, Natuna Sea Block A fields and Block 12W fields, or the Target Portfolio is the operator, for example with respect to East Damanhour, Emlichheim, Ogarrio, Maria, Nova, Vega, Dvalin and Dvalin North, it depends on its partners in the field to sanction any improvement or enhancement projects it may have planned for the area together with sanctioning its planned operations, timing and performance of such activities. There is therefore an inherent risk in producing fields where Harbour Energy is unable to exercise and, following Completion, the Enlarged Group will be unable to exercise a sufficient number of votes, as the management committee in charge of decision-making between the partners may make certain decisions on developments regardless of whether or not they have received consent from Harbour Energy and, following Completion, the Enlarged Group.

Certain risks also apply in circumstances where Harbour Energy is and, following Completion, the Enlarged Group will be a joint venture partner but not the operator in fields in which it holds an interest. For example, Apache Corporation ("**Apache**") is operator of the Beryl Area fields, CNOOC is operator of the Buzzard field, TotalEnergies is operator of the Elgin Franklin area fields, BP is operator of the Schiehallion and Clair fields, Ithaca Energy is operator of the Alder and Erskine fields, Wintershall Dea is operator of Block 30 in the Sureste Basin (although from Completion, the Enlarged Group will become the operator) and Mubadala Energy is operator of South Andaman in the Andaman Sea. For example, the Target Portfolio is dependent and, following Completion, the Enlarged Group will be dependent on Groupement Reggane Nord who acts as the operator of Reggane Nord, TotalEnergies who acts as the operator of Aguada Pichana Este Residual, Aguada Pichana Este Vaca Muerta, CMA-1, and Fénix, DISOUCO who acts as the operator of Disouq, BP who acts as the operator of West Nile Delta, Mabruk Oil Operations who acts as the operator of Contract areas 15, 16, 32 (Al-Jurf), Hokchi Energy who acts as the operator of Hokchi Block, PEMEX who acts as the operator of Zama, Repsol who acts as the operator of Block 29 (Polok, Chinwol), Equinor who acts as the operator of Njord, Bauge, Hyme, and Snorre, Aker BP who acts as the operator of Ærfugl Nord, Edvard Grieg, and Skarv, and Vår Energi (following its acquisition of Neptune Energy's Norwegian business) who acts as the operator of Gjøa. In circumstances where Harbour Energy is not and, following Completion, the Enlarged Group will not be the operator, it will not be able to direct or control operations, the timing and performance of such activity or the costs thereof, will have limited ability to influence decisions taken by the operator, and will be reliant on their capabilities which might result in increased operational costs, heightened health, safety and environment risks and/or reputational damage.

Harbour Energy and, following Completion, the Enlarged Group may suffer unexpected costs or other losses if a joint venture partner does not meet obligations under agreements governing their relationship. For example, other joint venture partners who have invested in Harbour Energy's or the Target Portfolio's properties may default in their obligations to fund capital or other funding obligations in relation to such properties. In such circumstances, Harbour Energy and, following Completion, the Enlarged Group 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 have been agreed with such joint venture partner under such arrangements. Harbour Energy and, following Completion, the Enlarged Group may also be subject to claims by its joint venture partners regarding potential non-compliance with its obligations.

A failure to reach an agreement with joint venture partners may lead to delays in development. Additionally, failure by joint venture partners to comply with obligations under relevant licences, production sharing contracts or the agreements pursuant to which Harbour Energy operates and, following Completion, the Enlarged Group will operate may lead to fines, penalties, restrictions and withdrawal of licences, production sharing contracts or the agreements under which it operates. For example, in Norway, where Harbour Energy holds and, following Completion, the Enlarged Group will hold some licences, the licence participants are jointly and severally responsible to the Norwegian Government for financial obligations arising out of petroleum activities pursuant to such licence. Hence, if one or more of the other licensees fails to cover their share of licence costs (e.g. related to the mandatory work program or decommissioning liability), Harbour Energy and, following Completion, the Enlarged Group can be held liable for such licensee's share of the relevant cost. If any of Harbour Energy's and, following Completion, the Enlarged Group's joint venture partners becomes insolvent or otherwise unable to pay debts as they come due, licences or agreements awarded to them may revert back to the relevant government authority who will then reallocate the licence. Although it is anticipated that the relevant government authority may permit Harbour Energy and, following Completion, the Enlarged Group to continue operations at a field during a reallocation process, there can be no assurances that it will be able to continue operations pursuant to these reclaimed licences or that any transition related to the reallocation of a licence would not materially disrupt its operations or development and production schedule. The occurrence of any of the situations described above could materially and adversely affect Harbour Energy's and, following Completion, the Enlarged Group's business, financial condition and results of operations.

Harbour Energy's and, following Completion, the Enlarged Group's exit strategy in relation to any particular oil or gas interest may also be subject to the prior approval of its joint venture partners and relevant government agency, such as the NSTA in the case of its UKCS assets and other agencies internationally. The terms of operating agreements often require joint venture partners to approve of an incoming participant to the business venture or provide them pre-emption rights with respect to the transfer of Harbour Energy's and, following Completion, the Enlarged Group's interest, either of which could affect its ability to sell or transfer an interest. In certain circumstances, Harbour Energy and, following Completion, the Enlarged Group may also be required to consent to new business partners becoming party to its agreements who have a lower financial standing than the outgoing party. As a consequence of having entered into joint venture arrangements, Harbour Energy is and, following Completion, the Enlarged Group will be exposed to the risk of partner default or insolvency both in respect of existing partners and also potential new partners. For example, in the UK, the effects of the Energy Profits Levy (the "**EPL**") coupled with rising interest rates and inflation during the period since March 2022 have impacted the resilience and reliability of some of Harbour Energy's joint venture partners and their appetite to continue to invest in the UK alongside Harbour Energy and, following Completion, the Enlarged Group, which could impact its operational performance, increase health, safety, environmental and social risks and create potential reputational exposure. Increasing financial distress amongst some of Harbour Energy's and, following Completion, the Enlarged Group's joint venture partners may also increase the risk of default on UK decommissioning security obligations (including failure to provide adequate financial security for future decommissioning costs) which could materially and adversely impact its business, prospects, financial condition and results of operations. See "*Harbour Energy and, following Completion, the Enlarged Group may fail to accurately estimate the cost and timing of projects including decommissioning which could lead to inaccurate or inadequate provision for future liabilities*" in this "*Risk Factors*" section.

8. ***Harbour Energy and, following Completion, the Enlarged Group may face interruptions or delays in the availability of downstream third-party-operated infrastructure, including pipelines and storage facilities, on which production and transportation activities are dependent***

Harbour Energy's production activities are and, following Completion, the Enlarged Group's production activities will be dependent upon the continued availability of oil and gas pipelines and transportation systems, many of which are shared with third party producers and/or operated by third parties.

Shared infrastructure risks are faced by Harbour Energy and will be faced by the Enlarged Group following Completion. Harbour Energy's production assets in the Central, Southern and Northern North Sea basins of the UKCS rely and, following Completion, the Enlarged Group's production assets will rely on access to the Central Area Transmission System ("**CATS**") gas export pipeline and processing terminal at Teesside (which are currently operated by Kellas Midstream), the Forties Pipeline System (the "**FPS**") offshore and onshore liquids export pipeline system and onshore processing terminal at Kinneil (which is currently owned and operated by INEOS), the Shearwater Elgin Area Line ("**SEAL**") gas export pipeline (which is currently operated by TotalEnergies), the Scottish Area Gas Evacuation System ("**SAGE**") gas export pipeline and gas processing terminal at St Fergus (which are currently operated by Ancala) and the Norpipe oil export pipeline and Norsea terminal, Teesside (which are currently operated by ConocoPhillips Midstream). In addition, Harbour Energy's assets in the Catcher Area rely on the Catcher floating production storage and offloading ("**FPSO**") vessel (which is currently operated by BW Offshore) and those in the Tolmount area on the Easington gas processing terminal, East Yorkshire (which is currently operated by Centrica Storage). Harbour Energy relies and, following Completion, the Enlarged Group will also rely on the West of Shetland gas export pipeline, the Sullom Voe oil terminal (operated by EnQuest) and the Glen Lyon FPSO vessel (operated by BP). Moreover, gas produced from Harbour Energy's offshore gas fields in Indonesia is exported to Singapore via the 540 kilometre West Natuna Transportation System pipeline, which is the only means of exporting gas from these fields. The Target Portfolio's assets also rely on third-party operated transport infrastructure such as the Norwegian production which flows through various third-party transport infrastructure systems connecting Norway to the UK and the European continent.

If any of these pipelines, terminals, systems or FPSO vessels (or any infrastructure connecting to the respective pipeline, terminal, system or FPSO) experiences mechanical problems, an explosion, adverse weather conditions, a terrorist attack, labour dispute or any other event that causes an interruption in operations or a shut-down, Harbour Energy's and, following Completion, the Enlarged Group's ability to transport product could be severely affected and production performance could materially differ from that forecast.

Furthermore, for assets that use the services of different hosts for transportation and processing of their production, Harbour Energy and the Enlarged Group could encounter challenges in maintaining control of costs. Use of third-party infrastructure is in general subject to tariff charges, which can be substantial and the per barrel charge will not be subject to the Enlarged Group's direct control. For example, the existing tariffing arrangements with CATS and FPS could in certain cases be replaced with more expensive cost sharing arrangements as production levels in the host systems decrease.

A substantial portion of Harbour Energy's current production is and, following Completion, the Enlarged Group's production will be reliant on some third party owned and controlled infrastructure which has been in operation for a number of years. For example, Harbour Energy relies and, following Completion, the Enlarged Group will rely on the FPS, which has been owned by INEOS since 2017, for the offtake of oil and condensate produced at the Armada Area, Elgin Franklin area, Everest Area, Britannia Area and Buzzard fields. As the FPS has been extensively used, it requires frequent inspection, maintenance and repair to maintain efficiency. The pipeline systems may also need to be shut down to stop oil and gas leaks, as was the case in December 2017 when the FPS was shut down for three weeks for repairs. More recently, in May 2021, the FPS was shut down for planned maintenance that had been delayed from 2020 as a result of the COVID-19 pandemic. Any unscheduled inspection, maintenance or repairs to or closure of the infrastructure on which Harbour Energy's or, following Completion, the Enlarged Group's production relies could result in production being lower than forecast which could have a material adverse effect on its business, financial condition, results of operation and cash flows.

If the owners or operators of this infrastructure, as well as of other, third party infrastructure upon which Harbour Energy's operations rely and, following Completion, the Enlarged Group's will rely fail to adequately maintain their integrity or fail to invest into such infrastructure to ensure that uptime levels are maintained, Harbour Energy and, following Completion, the Enlarged Group may not be able to efficiently deliver product to onshore terminals for sale. Furthermore, Harbour Energy's and, following Completion, the Enlarged Group's use of third party infrastructure exposes it to the possibility that such infrastructure will cease to provide services or be decommissioned and therefore prevent economic production from its assets. This could also have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's business. A reduction or potential stoppage in the delivery of its product or any consequential adverse impact on the efficiency of Harbour Energy's and, following Completion, the Enlarged Group's operations could have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's results of operations and financial condition.

No assurance can be given that Harbour Energy or, following Completion, the Enlarged Group will be able to secure contractual agreements to access the third party infrastructure which it needs to transport production to market. Failure to reach agreement on terms commercially acceptable to Harbour Energy and, following Completion, the Enlarged Group may mean that it is not economically viable to sanction the development of projects or develop reserves. Any delay in reaching agreement on commercially acceptable terms may also delay the construction of new infrastructure to the extent this is required which in turn could delay the development of reserves or the delivery of capital projects. The consequences of any of these circumstances could have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's results of operations and financial condition.

Finally, the inability or failure of Harbour Energy's and, following Completion, the Enlarged Group's current or future major offtakers to meet their obligations or their insolvency or liquidation may adversely affect Harbour Energy's and, following Completion, the Enlarged Group's financial results. Harbour Energy is and, following Completion, the Enlarged Group will be, therefore, subject to the risk of delayed payment for delivered production volumes or counterparty default. Certain gas sale and purchase agreements provide buyers with a right to take only a minimum natural gas volume which may be below committed volumes. If a specific buyer exercises this right, then this would have the effect of deferring natural gas and associated production from the asset. In addition, downstream infrastructure operators may fail to deliver their anticipated service level due to technical or commercial reasons, and the remedies available to Harbour Energy and, following Completion, the Enlarged Group may be limited. Furthermore, a potentially limited number of buyers for oil and gas produced by Harbour Energy and, following Completion, the Enlarged Group may expose it to adverse pricing or other contractual terms. The limited number of offtakers may impact Harbour Energy's and, following Completion, the Enlarged Group's overall credit risk in that its current or future major offtakers may be similarly affected by various economic and other conditions. Such delays, defaults, difficulties or adverse pricing or other contractual terms could adversely affect Harbour Energy's and, following Completion, the Enlarged Group's business, financial condition, results of operations and cash flows.

Access to Capital Risks

9. ***Harbour Energy and, following Completion, the Enlarged Group may fail to maintain a robust balance sheet by ensuring sufficient access to capital on satisfactory terms through the commodity price cycle to implement its strategy***

Harbour Energy and, following Completion, the Enlarged Group needs to ensure sufficient access to capital through the commodity cycle to invest in its existing asset base, fund organic and/or inorganic growth and return capital to Shareholders. If Harbour Energy and, following Completion, the Enlarged Group were unable to raise sufficient cash on satisfactory terms, if a liquidity event were to occur that would prevent it from making such large capital expenditures, or it failed to allocate its capital and budget efficiently, the performance of the business and the execution of the strategy would be impacted.

Harbour Energy's liquidity requirements arise and, following Completion, the Enlarged Group's liquidity requirements will arise from its need to invest in its asset base, including funding capital and other expenditures for exploration, development and production activities, to fund organic and inorganic growth and to return capital to Shareholders. Harbour Energy's and, following Completion, the Enlarged Group's liquidity position may be adversely impacted by a number of factors which are inherently uncertain and some of which it does not control, including a prolonged decline in oil and gas prices, lower than forecasted production levels, higher than expected capital expenditure requirements, increased financing costs and declining lender or investor appetite to finance and/or invest in the oil and gas sector. Going forward, Harbour Energy and, following Completion, the Enlarged Group intends to finance the majority of its future capital expenditures with cash flow from operations and, if necessary, borrowings under the Revolving Credit Facility (which will become available following Completion) or other financing arrangements. A suspension, reduction or withdrawal of the credit rating assigned to the Enlarged Group by one or more of the credit rating agencies may impact the margin payable on amounts drawn under the Revolving Credit Facility leading to an increase in the Enlarged Group's borrowing costs, both under the Revolving Credit Facility and on refinancing the Revolving Credit Facility when it matures. Additional sources of liquidity may also include debt or equity, as applicable, from sources including: its shareholders, funding in the capital markets, project financing and disposal proceeds from any portfolio management activity. The Enlarged Group's ability to make payments on and refinance its indebtedness and to fund its capital expenditures and working capital requirements and other expenses will depend on its future operating performance and ability to generate cash from operations.

For example, if Harbour Energy's and, following Completion, the Enlarged Group's revenues decrease as a result of lower oil or gas prices, operating difficulties, declines in reserves, increased costs or for any other reason, Harbour Energy and, following Completion, the Enlarged Group may have limited ability to obtain the capital necessary to invest in development opportunities or sustain its operations at current levels. If cash generated by operations or cash available under the Reserve Base Lending Facility and, following Completion, the Revolving Credit Facility Agreement is not sufficient to meet its capital requirements, the failure to obtain additional financing could result in a curtailment of Harbour Energy's and, following Completion, the Enlarged Group's operations relating to development of its prospects, which in turn could lead to a decline in its oil and natural gas reserves, or if it is not possible to cancel or stop a project, be legally obligated to carry out the project contrary to its desire or with negative economic impact. All of the above could adversely affect Harbour Energy's and, following Completion, the Enlarged Group's production, revenues and results of operations which could have a material adverse effect on its ability to invest in its existing asset base, fund organic and/or M&A growth, or return capital to Shareholders.

Following Completion, the Enlarged Group is expected to have predominantly fixed rate debt in the form of investment grade bonds. However, once these bonds reach maturity, the rate of interest which the Enlarged Group will have to pay to refinance this debt could be materially higher, particularly in circumstances where the credit rating assigned to the Enlarged Group has been suspended, reduced or withdrawn, which could have an adverse effect on the Enlarged Group's financial results.

Harbour Energy is and, following Completion, the Enlarged Group will be subject to fluctuations in interest rates, inflation, and economic conditions in the relevant countries in which it operates which may adversely affect its business, results of operations and financial condition beyond its control, for example as exploration, development, operating, administration and other costs may be higher than anticipated.

10. ***Harbour Energy and, following Completion, the Enlarged Group may be subject to currency fluctuation and exchange control which may adversely impact its financial condition, results of operations or prospects***

Harbour Energy operates, and following Completion, the Enlarged Group will operate, in a number of different countries and territories throughout the world. Harbour Energy is and, following Completion, the Enlarged Group will be as a consequence subject to risks from changes in currency values and exchange controls. Changes in currency values and exchange controls could have a material adverse effect on Harbour Energy's and the Enlarged Group's business, operating results, financial condition or prospects.

The functional currency of Harbour Energy is, and that of the Enlarged Group will be, US dollars. Harbour Energy receives a mix of US dollar and pound sterling revenues. The Enlarged Group will also receive material Euro revenues, amongst other local currencies, albeit in small amounts relative to the Enlarged Group as a whole. In the first instance, it is anticipated that revenues received in these local currencies will be used to cover any local costs such as labour and employee costs, which are incurred in the local currency. To cover any remaining non-US dollar costs the Enlarged Group will convert funds to foreign currencies to meet those payment obligations.

Exchange rates between the US dollar and other currencies that Harbour Energy is and, following Completion, the Enlarged Group will be exposed to have fluctuated significantly in the past and may do so in the future. Consequently, exploration, development, operating, administration and other costs may be higher in US dollars than anticipated.

Harbour Energy seeks and, following Completion, the Enlarged Group will seek to mitigate its exposure to currency fluctuations through various FX instruments in line with Harbour Energy's and, following Completion, the Enlarged Group's hedging policy. No assurance can be given that Harbour Energy's or the Enlarged Group's hedging policies will sufficiently protect against currency fluctuations or that Harbour Energy or the Enlarged Group will be able to put hedging in place with counterparties on acceptable terms in order to successfully implement their hedging policies.

The Target Portfolio includes interests in certain jurisdictions, including in Argentina and Egypt, where the value of the local currency against the US dollar has fluctuated significantly in recent times as a result of, amongst other things, global events, changes in political and economic conditions and changes in foreign exchange policy. In addition, from time to time and, in particular since February 2022 (in the case of Egypt) and the middle of 2022 (in the case of Argentina), there has been a shortage of US dollars in Egypt and Argentina to service foreign currency transactions with the central bank in both countries having limited foreign currency remittance to the importation of strategic goods and limited the amounts of remitted foreign currency, including for legitimate business purposes. The shortage of US dollars in Egypt and Argentina, limitations on remittance and devaluation of the Egyptian Pound and the Argentinian Peso against the US dollar mean that any profits generated by the Target Portfolio and, following Completion, the Enlarged Group in Egypt or in Argentina may not be capable of being repatriated by way of dividend or distribution to the Company as the ultimate holding company of Harbour Energy. To the extent that profits are not repatriated, over time this may result in the US dollar value of such profits devaluing as a result of any devaluation in the local currency against the US dollar. If profits or cash remains "trapped" in Egypt or in Argentina or in any other jurisdiction in which the Target Portfolio has interests in licences or production sharing contracts for a prolonged period, it may have an adverse effect on the Enlarged Group's financial condition and liquidity.

11. ***Harbour Energy's and, following Completion, the Enlarged Group's letter of credit facilities, bank guarantees or other similar security may be insufficient to enable it to meet its security posting requirements***

The various decommissioning security arrangements to which Harbour Energy is, and the Enlarged Group will be, party typically permit Harbour Energy to make provision for decommissioning security in the form of parent company guarantees, if Harbour Energy meets various credit rating requirements, letters of credit, bank guarantees, surety bonds or similar and in some cases cash collateral. Under the various decommissioning security arrangements, the letters of credit, bank guarantees or similar security are required to be provided by banks which meet certain credit rating thresholds and other criteria. Market-related and other developments affecting the credit ratings of banks over the last few years have reduced the number of banks which meet these applicable credit rating requirements. Further developments of this sort may mean that banks which have issued letters of credit to satisfy Harbour Energy's and the Target Portfolio's decommissioning security obligations in the past will cease to meet the applicable credit rating requirements and that those banks that continue to meet these requirements may not be willing to continue to issue letters of credit or bank guarantees for amounts greater than their existing commitments or to take on the letter of credit and/or bank guarantee commitments of banks who no longer meet these requirements; or may only be willing to do so on more onerous terms for Harbour Energy and, following Completion, the Enlarged Group.

Additionally, the number of banks offering these services to oil and gas exploration and production companies has decreased in recent years and could decrease further in the future.

If these developments were to continue or worsen, or if Harbour Energy or the Enlarged Group did not have sufficient credit rating to meet obligations through parent company guarantees or did not have sufficient letter of credit facilities available to enable it to meet these decommissioning obligations, it may not be possible or it may be more difficult and/or costly for Harbour Energy or the Enlarged Group to obtain or maintain letters of credit or bank guarantees which meet the requirements under these decommissioning security arrangements or to obtain new letters of credit or bank guarantees to replace letters of credit or bank guarantees from banks which have ceased to meet the requirements of the decommissioning security arrangements and, in these circumstances, Harbour Energy and the Enlarged Group may be required to make provision for some or all of their decommissioning liabilities using cash. If such risks materialise, they could have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's business, operating results and/or financial condition.

Members of Harbour Energy are party to and, following Completion, the Enlarged Group will be party to, various decommissioning security arrangements relating to certain oil and gas fields in the UK which require them to, amongst other things, make provision for their share of the anticipated costs of future decommissioning of these fields. To date, the highest amounts of decommissioning security for Harbour Energy has been posted in respect of the J-Block, Balmoral and Beryl Areas. In respect of a number of other fields, Harbour Energy has also entered into bilateral security arrangements with, for example, former owners Shell and ConocoPhillips. The vast majority of security requirements in the Target Portfolio are met through parent company guarantees, satisfied by the fact that the relevant entity is rated as being investment grade. The Enlarged Group is expected to be rated as being investment grade at Completion and therefore will continue to meet those obligations via parent company guarantees. The requirement to post security is dependent on the forecast cash flows from a field. Factors impacting such forecasts, such as production and commodity prices, can impact the timing and quantum of such requirements.

12. ***Harbour Energy is and, following Completion, the Enlarged Group will be subject to certain tax exposures***

Harbour Energy is and, following Completion, the Enlarged Group will be subject to various tax exposures which arise in the ordinary course of its business in the different jurisdictions in which it operates and, following Completion, in which it will operate. In assessing whether these uncertainties should be provided for in Harbour Energy's and, following Completion, the Enlarged Group's financial statements, management apply and will apply significant judgments of the likely outcome, based on external advice and prior experience of such claims.

One of these uncertain tax exposures relate to the timing of taxation of fair value movements and realised gains and losses on hedges entered into in order to manage commodity price risk which may be challenged by tax authorities. Additional challenges from tax authorities may also relate to the deductibility of expenses for corporate income tax purposes and the recoverability of value added tax on those expenses. Should the tax authorities in jurisdictions in which Harbour Energy operates and, following Completion, the Enlarged Group will operate seek to make such challenges, and if any such challenges are successful and are not overturned, this could lead to additional material tax liabilities and negative cumulative tax loss positions which could have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's business, financial condition and results of operations.

Further, Harbour Energy undertakes and, following Completion, the Enlarged Group will continue to undertake many cross border transactions in relation to which it seeks to comply with transfer pricing laws. However there is a risk that tax authorities in the relevant jurisdictions could seek to challenge the allocation methodology used or pricing applied to charges by Harbour Energy and if any such challenges are successful and are not overturned, they may have an adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's business, financial condition and results of operations.

Harbour Energy operates and owns interests and, following Completion, the Enlarged Group will operate and own interests in assets in a number of jurisdictions. It is therefore exposed to a wide range of tax environments that are subject to change in a manner that may be materially adverse for Harbour Energy and, following Completion, the Enlarged Group which could include changes to and uncertainty surrounding subsidies, royalties or taxation (including policies relating to the granting of advance rulings on taxation matters). For example, as a result of an increase in carbon credit prices or changes in specific targeted tax liabilities on emissions flowing from changes in government policy or adverse sentiment towards the oil and gas industry, Harbour Energy and, following Completion, the Enlarged Group may be subject to increased tax liabilities, and increases in its costs of operations or its effective tax rate which could have an adverse effect on its business, financial condition and results of operations.

Climate Change and Energy Transition Risks

13. ***Harbour Energy's and, following Completion, the Enlarged Group's failure to deliver on its stated climate change commitments and to adapt its strategy in the context of evolving external requirements and expectations, coupled with the effects of climate change and political and societal perception of the production and use of fossil fuels, may have a material adverse effect on the hydrocarbon industry, Harbour Energy and, following Completion, the Enlarged Group***

The consequences of the effects of global climate change, the transition towards a low carbon economy, and the continued political and societal attention afforded to mitigating the effects of climate change, may generate:

- adverse investor and other stakeholder sentiment towards the hydrocarbon industry and negatively impact the investability of the sector;
- changes in the supply and demand for hydrocarbon products due to the pace of commercial deployment of alternative energy technologies or shifts in consumer preference for lower greenhouse gas emission products in each case as an industry response to the reduction in demand or in response to adverse investor or stakeholder sentiment towards the hydrocarbon industry; and
- Longer term physical changes in weather patterns and ocean currents and more frequent extreme weather events related to climate change could potentially disrupt business activities, increase business costs and raise insurance premiums.

any of which may have a material adverse effect on the hydrocarbon industry in general or specifically on Harbour Energy and, following Completion, the Enlarged Group.

There have been efforts in recent years aimed at the investment community, including investment advisors, sovereign wealth funds, public pension funds, universities and other groups, promoting the divestment of equities issued by companies connected to fossil fuels as well as to pressure lenders and other financial services companies to limit or curtail activities with companies similarly connected. If these efforts are successful, and if Harbour Energy's and, following Completion, the Enlarged Group's business is deemed to be sufficiently tied to the use of fossil fuels by such communities, its ability to access capital markets may be limited and its share price may be negatively impacted. Further, members of the investment community have increased their focus on sustainability practices with regard to the oil and gas industry, including practices related to greenhouse gas emissions and climate change. An increasing percentage of the investment community considers sustainability factors in making investment decisions and an increasing number of entities consider sustainability factors in awarding business. If Harbour Energy and, following Completion, the Enlarged Group is unable to appropriately address sustainability enhancement, it may lose customers, partners, its share price may be negatively impacted, its reputation may be negatively affected, and it may be more difficult for it to effectively compete.

Continued political attention to issues concerning climate change, the role of human activity in it and potential mitigation through regulation could have a material impact on Harbour Energy's and, following Completion, the Enlarged Group's business. International agreements, national and regional legislation, and regulatory measures to limit greenhouse gas emissions are currently in various stages of discussion or implementation. Given that Harbour Energy's and, following Completion, the Enlarged Group's operations involve, and its products are associated with, emissions of greenhouse gases, these and other greenhouse gas emission related laws, policies and regulations may result in substantial capital, compliance, operating and maintenance costs. The level of expenditure required to comply with these laws and regulations is difficult to accurately predict and will vary depending on, among other things, the laws enacted by particular countries. Further, there is evidence that some lenders may be unwilling to provide capital to oil and gas companies. Climate change legislation and regulatory initiatives restricting emissions of greenhouse gases may materially adversely affect Harbour Energy's and, following Completion, the Enlarged Group's operations and increase its cost structure, and could also potentially limit the investment capital available to the industry. For example, in the UK, where a significant proportion of the hydrocarbons produced by Harbour Energy is and, following Completion, the Enlarged Group will be sold and consumed, the UK Parliament passed legislation in June 2019 enshrining in law a target for at least a 100 per cent. reduction in greenhouse gas emissions (compared to 1990 levels) in the UK by 2050 (also known as a "**net zero target**") and in November 2020 the UK Government announced a ban on sales of new petrol and diesel powered cars and vans from 2030. It is anticipated that the governments of other major economies may introduce similar long-term emissions reduction targets.

Additionally, as a company with operations in Norway and Germany, Harbour Energy is subject and, following Completion, the Enlarged Group will be subject to European Union climate change abatement legislation. Due to the requirements of the European Union's Emissions Trading System (the "**EU ETS**"), Member States' governments, including Norway, have put forward national plans that set carbon dioxide emission reduction requirements for 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).

In the wake of Brexit, the UK Government has introduced the United Kingdom Emissions Trading System ("**UK ETS**") which has resulted in transition costs for companies, like Harbour Energy and, following Completion, the Enlarged Group, which were formerly subject to the EU ETS but that must now operate within the UK ETS regime. Such legislation or regulatory initiatives could also have a material adverse effect by diminishing the demand for oil and gas, increasing Harbour Energy's and, following Completion, the Enlarged Group's cost structure or causing disruption to its operations by regulators, including via increased administration requirements.

In addition to legislative or regulatory initiatives, Harbour Energy and, following Completion, the Enlarged Group may be subject to activism from groups campaigning against fossil fuel extraction, which could affect its reputation, disrupt its campaigns or programs or otherwise negatively impact its business. For example, as a result of an activist investor campaign, ExxonMobil has advanced its climate plans, but is under pressure to set more ambitious goals. In addition, in 2021, a court in the Netherlands ruled that Royal Dutch Shell must reduce its greenhouse gas emissions 45 per cent. by 2030, based on 2019 levels.

The emission reduction targets and other provisions of national, regional and international legislative or regulatory initiatives enacted in the future, could adversely impact Harbour Energy's and, following Completion, the Enlarged Group's business by imposing increased costs in the form of taxes or for the purchase of emission allowances, limiting its ability to develop new oil and gas reserves, decreasing the value of its assets, or reducing the demand for hydrocarbons and refined petroleum products.

Longer term changes in weather patterns and more frequent extreme weather events could potentially disrupt business activities and Harbour Energy's and, following Completion, the Enlarged Group's offshore operations are particularly at risk from severe climatic events. If any such climate changes were to occur, they could have an adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's financial condition and results of operations.

The transition towards a low carbon worldwide economy is impacting both the supply and demand for oil and gas. The interplay of these changes could lead to long-term volatility in oil and gas prices and Harbour Energy and, following Completion, the Enlarged Group may face more demanding regulatory requirements or lose some sources of funding if it is unable to meet such evolving investor, lender and societal expectations. Overall, the long-term viability of the business may be in question if Harbour Energy and, following Completion, the Enlarged Group is unable to maintain a strategy and portfolio that is demonstrably resilient to evolving market conditions, requirements and expectations related to climate change and the energy transition. By way of example of evolving expectations in relation to climate change, non-governmental organisations and shareholder activists are increasing the number of climate change litigations against corporate entities both in the extractive industries and in support sectors, such as banks and financial institutions. Such activities seek new arguments and raise new challenges for such industries, and it is difficult to predict what litigation might arise in the future or the prospects of success. In the UK courts, ClientEarth has brought a claim against Shell, alleging a breach of duties under section 172 and 174 of the Companies Act resulting from a failure to adopt and implement a climate strategy that aligns with the 2015 Paris Agreement. The High Court of England and Wales dismissed the lawsuit without considering the merits in July 2023, which ClientEarth appealed. It is expected that such litigations will continue in the future, and that there may be an increase in climate-related litigation and challenges. No assurance can be given that Harbour Energy and, following Completion, the Enlarged Group will not be named in similar or other climate change related proceedings in the future and, if named, what the outcome of any such proceedings might be.

14. ***Harbour Energy and, following Completion, the Enlarged Group may not be able to meet the current climate related targets that it has formulated to achieve Net Zero by 2035***

Harbour Energy and, following Completion, the Enlarged Group may not be able to meet its current long term commitment to achieve Net Zero for its gross operated Scope 1 and Scope 2 CO2 equivalent (CO_2e) emissions by 2035. Harbour Energy's and, following Completion, the Enlarged Group's Net Zero strategy, emission targets and Net Zero commitment are "forward-looking" statements that involve various risks and uncertainties (see "*—Forward-Looking Statements*" in the section entitled "*Important Information*"). These "forward-looking" statements are not intended to be a forecast or guarantees of Harbour Energy's or the Enlarged Group's future performance and Harbour Energy's or the Enlarged Group's actual operations and performance between now and 31 December 2035 may differ significantly from these "forward-looking" statements. Factors that might cause such difference include those discussed in this "*Risk Factors*" section and elsewhere in this Prospectus.

Long term emission targets are used by Harbour Energy and, following Completion, will be used by the Enlarged Group to measure progress towards its Net Zero commitment. These targets are subject to change and Harbour Energy and, following Completion, the Enlarged Group may determine that it is appropriate to adapt its strategy and business plan, including in relation to its Net Zero commitment, in the future to achieve Net Zero in the timeframe currently envisaged. In particular, Harbour Energy's current strategy in relation to its Net Zero commitment is specific to Harbour Energy's existing portfolio and is executed through its specific emissions reduction action plans as well as through the safe and responsible decommissioning of assets at the end of their economic life, a process that is often complex in nature and which may face delays, cost overruns, unsatisfactory quality or poor health, safety, environmental or social performance (see "*Harbour Energy and, following Completion, the Enlarged Group may fail to successfully define and deliver capital intensive projects (including decommissioning projects) that optimise value*" in this "*Risk Factors*" section). The integration of the Target Portfolio into Harbour Energy will require careful evaluation of the technical emission reduction options as well as the formulation of a new greenhouse gas ("**GHG**") emissions strategy that will aim to honour the existing Net Zero commitment of Harbour Energy and that of the Enlarged Group post Completion. It is currently intended that this process will commence following Completion and will rely in part on the successful integration of the acquired businesses, operating assets, organisational structures and processes, controls and systems of the Target Portfolio which may prove more difficult, be more expensive or take longer than anticipated. The formulation of a new GHG emissions strategy aimed at fulfilling the Enlarged Group's Net Zero commitment may, at least initially, lead to increased complexity and increased workloads which in turn could have an adverse impact on the timing, implementation and ultimate success of its Net Zero strategy.

Further, evolving stakeholder requirements and expectations as well as changes in the regulatory environment may also lead to a change in Harbour Energy's and, following Completion, the Enlarged

Group's strategy in relation to its Net Zero commitment. In order for Harbour Energy and, following Completion, the Enlarged Group to fulfil its Net Zero commitment in the timeframe currently envisaged may require higher than anticipated operating, administration and other costs which could in turn adversely affect its business, prospects, financial condition and results of operations and may result in the need for senior management to devote more of their time and focus on fulfilling Harbour Energy's and, following Completion, the Enlarged Group's Net Zero commitment within the timeframe currently envisaged, which may have an adverse impact on other aspects of the business. A failure to successfully implement its Net Zero strategy or meet its emission targets and ultimately its long term Net Zero commitment or any change to the foregoing could adversely affect Harbour Energy's and, following Completion, the Enlarged Group's reputation with its shareholders, potential investors, the investment community or other key stakeholders, impair its ability to access capital on favourable terms, negatively impact its share price and/or lead to increased or unexpected costs.

15. ***Harbour Energy and, following Completion, the Enlarged Group may be unable to secure a viable investment case for carbon capture and storage ("CCS") projects***

Harbour Energy and, following Completion, the Enlarged Group can contribute to support governments and nations as they seek to limit global warming and meet their net zero emission targets through broader decarbonisation projects and technologies, such as CCS, through repurposing oil and gas skills and infrastructure to technologies such as CO_2 transportation and storage.

Harbour Energy currently leads and, following Completion, the Enlarged Group will lead the Viking CCS project in the UK's Humber region. By repurposing oil and gas infrastructure in the heavily industrialised Humber region, Viking CCS has the potential to meet one third of the UK Government's target to capture and store 20-30 mtpa of CO_2 by 2030. In addition, Harbour Energy has invested in Acorn, another early-stage CCS project.

The success of Harbour Energy's and, following Completion, the Enlarged Group's existing and future CCS projects depends on its ability to demonstrate a viable investment case for CCS including an adequate likely return on investment and adequate risk management across the CO_2 capture, transport and storage chain. In particular, if the Viking or Acorn CCS projects, or other new CCS projects which may be undertaken by the Enlarged Group following Completion, or Harbour Energy and, following Completion, the Enlarged Group fail to secure the appropriate regulatory approvals such as economic licences, encounters project delivery issues or operational challenges post commercial operation, this could result in a weakened case for, and reduce the attractiveness of, CCS and adversely impact Harbour Energy's and, following Completion, the Enlarged Group's reputation, its position as a leader in CCS and its relationship with the UK Government in matters of climate change and energy transition.

Organisation and Talent Risk

16. ***Harbour Energy and, following Completion, the Enlarged Group may fail to create and maintain an organisation with sufficient capability and capacity that aligns with its business needs. Harbour Energy and, following Completion, the Enlarged Group may also fail to attract, develop, and retain talent or to maintain a cohesive and engaged culture that aligns with its values***

Harbour Energy's success is and, following Completion, the Enlarged Group's success will be dependent on the capability and capacity of its board of Directors, management and staff to operate its growing business and, at the same time, to execute additions to the portfolio via acquisition or other means and to successfully integrate newly acquired assets and any required additional staff into the business.

Attracting, developing and retaining additional skilled personnel will be fundamental to the continued growth of Harbour Energy's and, following Completion, the Enlarged Group's business. Harbour Energy requires and, following Completion, the Enlarged Group will require skilled personnel in areas including exploration and development, operations, engineering, business development, oil marketing, finance and accounting relating to its projects. Personnel costs, including salaries, are increasing as industry wide demand for suitably qualified personnel increases. There is a scarcity of qualified personnel in the more technical areas in which Harbour Energy's and, following Completion, the Enlarged Group's business operates and it may fail to maintain an organisation with sufficient capability and capacity that aligns with its business needs. Harbour Energy and, following Completion, the Enlarged Group may also fail to maintain a cohesive and engaged culture that aligns with its values. A misaligned or unhealthy culture could adversely affect Harbour Energy's and, following Completion, the Enlarged Group's business decisions, damage its reputation and so hinder its attractiveness, cause staff disengagement and increase employee attrition and reduced productivity. Consequently, Harbour Energy and, following Completion, the Enlarged Group may lack the capability, capacity, and culture to effectively execute its strategy and business plans which could materially and adversely affect its business, prospects, financial condition and results of operations.

Harbour Energy also uses and, following Completion, the Enlarged Group will use independent contractors to provide it with certain technical, financial, commercial and legal assistance and services. In certain cases, Harbour Energy and, following Completion, the Enlarged Group may exercise limited control over the activities and business practices of these providers and any failure on their part to conduct their business in accordance with acceptable business practices or their failure to provide services of adequate quality that meet the contractually agreed standards on a timely basis could materially adversely affect its business performance, its relationship with key counterparties or its reputation or expose it to the risk of legal proceedings, any of which could have a material adverse impact on its business, prospects, results of operations and financial condition.

The offshore workforce across the industry is aging and a significant number of experienced offshore workers are expected to retire during this decade. This is especially the case in the UKCS where the majority of Harbour Energy's production is currently located and in the UKCS and Norway where the majority of the Enlarged Group's production will be located following Completion. As its workforce ages, Harbour Energy and, following Completion, the Enlarged Group may face more challenges in recruiting or contracting appropriately skilled and experienced replacements as such workers and contractors retire from the industry. The oil and gas industry requires specialised knowledge and Harbour Energy and, following Completion, the Enlarged Group may lose institutional knowledge as members of its workforce retire. As well as the risk of failure to achieve adequate knowledge transfers, such new workers will require extensive training to ensure they are able to work safely on Harbour Energy's and, following Completion, the Enlarged Group's facilities. A major accident or incident could significantly impact production, impair financial performance and damage the reputation of Harbour Energy and, following Completion, the Enlarged Group.

More generally, the recruitment of personnel to the industry is proving challenging in some regions. This increases the time and costs associated with recruitment and training. Further, Harbour Energy and, following Completion, the Enlarged Group may be unable to recruit new workers on the same terms or with the same skillset to replace departing employees, or at all. A failure to recruit or retain sufficient new offshore workers could materially and adversely impact Harbour Energy's and, following Completion, the Enlarged Group's operational and financial performance.

Integration of Future Acquired Businesses Risk

17. ***Harbour Energy and, following Completion, the Enlarged Group may be exposed to risks inherent in any future acquisitions and disposals of oil and gas assets and businesses and may fail to properly integrate acquired assets and businesses and realise anticipated synergies in a timely manner***

Harbour Energy has grown its asset portfolio in recent years through acquisitions, including through the acquisition of UKCS assets previously held by Shell and ConocoPhillips for $3.0 billion and $2.7 billion, respectively, and through a reverse takeover of Premier Oil in 2021 to create Harbour Energy. The proposed Acquisition, if completed, will result in further significant growth of Harbour Energy's asset portfolio.

Harbour Energy and, following Completion, the Enlarged Group plans to continue to increase its oil and gas reserves through means that include strategic business and asset acquisitions and other inorganic opportunities. Even in circumstances where Harbour Energy conducts due diligence on potential target acquisitions, 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 prior to completion of the transaction. Physical inspections may not be performed on every facility or well, and structural or environmental problems are not necessarily observable even when an inspection is undertaken. In the context of any future acquisitions, as Harbour Energy and, following Completion, the Enlarged Group integrates any such acquisitions, it may learn additional information about acquired assets and businesses that adversely affects it, such as unknown or contingent liabilities and issues relating to non-compliance with applicable laws. Any such liabilities, individually or in the aggregate, could have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's business, financial condition and results of operations.

Harbour Energy and, following Completion, the Enlarged Group 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. There can be no assurance that any potential future acquisition by Harbour Energy and, following Completion, the Enlarged Group will be successful or that the value of any business, company or property that it acquires or invests in may not actually be less than the amount paid for it.

In addition, successful future acquisitions of oil and gas assets require an assessment of a number of other factors, including estimates of recoverable reserves, the time of recovering reserves, exploration potential, future oil, natural gas liquids and natural gas prices and operating costs. Such assessments are inexact and may prove to be wrong.

Harbour Energy and, following Completion, the Enlarged Group can give no assurance that future acquisitions will perform in accordance with its expectations or that its expectations with respect to integration synergies or other sources of value as a result of such acquisition will materialise in a timely matter or at all. A failure to accurately assess a target's business, assets and liabilities and unanticipated events relating to such businesses or significant unanticipated changes in the external environment could have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's results of operations, financial condition and cash flow. Such failures to achieve Harbour Energy's and, following Completion, the Enlarged Group's acquisition target performance goals could in turn have material adverse effects on its revenue, results of operations, financial condition and cash flows.

18. ***Harbour Energy and, following Completion, the Enlarged Group may be unable to dispose of assets on attractive terms and may be required to retain liabilities for certain matters.***

Whilst Harbour Energy's and, following Completion, the Enlarged Group's strategy is to continue to increase its oil and gas reserves, including through pursuing inorganic opportunities, Harbour Energy regularly reviews and, following Completion, the Enlarged Group will regularly review its asset base to assess the market value versus holding value of existing assets, with a view to disposing of non-strategic assets and optimising deployed capital.

The ability of Harbour Energy and, following Completion, the Enlarged Group to dispose of non-strategic assets could be affected by various factors, including the availability of purchasers who are willing and able to acquire such assets at prices acceptable to it. Sellers typically retain certain liabilities or agree to indemnify buyers for certain matters and to divest certain assets Harbour Energy and, following Completion, the Enlarged Group may provide certain indemnities 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 Harbour Energy and, following Completion, the Enlarged Group from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, Harbour Energy and, following Completion, the Enlarged Group may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

SECTION C: RISKS RELATING TO THE OIL AND GAS INDUSTRY

Health, Safety and Environment Risk

1. ***Harbour Energy and, following Completion, the Enlarged Group may face a major health, safety, environmental or physical security incident resulting in personal injury, physical property damage and/ or environmental harm***

Oil and gas exploration, development and production operations are inherently hazardous. There is a risk of a major accident or physical security incident resulting in personal injury, physical property damage and/or environmental harm. A serious incident could also significantly impact production, impair financial performance, and tarnish the reputation of Harbour Energy and, following Completion, the Enlarged Group. Harbour Energy's and, following Completion, the Enlarged Group's business might be subject to punitive fines and individual Directors could face sanctions.

Examples of the hazards present in exploration, development and production operations and decommissioning activity include blowouts, oil and other chemical spills, explosions, fires, catastrophic equipment damage or failure, natural disasters, uncontrollable flows of oil, gas or well fluids, severe weather conditions, terrorism, sabotage, pollution and other environmental risks. This is especially the case when drilling 'high pressure, high temperature' gas condensate fields (including the Elgin Franklin area fields). In addition the facilities and transportation and processing facilities upon which offshore oil and gas production is dependent, 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 or tidal conditions.

Moreover, should any of these risks materialise, Harbour Energy and, following Completion, the Enlarged Group could incur legal defence 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, clean up responsibilities, regulatory investigations and penalties, increased public interest in Harbour Energy's and, following Completion, the Enlarged Group's operational performance and suspension of operations. The liability frameworks for offshore oil and gas pollution incidents, including in the European Union, the UK and other jurisdictions in which Harbour Energy operates and, following Completion, the Enlarged Group will operate have been under increased scrutiny since the 2010 Deepwater Horizon drilling rig explosion in the Gulf of Mexico on the Macondo prospect and its aftermath. Contractual arrangements among various licensees, operators and third party contractors are under similar scrutiny, and allocation of pollution liability among parties to offshore exploration or production contracts may change as a result. Harbour Energy and, following Completion, the Enlarged Group may be exposed to increased liability for offshore incidents or the requirement to procure insurance coverage at higher amounts if these changes occur. Similar hazards and impacts from third party operations also could result in increased regulatory costs and operational restrictions impacting Harbour Energy's and, following Completion, the Enlarged Group's operations and those of others in its industry.

In addition, failure by Harbour Energy or, following Completion, the Enlarged Group to comply with applicable legal requirements or recognised international standards may give rise to significant liabilities. HSES laws and regulations may over time become more complex and stringent or the subject of increasingly strict interpretation or enforcement. The terms of production sharing contracts may include more stringent HSES requirements. The obtaining of exploration, development or production sharing contracts and permits may become more difficult or be the subject of delay by reason of governmental, regional or local environmental consultation, approvals or other considerations or requirements. These factors may lead to delayed or reduced exploration, development or production activity as well as to increased costs, which in turn could have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's business, operating results, financial condition or prospects.

Commodity Price Exposure Risk

2. ***Harbour Energy is and, following Completion, the Enlarged Group will be exposed to volatility in prevailing hydrocarbon prices and failure to manage the impact of commodity price fluctuations on the business may have a material adverse impact on its business, operating results, financial condition and prospects***

The price of oil and gas is impacted by changes in global and regional supply and demand, and expectations of future supply and demand. A sustained decline in oil and gas prices could undermine Harbour Energy's and, following Completion, the Enlarged Group's ability to deliver on its strategy by reducing cash flow available to fund growth and distributions and impairing access to capital. Excessive price volatility could also impede business planning and financial decision-making.

Prices for oil and gas have historically fluctuated widely for many reasons, including:

- global and regional economic and social conditions, including economic disruptions or slow-downs, for example as a result of natural disasters, trade-wars or pandemics;
- disruptions, volatility or slowdowns or fluctuations in the demand for oil or natural gas;
- changes in stocks of oil and related products;
- increases in production of oil and gas due to the development of new oil and gas discoveries, or improved extraction and production methods;
- geopolitical uncertainty;
- threats or acts of terrorism, cyber security attacks, war or threat of war, which may affect supply, transportation or demand;
- weather conditions, natural disasters and environmental incidents;

- development of extraction costs and inflation pressures;
- availability of, cost of and access to, pipelines and pipeline capacity, storage platforms, shipping vessels and other means of transporting, storing and refining oil and gas;
- petroleum refining capacity;
- prices and availability of alternative fuels and increases in competition from alternative energy sources;
- prices and availability of new oil and gas or alternative fuel technologies;
- the ability and willingness of the members of the Organisation of the Petroleum Exporting Countries ("**OPEC**"), and other oil producing nations, to set and maintain specified levels of production;
- political, economic and military developments in oil and gas producing regions, particularly the Middle East, Russia, Africa and Central and South America;
- domestic and foreign governmental regulations and actions, including the imposition of import and export restrictions, taxes, repatriations, nationalisations and environmental requirements and restrictions which aim to reduce the environmental impact of oil and gas exploration, development and production activities;
- trading activities by market participants and others either seeking to secure access to oil and gas and natural gas liquids or to hedge against commercial risks, or as part of an investment portfolio; and
- market uncertainty, including fluctuations in currency exchange rates, and speculative activities by those who buy and sell oil and gas on the world markets.

In recent years, the price of oil and gas has been materially impacted by trade tensions between the US and China, geopolitical developments between key oil producing nations, and decisions by OPEC and its allies ("**OPEC+**") to cut or increase its oil supply quotas. Oil and gas prices were also impacted by the novel strain of the coronavirus identified in late 2019 ("**COVID-19 pandemic**") and related unfavourable macroeconomic conditions. More recently, Russia's military action in Ukraine and conflict in the Middle East, has led to further volatility in commodity prices.

Further, the price of oil and gas is impacted by changes in global and regional supply and demand, and expectations regarding future supply and demand, for oil and gas. For example, the Nord Stream 2 subsea pipeline to Germany had previously been positioned as a mechanism to increase gas supply and thus reduce gas prices in the region. However, in February 2022, German regulators halted the Nord Stream 2 pipeline project in response to the conflict in Ukraine.

Even without the uncertainty caused by such factors, no assurance can be given regarding the ability to accurately predict future oil and gas prices and prices may continue to remain volatile. In addition, Harbour Energy currently cannot and, following Completion, the Enlarged Group will not be able to predict the impact of market shifting developments, such as the impact of unanticipated military conflict and its impact on oil and gas supply. Further, as oil and gas are globally traded, Harbour Energy is and, following Completion, the Enlarged Group will be unable to control the index/benchmark prices it receives for the oil and gas it produces since it is one of many participants globally. Historically, crude oil prices have been highly volatile and subject to large fluctuations in response to changes in the supply of and demand for oil. For example, since 1 January 2020, Dated Brent oil prices have ranged from below $14/bbl to over $137/bbl.

Harbour Energy's profitability is and, following Completion, the Enlarged Group's profitability will be largely determined by the difference between the income it receives from the oil and gas that it produces and the costs it incurs and the taxes it pays in producing, transporting and selling oil and gas to market. Lower prices for oil and gas may reduce the amount of oil and gas that Harbour Energy and, following Completion, the Enlarged Group is able to produce economically and may reduce the economic viability of prospective future investments to develop new oil and gas production. A sustained decline in oil and gas prices may cause Harbour Energy and, following Completion, the Enlarged Group to reduce its investment in oil and gas exploration, development and acquisition activities. Harbour Energy and, following Completion, the Enlarged Group may be required to postpone or cancel one or more planned development projects, or if it is not possible to cancel the projects, it may be required to complete such projects at a loss. In addition, a sustained decline in oil and gas prices may result in Harbour Energy and, following Completion, the Enlarged Group, or its production sharing contract partners, electing to stop production from certain wells or decommission producing fields earlier than expected.

A reduction in the long term outlook for oil and gas prices and the consequential profitability and the economic viability of Harbour Energy's and, following Completion, the Enlarged Group's assets could also result in having to make substantial downward adjustments to its oil and gas reserves.

Further, if a sustained reduction in oil and gas prices causes Harbour Energy and, following Completion, the Enlarged Group to make a substantial downward revision to its oil and gas reserves, it may be required to write-down the carrying value of its proved oil and gas properties as a non-cash charge to earnings. Accounting rules applicable to Harbour Energy and, following Completion, the Enlarged Group require that it periodically reviews the book value of its properties and goodwill for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, which may be impacted by lower oil and gas prices, it may be required to write down the carrying value of its oil and natural gas properties or goodwill to the extent that such tests indicate that the carrying value may not be recoverable due to a reduction of the estimated useful life or estimated future cash flows of its oil and natural gas properties. Such write downs constitute a non-cash charge against current earnings.

Harbour Energy seeks to mitigate and, following Completion, the Enlarged Group will seek to mitigate the impact of volatility in hydrocarbon prices by maintaining oil and gas price hedging to underpin its financial strength, protect its capacity to fund future developments and operations and underpin its business planning and financial decision-making. Oil and gas hedging can be undertaken with swaps, put options and collar option structures as well as through hedges embedded in hydrocarbon offtake agreements. All hedging references index pricing that relates to the underlying revenue from hydrocarbon sales. No assurance can be given that Harbour Energy's or the Enlarged Group's hedging policies will sufficiently protect against volatility in commodity prices or that Harbour Energy or the Enlarged Group will be able to put hedging in place with counterparties on acceptable terms in order to successfully implement their hedging policies.

Hedging policies could adversely affect Harbour Energy and the Enlarged Group due to a range of reasons including mismatch between the hedging instrument and risk for which protection is sought, mismatch between the nominal amount or duration of the hedging instrument and the related liability, default on obligation by the hedge counterparty, adjustment of the value of the derivatives, the high level of transaction costs, unanticipated tax consequences and subsequent exposure to financial risk. If Harbour Energy and, following Completion, the Enlarged Group is unable to hedge its hydrocarbon price risks effectively or experiences a loss as a result of its hedging activities, this could have a material adverse effect on the business, operating results, financial condition or prospects of Harbour Energy and, following Completion, the Enlarged Group.

Operational Performance Risk

3. ***Harbour Energy and, following Completion, the Enlarged Group may fail to maintain reliable and cost-effective production operations; production performance may also differ from that forecast***

Harbour Energy and, following Completion, the Enlarged Group may fail to maintain reliable and cost-effective production operations. Additionally, forecasting future production and operating costs is inherently uncertain, and actual performance may deviate from expectations.

Substantial expenditures and outages may be required to maintain the operability and integrity of the asset base as it ages and replacement parts may not be readily available. As Harbour Energy's and, following Completion, the Enlarged Group's asset base ages, ongoing maintenance is required to ensure continued operational integrity. Harbour Energy and, following Completion, the Enlarged Group intends to incur significant planned expenditure on the assets used to service production from its fields. Despite significant planned operating and capital expenditure, there can be no guarantee that Harbour Energy's and, following Completion, the Enlarged Group's assets or the assets used by it will continue to operate without fault and not suffer material damage in this period through, for example, wear and tear, severe weather conditions, natural disasters or industrial accidents. If Harbour Energy's and, following Completion, the Enlarged Group's assets or the assets used by it do not operate at or above expected efficiencies, Harbour Energy and, following Completion, the Enlarged Group may be required to invest substantial expenditure beyond the amounts budgeted. Any material damage to Harbour Energy's and, following Completion, the Enlarged Group's equipment or significant capital expenditure on its equipment for improvement or maintenance may have a material adverse effect on its results of operations and financial condition. In addition, while Harbour Energy and, following Completion, the Enlarged Group may endeavour to repair, re use, retrofit or refurbish producing assets where possible to maximise the efficiency of its operations while avoiding significant expenses associated with purchasing new equipment, no assurance can be given that any such repair, re use, retrofitting or refurbishment will be commercially feasible to undertake in the future or that it will not face unexpected costs during the re use, retrofitting or refurbishment process. Furthermore, opportunities to add production or increase throughput may be limited.

Harbour Energy's employees reside and, following Completion, the Enlarged Group's employees will reside in the UK, Norway, Germany, Denmark, Argentina, Egypt, Libya, Algeria, Indonesia, Vietnam and Mexico. Additionally, Harbour Energy hires and, following Completion, the Enlarged Group will hire contractors who, in turn, have their own employees. Harbour Energy's and, following Completion, the Enlarged Group's employees, and those employed by its contractors, may become members of or represented by labour unions. Work stoppages or other labour disturbances, such as industrial action, with its employees or those of its contractors, suppliers and customers may occur in the future. If this occurred, Harbour Energy and, following Completion, the Enlarged Group or its 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 Harbour Energy's and, following Completion, the Enlarged Group's results of operations and financial performance.

Production shortfalls may not be matched by proportional transportation and marketing cost savings due to minimum tariff provisions. Consequently, Harbour Energy and, following Completion, the Enlarged Group may fail to deliver forecast production levels, maintain competitive operating costs, meet guidance or fulfil contractual obligations, any of which would impact Harbour Energy's and, following Completion, the Enlarged Group's financial performance, position and liquidity.

Third-Party Reliance Risk

4. ***Harbour Energy and, following Completion, the Enlarged Group may be unable to source products and services required to find and develop and decommission oil and gas and to maintain production in a timely or cost efficient manner. Access restrictions may further affect Harbour Energy's and, following Completion, the Enlarged Group's operations***

Oil and gas exploration, development, production and decommissioning activities are dependent on the availability of specialised products and services and experienced manpower from supply chain providers including, but not limited to, drilling and related equipment and manpower in the regions where such activities will be conducted.

From time to time, the demand for such specialised products and services and experienced manpower may exceed available capacity or capability. Access and/or import restrictions may also affect the availability and cost of such products and services and may in turn lead to more costly and/or time consuming exploration, development, production and decommissioning activities. Also, to the extent that Harbour Energy and, following Completion, Enlarged Group is not the operator of its oil and gas assets, it will be dependent on the relevant operator to secure the products and services necessary to manage these activities related to such assets and its ability to influence the relevant operator may be limited. If any of these risks materialise they may have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's business, results of operations, cash flow and financial condition.

Furthermore, Harbour Energy is and, following Completion, the Enlarged Group will be heavily dependent on third party providers of specialised products and services to deliver these products and services to time, cost and quality criteria. Failure by such third party providers to deliver project-critical products and services to contractual schedule, cost and quality requirements and safety standards or if the costs of third party products and services are higher than expected, it may have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's business, cash flows and results of operations.

In particular, scarcity of products and services and increased prices may result from any significant increase in regional exploration and development activities such as may be encountered during periods of higher oil and gas prices. In the event that there is a sharp increase in underlying oil and gas prices before Harbour Energy and, following Completion the Enlarged Group enters into contracts for the delivery of a suitable drilling rig, other major construction activities, or essential supporting services in connection with future exploration or development activities, the scarcity of such equipment and services, combined with their potentially high cost, could delay, restrict or lower the profitability and viability of its projects, including its development and pre-development projects, and therefore have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's business, operating results, financial condition or prospects.

In recent years there has been increased demand for third party products and services due to higher oil and gas prices and continued competing demand from renewable energy and infrastructure projects, as well as from international markets. Harbour Energy is and, following Completion, the Enlarged Group will also be impacted by the general decline in UK oil and gas activity and geopolitical risks. These conditions, alongside rising interest rates and inflation, have impacted and may continue to impact the ability and/or willingness of contractors to invest in assets and services provisions, in particular in the UK. These conditions could also create a context for default, unsafe practices or unethical behaviours, including fraud or human rights violations.

Cyber, IT and Information Security Risk

5. ***Harbour Energy and, following Completion, the Enlarged Group may fail to maintain adequate cyber and information security measures making it vulnerable to a serious cyber-security incident or slow to recover in the event of a serious incident***

Harbour Energy relies and, following Completion, the Enlarged Group will rely on safe, secure and reliable IT systems (including back-up measures) and underlying data and it may fail to maintain adequate cyber and information security measures making its internal systems vulnerable to a serious cyber-security incident or slow to recover in the event of an incident.

Information and communication systems by their nature are susceptible to internal and external security breaches, including computer hacker and cyber-terrorist breaches, wilful breaches by employees and employees succumbing to criminal scamming from external sources, and can fail or become unavailable for a significant period of time. Harbour Energy's operations are dependent and, following Completion the Enlarged Group's operations will be dependent on the use of protected, sensitive or personal data. Harbour Energy has been and, following Completion, the Enlarged Group may be the target of attempted cyber-attacks. Such cyber-attacks are designed to penetrate Harbour Energy's and, following Completion, the Enlarged Group's network security or the security of its internal systems, misappropriate proprietary information and/or cause disruption to its business.

In addition, confidential information that Harbour Energy or, following Completion, the Enlarged Group maintains 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 Harbour Energy's or, following Completion, the Enlarged Group's information could result in, among other things, being in breach of certain data protection requirements and related legislation.

Whilst Harbour Energy has incurred expenses to comply with mandatory privacy and security standards and protocols imposed by law, regulation, industry standards or contractual obligations relating to the collection, use and security of personal data, no assurance can be given by Harbour Energy or, following Completion, the Enlarged Group that it will be able to prevent, detect and respond adequately to such attacks on its systems and information. Such future attacks could include hackers obtaining access to Harbour Energy's and, following Completion, the Enlarged Group's systems, the introduction of malicious computer code or denial of service attacks. In addition, the development and emerging effects of artificial intelligence and other tools that involve the non-malicious sharing of information with third parties may present a further security and operational risk to Harbour Energy's and, following Completion, the Enlarged Group's IT systems and security protocols which may lead to data leaks and malicious attacks.

A security breach could also impair Harbour Energy's and, following Completion, the Enlarged Group's ability to operate its business and potentially result in heightened health, safety or environmental risk. A failure to adequately manage this risk could result in business or operational interruption, impact the confidentiality, integrity, availability and regulatory compliance of company information, including important intellectual property and violation of confidentiality agreements, and potentially lead to heightened safety or environmental risk. Such outcomes may lead to regulatory fines, impact business performance and damage Harbour Energy's and, following Completion, the Enlarged Group's reputation. Any of the foregoing could have a material adverse effect on Harbour Energy's and, following Completion, the Enlarged Group's business, financial condition and results of operations.

Legal and Regulatory Compliance Risk

6. ***Harbour Energy and, following Completion, the Enlarged Group may fail to maintain effective legal and regulatory compliance***

Harbour Energy's and, following Completion, the Enlarged Group's ability to operate will depend on maintaining and demonstrating effective legal and regulatory compliance with existing and future requirements. Harbour Energy's and, following Completion, the Enlarged Group's exploration and development operations must be carried out in accordance with the terms of their concession agreements, licences, oil exploration, development and production sharing contracts, and applicable annual work programmes, field development plans and budgets as established in relation thereto, together with any conditions incumbent on it at the time the relevant asset was acquired such as ongoing royalty payments or one off payments triggered on specific events, as well as applicable legislation.

Relevant legislation in the jurisdictions in which Harbour Energy does and, following Completion, the Enlarged Group will do business provide that fines may be imposed or damages claimed and a licence or production sharing contract may be suspended or terminated if a party to the contract fails to (i) comply with its obligations under such contract; (ii) make timely payments of levies and taxes for the contracted activity; or (iii) provide required technical or financial information or meet other reporting requirements. It may from time to time be difficult to ascertain whether Harbour Energy and, following Completion, the Enlarged Group has complied with obligations under licences or production sharing contracts as the extent of such obligations may be unclear or ambiguous and regulatory authorities in jurisdictions in which Harbour Energy does and, following Completion, the Enlarged Group will do business, or in which it may do business in the future, may not be forthcoming with confirmatory statements that work obligations have been fulfilled, which can lead to further operational uncertainty. In some instances, Harbour Energy and, following Completion, the Enlarged Group may be jointly and severally liable for required payments pursuant to the terms of the licences or production sharing contracts under which it operates. Moreover, there can be no assurance that Harbour Energy and, following Completion, the Enlarged Group will be successful in obtaining any required extensions to licences or production sharing contracts or in obtaining licences or production sharing contracts where oil and/or gas is discovered during the term of such contract.

In addition, Harbour Energy and, following Completion, the Enlarged Group and its commercial partners, as applicable, have obligations to develop the fields in accordance with specific requirements under certain licences or production sharing contracts and related agreements, field development plans, laws and regulations. If Harbour Energy and, following Completion, the Enlarged Group were to fail to satisfy such obligations with respect to a specific field, the licence, production sharing contract or related agreements for that field may be suspended, revoked or terminated.

The authorities in the jurisdictions in which Harbour Energy does and, following Completion, the Enlarged Group will do business are typically authorised to, and do from time to time, inspect to verify compliance by it or its commercial partners, as applicable, with relevant laws and the licences, production sharing contracts or the agreements pursuant to which it conducts its business. There can be no assurance that the views of the relevant government agencies regarding the development of the fields that Harbour Energy and, following Completion, the Enlarged Group or its commercial partners operate or the compliance with the terms of the licences or production sharing contracts pursuant to which it conducts such operations will coincide with its views, which might lead to disagreements that may not be resolved. In addition, Harbour Energy's and, following Completion, the Enlarged Group's licences or production sharing contracts may also be modified or withdrawn by sovereign authorities, notwithstanding the terms of such contracts, as a result of changes in law, public policy or the politics of such countries. There can be no assurances that the terms of any licence or production sharing contract would not be changed to impose more onerous requirements on Harbour Energy and, following Completion, the Enlarged Group or to alter the economic terms to be less favourable to Harbour Energy and, following Completion, the Enlarged Group.

A portion of the licences and production sharing contracts pursuant to which Harbour Energy conducts and, following Completion, the Enlarged Group will conduct operations are solely exploration and/or development contracts, and as such the assets which are the subject of such contracts are not currently producing, and may never produce commercial quantities of, oil or gas. Rather, these licences and production sharing contracts have a limited life before Harbour Energy conducts and, following Completion, the Enlarged Group is obliged to seek to extend the licence or production sharing contract into the production phase or relinquish the relevant area.

For example, in the UK where the majority of Harbour Energy's assets are located, if hydrocarbons were to be discovered during the exploration phase, it or its commercial partners, as applicable, may apply for an extension of the licence into the development phase. This will be subject to the submission of a field development plan and its approval by the NSTA. Upon completion of the development phase, Harbour Energy and, following Completion, the Enlarged Group or its commercial partners may then request a further extension of the licence into the production phase. If Harbour Energy and, following Completion, the Enlarged Group or its commercial partners, as applicable, comply with the terms of the relevant licence and the field development plan, it would normally be expected that extensions by the NSTA would be granted; however, no assurance can be given that any necessary approvals will be given.

Furthermore, in order to maintain Harbour Energy's existing licences or production sharing contracts to operate and to secure access to new reserves and resources, it is important that Harbour Energy and, following Completion, the Enlarged Group maintains and, to the extent Harbour Energy has less or no previous experience in such countries seeks to develop, strong and positive relationships with the governments and communities in the countries where its business is conducted. For instance, Harbour Energy and, following Completion, the Enlarged Group will need to engage constructively with the Mexican and Indonesian governments as well as local regulators, including amongst others, SKK Migas in Indonesia and the National Hydrocarbons Commission in Mexico.

Failure to comply with licence or production sharing contract obligations and regulatory requirements in the jurisdictions in which Harbour Energy and, following Completion, the Enlarged Group has assets may lead to fines, penalties, restrictions and termination of related agreements. The termination of any of the licences or production sharing contracts or related agreements pursuant to which Harbour Energy and, following Completion, the Enlarged Group conducts business, as well as any delays in the continuous development of or production at its fields caused by the issues detailed above could materially and adversely affect its business, prospects, financial condition and results of operations. In addition, failure to comply with the obligations under the licences, production sharing contracts or agreements pursuant to which Harbour Energy and, following Completion, the Enlarged Group conducts business, whether inadvertent or otherwise, may lead to fines, penalties, restrictions, and termination of related agreements, which could materially and adversely affect Harbour Energy's and, following Completion, the Enlarged Group's business, prospects, financial condition and results of operations.

Harbour Energy's and following Completion, the Enlarged Group's employees and contractors are also subject to various laws and regulations governing corporate and personal conduct and disclosure, including areas such as human rights, fraud, bribery, corruption and tax evasion. Should a major compliance breach occur, a failure to demonstrate adequate legal and regulatory compliance processes could lead to financial penalties being imposed on Harbour Energy or, following Completion, the Enlarged Group, or erosion of its value-based culture and damage to its reputation amongst its employees and external stakeholder. Individual Directors of Harbour Energy could also face personal sanctions.

Other Risks

7. ***Following Completion, the Enlarged Group may be unable to compete effectively due to the hydrocarbons industry being highly competitive***

The oil and gas industry is highly competitive. The key areas in respect of which Harbour Energy faces and, following Completion, the Enlarged Group will face competition include:

- acquisition of other companies which find, develop or produce oil and gas;
- acquisition of assets offered for sale by other companies;
- acquisition of exploration or production sharing contracts, or interests in such contracts, at auctions or sales run by governmental authorities;
- availability of, and access to, pipeline ullage and tanker capacity together with other storage, processing and delivery facilities;
- purchasing, leasing, hiring, chartering or other procuring of equipment that may be scarce;
- engagement of third party service providers whose capacity to provide key products and services may be limited; and
- employment of qualified and experienced skilled management and oil and gas professionals.

Competition in market in which Harbour Energy operates and, following Completion, the Enlarged Group will operate is intense and depends, amongst other things, on the number of competitors in the market, their financial resources, their degree of geological, geophysical, engineering and management expertise and capabilities, their degree of vertical integration, their pricing policies, their ability to develop assets on time and on budget, their ability to select, acquire and develop proved reserves and their ability to foster and maintain relationships with host governments of the countries in which they have assets. Harbour Energy's and, following Completion, the Enlarged Group's competitors include entities that may have greater technical, physical and financial resources including those who may not only engage in the acquisition, exploration, development and production of oil and gas reserves, but also carry out refining operations and marketing of refined products. When looking at acquisition opportunities, Harbour Energy and the Enlarged Group also compete with demand from other enterprises which may possess the financial resources to offer more attractive and/or favourable prices to sellers. The supply of asset acquisition opportunities may fluctuate depending on, amongst other factors, the divestment strategies of other companies as companies consider rebalancing their portfolios, for example shifting their focus from traditional oil and gas to low carbon businesses. In addition, competition for new production sharing contracts in each region may fluctuate depending on the supply of new production sharing contracts in each region and the perceived attractiveness of investment opportunities in that region. Finally, companies and private equity firms not previously investing in oil and gas may choose to acquire reserves to establish a firm supply or simply as an investment. Any such companies will also increase market competition which may directly affect Harbour Energy and, following Completion, the Enlarged Group.

The effects of operating in a competitive industry may include:

- higher than anticipated prices for the acquisition of licences or assets;
- the hiring by competitors of key management or other personnel;
- restrictions on the availability of equipment or services; and
- potentially unfair practices including unconscionable pressure on Harbour Energy and, following Completion, the Enlarged Group directly or indirectly or the dissemination of false or misleading information or rumours by competitors or third parties.

If Harbour Energy and, following Completion, the Enlarged Group is unsuccessful in competing against other companies for reasons including any of the foregoing circumstances, its business, prospects, financial condition and results of operations could be materially adversely affected.

8. ***Harbour Energy and, following Completion, the Enlarged Group may not be able to keep pace with or capitalise on opportunities presented by technological developments in the oil and gas industry and the use of new, emerging or unproven technologies may have unanticipated or unforeseen adverse consequences***

The oil and gas industry is characterised by the development and introduction of new products and services using new technologies. As others use or develop new technologies, Harbour Energy and, following Completion, the Enlarged Group 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 Harbour Energy and, following Completion, the Enlarged Group can. Harbour Energy and, following Completion, the Enlarged Group may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies it heavily relies on now or in the future were to unexpectedly become obsolete, Harbour Energy's and, following Completion, the Enlarged Group's business, prospects, financial condition and results of operations could be materially adversely affected. In addition, any new, emerging or unproven technologies that Harbour Energy and, following Completion, the Enlarged Group may implement may fail to perform as intended or at all, may result in unanticipated costs and may have an adverse impact on its performance.

9. ***Harbour Energy's operations are and, following Completion, the Enlarged Group's operations will be subject to the risk of litigation***

From time to time, Harbour Energy and, following Completion, the Enlarged Group may be subject to or otherwise impacted by litigation or arbitration arising out of its activities or operations, whether or not a direct party to those matters. Damages claimed, or the potential impact on Harbour Energy and, following Completion, the Enlarged Group of the result under any such proceedings, may be material or may be indeterminate, and the outcome of such litigation or arbitration could materially and adversely affect

Harbour Energy's and, following Completion, the Enlarged Group's reputation, business, results of operations, financial condition and/or prospects.

While Harbour Energy assesses and, following Completion, the Enlarged Group will assess the merits of each action and will consider defending it accordingly, it may be required to incur significant expenses in defending against litigation or arbitration and there can be no guarantee that a court or tribunal will find in favour of Harbour Energy or, following Completion, the Enlarged Group. Any adverse publicity, convictions and prosecution in respect of any future claims, or any liability that may result from any such claims against the Enlarged Group or its employees in the future, could have a material adverse effect on the Enlarged Group's business.

10. ***Harbour Energy's and, following Completion, the Enlarged Group's insurance and indemnities may not adequately cover all risks and expenses including losses arising from potential operational hazards and unforeseen interruptions***

Consistent with insurance coverage generally available to the industry, Harbour Energy's insurance currently includes and, following Completion, the Enlarged Group's insurance will include cover for damage to physical assets, operator's extra expense (including well control, seepage and pollution clean-up and re drill costs), contingent business interruption insurance and third party liabilities for its global exploration and production activities, in each case subject to excesses, exclusions and limitations. There can be no assurance that such insurance will be adequate to cover any losses or exposure for liability, or that Harbour Energy and, following Completion, the Enlarged Group will continue to be able to obtain insurance to cover such risks.

Harbour Energy and, following Completion, the Enlarged Group is unable to give any guarantee that expenses relating to losses or liabilities will be fully covered by the proceeds of applicable insurance. Consequently, Harbour Energy and, following Completion, the Enlarged Group may suffer material losses from uninsurable or uninsured risks or insufficient insurance coverage. Harbour Energy is subject and, following Completion, the Enlarged Group will be subject to the future risk of unavailability of insurance, increased premiums or excesses, and expanded exclusions.

SECTION D: RISKS RELATING TO READMISSION AND ADMISSION AND AN INVESTMENT IN THE ORDINARY SHARES

1. ***The market price of the Ordinary Shares could be negatively affected by sales of substantial amounts of Ordinary Shares by BASF and, in the event Non-Voting Shares are converted into Ordinary Shares, LetterOne in the public markets (or the perception that these sales could occur) following the expiry of lock-up agreements and/or the fact that the Enlarged Group will have a more concentrated shareholder base following Completion***

Upon Completion, BASF and LetterOne are expected to hold approximately 39.6 per cent. and 14.9 per cent., respectively, of the enlarged share capital of the Company (assuming for these purposes that the Non-Voting Shares had converted into Ordinary Shares). The BASF Consideration Shares will be subject to a six month lock-up following Completion (subject to customary exceptions). The lock-up arrangements will also apply to any Ordinary Shares held by LetterOne in the event LetterOne were to convert its Non-Voting Shares into Ordinary Shares within the period of six months from Completion.

The cumulative effect of the issue of the BASF Consideration Shares and the lock-up arrangements may have an impact on the liquidity of the market for the Ordinary Shares. If an active trading market is not maintained, the liquidity and trading price of the Ordinary Shares may be adversely affected. The sale of a substantial number of Ordinary Shares by BASF (and/or LetterOne in the event that it were to convert its Non-Voting Shares into Ordinary Shares), or the perception that such a sale may occur, may depress the market price of the Ordinary Shares and could impair the Company's ability to raise capital through the sale of additional equity securities or delay, deter or prevent a change in control, acquisition, consolidation, takeover or other business combination, which could in turn have an adverse effect on the trading price of the Ordinary Shares.

2. ***Shareholders will experience dilution in their ownership of the Company as a result of the Acquisition and any future Ordinary Share issues may dilute existing shareholdings, may reduce the price of the Ordinary Shares and make it more difficult for Shareholders to sell their Ordinary Shares at a price they deem appropriate***

If Admission occurs, it will result in the issue and allotment of 669,714,027 BASF Consideration Shares. If the Acquisition completes, therefore, existing Shareholders will suffer an immediate dilution as a result of Admission, following which they will hold, assuming that 669,714,027 BASF Consideration Shares are issued and allotted, approximately 53.5 per cent. of the enlarged share capital of the Company.

Other than pursuant to the Acquisition, and except for Ordinary Shares issued in the ordinary course to executives and employees in connection with the Employee Share Schemes, Harbour Energy has no current plans for a subsequent offering of Ordinary Shares. However, Harbour Energy may decide to offer additional Ordinary Shares in the future. If existing Shareholders do not take up any additional offering of Ordinary Shares or are ineligible to participate in such an offering, their percentage ownership and voting interests in Harbour Energy would be reduced. An additional offering or significant sales of Ordinary Shares by major Shareholders, or the perception or any announcement that such an additional offering or sales could occur, could adversely affect the market price of the Ordinary Shares as a whole and may make it more difficult for Shareholders to sell their Ordinary Shares at a time and price which they deem appropriate.

3. ***Following Completion, BASF may be able to influence decision-making within the Company and its interests may differ from those of other Shareholders***

Upon Completion, BASF is expected to hold approximately 39.6 per cent. of the enlarged share capital of the Company. Given BASF will hold more than 30 per cent. of the shares of the Enlarged Group, it will be deemed a controlling shareholder for the purposes of the Listing Rules. As a result, the Company will enter into a relationship agreement at Completion (but conditional on Admission) with BASF (referred to in this document as the BASF Relationship Agreement).

If and for so long as BASF (together with any of its associates) hold: (i) at least ten per cent. of the Ordinary Shares, it will have the right to nominate one non-executive director to the Board; and (ii) at least 25 per cent. of the Ordinary Shares, it will have the right to nominate two non-executive directors to the Board. While BASF holds more than 25 per cent. of the Ordinary Shares, it will have the ability to block special resolutions of the Company proposed by the Board or members of the Company from time to time. BASF, however, will not be entitled to vote on a given shareholder resolution if it would be considered a related party for the purposes of the Listing Rules in respect of that shareholder resolution. As such, BASF may be able to exercise significant influence over the Board and the Company but it will not be under any obligation to act in the best interests of the Company, other Shareholders or other stakeholders.

The BASF Relationship Agreement will take effect upon Admission and will continue in force unless and until BASF and its associates cease to own at least ten per cent. or more of the Ordinary Shares or the voting rights attaching to the Ordinary Shares. BASF may terminate the Relationship Agreement in certain circumstances, including where the Ordinary Shares cease to be admitted to the premium segment of the Official List (or, in circumstances where the Listing Rules have been amended such that the premium listing segment ceases to exist, the Ordinary Shares cease to be listed on the replacement segment of the Official List of the FCA for issuers of equity shares in commercial companies) and cease to be admitted to trading to the London Stock Exchange's main market for listed securities. For more information on the BASF Relationship Agreement, see paragraph 15.2 (BASF Relationship Agreement) in Part XIV (*Additional Information*).

The Company will also enter into a relationship agreement at Completion (but conditional on Admission) with LetterOne (referred to in this document as the LetterOne Relationship Agreement). Pursuant to the LetterOne Relationship Agreement, LetterOne will have equivalent rights to BASF to nominate non-executive directors to the Board, however any such rights will only apply to the extent that LetterOne has converted Non-Voting Shares into Ordinary Shares (following satisfaction of the relevant Conversion Conditions) and, as a result, holds the requisite percentage of Ordinary Shares. For more information on the LetterOne Relationship Agreement and the Conversion Conditions, see paragraphs 15.3 (LetterOne Relationship Agreement) and 15.1 (Business Combination Agreement), respectively, in Part XIV (*Additional Information*).

4. ***The price of the Ordinary Shares may fluctuate***

Prospective investors should be aware that the value of an investment in Harbour Energy may go down as well as up. The market value of the Ordinary Shares could be volatile and subject to significant fluctuations due to a variety of factors, including:

- volatility in commodity prices;
- changes in market sentiment regarding the Ordinary Shares;
- any regulatory changes affecting Harbour Energy's and, following Completion, the Enlarged Group's operations;
- variations in Harbour Energy's and, following Completion, the Enlarged Group's operating results;
- business developments of Harbour Energy and, following Completion, the Enlarged Group, their competitors, or the hydrocarbons industry;
- the operating and share price performance of other companies in the industries and markets in which Harbour Energy operates and in which the Enlarged Group will operate;
- the use of investment strategies by the investment community, such as shorting;
- speculation about Harbour Energy's and, following Completion, the Enlarged Group's business in the press, media or investment community; and
- litigation against Harbour Energy and, following Completion, the Enlarged Group which is commenced or threatened.

Stock markets have, from time to time, experienced significant price and volume fluctuations that have affected market prices for securities and which may be unrelated to Harbour Energy's and, following Completion, the Enlarged Group's operating performance or prospects. Prospective investors should not rely on Harbour Energy's results or the financial information on the Target Portfolio made available to date as an indication of future performance. Furthermore, Harbour Energy's and, following Completion, the Enlarged Group's operating results and prospects from time to time may be below the expectations of market analysts and investors. Any of these events could result in a decline in the market price of the Ordinary Shares. The market value of the Ordinary Shares can fluctuate and may decline below the price at which investors subscribe for Ordinary Shares. The market value of the Ordinary Shares may not always reflect the underlying asset value or prospects of Harbour Energy or, after Completion, those of the Enlarged Group.

5. ***There is no guarantee that there will be an active trading market for the Ordinary Shares***

Admission of the BASF Consideration Shares to trading should not be taken as implying that there will be a liquid market for the Ordinary Shares and there is no guarantee that there will be an active trading market after admission. If an active trading market is not maintained, the liquidity and trading price of the Ordinary Shares may be adversely affected.

6. ***The ability of Overseas Shareholders to bring actions or enforce judgments against the Enlarged Group or its directors or officers may be limited***

The Company is a public limited company incorporated in Scotland. The rights of the Company's shareholders are governed by Scottish law and the Articles and therefore differ from the rights of shareholders in typical US corporations and some other non-UK corporations.

Shareholders may not be able to bring or enforce any judgments in civil and commercial matters or any judgments under the securities laws of countries other than the UK against the Company, the Directors and/or executive officers who are residents of the UK or countries other than those in which judgment is made, and it may not be possible for investors outside of the UK to effect service of process outside the UK on the Company, the Directors and/or executive officers.

7. ***Pre-emptive rights may not be available to Overseas Shareholders***

Under the Articles (save for certain exceptions set out therein) and pursuant to the Listing Rules, prior to the issue of any new shares, holders of Ordinary Shares generally have pre-emptive rights to subscribe and pay for a sufficient number of Ordinary Shares to maintain their existing ownership percentages.

In connection with the Acquisition, the share capital of the Company will be increased and Ordinary Shares will be issued. In addition, further share capital increases and share issues may be proposed in the future. Shareholders are entitled to pre-emptive rights in respect of new issues of Ordinary Shares for cash unless those rights are waived by a Shareholders' resolution.

Overseas Shareholders may not be able to exercise their pre-emptive rights as part of a future issue of shares for cash (even if pre-emption rights were not waived), unless the Company decides to comply with applicable local laws and regulations. This is because securities laws of certain jurisdictions may restrict the Company's ability to allow participation by certain Shareholders in any future issue of shares. In particular, Overseas Shareholders who are located in the United States may not be able to exercise their rights on a future issue of shares, unless a registration statement under the US Securities Act is effective with respect to such rights or an exemption from the registration requirements is available thereunder. The Ordinary Shares are not and will not be registered under the US Securities Act and the Company may not file any such registration statements for future share issues, and an exemption from the registration requirements of the US Securities Act may not be available. In such an event, Overseas Shareholders who are located in the United States would be unable to participate in such an issue.

IMPORTANT INFORMATION

FORWARD-LOOKING STATEMENTS

Certain statements contained in this Prospectus constitute "forward-looking statements". These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond the Company's control and all of which are based on the Directors' current beliefs and expectations about future events. In some cases, these forward-looking statements can be identified by the use of forward-looking terminology, including the terms "targets", "believes", "estimates", "plans", "prepares", "anticipates", "expects", "intends", "may", "will" or "should" or, in each case, their negative or other variations or comparable terminology.

Such forward-looking statements are based on numerous assumptions regarding the Company's present and future business strategies and the environment in which Harbour Energy, the Target Company and/or the Enlarged Group will operate in the future. By their nature, such forward-looking statements involve known and unknown risks, uncertainties and other factors because they relate to events and depend on circumstances which may or may not occur in the future. Forward-looking statements are not guarantees of future performance. Actual results, performance or achievements of Harbour Energy, the Target Company and/or the Enlarged Group, or industry results, may be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. In addition, even if actual performance, results of operations, internal rate of return, financial condition, distributions to Shareholders and the development of its financing strategies are consistent with the forward-looking statements contained in this Prospectus, those results or developments may not be indicative of results or developments in subsequent periods.

Key risks, uncertainties and other factors that could cause actual results to differ from those expected are set out more fully in the section of this Prospectus headed "*Risk Factors*". Investors should specifically and carefully consider these factors, which could cause actual results to differ, before making an investment decision.

Each forward-looking statement speaks only as at the date of the particular statement and is not intended to provide any representations, assurances or guarantees as to future events or results. To the extent required by the UK Prospectus Regulation, the Listing Rules, the Prospectus Regulation Rules, the Disclosure Guidance and Transparency Rules, the UK Market Abuse Regulation and other applicable regulation, the Company will update or revise the information in this Prospectus. Otherwise, the Company undertakes no obligation to update or revise any forward-looking statements or other information, and will not publicly release any revisions it may make to any forward-looking statements or other information that may result from events or circumstances arising after the date of this Prospectus.

For the avoidance of doubt, nothing in this Prospectus constitutes a qualification of the working capital statement set out in paragraph 19 (Working Capital) of Part XIV (*Additional Information*) of this Prospectus.

NO PROFIT FORECASTS AND ESTIMATES

No statement in this Prospectus is intended as a profit forecast or profit estimate for any period and no statement in this Prospectus should be interpreted to mean that earnings or earnings per share for the Company, the Target Company or the Enlarged Group for the current or future financial years would necessarily match or exceed the historical published earnings or earnings per share of the Company or the Target Company.

PRESENTATION OF RESERVES AND RESOURCES

Unless otherwise stated, statements in this document relating to the reserves and resources attributed to Harbour Energy, the Target Company or the Enlarged Group have been prepared using the classification system set out in the Petroleum Resources Management System approved in March 2007 and revised in June 2018 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. These standards of reporting may be different from those adopted in the United States and other jurisdictions. Shareholders, therefore, should not assume that the data found in the reserves and resources information set forth in this document is directly comparable to similar information that has been prepared in accordance with the reserve and resource reporting standards of other jurisdictions.

Unless stated otherwise, all references to "reserves" are to proved plus probable ("**2P reserves**") and all references to "contingent resources" are to proved plus probable discovered hydrocarbons that are potentially recoverable ("**2C resources**") but not yet considered mature enough for commercial development due to technological or business hurdles (e.g. all required internal and external approvals are not yet in place).

The accuracy of reserves estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. This document should be accepted with the understanding that reserves, resources and financial performance subsequent to the date of the estimates may necessitate revision. These revisions may be material. Unless otherwise stated, all information about the oil and gas reserves and resources attributable to the Target Company, and forward-looking production estimates and other geological information in relation thereto, has been extracted without material adjustment from the Target Company's competent person's report (the "**Target Company CPR**") included in Part XI (*Competent Person's Report on the Target Company's Portfolio*). Unless otherwise stated, all information about the oil and gas reserves and resources attributable to Harbour Energy, and forward-looking production estimates and other geological information in relation thereto, has been extracted without material adjustment from Harbour Energy's 2023 Annual Report and Financial Statements.

FINANCIAL INFORMATION RELATING TO HARBOUR ENERGY

All financial information relating to Harbour Energy contained in this Prospectus, unless otherwise stated, has been extracted from the Company's audited financial statements as at and for the years ended 31 December 2023, 2022 and 2021 as set out in the Harbour Energy Annual Report 2023, the Harbour Energy Annual Report 2022 or the Harbour Energy Annual Report 2021 or from Harbour Energy's accounting records used to prepare such financial statements.

Unless otherwise stated, all financial information relating to Harbour Energy contained in or incorporated by reference into and forming part of this Prospectus has been prepared in accordance with UK-adopted International Accounting Standards and should be read in conjunction with the independent auditor's report thereon.

FINANCIAL INFORMATION RELATING TO THE TARGET PORTFOLIO

All financial information relating to the Target Portfolio contained in this Prospectus, unless otherwise stated, has been extracted from the combined historical financial information as at and for the years ended 31 December 2023, 2022 and 2021, as set out in Part IX (*Historical Financial Information relating to the Target Portfolio*) of this Prospectus or from the Target Portfolio's accounting records used to prepare such combined historical financial information. Unless otherwise stated in "*Note 2*" in Part IX (*Historical Financial Information relating to the Target Portfolio*), the accounting policies that have been applied are consistent with those used by Harbour Energy in its audited financial statements as at and for the year ended 31 December 2023.

PRO FORMA FINANCIAL INFORMATION

Certain unaudited pro forma financial information in relation to the Enlarged Group is set out in Part X (*Unaudited Pro Forma Financial Information*) of this Prospectus.

ALTERNATIVE PERFORMANCE MEASURES

Harbour Energy utilises a range of alternative performance measures to assess Harbour Energy's performance. These are defined in the section of the Harbour Energy Annual Report 2023 entitled "*Non-IFRS measures*", which together with the relevant paragraphs and sections of the Annual Report 2023 providing reconciliations of such alternative performance measures to IFRS, are incorporated by reference into and form part of this Prospectus.

MARKET, ECONOMIC AND INDUSTRY DATA

Market, economic and industry data used throughout this Prospectus is derived from various industry and other independent sources. Where third party information has been used in this Prospectus, the source of such information has been identified. The Company confirms that all third party information has been accurately reproduced and, as far as the Company is aware and able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

CURRENCY PRESENTATION

Unless otherwise indicated in this document, all references to:

(a) "**pounds sterling**" or "**£**" or "**pence**" are to the lawful currency of the United Kingdom;

(b) "**US dollars**", "**dollars**", "**US$**", "**$**" or "**cents**" are to the lawful currency of the United States; and

(c) "**euro**" or "**€**" are to the lawful currency of the European Union (as adopted by certain member states).

Unless otherwise indicated, the financial information contained in this document has been expressed in US dollars. Harbour Energy presents its financial statements in US dollars.

ROUNDING

Certain figures contained in this Prospectus or incorporated into this Prospectus by reference, including financial and numerical information, have been subject to rounding adjustments. Accordingly, in certain instances, the sum of the numbers in a column or a row in tables contained in this Prospectus or incorporated into this Prospectus by reference may not conform exactly to the total figure given for that column or row.

REFERENCES TO DEFINED TERMS

Certain terms used in this Prospectus, including certain capitalised terms and certain technical and other terms, are defined, and certain selected industry and technical terms used in this Prospectus are defined and explained in Part XV (*Definitions and Interpretation*) of this Prospectus.

NO INCORPORATION OF WEBSITE INFORMATION

The contents of Harbour Energy's website does not form part of this Prospectus.

INFORMATION INCORPORATED BY REFERENCE

The table below sets out the documents of which certain parts are incorporated by reference into this Prospectus and which are available for inspection as set out in paragraph 27 of Part XIV (*Additional Information*) of this Prospectus. This Prospectus should be read and construed in conjunction with the following documents which have been previously published and filed with the FCA.

Documents containing information incorporated by reference	Part and paragraph in this Prospectus in which the document is referred to	Information incorporated by reference into this Prospectus
Harbour Energy Annual Report 2023	Part II (*Information on Harbour Energy*) and Part VIII (*Historical Financial Information relating to Harbour Energy*)	All text under the heading "*Non-IFRS measures*" on page 187
	Part VIII (*Historical Financial Information relating to Harbour Energy*)	Independent auditor's report to the members of Harbour Energy plc on pages 109 to 117 (inclusive) Consolidated income statement on page 118 Consolidated statement of comprehensive income on page 119 Consolidated balance sheet on page 120 Consolidated statement of changes in equity on page 121 Consolidated statement of cash flows on page 122 Notes to the consolidated financial statements on pages 123 to 171 (inclusive) Company balance sheet on page 172 Company statement of changes in equity on page 173 Notes to the company financial statements pages 174 to 176 (inclusive)
	Part II (*Information on Harbour Energy*)	All text under the heading "*Environment*" from pages 38 to 47 (inclusive)
	Part XIV (*Additional Information*)	All text under the heading "*Service contracts and exit payments and change of control provisions*" from pages 92 to 93 (inclusive)
Harbour Energy Annual Report 2022	Part II (*Information on Harbour Energy*) and Part VIII (*Historical Financial Information relating to Harbour Energy*)	All text under the heading "*Non-IFRS measures*" on page 185
	Part VIII (*Historical Financial Information relating to Harbour Energy*)	Independent auditor's report to the members of Harbour Energy plc on pages 108 to 117 (inclusive) Consolidated income statement on page 118 Consolidated statement of comprehensive income on

Documents containing information incorporated by reference	**Part and paragraph in this Prospectus in which the document is referred to**	**Information incorporated by reference into this Prospectus**
		page 119 Consolidated balance sheet on page 120 Consolidated statement of changes in equity on page 121 Consolidated statement of cash flows on page 122 Notes to the consolidated financial statements on pages 123 to 172 (inclusive) Company balance sheet on page 173 Company statement of changes in equity on page 174 Notes to the company financial statements pages 175 to 176 (inclusive)
Harbour Energy Annual Report 2021	Part II (*Information on Harbour Energy*) and Part VIII (*Historical Financial Information relating to Harbour Energy*)	All text under the heading "*Non-IFRS measures*" on page 177
	Part VIII (*Historical Financial Information relating to Harbour Energy*)	Independent auditor's report to the members of Harbour Energy plc on pages 103 to 113 (inclusive) Consolidated income statement on page 114 Consolidated statement of comprehensive income on page 115 Earnings per share on page 115 Consolidated balance sheet on page 116 Consolidated statement of changes in equity on page 117 Consolidated statement of cash flows on page 118 Notes to the consolidated financial statements on pages 119 to 165 (inclusive) Company balance sheet on page 166 Company statement of changes in equity on page 167 Notes to the company financial statements pages 168 to 169 (inclusive)
Circular	*Notice of General Meeting*	The resolutions, authorisations and approvals by virtue of which the BASF Consideration Shares will be issued set out in the Notice of General Meeting, set out at the end of the Circular

To the extent that any document or information incorporated by reference or attached to this Prospectus itself incorporates any information by reference, either expressly or impliedly, such information will not form part of this Prospectus for the purposes of the Prospectus Regulation Rules, except where such information or documents are stated within this Prospectus as specifically being incorporated by reference or where this Prospectus is specifically defined as including such information.

Except as set out above, no other portion of these documents is incorporated by reference into this Prospectus and those portions which are not specifically incorporated by reference in this Prospectus are either not relevant for the prospective investors and/or Shareholders or the relevant information is included elsewhere in this Prospectus.

Any statement contained in a document which is deemed to be incorporated by reference into this Prospectus shall be deemed to be modified or superseded for the purpose of this Prospectus to the extent that a statement contained in this Prospectus (or in a later document which is incorporated by reference into this Prospectus) modifies or supersedes such earlier statement (whether expressly, by implication or otherwise). Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Prospectus.

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

The times and dates set out in the expected timetable of principal events below and mentioned throughout this Prospectus are based on the Directors' current expectations and will depend, amongst other things, on the dates upon which conditions to the Acquisition are satisfied. The times and dates set out below may be adjusted by the Company in which event details of the new times and dates will be notified to the FCA, the London Stock Exchange and, where appropriate, Shareholders through a Regulatory Information Service. Notwithstanding the foregoing, Shareholders may not receive any further written communication. All references to times in this Prospectus are to London times unless otherwise stated.

Event	Time and/or Date(1)
Announcement of the Acquisition	21 December 2023
Publication of the Circular	12 June 2024
Publication of this Prospectus	12 June 2024
General Meeting	10:00 a.m. on 5 July 2024
Completion	Q4 2024
BASF Consideration Shares issued in connection with the Acquisition	On Completion
Readmission and Admission and commencement of dealings in the Ordinary Shares and the BASF Consideration Shares on the London Stock Exchange	Following Completion(2)

Notes

(1) Dates and times may be brought forward or extended and any changes will be notified via a RIS announcement. References to times are to London time unless otherwise stated.

(2) As soon as reasonably practicable once all the Conditions to Completion have been satisfied, which is currently expected to be in Q4 2024.

ACQUISITION STATISTICS

Number of BASF Consideration Shares to be issued	669,714,027
Number of Non-Voting Shares to be issued	251,488,211
Number of Ordinary Shares in issue as at the Latest Practicable Date (with no Ordinary Shares held in treasury)	770,377,712(1)
Number of Ordinary Shares in issue immediately following Admission	1,440,091,739(1)
BASF Consideration Shares as a percentage of the issued share capital of the Company immediately following Admission	c. 39.6 per cent.(1)
Non-Voting Shares as a percentage of the issued share capital of the Company immediately following Admission	14.9 per cent.

Notes

(1) These figures are calculated assuming that the number of Ordinary Shares in issue and to be issued as at close of business on the Latest Practicable Date do not change and that no issues of Ordinary Shares, other than the BASF Consideration Shares (and excluding any Ordinary Shares issued in the ordinary course pursuant to the Harbour Share Plans), occur between the Latest Practicable Date and Admission.

DIRECTORS, COMPANY SECRETARY, REGISTERED OFFICE AND ADVISERS

Directors	R. Blair Thomas, *Chair* Linda Z. Cook, *Chief Executive Officer* Alexander Krane, *Chief Financial Officer* Simon Henry, *Senior Independent Non-Executive Director* Belgacem Chariag, *Independent Non-Executive Director* Alan Ferguson, *Independent Non-Executive Director* Andy Hopwood, *Independent Non-Executive Director* Louise Hough, *Independent Non-Executive Director* Margareth Øvrum, *Independent Non-Executive Director* Anne L. Stevens, *Independent Non-Executive Director*
Company Secretary	Rachel Rickard
General Counsel	Howard Landes
Registered Office	4th Floor, Saltire Court 20 Castle Terrace Edinburgh EH1 2EN United Kingdom
Joint Financial Adviser and Sponsor	Barclays Bank PLC 1 Churchill Place Canary Wharf London E14 5HP United Kingdom
Joint Financial Adviser	J.P. Morgan Securities plc 25 Bank Street Canary Wharf London E14 5JP United Kingdom
Legal Adviser to the Company	Clifford Chance LLP 10 Upper Bank Street London E14 5JJ United Kingdom
Legal Adviser to the Sponsor	Davis Polk & Wardwell London LLP 5 Aldermanbury Square London EC2V 7HR United Kingdom
Auditor and Reporting Accountants to the Company	Ernst & Young LLP 1 More London Place London SE1 2AF United Kingdom
Reporting Accountants	KPMG LLP 15 Canada Square London E14 5GL United Kingdom
Competent Person	DeGolyer and MacNaughton Corp. 5001 Spring Valley Road, Suite 800 East Dallas, Texas 75244 U.S.A.
Registrar	Equiniti Limited Aspect House Spencer Road Lancing West Sussex BN99 6DA United Kingdom

PART I
INFORMATION ABOUT THE ACQUISITION

1. INTRODUCTION AND SUMMARY OF THE TERMS OF THE ACQUISITION

Introduction

On 21 December 2023, the Company announced (the "**Announcement**") that it had reached an agreement with BASF and LetterOne, the shareholders of Wintershall Dea AG ("**Wintershall Dea**"), for the acquisition of substantially all of Wintershall Dea's upstream oil and gas assets, including those in Norway, Germany, Denmark, Argentina, Mexico, Egypt, Libya and Algeria as well as Wintershall Dea's Carbon Capture and Storage ("**CCS**") licences in Europe (the "**Target Portfolio**") for $11.2 billion (the "**Acquisition**").

The Acquisition is expected to transform the Company into one of the world's largest and most geographically diverse independent oil and gas companies, increasing Harbour Energy's production to c.500 kboepd and adding significant positions in Norway, Germany, Argentina and Mexico to the Company's existing position as the largest London-listed independent oil and gas company. Importantly, the Acquisition will enhance Harbour Energy's reserve life, adding 1.1 bnboe of 2P reserves at $9.7/boe.

The Acquisition is accretive across all key metrics on a per share basis, including free cash flow which was a key criterion for the Company, and supports enhanced and sustainable shareholder returns. In addition, the Acquisition advances Harbour Energy's energy transition goals by shifting its portfolio towards natural gas, significantly lowering its GHG emissions intensity and expanding its already strong CCS interests into new European markets.

Consistent with its M&A track record, the Company will retain a strong financial position. In fact, the Acquisition transforms its capital structure and materially lowers its cost of financing. Further, the quality of the portfolio together with the way in which the Acquisition has been structured means that the Company is expected to receive investment grade credit ratings upon completion of the Acquisition ("**Completion**"). This is another important step in the Company's journey, allowing it to access more liquid and lower cost sources of capital to support its future growth.

Consequently, the Board believes that the Acquisition will create substantial value for Shareholders and important benefits for Harbour Energy's employees and other stakeholders and will position the Company for future success as a large, global diversified oil and gas producer.

Funding Structure

Under the terms of the business combination agreement entered into between the Company, BASF and LetterOne on 21 December 2023, as amended on 7 June 2024 (the "**Business Combination Agreement**"), the Company will acquire the Target Portfolio for $11.2 billion comprising:

(a) the porting of existing Wintershall Dea Bonds with a nominal value of c.$4.9 billion and a weighted average coupon of c.1.8 per cent. to Harbour Energy;

(b) approximately 921.2 million new Company shares to be issued to BASF and LetterOne (the "**Consideration Shares**") at an agreed value of $4.15 billion or 360 pence per Ordinary Share, representing a premium of c.60 per cent. to the Company's 30-day volume weighted average share price of c.227 pence[1] prior to the Announcement, such that on Completion:

- BASF, a 72.7 per cent. shareholder in Wintershall Dea, will own 669.7 million Ordinary Shares or 46.5 per cent. of the Company's listed Ordinary Shares with the Company's current shareholders owning 53.5 per cent.[2]; and
- LetterOne, a 27.3 per cent. shareholder in Wintershall Dea, will own 251.5 million non-voting, non-listed convertible ordinary shares with preferential rights (the "**Non-Voting Shares**"). If the Non-Voting Shares were to be converted into Ordinary Shares, the Company's current shareholders would own 45.5 per cent. of the Company; BASF and LetterOne would own 39.6 per cent. and 14.9 per cent., respectively; and

1 Based on 30 calendar days, as at 20 December 2023.

2 Prior to conversion of the Non-Voting Shares.

(c) $2.15 billion of cash consideration to be funded through cash flow generated from the Target Portfolio between the effective date of 30 June 2023 and Completion, and an underwritten bridge facility.

Terms of the Acquisition

The Acquisition constitutes a reverse takeover for the Company for the purposes of the Listing Rules, with the intention that the Company will apply to readmit its Ordinary Shares, and admit the BASF Consideration Shares, to listing on the London Stock Exchange on Completion.

The Acquisition is conditional therefore on, among other things:

(a) Shareholder approval at the General Meeting convened pursuant to the Circular;

(b) publication of an FCA approved prospectus;

(c) a Rule 9 Waiver having been granted in respect of BASF by the Takeover Panel, subject to the approval of the waiver by the independent shareholders of the Company;

(d) FCA and LSE approval of the admission of all BASF Consideration Shares ("**Admission**") and re-admission of all existing Ordinary Shares ("**Readmission**") to listing on the premium segment of the Official List of the FCA (or a listing on the single category for equity shares in commercial companies if such new listing category as contemplated in FCA Consultation Paper CP23/31 has been implemented by the FCA and taken effect at the relevant time) and to trading on the main market of the London Stock Exchange; and

(e) satisfaction of certain regulatory, merger control, foreign direct investment and foreign subsidies regulation approvals in relevant jurisdictions.

It is anticipated that Completion will occur in Q4 2024. The Business Combination Agreement will be capable of being terminated if Completion has not occurred on or before 21 June 2025 (the "**Longstop Date**").

Additional financing details

The Wintershall Dea Bonds form part of the Target Portfolio to be acquired by Harbour Energy and the liabilities in respect of the Wintershall Dea Bonds will be assumed by Harbour Energy at Completion. Completion will not trigger a change of control (as defined in the relevant terms and conditions of the Wintershall Dea Bonds) or a bond investor put right given the Company's expected investment grade credit rating status.

In addition to the underwritten $1.5 billion bridge facility, Harbour Energy has secured a new underwritten $3.0 billion unsecured revolving credit and letter of credit facility to cover its letter of credit requirements and to provide additional liquidity. This will replace its existing RBL Facility.

Following Completion and conditional upon the average price of Brent oil in certain agreed test periods, potential contingent payments of up to a maximum of $300 million may be made by Harbour Energy to BASF and LetterOne at six monthly intervals commencing from 18 months following Completion.

Acquisition Financing

On 5 March 2024 certain members of Harbour Energy entered into a bridge facility agreement (the "**BFA**") with, among others, DNB Bank ASA, London Branch as facility agent, pursuant to which an up to US$1,500,000,000 bridge facility is made available by the lenders thereunder.

The purpose of the BFA is to fund a proportion of the purchase price of the Acquisition, and any associated acquisition costs, and is expected to be drawn, to the extent required, at Completion in Q4 of 2024. The BFA contains customary certain funds provisions to protect the ability of Harbour Energy to fund the Acquisition by restricting the recourse of lenders to certain drawstop and acceleration rights during the period in which the bridge facility is available to be drawn down. Please see paragraph 15.10 (Bridge Facility Agreement) in Part XIV (*Additional Information*) for more information.

Other key details of the Acquisition

LetterOne will not be permitted to acquire any Ordinary Shares for a period of six months following Completion and LetterOne will not be able to hold more than (i) 19.99 per cent. of the Company's issued share capital; or (ii) 5 per cent. of the Ordinary Shares (on a fully diluted basis).

The dividend payable on each Non-Voting Share will be at a 13 per cent. premium to any dividend payable in respect of each Ordinary Share, reflecting the fact that the Non-Voting Shares are unlisted and do not have voting rights attached to them.

2. BACKGROUND TO AND REASONS FOR THE ACQUISITION

Background to the Acquisition

The Company was founded in 2014 with the ambition to build a geographically diverse, independent oil and gas company through the acquisition of high quality, conventional, producing assets. Since then, the Company has grown to become the largest London-listed independent oil and gas company by acquiring assets from motivated sellers and investing in those assets to add reserves and support future cash flow.

In 2023, Harbour Energy produced 186 kboepd, split broadly evenly between liquids and gas, from a 2P reserve and 2C resource base of 880 mmboe as at 31 December 2023. Over 90 per cent. of Harbour Energy's production is from the UK, with the balance from its assets in Southeast Asia. In addition, Harbour Energy has a portfolio of international growth opportunities including in Indonesia and Mexico and is progressing two carbon capture and storage projects in the UK, including the Harbour Energy-led Viking project.

Harbour Energy made its first acquisition in 2017, through local operating company Chrysaor Holdings Limited ("**Chrysaor**"), buying a package of UK North Sea assets from Shell for $3.0 billion (the "**Shell Acquisition**"). Harbour Energy subsequently acquired ConocoPhillips' UK business in 2019 for US$2.675 billion and, as a result of that acquisition, became the largest producer in the UK North Sea. In 2021, the Company merged with Premier Oil plc through a reverse takeover (the "**Premier Merger**") to create Harbour Energy plc. The Premier Merger added complementary UK assets as well as some high quality, international assets which provided a starting point for future diversification.

Since becoming a public company in 2021, the Company has been very clear about its aim to establish material production outside the UK by acquiring cash generative assets that improve the Company's reserve life, margins and GHG intensity. The Company believed that this in turn would strengthen its credit quality and support enhanced shareholder returns over the longer run.

The Board evaluated numerous M&A opportunities but maintained a disciplined approach throughout and, in December 2023, the Company announced the acquisition of substantially all of Wintershall Dea's upstream oil and gas assets. The Acquisition will mark the Company's fourth major acquisition since its foundation in 2014 and, in the Board's opinion, is the most transformational and compelling value proposition yet for Shareholders.

Reasons for the Acquisition

The Board believes the Acquisition is a strong strategic fit, in line with its stated M&A objectives, and offers a transformational value-creating opportunity for Shareholders.

The Acquisition:

(a) **Transforms Harbour Energy's scale and geographic diversification**

- Combined production of c. 500 kboepd[3] and 2P reserves of 1.5 bnboe[4].
- Significant production of 175 kboepd[5] in Norway with additional material positions in Argentina, Egypt and Germany.
- Combined revenue of $10.1 billion for 12 months to end December 2023.

3 Based on 2023 production, as the results presentations for the financial year ended 31 December 2023 for the Company.

4 Based on the Company's 2023 Annual Report and the Target Company CPR.

5 Based on 2023 production, as per Wintershall Dea's annual report for its 2023 fiscal year (the "**WD 2023 Annual Report 2023**").

(b) **Adds high quality assets which are accretive to Harbour Energy's reserve life and margins**

- Increases Harbour Energy's 2P reserve life[6] to c.8 years with organic reserve replacement opportunities from c.1.8 bnboe[7] of combined 2C resources.
- Enhances Harbour Energy's natural gas-weighting with combined natural gas production of over 300 kboepd[8] (c.60 per cent. of total production).
- Materially accretive to margins with lower combined opex[9] of c.$11/boe and exposure to advantaged markets (Brent for oil and TTF for European gas).

(c) **Supports Harbour Energy's Energy Transition goals**

- Step change in Harbour Energy's GHG emissions intensity, with lower combined pro forma net equity share Scope 1 & 2 CO_2e GHG emissions intensity of c.10 kgCO_2e/boe.
- Adds to Harbour Energy's UK CCS projects a strong portfolio of European CCS projects with potential to store more than c.10 mtpa of CO_2 (net equity share) by 2035.
- Harbour Energy's 2035 Net Zero commitment reaffirmed[10].

(d) **Significantly enhances Harbour Energy's financial strength**

- Material financial synergies with porting of existing Wintershall Dea Bonds with a nominal value of c.$4.9 billion, a weighted average coupon of c.1.8 per cent. and weighted average maturity of c.4.5 years.
- Post Completion, the Company expects to receive investment grade credit ratings, increasing its access to low cost, diverse sources of capital.
- Significantly increases the Company's per share free cash flow[11].

(e) **Enables enhanced and sustainable shareholder returns framework**

- Supports an increase in the Company's annual dividend from $200 million to c.$455 million, of which c.$380 million will be paid to holders of Ordinary Shares. This reflects a five per cent. increase in dividend per Ordinary Share to 26.25 cents[12].
- High quality portfolio, free cash flow accretion and significantly enhanced financial strength enable sustainable dividends over the long term.
- Potential for additional returns, including through buybacks, in line with the Company's existing policy.

3. IRREVOCABLE UNDERTAKINGS

3.1 Directors

The following Directors of the Company and certain of their connected persons have provided irrevocable undertakings in favour of the Company, BASF, BASF TopCo, LetterOne and LetterOne TopCo, to vote in favour of the Resolutions to be proposed at the General Meeting in their capacity as Shareholders. These irrevocable undertakings cover, in aggregate, approximately 1.77 per cent. of the Company's total issued Ordinary Share capital as at the Latest Practicable Date.

---

6 Based on year end 2023 2P reserves (as per the Company's 2023 Annual Report and Target Company CPR) and average 2024 production (as per management estimates).

7 Based on verified year end 2023 2C resources.

8 Based on 2023 production, as per the Company's 2023 Annual Report and the WD 2023 Annual Report.

9 Direct operating costs (excluding over/under-lift), including insurance costs, mark to market movements on emissions hedges and tariff expense, less tariff income, divided by working interest production.

10 Scope 1 and 2 emissions on a gross operated basis.

11 Free cash flow is post tax and before distributions.

12 Based on 770.4 million existing Ordinary Shares and 1,440.1 million Ordinary Shares post-completion.

	As at the Latest Practicable Date	
	Number of Ordinary Shares held	Percentage of issued Ordinary Share capital of the Company
R. Blair Thomas	4,534,797(1)	0.5886
Linda Z. Cook	1,730,844	0.2247
Alexander Krane	149,507	0.0194
Simon Henry	20,000	0.0026
Margareth Øvrum	8,500	0.0011
Alan Ferguson	19,942	0.0026
Andy Hopwood	10,000	0.0013
Anne L. Stevens	30,000	0.0039
Louise Hough	6,800	0.0009
Steven R. Cook	7,144,646(2)	0.9274

Notes

(1) In addition, Mr Thomas is indirectly interested in 1.07 per cent. of the Company's Ordinary Shares through his interest in certain EIG-managed entities.

(2) Mr Steven R. Cook is the spouse of Ms Linda Z. Cook.

The irrevocable undertakings referred to in this paragraph 3.1 cease to be binding on the earlier of the following occurrences: (i) the Business Combination Agreement is terminated in accordance with its terms; (ii) Completion occurs in accordance with the terms of the Business Combination Agreement; or (iii) the Acquisition has not become effective by 23:59 on the Longstop Date.

3.2 **Shareholders**

In addition, EIG Asset Management LLC, EIG Separate Investments (Cayman) LP, Potomac View Investments LP, Control Empresarial de Capitales, S.A. de C.V., certain funds, affiliates and/or accounts of Fortress Investment Group LLC ("**Fortress**"), Schroders Investment Management Limited, San Bernardino County Employees' Retirement Association, Clareant SCF S.à.r.l., Cetus Capital III, LP, Cetus Capital VI, LP, Littlejohn Opportunities Master Fund LP, OFM II, LP and VSS Fund, LP have each irrevocably undertaken to vote in favour of the Resolutions to be proposed at the General Meeting in respect of their holdings of Ordinary Shares as set out below. These irrevocable undertakings cover, in aggregate, approximately 30.34 per cent. of the Company's total issued Ordinary Share capital as at the Latest Practicable Date.

	As at the Latest Practicable Date	
	Number of Ordinary Shares held(1)	Percentage of issued Ordinary Share capital of the Company
EIG Asset Management LLC	19,925	0.0026
EIG Separate Investments (Cayman) LP	14,853,009	1.9280
Potomac View Investments LP	114,775,572	14.8986
Control Empresarial de Capitales, S.A. de C.V.	62,094,730	8.0603
Fortress	18,942,627	2.4589
Schroders Investment Management Limited	7,477,243	0.9706
San Bernardino County Employees' Retirement Association	1,426,236	0.1851
Clareant SCF S.à.r.l	5,928,636	0.7696
Cetus Capital III, LP	855,050	0.1110
Cetus Capital VI, LP	3,022,153	0.3923
Littlejohn Opportunities Master Fund LP	869,297	0.1128
OFM II, LP	2,959,180	0.3841
VSS Fund, LP	544,833	0.0707

Notes

(1) The figures in this column refer to the total number of Ordinary Shares held by the relevant Shareholder and which are subject to the relevant irrevocable undertaking as at the Latest Practicable Date. The irrevocable undertakings entered into by the Shareholders listed above do not contain restrictions on the disposal, transfer or other dealings in Ordinary Shares, therefore the number of Ordinary Shares in respect of which a Shareholder votes in favour of the Resolutions to be proposed at the General Meeting may differ from the number of Ordinary Shares set out in this column.

The irrevocable undertakings referred to in this paragraph 3.2 cease to be binding on the earlier of the following occurrences: (i) the Business Combination Agreement is terminated in accordance with its terms; (ii) Completion occurs in accordance with the terms of the Business Combination Agreement; or (iii) the Acquisition has not become effective by 23:59 on the Longstop Date. In addition, the irrevocable undertaking provided by Fortress will cease to be binding at 23:59 on 31 December 2024 in the event that the Resolutions have not been approved at the General Meeting.

4. INTEGRATION

Harbour Energy has a strong track record in delivering large-scale transformation, as evidenced by the Premier Merger. Harbour Energy will leverage its experience from previous transactions, set out as part of its transition planning, in delivering the Day 1 readiness and subsequent integration of the Target Company Group.

Harbour Energy, LetterOne and BASF have established a joint integration committee to provide for, among other things, a seamless integration of the two businesses and to ensure that the Enlarged Group will benefit from having access to the resources and being able to apply the practices and skills of both Harbour Energy and the Target Company Group. While detailed integration planning is yet to take place, it is anticipated that the current Harbour Energy organisation structure, based around fully-resourced country-level business units with assurance provided by—and additional resources available from—corporate centre functional groups, will be adopted for the organisational structure of the Enlarged Group.

5. STRATEGIC PLANS AND INTENTIONS WITH REGARD TO MANAGEMENT, EMPLOYEES AND PLACES OF BUSINESS

R. Blair Thomas will continue to chair Harbour Energy, with Linda Z. Cook and Alexander Krane remaining as Chief Executive Officer and Chief Financial Officer, respectively.

Following Completion, BASF will be entitled to nominate two non-executive directors to the Board provided BASF holds at least 25 per cent. of the Ordinary Shares, and one non-executive director in the event BASF holds between 10 per cent. and 25 per cent. of the Ordinary Shares.

While LetterOne itself is not a sanctioned entity, certain of LetterOne's minority ultimate beneficial owners are subject to sanctions administered by competent authorities of the UK, EU and US. No single ultimate beneficial owner holds more than 50 per cent. of the shares or voting rights in LetterOne. Following the imposition of such sanctions, LetterOne took immediate action to separate its business, investments and operations from its sanctioned minority ultimate beneficial owners and to freeze their interests, including in respect of voting rights attaching to shares held indirectly, in LetterOne. As a result, none of LetterOne's sanctioned minority ultimate beneficial owners has any involvement in, or influence over, LetterOne and LetterOne is neither owned nor controlled by sanctioned parties as those terms are understood in applicable sanctions law and guidance.

The Acquisition has been structured in a manner that balances (as far as possible) the respective interests of the Company's major stakeholders with the respective commercial interests of the parties in order to optimise the likelihood of a successful and timely Completion, and, as such, LetterOne will receive Non-Voting Shares as described above. LetterOne's Non-Voting Shares have no governance rights attached to them and, for so long as the described sanctions of certain ultimate beneficial shareholders remain in place, LetterOne will have no representation on the Board. Upon satisfaction of certain conditions, including receipt of relevant regulatory approvals (if applicable) and the absence of sanctions restrictions, LetterOne is able to convert its Non-Voting Shares into Ordinary Shares, after which LetterOne will be entitled to equivalent rights as BASF regarding the nomination of non-executive directors.

Harbour Energy's global business will continue to be headquartered in London and following Admission and Readmission, the Company will retain its premium listing on the Official List (or will be listed on the segment of the Official List for ESCCs, if applicable at the time of application) and will continue to be traded on the London Stock Exchange's main market for listed securities as Harbour Energy plc.

Substantially all of the current employees of the Target Portfolio will be transferred to Harbour Energy on Completion. In addition, Harbour Energy intends to take on some employees from Wintershall Dea's corporate headquarters.

6. CURRENT TRADING OF HARBOUR ENERGY

The Company issued its unaudited trading and operations update for the first quarter of 2024 (the "**Q1 2024 Update**") on 9 May 2024. Since 31 December 2023, the financial and operational performance of Harbour Energy has been stable and in line with the expectations of the board of Directors of the Company. Harbour Energy has continued to deliver safe and responsible operations, maximise the value of its UK production base through targeted investment and advance its organic growth projects. In its Q1 2024 Update, the Company reiterated its guidance to the market for the Harbour Energy business, including for production, operating costs and total capital expenditure.

7. CURRENT TRADING OF THE TARGET COMPANY GROUP

Since 31 December 2023, the financial and operational performance of the Target Company Group has been stable and in line with the expectations of the management of Wintershall Dea. The Target Company Group's production, operating costs and capital programme remains consistent with the performance at the end of 2023, underpinned by a significant reserve and resource base, well-established operators with deep in-country operating experience and strong stakeholder relationships.

8. INFORMATION ON WINTERSHALL DEA AND THE TARGET PORTFOLIO

Wintershall Dea is a leading European independent gas and oil company, headquartered in Kassel and Hamburg, Germany, with more than 120 years of experience as an operator and project partner across the entire exploration and production value chain. As at 31 December 2023, Wintershall Dea had gross assets of $18,497 million[13]. This does not reflect the gross assets of the defined perimeter of the Acquisition.

The Target Portfolio consists of Wintershall Dea's non-Russia related upstream oil and gas assets, including producing and development assets as well as exploration rights in Norway, Germany, Denmark[14], Argentina, Mexico, Egypt, Libya[15] and Algeria as well as Wintershall Dea's CCS licences in Europe.

Wintershall Dea's Russian assets are excluded from the Acquisition. This includes those assets located in Russia and those held through joint ventures with Russian majority state-owned energy corporation Gazprom outside of Russia.[16] WIGA Transport Beteiligungs-GmbH & Co. KG (50.02 per cent. Wintershall Dea / 49.98 per cent. SEFE, registered in Kassel, Germany) is also not part of the asset perimeter.

9. ACQUISITION RELATED ARRANGEMENTS

9.1 Business Combination Agreement

The Business Combination Agreement was entered into on 21 December 2023, and amended on 7 June 2024, between the Company, BASF, BASF TopCo, LetterOne and LetterOne TopCo in relation to the Acquisition.

Amongst other things, the Business Combination Agreement provides that the Company will acquire the Target Portfolio for $11.2 billion comprising:

(a) the porting of existing Wintershall Dea Bonds with a nominal value of c.$4.9 billion and a weighted average coupon of c.1.8 per cent. to the Company;

(b) approximately 921.2 million new Company shares to be issued to BASF and LetterOne at an agreed value of $4.15 billion or 360 pence per Company share such that on Completion:

  (i) BASF will own 46.5 per cent. of the Company's Ordinary Shares; and

  (ii) LetterOne will own 251.5 million non-voting, non-listed convertible ordinary shares with preferential rights (the "**Non-Voting Shares**"). If the Non-Voting Shares were to be converted into Ordinary Shares, the Company's current shareholders would own 45.5 per cent. of the

13 €16,756, using Bloomberg's closing EUR/USD spot exchange rate as at 31 Dec 2023 of 1.1039.

14 Excluding the Ravn field.

15 Excluding Wintershall Aktiengesellschaft.

16 Wintershall Dea Noordzee B.V. (50 per cent. Wintershall Dea / 50 per cent. Gazprom, registered in Rijswijk, The Netherlands), Wintershall Aktiengesellschaft (51 per cent. Wintershall Dea / 49 per Rijswijk, The Netherlands), Wintershall Aktiengesellschaft (51 per cent. Wintershall Dea / 49 per cent. Gazprom, registered in Celle, Germany) and Nord Stream AG (15.5 per cent. Wintershall Dea / 51 per cent. Gazprom, registered in Zug, Schweiz).

Company and BASF and LetterOne would own 39.6 per cent. and 14.9 per cent., respectively; and

(c) cash consideration of $2.15 billion to be funded through cash flow generated from the Target Portfolio between the effective date of 30 June 2023 and Completion, and an underwritten bridge facility,

(the "**Completion Consideration Cash Amount**").

The Completion Consideration Cash Amount is subject to certain adjustments to be agreed between the parties as set out in more detail in the Business Combination Agreement.

For more information on the Business Combination Agreement, see paragraph 15.1 (Business Combination Agreement) in Part XIV (*Additional Information*).

9.2 **BASF Relationship Agreement**

A relationship agreement to be entered into between the Company and BASF (the "**BASF Relationship Agreement**") will take effect on Admission and will remain in full force and effect unless and until BASF and its associates cease to own at least 10 per cent. of the Ordinary Shares. BASF may terminate the BASF Relationship Agreement in certain circumstances, including where the Ordinary Shares cease to be admitted to trading on the London Stock Exchange's main market for listed securities.

The BASF Relationship Agreement provides, in accordance with Listing Rule 6.5.4, that:

(a) all transactions, arrangements and relationships between the Company or any other member of the Group on the one hand and BASF or any of its associates on the other hand shall be conducted at arm's length and on normal commercial terms;

(b) BASF shall not (and shall procure that its associates will not) take any action that would have the effect of preventing the Company from complying with its obligations under the Listing Rules; and

(c) BASF shall not (and shall procure that its associates will not) propose or procure the proposal of a shareholder resolution of the Company which is intended or appears to be intended to circumvent the proper application of the Listing Rules.

Furthermore, under the BASF Relationship Agreement, BASF undertakes that it shall not (and shall procure that its associates will not):

(a) exercise any of its voting rights in the Company in a way that would be inconsistent with, or breach any of the provisions of, the BASF Relationship Agreement;

(b) influence the day-to-day running of the Company at an operational level and shall allow the Company to operate on an independent basis; and

(c) act in a manner which would be inconsistent with the independence of the Board being maintained in accordance with the rules of the London Stock Exchange or the FCA applicable to the Company, including the Listing Rules.

For more information on the BASF Relationship Agreement, see paragraph 15.2 (BASF Relationship Agreement) in Part XIV (*Additional Information*).

9.3 **LetterOne Relationship Agreement**

A relationship agreement to be entered into between the Company and LetterOne (the "**LetterOne Relationship Agreement**") will take effect on Admission and will remain in full force and effect unless and until LetterOne and its associates cease to own Ordinary Shares or Non-Voting Shares representing (in the case of Non-Voting Shares assuming conversion at the applicable conversion rate) in aggregate, at least 10 per cent. of the Ordinary Shares. LetterOne may terminate the LetterOne Relationship Agreement in certain circumstances, including where the Ordinary Shares cease to be admitted to trading on the London Stock Exchange's main market for listed securities.

The LetterOne Relationship Agreement provides that from the date on which LetterOne (together with its associates) holds 10 per cent. or more of the Ordinary Shares, in accordance with Listing Rule 6.5.4:

(a) all transactions, arrangements and relationships between the Company or any other member of the Group on the one hand and LetterOne or any of its associates on the other hand shall be conducted at arm's length and on normal commercial terms;

(b) LetterOne shall not (and shall procure that its associates will not) take any action that would have the effect of preventing the Company from complying with its obligations under the Listing Rules; and

(c) LetterOne shall not (and shall procure that its associates will not) propose or procure the proposal of a shareholder resolution of the Company which is intended or appears to be intended to circumvent the proper application of the Listing Rules.

Furthermore, under the LetterOne Relationship Agreement, LetterOne undertakes that it shall not (and shall procure that its associates will not):

(a) exercise any of its voting rights in the Company in a way that would breach any of the provisions of the LetterOne Relationship Agreement;

(b) influence the day-to-day running of the Company at an operational level and shall allow the Company to operate on an independent basis; and

(c) act in a manner which would be inconsistent with the independence of the Board being maintained in accordance with the rules of the London Stock Exchange or the FCA applicable to the Company, including the Listing Rules.

For more information on the LetterOne Relationship Agreement, see paragraph 15.3 (LetterOne Relationship Agreement) of Part XIV (*Additional Information*).

9.4 **BASF Lock-Up Agreement**

In accordance with the Business Combination Agreement, BASF and the Company will enter into a lock-up agreement at Completion which will take effect on Admission whereby BASF undertakes that it will not sell its Ordinary Shares for a period of six months following Completion subject to customary exceptions.

9.5 **LetterOne Lock-Up Agreement**

In accordance with the Business Combination Agreement, LetterOne and the Company will also enter into a lock-up agreement at Completion which will take effect on Admission whereby LetterOne undertakes that, in the event that LetterOne converts its Non-Voting Shares into Ordinary Shares, it will not sell its Ordinary Shares for a period of six months following Completion subject to customary exceptions.

9.6 **LetterOne Standstill Agreement**

In accordance with the Business Combination Agreement, the Company and LetterOne will enter into a standstill agreement at Completion whereby LetterOne undertakes that it will not and will procure that its associates and concert parties (excluding BASF entities) will not, directly or indirectly, among other things:

(a) acquire or make an offer for Ordinary Shares for a period of six months following Completion subject to customary exceptions; and

(b) hold in aggregate more than (i) 19.99 per cent. of the issued Ordinary Share capital of the Company or (ii) 5 per cent. of the issued Ordinary Shares (on a fully diluted basis) for the period commencing on Completion and ending on the first date on which both (x) none of the (direct or indirect) shareholders of LetterOne is subject to certain sanctions restrictions; and (y) LetterOne is not subject to certain sanctions restrictions (as is currently the case).

9.7 **Transitional Services Agreement**

In connection with the Acquisition, the Company and Wintershall Dea entered into a transitional services agreement (the "**TSA**"), effective 19 April 2024, pursuant to which Wintershall Dea provides transitional support services to the Company.

Under the TSA, Wintershall Dea is required to provide the transitional services in accordance with the same standards and volumes as achieved in respect of the same services during the six-month period immediately before the date of Completion, as well as in accordance with good industry practice and applicable law. The services are typical transitional support services, including accounting, reporting, treasury, tax data provisions, access and maintenance of critical systems and human resources services. In consideration for the services, the Company pays Wintershall Dea service charges on an "at cost" basis (plus a margin of 5 per cent.). Specific service terms have been agreed in respect of each service (mostly in the region of 12 months).

For more information on the TSA, see paragraph 15.7 (Transitional Services Agreement) of Part XIV (*Additional Information*).

10. GENERAL MEETING

The Acquisition, due to its classification as a reverse takeover of the Company pursuant to the Listing Rules, requires the approval of the Shareholders.

Accordingly, a notice convening a General Meeting to be held at Clifford Chance LLP, 10 Upper Bank Street, London, E14 5JJ at 10:00 a.m. on 5 July 2024 at which the Resolutions will be proposed is set out in Part X (the "**Notice of General Meeting**") of the Circular. The purpose of the General Meeting is to consider and, if thought fit, pass the Resolutions, as set out in full in the Notice of General Meeting.

The Resolutions propose that:

(a) **Resolution 1**—the proposed acquisition of the Target Company by the Company on the terms and subject to the conditions set out in the Business Combination Agreement and all other associated agreements and ancillary arrangements related to the Business Combination Agreement or the Acquisition, be approved;

(b) **Resolution 2**—the waiver granted by the Takeover Panel of the obligations that would otherwise arise pursuant to Rule 9 of the Takeover Code on BASF or any person acting in concert with BASF to make an offer for the entire issued share capital of the Company as a result of (i) the issue to BASF of the BASF Consideration Shares pursuant to the Business Combination Agreement, and/or (ii) the exercise by the Company of the Buyback Authority, be approved; and

(c) **Resolution 3**—the Directors be authorised to exercise all of the powers of the Company to allot the BASF Consideration Shares and the Non-Voting Shares (and, in the case of the Non-Voting Shares, on the terms and with the rights set out in the Annex to the Notice of General Meeting), up to an aggregate nominal value £18,424.0448, required to be allotted and issued to BASF and LetterOne respectively in connection with the Acquisition, in accordance with section 551 of the Companies Act 2006.

11. ADMISSION TO THE OFFICIAL LIST AND TO TRADING ON THE LONDON STOCK EXCHANGE AND DEALINGS IN THE NEW HARBOUR ENERGY SHARES

The Company will, through its Sponsor, be required to apply to the FCA and to the London Stock Exchange for the Ordinary Shares to be readmitted to the premium listing segment of the Official List (or the segment of the Official List for ESCCs, if applicable at the time of application) and to the London Stock Exchange for the Ordinary Shares to be readmitted to trading on the London Stock Exchange's main market for listed securities. Applications will also be made to the FCA for the BASF Consideration Shares to be admitted to the premium listing segment of the Official List of the FCA (or the segment of the Official List for ESCCs, if applicable at the time of application) and to the London Stock Exchange for the BASF Consideration Shares to be admitted to trading on the main market for listed securities of the London Stock Exchange.

No such applications to the FCA or the London Stock Exchange in respect of Readmission or Admission have been made yet (and there have been no discussions in respect of such applications), and there is no guarantee that such applications will be accepted or that the share capital of the Enlarged Group (including the BASF Consideration Shares) will be deemed eligible for Readmission or Admission, as applicable. Given that Completion is conditional on the FCA and the London Stock Exchange having confirmed to the Company that applications for Admission and Readmission have been approved, if Admission does not occur by the Longstop Date, the Business Combination Agreement will terminate.

Upon Admission, the BASF Consideration Shares will rank *pari passu* in all respects with the existing issued Ordinary Shares and will rank in full for all dividends and other distributions declared, made or paid on the Ordinary Share capital of Harbour Energy with a record date on or after the date of allotment.

The Non-Voting Shares will not be admitted to listing therefore no application will be made in respect of the Non-Voting Shares to the FCA or the London Stock Exchange. The rights and restrictions attaching to the Non-Voting Shares are set out in full in the Annex to the Notice of General Meeting set out in the Circular.

The Company will publish the Circular to convene the Harbour Energy General Meeting in connection with the Acquisition on or around the date of this Prospectus.

PART II
INFORMATION ON HARBOUR ENERGY

The following information should be read in conjunction with the information appearing elsewhere in, or incorporated by reference in, this Prospectus, including the financial and other information in, or incorporated by reference in, Part VIII (Historical Financial Information relating to Harbour Energy).

Overview

Harbour Energy is an independent oil and gas company which is building a large-scale, geographically diverse asset base, mainly through acquisition of high quality, cash generative producing portfolios.

Critical to Harbour Energy's success is safe and responsible operations, and safety remains the number one priority at every level of the business. Harbour Energy is also committed to playing an important role in the energy transition through reducing the emissions associated with its own operations and by deploying its skills and infrastructure to deliver CCS.

For the year ended 31 December 2023, Harbour Energy delivered 186 kboepd, with over 90 per cent. of its production coming from its diverse UK asset base and split broadly equally between liquids and gas. The remaining balance of Harbour Energy's production comes from assets in South East Asia. Harbour Energy has identified numerous short cycle, high return infrastructure-led investment opportunities within its producing portfolio to help offset natural decline and underpin future cash flow.

Harbour Energy has a portfolio of international growth opportunities in Indonesia and in Mexico which have the potential to materially add to its reserves and diversify its portfolio over time. These include a potential major gas development in the Andaman Sea in Indonesia and the Zama oil field offshore Mexico. In addition, Harbour Energy has an interest in two UK CCS projects, including Harbour Energy's flagship Viking CCS project which has the potential to provide Harbour Energy with a long-term, stable income stream.

As at 31 December 2023, Harbour Energy has 361 mmboe and 519 mmboe of oil and gas 2P reserves and 2C resources, respectively, and 222 million tonnes of independently-certified net 2C contingent storage resources.

For the year ending 31 December 2023, Harbour Energy generated significant free cash flow of $1 billion, which enabled the Board to approve $439 million of shareholder returns and the Company to reduce its net debt to $0.2 billion. This is consistent with Harbour Energy's disciplined approach to capital allocation which, together with sustained operational and financial delivery, has enabled Harbour Energy to reduce its net debt by $2.7 billion, return $1 billion to shareholders and retain flexibility to agree a transformational $11.2 billion acquisition since becoming a public company in April 2021.

The Company is a premium-listed, FTSE 250 company headquartered in London with approximately 2,000 staff and contractors across its offshore platforms and offices.

History and Development

The legacy Harbour Energy business (the "**Harbour Energy Business** was founded in 2014 by US private equity firm EIG with the ambition to build a geographically diverse independent oil and gas company through the acquisition of high quality, conventional, producing assets outside of North America.

The Harbour Energy Business evaluated a number of opportunities before focusing on the UK North Sea where several of the major multinational oil companies were starting to exit. On 1 November 2017, it completed its first acquisition by acquiring, through local operating company Chrysaor, a portfolio of oil and gas assets in the UK North Sea from Shell for $3.0 billion (the "**Shell Acquisition**"). The package included an operated interest in the Armada, Everest and Lomond fields and a non-operated interest in the Erskine field, as well as non-operated interests J-Area, Elgin Franklin area, Buzzard, Beryl and Schiehallion. The funding for the acquisition was a combination of equity and debt. The majority of the equity was contributed from Harbour Chrysaor Equity Holdings, Ltd. which, as a result of the investment, became the owner of an approximate 90 per cent. economic interest in Chrysaor.

On 30 September 2019, the Harbour Energy Business through Chrysaor completed its second major acquisition with the purchase of ConocoPhillips' UK oil and gas business for $2.675 billion (the "**COP Acquisition**"). As a result of the COP Acquisition, the Harbour Energy Business became the largest producer of oil and gas in the UK North Sea and took over operatorship of two additional production hubs: the Greater Britannia Area and J-Area in the UK Central North Sea. Also included in the COP Acquisition were the producing Clair field, West of Shetland, and assets in the East Irish Sea. The COP Acquisition was funded by cash and an expansion of the Harbour Energy Business' existing debt facility.

Following the completion of the COP Acquisition, the Harbour Energy Business became interested in a combination with Premier Oil and, on 1 April 2021, merged with Premier Oil (the "**Premier Merger**") to create Harbour Energy plc by way of a reverse takeover. The Premier Merger added complementary UK assets as well some high quality, international assets which provided a starting point for future diversification. The Premier Merger also created the largest independent oil and gas company listed on the London Stock Exchange and, in August 2021, the Company became a constituent of the FTSE 250 index.

Since the Premier Merger, Harbour Energy has had a clear strategy to establish material production outside the UK by acquiring cash generative assets that improve Harbour Energy's reserve life, margins and GHG intensity in the belief that this in turn would strengthen its credit quality and support enhanced shareholder returns over the longer run.

Harbour Energy has maintained its disciplined approach and, in December 2023, announced the Acquisition. This transaction will mark Harbour Energy's fourth major acquisition since the Harbour Energy Business was founded in 2014 and the most transformational step yet in its journey.

Purpose and strategy

Harbour Energy's purpose is to play a key role in meeting the world's energy needs through the safe, efficient and responsible production of hydrocarbons, while creating value for its stakeholders.

Harbour Energy's strategy comprises four core pillars which contribute towards it delivering its purpose:

Ensure safe, efficient and environmentally responsible operations

At the core of Harbour Energy's strategy is safe and responsible operations. The application of rigorous HSES standards and practices is therefore essential in all that it does. This not only helps Harbour Energy to protect the safety and wellbeing of its personnel, the environment and its assets but it also enables it to maintain operational continuity, regulatory compliance and its corporate reputation.

Harbour Energy strives to deliver top quartile operational performance, leveraging its scale, operational control and supply chain relationships to drive efficiencies, continuous improvement and maintain a competitive cost structure as assets mature.

Harbour Energy is also playing a key role in the transition to a lower carbon economy through taking steps to reduce emissions from its operations and by investing in CCS projects which have the potential to transport and store multiple times the annual emissions of Harbour Energy. Harbour Energy has a 2035 net zero goal for its gross operated Scope 1 and Scope 2 CO_2 equivalent (CO_2e) emissions and has also set itself an interim target of 50 per cent. reduction in its emissions in 2030 compared to a 2018 baseline.

Maintain a high-quality portfolio of reserves and resources

Harbour Energy seeks to ensure a robust and diverse portfolio of production, reserves and resources with a balance of oil and gas and high degree of operational control.

Harbour Energy aims to maximise the value of its producing assets by investing in short cycle, high return opportunities, including plant modifications and well intervention programmes, operating cost initiatives, infill drilling, satellite developments and near field exploration to support production and future cash flow. The majority of Harbour Energy's capital programme is targeted at such investment opportunities in or near existing fields and infrastructure.

In addition, Harbour Energy selectively allocates capital to its international growth opportunities which have the potential to materially increase its reserves and production, leading to a more balanced and diversified portfolio. At the same time, it actively manages its portfolio, divesting assets which have become non-core, to ensure that its capital and resources are deployed in line with the Company's strategy.

Leverage Harbour Energy's full cycle capability to diversify and grow

Harbour Energy aims to leverage its full cycle capabilities and extensive M&A and integration expertise to grow and diversify its business, with a focus on acquiring high quality, cash generative assets to establish material production outside the UK. Harbour Energy maintains a disciplined approach with a focused acquisition criteria. As a proven, capable and well-capitalised buyer with a strong track record of executing large scale M&A and integration projects, Harbour Energy is well positioned to take advantage of M&A opportunities.

While Harbour Energy seeks to grow mainly via M&A, it also continues to advance its organic oil and gas growth opportunities in Mexico and Indonesia and its UK CCS projects which have the potential to grow and diversify the Company over time.

Ensure financial strength through the commodity price cycle

Harbour Energy aims to deliver reliable and predictable cash flows, maintain a robust balance sheet with low levels of leverage and retain access to diversified sources of capital throughout the commodity price cycle. To achieve this, it employs a conservative approach to financial risk management and hedging. This, alongside disciplined capital allocation, enables Harbour Energy to retain a strong financial position, fund investment in its portfolio and deliver shareholder returns, including a sustainable dividend, whilst retaining the optionality for value-accretive transactions.

Longer term, Harbour Energy seeks to move towards an unsecured debt financing structure and to achieve investment grade credit ratings in order to access more liquid and lower cost sources of capital.

Strengths

A diversified, cash generative business of scale

Harbour Energy has a diverse, cash generative asset base of significant scale in the UK with material interests in multiple key producing hubs with incremental investment opportunities to add reserves and support production. Today, Harbour Energy is the largest London-listed independent oil and gas company, representing approximately 15 per cent. of the UK's domestic oil and gas production for the year ended 31 December 2023.

While more than 90 per cent. of Harbour Energy's production comes from the UK, it has a diversified asset base with no single hub accounting for more than 20 per cent. of its production. Harbour Energy's portfolio has a balanced mix of oil and gas with production split between liquids (48 per cent.) and (gas 52 per cent.) for the year ended 31 December 2023.

Harbour Energy's asset base generates material cash flow, benefitting from relatively strong margins. In the year ended 31 December 2023, Harbour Energy generated $1 billion of free cash flow.

Significant operational control

Harbour Energy has significant operational control over its portfolio, operating approximately 70 per cent. of its production and total capital expenditure for the year ended 31 December 2023. This enables Harbour Energy to exert influence over the planning and execution of investment in its asset base and provides significant control and flexibility over the nature, timing and amount of capital expenditure invested in its key operating hubs.

In addition, Harbour Energy is able to leverage its scale in the UKCS and its regional operator expertise to pursue operational and cost efficiencies and to cultivate strong relationships within its supply chain to secure cost effective, long term capacity in critical areas such as aviation, marine and engineering services. As a result of its scale and level of activity in the UK, Harbour Energy is a top three European client for the majority of its UK North Sea services providers.

Experienced and proactive operator

Harbour Energy has extensive operational experience and capability and a proven track record of investing in its asset base to improve reliability, increase recovery and add reserves, thereby extending producing field life and deferring abandonment.

For example, the Armada Area fields were acquired as part of the Shell Acquisition in 2017 and were scheduled for decommissioning in 2018. However, Harbour Energy saw the opportunity to invest in the asset, including via the execution of a drilling campaign, to materially improve uptime and add reserves which resulted in field life being extended. In 2022, Harbour Energy also approved an infill well at North West Seymour which, together with plant modifications, has the potential to further extend Armada's producing life beyond 2030.

Harbour Energy has identified numerous opportunities within its existing production base to increase recovery and add reserves—including through infill drilling and well intervention programmes, secondary recovery mechanisms, plant modifications and new well design, satellite developments and near field exploration—to help offset natural production decline and underpin future cash flow.

Portfolio of attractive international growth opportunities

Harbour Energy has a portfolio of attractive international organic growth opportunities. For instance, in Indonesia, it has access to a potential multi-TCF gas development in the Andaman Sea, near a number of significant gas markets. Notably, Harbour Energy made the Timpan-1 discovery in 2022, which it followed in 2023 with the significant Layaran-1 discovery and in 2024, with the significant Tangkulo discovery, operated by Mubadala. These wells form part of a multi-well drilling campaign across Harbour Energy's Andaman licences.

In Mexico, Harbour Energy has organically grown its position through two significant oil discoveries, Zama and Kan. The fully appraised Zama field could replace reserves equivalent to a year's worth of Harbour Energy's production and, with a high-quality reservoir containing significant resource in shallow water close to shore, it represents a potential long life, low GHG intensity, cash generative asset. Harbour Energy also has an interest in the approximately 100 mmboe gross Kan oil discovery on Block 30 in shallow water close to shore which is scheduled to be appraised in 2024.

Significant in-house decommissioning expertise and experience

Harbour Energy has significant decommissioning expertise and experience and has built a distinctive in-house capability to consistently and reliably deliver decommissioning programmes.

Harbour Energy's decommissioning team, which was acquired through the COP Acquisition, has a proven track record of delivering continuous safe and responsible decommissioning in the UK North Sea since 2014. Notably, its decommissioning team has plugged and abandoned more than 165 wells, removed and recycled 33 platforms, including three manned complexes, and flushed, cleaned and made safe more than 1,500 kilometres of pipeline. This has resulted in Harbour Energy realising costs savings and efficiency gains through its decommissioning programme. In 2023, of the 5,307 tonnes of subsea infrastructure removed as a result of Harbour Energy's decommissioning activities, 97 per cent. was recycled.

Significant financial strength and disciplined capital allocation

Harbour Energy is financially strong. Its producing assets generate resilient and reliable operating cash flow through the commodity price cycle, supported by a prudent risk management framework and hedging programme. This, together with a disciplined approach to capital allocation, ensures that Harbour Energy has access to significant liquidity allowing the Company to maintain a robust balance sheet, invest in its existing portfolio and make material shareholder distributions over and above its base dividend while retaining flexibility for meaningful M&A aligned with its strategic drivers.

Harbour Energy has a proven track record of sustained operational and financial delivery and capital allocation discipline. It is this that has enabled the Company to reduce its net debt by approximately $2.7 billion, return $1 billion to shareholders and retain flexibility to agree a $11.2 billion transformational acquisition since completing the Premier Merger in 2021.

Successful delivery of value-accretive, large scale M&A and integration

One of Harbour Energy's core competencies is its ability to identify and execute meaningful M&A transactions aligned with its strategy and completing large-scale integration projects, delivering material value for its stakeholders.

The Shell Acquisition and the COP Acquisition provided Harbour Energy with a material production base in the UK and the opportunity to add value to the assets acquired by investing in them to improve recovery, add reserves and extend producing field life. Notably, to date, Harbour Energy has added approximately 170 mmboe of 2P reserves to the assets acquired from the Shell Acquisition and the COP Acquisition. The Premier Merger added to Harbour Energy's production portfolio in the UK and provided a starting point for future geographical diversification, including international growth opportunities.

Harbour Energy has proven integration capabilities and a business that is scalable, with distinctive in-house integration expertise with an organisation and systems designed for growth. Harbour Energy's demonstrated track record in major organisational restructuring, systems integration, and simplification gives the Company a toolkit with which it can address a wide range of types of acquisitions with confidence, at speed whilst minimising risks. Harbour Energy has quickly and materially reduced contract numbers, IS complexity and real estate footprints following recent acquisitions, and now has stable core business systems and data sets that support consistency and performance transparency.

Well positioned for the Energy Transition

Harbour Energy is well-positioned to support the energy transition through plans to reduce emissions from operations and by deploying its skills and infrastructure to deliver CCS which is critical for countries to achieve their Net Zero goals.

Harbour Energy has a 2035 Net Zero commitment which it is on track to achieve through a combination of emission reduction activities, responsibly decommissioning retired oil and gas infrastructure and by investing in high quality and independently verified carbon credits. In addition, Harbour Energy is exploring opportunities which could result in a step change in its emissions profile, including partial electrification.

Harbour Energy has an interest in two UK CCS projects, including through its leadership of the Viking CCS project. The project allows for the scalable transportation and storage of CO_2 emissions from the Humber and also for shipped CO_2 emissions from both stranded emitters around the UK and in Europe.

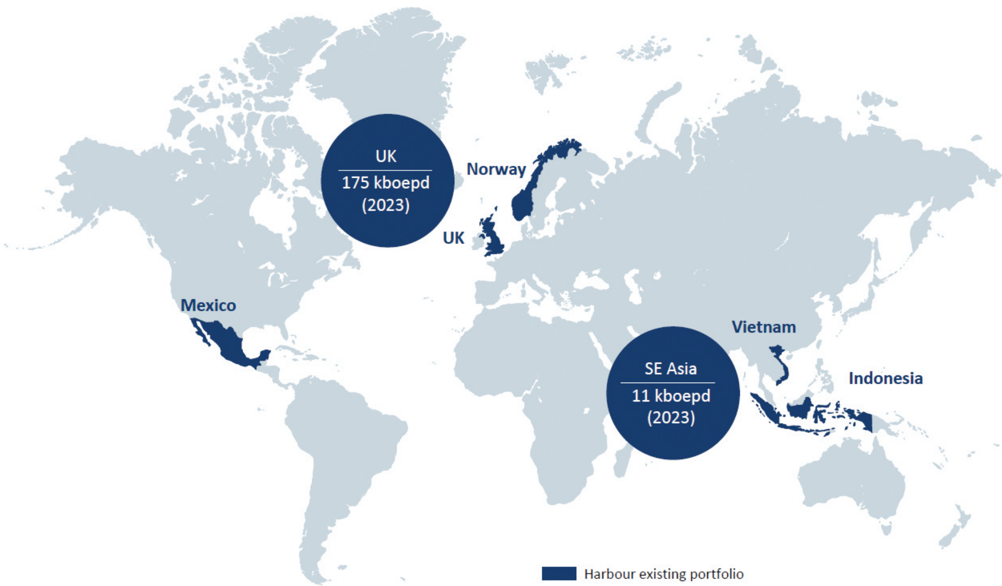
Experienced Board and Leadership Team

Harbour Energy's senior management team has extensive experience in the oil and gas industry and a strong track record of financial and operational delivery, disciplined capital allocation and identifying and executing transformative M&A. The management team has strong support from the Board, which includes eight highly skilled non-executives with significant executive and governance experience globally in the oil and gas industry and other sectors.

The Directors believe that the Board and the senior management, with their experience and proven track record, provide the right mix of skills, expertise and know-how to ensure that Harbour Energy continues to deliver on its strategy, keeping safety and sustainability front of mind, while adhering to the highest standards of corporate governance.

Harbour Energy's Assets

Harbour Energy is headquartered in London with offices in key locations, including Aberdeen, Jakarta, Oslo and Ho Chi Minh City. The following map sets forth the geographic locations of Harbour Energy's assets.



Harbour Energy is active in five countries and is the operator of approximately 70 per cent. of its production for the twelve months ended 31 December 2023.

As of 31 December 2023, Harbour Energy's working interest 2P reserves were estimated to be 361 mmboe, split approximately 53 per cent. and 47 per cent. between liquids and gas, respectively. The UK accounts for approximately 95 per cent. of Harbour Energy's working interest 2P reserves.

As of 31 December 2023, Harbour Energy's working interest 2C contingent resources were estimated to be 519 mmboe, split approximately 59 per cent. and 41 per cent. between liquids and gas, respectively. Within its contingent resources, Harbour Energy has an increasing number of potential international growth projects, with over half of its 2C resources from outside the UK as of 31 December 2023, underpinning potential future reserves replacement.

The following table sets forth Harbour Energy's daily average production in the UK and internationally for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

	Working Interest Production		
	Year ended 31 December		
Region	**2021**	**2022**	**2023**
		(kboepd)	
North Sea[(1)]	163	195	175
International[(2)]	12	13	11
Total	**175**	**208**	**186**

Notes:

(1) North Sea includes the UKCS.

(2) International includes Indonesia and Vietnam.

The following table sets forth the daily average production for the key producing assets in its portfolio for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

			Production[(1)]		
			Year ended 31 December		
Asset	**Working Interest (per cent.)**	**Operator**	**2021**	**2022**	**2023**
				(kboepd)	
UK					
J-Area hub	Between 67–67.5[(2)]	Harbour Energy	26	30	34
Greater Britannia Area	Between 26.3–93.8	Harbour Energy, Ithaca Energy[(3)]	33	31	27
AELE hub	Between 32–100	Harbour Energy, Ithaca Energy[(4)]	24	27	22
Catcher Area	50	Harbour Energy	18	19	16
Tolmount Area	50	Harbour Energy	—	14	13
Elgin Franklin	Between 19.3–33.3[(7)]	TotalEnergies	18	24	19
Beryl Area	Between 34–49[(8)]	Apache	12	11	14
West of Shetland[(5)]	Between 7.5–100	bp/Harbour Energy	13	14	14
Buzzard	21.7	CNOOC	13	15	11
Other UKCS[(6)]	Between 8.4–100	Harbour Energy/Perenco/Shell	6	10	6
North Sea			163	195	175
International			12	13	11

Notes

(1) Production data reflects its working interest in each of the fields.

(2) The working interest of Harbour Energy in the Judy, Joanne, Jasmine and Jade fields is 67, 67, 67 and 67.5 per cent., respectively.

(3) Harbour Energy operates all fields within Greater Britannia Area, with the exception of Alder, which is operated by Ithaca Energy. The working interest of Harbour Energy in the Britannia, Brodgar, Callanish, Enochdhu and Alder fields is 58.7, 93.8, 83.5, 50 and 26.3 per cent., respectively.

(4) Harbour Energy operates all fields within AELE hub, with the exception of the Erskine field, which is operated by Ithaca Energy. The working interest of Harbour Energy in the Armada Area (including the Maria and Seymour fields), Everest, Lomond and Erskine fields is 100, 100, 100 and 32 per cent., respectively.

(5) Within West of Shetland, BP operates the Clair and Schiehallion fields and Harbour Energy operates the Solan field. The working interest of Harbour Energy in the Clair, Schiehallion and Solan fields is 7.5, 10 and 100 per cent., respectively.

(6) Other UKCS fields includes Calder (East Irish Sea), Galleon, Ravenspurn North, and Johnston, in which the working interest of Harbour Energy is 100, 8.4, 28.75 and 28.75 per cent., respectively.

(7) The working interest of Harbour Energy in the Elgin, Franklin and Glenelg fields is 19.3, 19.3 and 33.3 per cent., respectively.

(8) The working interest of Harbour Energy in the Beryl, Buckland, Callater, Ness, Nevis, Skene and Storr fields is 39.4, 37.5, 45, 39.4, 39-49, 34 and 41 per cent., respectively.

The following table sets forth a summary of its historic 2P reserves and 2C contingent resources as of 31 December 2021, 31 December 2022 and 31 December 2023:

Reserves and resources as of 31 December	2P (Working Interest)	2P (Net Entitlement)	2C (Working Interest)
		(mmboe)	
2021	488	481	460
2022	410	405	455
2023	361	357	519

Source: Management estimates. ERCE as a competent independent person has audited Harbour Energy's 2P net entitlement and working interest reserves as of 31 December 2021, 2022 and 2023 and ERCE considers such management estimates to be fair and reasonable as per the Society of Petroleum Engineers Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information. ERCE has also audited approximately 80 per cent. of Harbour Energy's 2C contingent resources as of 31 December 2021, 2022 and 2023 and is of the opinion that these management estimates are fair and reasonable. Further, ERCE believes that if its audit had included all of Harbour Energy's 2C resources then it would have been able to express the same opinion.

United Kingdom

Harbour Energy has a portfolio of licences in the UK which comprises a mixture of producing assets, development and pre-development assets, exploration acreage and infrastructure assets. Harbour Energy has interests in 41 producing oil and gas fields in the UK and is the operator of the following five key producing hubs:

- J-Area (comprising the Jade, Jasmine, Joanne and Judy fields and the Talbot field development);
- Greater Britannia Area (comprising the Britannia, Brodgar, Callanish and Enochdhu fields together with the non-operated Alder field and the Leverett gas discovery which was successfully appraised in 2023);
- AELE (comprising the Armada Area (Drake, Fleming, Hawkins, Maria and Seymour fields), Everest and Lomond fields together with the non-operated Erskine field);
- Catcher Area (comprising the Catcher, Varadero and Burgman fields); and
- Tolmount Area (comprising the Tolmount field and Tolmount East accumulation).

Harbour Energy produced, net to its interests, 175 kboepd from its UK assets for the year ended 31 December 2023, accounting for over 90 per cent. of its total production. Harbour Energy's UK 2P reserves, net to its interest, are estimated at 343 mmboe as of 31 December 2023, representing approximately 95 per cent. of its global total reserve base.

J-Area Hub—Production, Development and Exploration Assets

The J-Area hub consists of the Judy, Joanne and Jasmine fields (67.0 per cent. operated interest), the Jade field (67.5 per cent. operated interest) and the Talbot development (67.0 per cent. operated interest), all of which are located in the Central North Sea area of the UKCS. Jade, Jasmine, Joanne and Judy contain gas-condensates and oil while Talbot contains oil and associated gas. The J-Area hub has been developed with several fixed platforms. The Judy platform serves as the central processing facility for the J-Area hub fields, and separates production into gas and liquids streams. Gas is exported via the CATS pipeline system to Teesside for processing. Liquids are transported via the Norpipe liquids pipeline to the Norsea Terminal at Teesside for processing. The Judy and Joanne fields commenced production in 1995, Jade in 2002 and Jasmine in 2013.

Harbour Energy acquired an initial non-operated interest in the J-Area hub as part of the Shell Acquisition and subsequently increased its interest and became the operator as a result of the COP Acquisition. An active drilling programme, including development and production led exploration wells, satellite developments, active production enhancement and well interventions along with ongoing cost optimisation, has enabled Harbour Energy to significantly increase reserves and extend the producing field life of the J-Area hub since acquiring its initial interest in 2017.

The J-Area hub was Harbour Energy's largest producer in 2023 averaging 34 kboepd. This increase over 2022 (30 kboepd) was driven by improved uptime and the contribution from new wells on-stream at the end of 2022 and early 2023.

In 2024, Harbour Energy completed development drilling at the Talbot oil field, which is being developed as a three well subsea tie-back to the Judy platform and is on track for production start-up around the end of 2024. Once on-stream, Talbot is expected to materially boost production rates from the J-Area hub. The third-party

Affleck field (NEO Energy owned and operated) is currently being redeveloped to tie back via the Talbot subsea facilities to the Judy platform and is also targeting first production in 2024.

Harbour Energy is also evaluating opportunities to improve the recovery factor from J-Area hub. As part of this, Harbour Energy has approved investment in 2024 targeting the Judy Chalk, with plans to drill a well and retrofit three producing wells for gas lift. Additionally, Harbour Energy is progressing approval of potentially six new wells to be drilled from the J-Area hub infrastructure starting from 2025. If successful, these wells would add high return and incremental reserves and could potentially de-risk additional investment to unlock further reserves from these fields. Feasibility studies are also ongoing to assess viability of secondary recovery on J-Area fields, which could lead to a step change in recovery factor from the J-Area hub in the longer term.

Other 2024 activity at the J-Area hub includes the Jocelyn South exploration well which, if successful, could be brought directly online.

Net to the interest of Harbour Energy, the J-Area hub averaged 34 kboepd, split between 16 kboepd of liquids and 18 kboepd of gas, for the year ended 31 December 2023.

Greater Britannia Area—Production, Pre-Development and Exploration Assets

The Greater Britannia Area ("**GBA**") is located in the Central North Sea area of the UKCS and consists of the Britannia (58.66 per cent. operated interest), Brodgar (93.75 per cent. operated interest), Callanish (83.5 per cent. operated interest), Enochdhu (50.0 per cent. operated interest) and Alder (26.32 per cent. non—operated interest) fields. Britannia, Brodgar and Alder contain gas-condensates while Callanish and Enochdhu contain oil and associated gas. The Britannia field was developed with a fixed platform and subsea manifold, while the remaining fields were developed as subsea tiebacks. The Britannia platform serves as the central processing facility for the GBA fields. Liquids are exported via the FPS to the Kinneil processing plant at Grangemouth and commingled gas is exported via a dedicated pipeline to the SAGE gas terminal at St Fergus on the north east coast of Scotland ("**St Fergus**"). Britannia commenced production in 1998 followed by Brodgar and Callanish in 2008, Enochdhu in 2015 and Alder in 2016.

Harbour Energy acquired its interest in GBA as part of the COP Acquisition. Sustained outperformance from the satellite fields Callanish and Brodgar along with additional volumes from infill wells, active production enhancement to maximise recovery and ongoing cost optimisation has enabled Harbour Energy to significantly increase reserves and extend the producing field life of GBA since acquiring its interest in the hub in 2019.

GBA was Harbour Energy's second largest producer in 2023, averaging 27 kboepd. Natural decline was moderated by continued outperformance at Callanish and Brodgar, coupled with a high level of operational efficiency. Harbour Energy plans to return to infill drilling at Callanish and Brodgar in 2024, with further exploration planned at Brodgar North and Gilderoy, all within tie back distance to the GBA infrastructure.

Harbour Energy is evaluating the commerciality of the Leverett gas field, which was successfully appraised in 2023, and has the potential to be tied back to the Britannia platform in the future. In addition, Harbour Energy is developing a comprehensive, integrated area plan to evaluate exploration upside and third party business.

Net to the interest of Harbour Energy, the Greater Britannia Area averaged 27 kboepd, split between 9 kboepd of liquids and 18 kboepd of gas, for the year ended 31 December 2023.

AELE Hub—Production Assets

The AELE hub consists of the Armada Area, Everest and Lomond fields (100 per cent. operated interest) and a 32 per cent. non-operated interest in the Erskine field, all of which are located in the Central North Sea area of the UKCS.

The Armada Area includes the Fleming, Drake and Hawkins fields which contain gas-condensates, and the Maria and Seymour fields which contain oil and associated gas.

The Armada platform is the production hub for the Armada Area. Fleming, Drake and Hawkins were developed from the Armada platform, and Seymour and Maria were developed as subsea tiebacks. The Armada platform is also host to the third party owned Rev field which was developed as a subsea tieback and is located in Norway and operated by Repsol.

The Everest, Lomond and Erskine fields contain gas-condensates and were each developed with a fixed platform. Everest also includes two subsea templates which are tied back to the platform.

Hydrocarbons from the AELE hub are exported via the CATS Riser Platform, which is bridge linked to the North Everest platform. Gas is exported via the CATS pipeline system to Teesside while liquids are exported via the FPS pipeline system to Kinneil.

Everest and Lomond commenced production in 1993, Armada and Erskine in 1997, Seymour in 2003 and Maria in 2007.

Harbour Energy acquired its operated interest in the AELE hub as part of the Shell Acquisition and in June 2018 acquired the remaining minority non-operated interests in the Armada Area and Everest and Lomond fields from Spirit Energy.

The Armada Area is a good example of Harbour Energy investing in an asset to maximise economic recovery and extend producing life. Armada was originally scheduled for decommissioning in 2018. However, Harbour Energy saw the opportunity to invest in the asset, materially improving uptime and adding reserves. In addition, in 2023, Harbour Energy approved the North West Seymour infill well at the Seymour field which will be drilled in 2024, and which, together with plant modifications, has the potential to further extend Armada's producing life beyond 2030.

Net to the interest of Harbour Energy, production from the AELE hub averaged 22 kboepd, split between 5 kboepd of liquids and 17 kboepd of gas, for the year ended 31 December 2023.

Catcher Area—Production Assets

The Catcher Area (50 per cent. operated interest) currently produces from three oil fields, Catcher, Varadero and Burgman, located in the Central North Sea Area of the UKCS.

The subsea wells on Catcher, Varadero and Burgman fields are tied back to the Catcher FPSO vessel. BW Offshore owns and operates the Catcher FPSO. Oil is offloaded by tankers and gas that is not required for fuel is either exported via the SEGAL system to St. Fergus, or reinjected into the reservoir for incremental oil recovery. The Catcher Area commenced production in 2017.

Harbour Energy's interest in the Catcher Area was acquired as part of the Premier Merger.

In 2023, the Catcher Area produced its 100 millionth barrel, exceeding the mid-point reserves case set out in the approved field development plan. Natural decline from the Catcher Area in 2023 was partially offset by a full year of production from the Catcher North and Burgman Far East wells which came on-stream in 2022.

Harbour Energy continues to evaluate options to maximise economic recovery and will acquire a 4D seismic survey in 2024 ahead of potentially returning to drilling in 2025.

Net to the interest of Harbour Energy, production from the Catcher Area averaged 16 kboepd, split between 15 kboepd of liquids and 1 kboepd of gas, for the year ended 31 December 2023.

Tolmount Area—Production and Pre-Development Assets

The Tolmount Area (50 per cent. operated interest) which includes the Tolmount and Tolmount East fields is located in the Southern Gas Basin of the UKCS. Both Tolmount and Tolmount East contain gas-condensate. Tolmount was developed with a fixed platform and Tolmount East was developed as a single well subsea tieback to the Tolmount platform. Hydrocarbons are exported via a dedicated pipeline to the Easington terminal for processing. Tolmount commenced production in April 2022 followed by Tolmount East in December 2023.

Harbour Energy's interest in Tolmount was acquired as part of the Premier Merger.

In addition to Tolmount East first production, activity in the area in 2023 included the Dana-operated Earn exploration well (50 per cent. non-operated interest) which made a small gas discovery, the potential commerciality of which is now being evaluated.

Net to the interest of Harbour Energy, production from the Tolmount Area averaged 13 kboepd, split between 0.6 kboepd of liquids and 12.2 kboepd of gas, for the year ended 31 December 2023.

Elgin Franklin area—Production Assets

The Elgin Franklin area is located in the Central North Sea area of the UKCS and consists of the Elgin, Franklin and West Franklin (19.31 per cent. non-operated interest), and Glenelg (33.27 per cent. non-operated interest) fields. The Elgin Franklin area is operated by TotalEnergies. The fields contain high pressure, high temperature gas condensate and are developed with several fixed platforms. The Elgin production, utilities and quarters platform serves as the central processing facility for the Elgin Franklin area fields and separates production into gas and liquids streams. Gas is exported via the SEAL pipeline to the Bacton terminal and Liquids are exported via the FPS pipeline system to Kinneil. The Elgin and Franklin fields commenced production in 2001 followed by Glenelg in 2006 and West Franklin in 2007.

Harbour Energy's interests in the Elgin Franklin area were acquired as part of the Shell Acquisition and the Premier Merger.

The Elgin Franklin area's 2023 production was impacted by the operator's decision to defer drilling of the EIH well, which was originally expected online towards the end of the year. The operator is currently screening a number of infill well opportunities with the potential to add incremental production in the near future.

Net to the interest of Harbour Energy, production from the Elgin Franklin area averaged 19 kboepd, split between 7 kboepd of liquids and 12 kboepd of gas, for the year ended 31 December 2023.

Beryl Area—Production Assets

The Beryl Area is located in the Northern North Sea area of the UKCS and consists of the Beryl and Loirston (39.44 per cent.), Buckland (37.47 per cent.), Skene (34.04 per cent.), Callater (45 per cent.), Ness (39.44 per cent.), Nevis unit (42.82 per cent.) and Storr (41 per cent.) fields. The Beryl Area fields are operated by Apache. The Beryl Area fields contain oil and gas-condensates. The Beryl field was developed with several fixed platforms, and the remaining fields were developed as subsea tiebacks. The Beryl Alpha platform serves as the central processing facility for the area and provides oil storage in its concrete gravity base structure. Oil is exported by tanker via offshore loading and gas is exported via the SAGE System to St Fergus. The Beryl field commenced production in 1976, followed by Ness in 1988, Nevis in 1996, Buckland in 1999, Skene in 2001, Callater in 2017 and Storr in 2019.

Harbour Energy's interests in the Beryl Area were acquired as part of the Shell Acquisition.

Higher production from the Beryl Area in 2023 was driven by improved operational uptime and strong performance from two new wells at satellite fields Buckland and Storr. However, production was impacted by the operator's decision to defer the subsea and platform drilling campaigns in response to the introduction of the EPL. Discussions are ongoing with the operator and the regulator with regards to future drilling and other investment opportunities to maximise economic recovery from the area.

Net to the interest of Harbour Energy, production from the Beryl Area averaged 14 kboepd, split between 9 kboepd of liquids and 5 kboepd of gas, for the year ended 31 December 2023.

West of Shetland—Production and Pre-Development Assets

Harbour Energy's West of Shetland assets comprise the Clair (7.5 per cent. non-operated interest), Schiehallion (10 per cent. non-operated interest) and Solan (100 per cent. operated interest) fields. BP operates both the Clair and Schiehallion fields. All three fields are located in the West of Shetland area of the UKCS.

The Clair field contains oil and associated and non-associated gas and is currently developed with three fixed platforms. Oil is exported via a dedicated pipeline to the Sullom Voe Terminal ("**SVT**"). Gas is exported via the West of Shetland Pipeline system ("**WoSPS**") to SVT. Clair commenced production in 2005 with the second phase of the Clair development, known as 'Clair Ridge', commencing production in 2018.

The Schiehallion field contains oil, associated and non-associated gas, and is developed with an FPSO and subsea wells. Oil is exported by shuttle tanker, and gas is exported via the WoSPS pipeline system to SVT. Schiehallion commenced production in 1998, was closed in 2013 for re-development, and resumed production in 2017.

The Solan field contains oil and associated gas and was developed with subsea wells tied back to a fixed platform. Oil is stored in a subsea tank and offloaded via shuttle tanker, and associated gas is used as fuel. Solan commenced production in 2016.

Harbour Energy's interest in the Clair field was acquired as part of the COP Acquisition, its interest in the Schiehallion field was acquired as part of the Shell Acquisition and its interest in the Solan field was acquired as part of the Premier Merger.

Production from Harbour Energy's West of Shetland assets for 2023 was supported by four wells drilled across Clair Phase One and Clair Ridge and a further three wells at Schiehallion. Drilling continues at Clair Ridge following the completion of the five-yearly rig recertification in the third quarter of 2023 with up to four wells planned in 2024. In addition, the operator continues to optimise the Clair Phase 3 development plan, which is expected to target Clair South. A programme of infill wells also continues at Schiehallion with the operator planning to bring on-stream two new wells during 2024 and further drilling activity planned for 2025.

Net to the interest of Harbour Energy, production from its West of Shetland assets averaged 14 kboepd, split between 13 kboepd of liquids and 1 kboepd of gas, for the year ended 31 December 2023.

Buzzard—Producing Asset

The Buzzard field (21.73 per cent. non-operated interest) is located in the Central North Sea area of the UKCS and is operated by China National Offshore Oil Corporation ("**CNOOC**").

The Buzzard field contains oil and associated gas and is one of the largest producing fields in the UKCS. The Buzzard field is developed with several fixed platforms and subsea manifolds. Oil is exported via the FPS pipeline system to Kinneil and gas is exported via the Frigg pipeline system to St Fergus. Buzzard commenced production in 2007.

Harbour Energy's interest in the Buzzard field was acquired as part of the Shell Acquisition. Production from Buzzard was lower in 2023 due to natural decline. In 2024, natural decline is expected to be partially offset by the two new North Terrace manifold wells which came on-stream in the first quarter of 2024. Furthermore, three infill wells are being evaluated with the potential to be drilled during 2025 and 2026.

Net to the interest of Harbour Energy, production from Buzzard averaged 11 kboepd (primarily liquid) for the year ended 31 December 2023.

Other UKCS—Production Assets

Harbour Energy has production from several smaller fields around the UKCS including the Calder field (100.0 per cent. operated interest) in the East Irish Sea, the Galleon (8.4 per cent. non-operated interest), Johnston (28.75 per cent. operated interest) and Ravenspurn North (28.75 per cent. non-operated interest) fields in the Southern North Sea and the Nelson field (1.66 per cent. non-operated interest) in the Central North Sea.

Harbour Energy's interests in the Calder and Galleon fields were acquired as part of the COP Acquisition and its interests in the Johnston, Ravenspurn North and Nelson fields were acquired as part of the Premier Merger.

Net to the interest of Harbour Energy, production from these other UKCS assets averaged 6 kboepd (primarily gas) for the year ended 31 December 2023.

CCS projects—Pre-Development Assets

Harbour Energy is participating in two CCS projects in the UK, the Harbour Energy-led Viking CCS project in England and the Acorn project in Scotland in which Harbour Energy is a joint venture partner.

Viking CCS

Harbour Energy operates Viking CCS with a 60 per cent. interest and is partnered with BP, who has a 40 per cent. share. Located in the Humber, the UK's most industrial emissions intensive region, Viking is aiming to transport and store 10 million tonnes of CO_2 emissions per annum by 2030 and up to 15 million tonnes by 2035, materially contributing to the UK's goal of 20 to 30 mtpa by 2030. The proposed development concept includes a new onshore pipeline from Immingham to Theddlethorpe, re-use of the existing LOGGS pipeline, and new offshore platforms that will inject CO_2 into depleted Viking area gas fields located in the Southern Gas Basin.

Viking CCS was established in July 2020 by Chrysaor. In December 2020, Chrysaor successfully applied for a CO_2 storage licence application for Viking with CS005 being awarded to Chrysaor Production Ltd in October 2021.

In 2023, Viking was selected in Track 2 of the UK government's regulatory process. This was a key milestone to progress the Viking project to the FEED phase and to start discussions with the UK government over the terms of the economic licence, ahead of a potential investment decision.

Through Harbour Energy's relationship with Associated British Ports, Viking CCS has the potential to provide storage for shipped CO_2 from emitters around the UK and from Europe. In December 2023, Viking announced its first CO_2 shipping customer.

Viking CCS has 300 million tonnes of gross CO_2 storage capacity (2C resource) independently evaluated by ERCE via a Competent Person's Report, becoming one of the first projects in the world to have done so. In

September 2023, Harbour Energy was awarded two additional CO_2 storage licences adjacent to its existing Viking licence, potentially increasing the project's storage capacity by 50 per cent.

Acorn

Harbour Energy has a 30 per cent. non-operated interest in the Acorn CCS project. Acorn is the backbone of the Scottish Cluster, aiming to transport and store CO_2 from the St Fergus terminal, Scottish heavy industries in the central belt and key petrochemical complexes. The proposed development includes re-use of the existing Goldeneye pipeline and new subsea wells that will inject CO_2 into the Acorn East and East May saline aquifers located in the Central North Sea.

Chrysaor became a partner in the Acorn CCS project in 2019.

Acorn, along with the Harbour Energy-led Viking project, was awarded Track 2 status by the UK government in July 2023. FEED on the Transportation and Storage System is expected to commence in 2024 ahead of a potential final investment decision.

Acorn targets five million tonnes of CO_2 storage per year by 2030. In September 2023, the project was awarded two further CO_2 storage licences, covering the East Mey and Acorn East areas.

Decommissioning Projects

CMS Area

The Caister Murdoch System ("**CMS**") Area is located in the Southern North Sea area of the UKCS and consists of the Murdoch, Caister, Boulton, CMS III Satellites (Boulton H., Hawksley, McAdam, Murdoch K. and Watt), Rita, Hunter, Kelvin, Katy and Munro fields.

Harbour Energy's working interest in the CMS Area fields range from 39.0 per cent. to 79.0 per cent. and its partners are Eni (following its acquisition of Neptune Energy's UK business) in each of the Boulton, Caister, CMS III Satellites, Hunter, Katy, Kelvin, Munro, Murdoch and Rita fields and Tullow Oil, in each of the Boulton, CMS III Satellites, Katy, Kelvin, Munro and Murdoch fields.

Harbour Energy's interest in the CMS Area was acquired as part of the COP Acquisition (other than Hunter and Rita which were acquired as part of the Premier Merger).

In 2020, the Murdoch complex transitioned to cold suspension, the Caister platform was removed and several wells were plugged and abandoned. The Murdoch platforms were removed in 2022 and the remaining wells are being plugged and abandoned as part of a continuous rig program through to 2024, with platform removals continuing through to 2025.

LOGGS Area

The Lincolnshire Offshore Gas Gathering System ("**LOGGS**") Area is located in the Southern North Sea area of the UKCS and consists of the North Valiant, South Valiant, Vanguard, Vulcan, Vampire, Viscount, Saturn, Mimas, Tethys and the Jupiter Area fields (Bell, Callisto, Europa, Ganymede and Sinope).

Harbour Energy's operated interest in the LOGGS Area ranges from 20.0 per cent. to 61.1 per cent., and its partners are BP (in each of the North Valiant, South Valiant, Vampire, Vanguard, Viscount and Vulcan fields) Equinor (in the Jupiter Area fields), INEOS (in the Mimas, Saturn and Tethys fields), NEO Energy (in the Jupiter Area fields) and Spirit Energy (in the Mimas and Saturn fields).

Harbour Energy's interest in the LOGGS Area was acquired as part of the COP Acquisition.

In 2019, the LOGGS complex was de-manned and transitioned into cold suspension and the platforms were removed in 2021. Decommissioning work to plug and abandon the final subsea wells will continue through to 2024, with removal of the remaining LOGGS area platforms continuing through to 2025.

East Irish Sea—Millom and Dalton

The East Irish Sea portfolio consists of the Millom, Dalton and Calder fields. Production from the Dalton and Millom fields ceased in 2019 and 2020, respectively, and decommissioning is in progress. Production from the Calder field is expected to continue through to later this decade.

Harbour Energy's working interest in all East Irish Sea fields is 100 per cent. and was acquired as part of the COP Acquisition.

Decommissioning work to plug and abandon the four Millom West wells and the Darwen and Crossans subsea exploration wells started in 2023 and is expected to complete in 2024. Removal of the Millom West and Calder platforms is expected to take place later this decade along with the plugging and abandoning of the Calder platform wells and the Millom East and Dalton subsea wells.

Balmoral Area

The Balmoral Area fields are comprised of the Balmoral, Glamis, Stirling, Brenda and Nicol fields which are located in Blocks 16/21a, 16/21b and 16/21c of the Central North Sea area of the UKCS.

Harbour Energy's operated interests in the Balmoral Area fields were acquired as part of the Premier Merger and are as follows: Balmoral unit (78.12 per cent.), Brenda (100 per cent.), Glamis (85 per cent.), Nicol (88 per cent.) and Stirling (68.68 per cent.).

The Balmoral Area fields ceased production in October 2020 and dismantlement and recycling of the Balmoral Floating Production Vessel was completed in 2023. Abandonment of the subsea wells is expected to commence in 2025 along with removal of significant subsea infrastructure.

Huntington

The Huntington field is located in Block 22/14b in the Central North Sea area of the UKCS. Production ceased in 2020 and the 'Voyageur Spirit' Floating Production Storage Offtake vessel formerly used to produce the Huntington field has been returned to its owner.

Harbour Energy's working interest in the Huntington field is 100 per cent. which was acquired as part of the Premier Merger.

Future decommissioning scope includes subsea well abandonments and removal of remaining subsea infrastructure potentially starting from 2028.

Non-Operated Decommissioning

Harbour Energy has a working interest across several active non-operated decommissioning projects, most notably Thistle, a large platform operated by BP located in the Northern North Sea area of the UKCS in which Harbour Energy has a 18.28 per cent. non operated interest. Harbour Energy also has a 18.9 per cent. non-operated interest in the Hewett-Bacton decommissioning project in the Southern North Sea, operated by Eni.

Both Thistle and Hewett-Bacton decommissioning projects were acquired as part of the COP Acquisition.

Plugging and abandonment of the Thistle wells started in 2017 and is expected to complete in 2025. Platform removal is scheduled for later this decade.

The Hewett-Bacton decommissioning project includes the plugging and abandonment of both platform and subsea wells and the removal of offshore platforms. Well abandonment commenced in 2020 and is expected to complete in 2024. Platform removals are scheduled to commence in 2024 and is expected to complete in 2026.

Infrastructure in the UK

Harbour Energy owns a number of non-operated interests in pipeline and terminal assets:

Scottish Area Gas Evacuation ("SAGE") System

Harbour Energy owns a 19.72 per cent. non-operated interest in the SAGE pipeline and gas processing terminal located at St Fergus (operated by Ancala Midstream) that was acquired as part of the Shell Acquisition. Gas exported from the Beryl Area is transported through the SAGE pipeline and processed in the SAGE Terminal. Gas from the GBA hub is delivered to the SAGE Terminal for processing via a dedicated pipeline.

Central Area Transmission System ("CATS")

Harbour Energy owns a 0.66 per cent. non-operated interest in CATS (operated by Kellas) that was acquired as part of the COP Acquisition. CATS comprises an offshore riser tower platform (bridge linked to Harbour Energy operated North Everest platform) which connects to a 404 kilometre in length 36" diameter gas export pipeline which in turn connects to the CATS onshore gas processing terminal at Teesside, UK. Gas exported from the AELE and J-Area hubs is transported through the CATS pipeline to Teesside, UK.

Shearwater Elgin Area Line ("SEAL")

Harbour Energy owns a 19.31 per cent. non-operated interest in SEAL (operated by TotalEnergies) that was acquired as part of the Shell Acquisition and as part of the Premier Merger. The SEAL pipeline is a 34" inch pipeline, 468 kilometre in length, that exports gas from the Elgin Franklin area to the SEAL gas processing terminal in Bacton, Norfolk (terminal operated by Shell, and owned by Shell and Esso).

SEAL Interconnector Link Pipeline ("SILK")

Harbour Energy owns 20.98 per cent. non-operated interest in SILK (operated by TotalEnergies) that was acquired as part of the Shell Acquisition and the Premier Merger. SILK is a 34" onshore pipeline, 900 metres in length, that connects the SEAL Bacton terminal to the pipeline system known as the UK to Zeebrugge "Interconnector". The SILK route has not been used since 2004 and is currently mothballed with all Elgin Franklin area gas instead being sent to the UK National Transmission System.

West of Shetland Pipeline system ("WoSPS")

Harbour Energy owns 2.66 per cent. non-operated interest in WoSPS (operated by BP) that was acquired as part of the Shell Acquisition. The WoSPS 20" diameter gas export pipeline is approximately 187 kilometres in length and connects the Glen Lyon FPSO to the onward gas processing and export facilities at Sullom Voe on the Shetland Islands, UK. Gas produced from the Schiehallion and Clair fields is transported through this pipeline.

Esmond Transportation System ("ETS")

Harbour Energy owns a 10 per cent. non-operated interest in ETS (operated by Kellas) that was acquired as part of the COP Acquisition. ETS was originally constructed as a 24" diameter, 204 kilometres long, wet gas pipeline system between the Esmond Area fields (Southern North Sea) and the Perenco Bacton terminal, Norwich, UK. The ETS pipeline was reconfigured in 2015 with the installation of a subsea wye manifold, creating a new subsea entry point to the ETS for both the existing 20" Trent/Tyne export pipeline, and the new 24" diameter Cygnus field export pipeline. Harbour Energy has no equity gas transported through ETS but derives income from tariffs.

Graben Area Export Line ("GAEL")—Northern and Southern Spurlines

The GAEL Pipeline System consists of two 24 inch spurline sections known as the GAEL Northern Spurline and the GAEL Southern Spurline respectively. Harbour Energy owns a 4.01 per cent. non-operated interest in the Northern Spurline and a 13.42 per cent. non-operated interest in the Southern Spurline. These interests were each acquired as part of the Shell Acquisition and the Premier Merger. GAEL is operated by Ineos. The GAEL Southern Spurline connects the Elgin Franklin area fields to the Northern Spurline downstream of the ETAP Marnock platform (BP operated). The GAEL Northern Spurline connects the ETAP central processing facility (BP operated) to the Unity Platform (Apache operated) which is the start of the Forties Pipeline System. Liquids exported from the Elgin Franklin area are transported through the GAEL Pipeline System and delivered offshore to the Forties Pipeline System.

Brent Pipeline System ("BPS")

Harbour Energy owns a 1.63 per cent. non-operated interest in the BPS (operated by TAQA) that was acquired as part of the COP Acquisition. The BPS comprises facilities on the Cormorant Alpha platform and the 36" diameter, crude oil pipeline 153 kilometres long which connects the Cormorant Alpha platform to the Sullom Voe Terminal. Harbour Energy has no equity production transported through BPS.

Northern Leg Gas Pipeline ("NLGP")

Harbour Energy owns a 1.34 per cent. non-operated interest in the NLGP (operated by EnQuest) that was acquired as part of the COP Acquisition and relates to its legacy interest in the Thistle field. The NLGP transports gas from the NLGP user fields into the FLAGS pipeline (part of the Shell operated SEGAL system), which exports gas back to the SEGAL gas terminal at St Fergus, Aberdeenshire. The NLGP is comprised of four parts: the main trunk line and the Thistle, Murchison and Statfjord UK spurlines. Harbour Energy has no equity production transported through the NLGP.

Following cessation of production from all the NLGP system fields, ownership interests in the NLGP will return to pre-2016 positions (Magnus field group—36 per cent., Murchison field group—18 per cent., Thistle field group—6 per cent. and Statfjord UK field group—40 per cent.). This will result in Harbour Energy's interest in the NLGP reducing to 1.1 per cent.

Sullom Voe Terminal ("SVT")

Harbour Energy owns a 0.99 per cent. non-operated interest in SVT (operated by EnQuest) that was acquired as part of the COP Acquisition. SVT is an oil and gas terminal located on the Shetland Isles which receives production piped from a number of fields located in the northern North Sea (east and west of Shetland). The Clair field, west of Shetland, in which Harbour Energy is an owner, is connected to SVT by a dedicated 103 kilometre oil export pipeline. Clair oil is exported via this pipeline to dedicated storage tanks located at SVT and leased from the SVT owners. Gas is exported via the WoSPS pipeline system to SVT (see "—*West of Shetland Pipeline system*" in this Part II (*Information on Harbour Energy*)).

Rivers Terminal

Harbour Energy owns a 100 per cent. operated interest in the Rivers terminal which was acquired as part of the COP Acquisition. The Rivers terminal receives wet sour gas (gas containing inert nitrogen and hydrogen sulphide ("**H_2S**")), separates the liquids, compresses the gas to export pressure, sweetens it by removing the H2S, then forwards it to the North Morecambe terminal for further processing. Within the Rivers terminal is an acid plant, which converts the H_2S and mercaptans (compounds containing both sulphur and hydrocarbon) removed from the gas to sulphuric acid and the removed liquids are sweetened before being forwarded to North Morecambe terminal. Spirit Energy operates the Rivers terminal on behalf of Harbour Energy under an operating services agreement.

Glen Lyon FPSO

Harbour Energy owns a 8.23 per cent. non-operated interest in the Glen Lyon FPSO vessel which is operated by BP and was acquired as part of the Shell Acquisition. The vessel receives production from the Schiehallion, Loyal and Alligin fields and exports produced gas into the WoSPS pipeline (see "—*West of Shetland Pipeline system*" in this Part II (*Information on Harbour Energy*)) with produced oil being offloaded by shuttle tanker. The FPSO has a storage capacity of up to 800,000 barrels and it can process and export up to 130,000 barrels of oil each day.

Norway

Harbour Energy's Norwegian operations are headquartered in Oslo.

Harbour Energy has built a portfolio of exploration licences on the Norwegian Continental Shelf mainly through successful participation in Norway's Award in Pre-Defined Areas ("**APA**") licensing rounds.

As of 31 December 2023, Harbour Energy had an interest in 17 licences over 25 blocks in Norway with an average working interest of 40 per cent. All the licences are in the exploration phase.

During 2023, Harbour Energy drilled one exploration well targeting the JDE prospect on Equinor's operated PL 1058. The well was unsuccessful and was plugged and abandoned. In early 2024, Harbour Energy's operated Ametyst exploration well on PL 1138 was drilled and encountered gas in the secondary target. The Vår operated exploration well targeting the Ringhorne North prospect on PL 956 licence was also drilled in early 2024 and made a small oil discovery.

International—Indonesia

Harbour Energy's Indonesian operations were acquired through the Premier Merger and are headquartered in Jakarta.

Harbour Energy's Indonesian operations comprise producing assets in the Natuna Sea, the Tuna pre-development asset and exploration and appraisal acreage in the Andaman Sea including the Timpan, Layaran, Gayo and Tangkulo discoveries.

Natuna Sea Block A—Production Asset

Natuna Sea Block A ("**NSBA**") fields (28.67 per cent. operated interest) are located offshore near the maritime borders between Malaysia, Indonesia and Vietnam and consist of seven producing fields: Anoa, Gajah Baru, Pelikan, Naga, Bison, Iguana and Gajah-Puteri. The fields contain a range of hydrocarbons including oil, associated and non-associated gas and gas-condensates. The NSBA fields are developed through a combination of platforms, an FPSO and subsea tie-backs. The Anoa field commenced production in 1990 and the remaining fields were developed from 2011 onwards.

Gas is delivered from the Natuna Sea Block A fields to Singapore through the West Natuna Transportation System under two gas sales agreements, "GSA1" and "GSA2". GSA1 and GSA2 are take or pay contracts due to expire in 2028. The pricing of the gas delivered under GSA1 and GSA2 is directly related to high sulphur fuel oil pricing. Liquids are exported from the FPSO via shuttle tanker.

While continuing to evaluate and progress incremental investment opportunities with the potential to support future production from the Natuna Sea Block A fields, Harbour Energy is currently preparing to drill two infill wells in 2025 as part of the marginal fields incentive commitment with the Government of Indonesia.

Net to the working interest of Harbour Energy, production from the Natuna Sea Block A fields averaged 7 kboepd, split between 0.3 kboepd of liquids and 6 kboepd of gas, for the year ended 31 December 2023.

Tuna field—Pre-Development Asset

Harbour Energy has a 50 per cent. operated interest in the Tuna field located in the Natuna Sea near the Indonesia Vietnam maritime border. The Tuna field discovered in 2014 by Premier Oil and was appraised via a two well programme in 2021. The field contains a range of hydrocarbons including oil, associated and non-associated gas and gas-condensates.

In October 2022, Harbour Energy submitted an initial plan of development ("**POD**") to the government which envisaged the Tuna field being developed via a single well head platform tied back to an FPSO and gas sales to Vietnam, with a view to moving to FEED once the POD had been approved. Whilst the Indonesian Government approved the POD in December 2022, subsequent progress has been impacted by EU and UK sanctions against Russia which limit Harbour Energy's ability as an operator to provide certain services to its Russian partner Zarubezhneft, which holds a 50 per cent. non-operated interest in the Tuna PSC.

Harbour Energy continues to have constructive discussions with Zarubezhneft and the Indonesian government to reach a solution which would allow FEED to commence ahead of a potential final investment decision.

Net to the working interest of Harbour Energy, 2C resource associated with the Tuna field is 53 mmboe for the year ended 31 December 2023, split between 18 mmboe of liquids and 35 mmboe of gas.

Andaman Sea licences—Exploration and Appraisal Assets

Harbour Energy has built a material position in the highly prospective Andaman Sea, offshore Aceh, including a 40 per cent. operated interest in the Andaman II PSC where it is partnered with Mubadala Energy and BP, and a non-operated 20 per cent. interest in the South Andaman PSC which is operated by Mubadala Energy. The Andaman Sea is attractively positioned in an area of high gas demand with Indonesia, Thailand, Malaysia and Singapore all within potential pipeline reach.

In July 2022, together with its partners Mubadala and BP, Harbour Energy made a material gas discovery on its Andaman II PSC with the Timpan-1 well, which de-risked a potential multi-TCF gas play.

In late 2023, Mubadala announced a significant gas discovery with the Layaran-1 well on the South Andaman licence. Layaran-1 is the first of what is now a five well exploration and appraisal campaign targeting a major gas play across the Andaman Sea licences. Harbour Energy subsequently drilled the Halwa and Gayo prospects on its operated Andaman II licence. The Halwa well encountered improved reservoir quality but found non-commercial gas saturations and a small gas discovery was made at Gayo. The rig has since returned to South Andaman where it is batch drilling the Tangkulo prospect and the Layaran-2 appraisal well which will test another fault segment of the Layaran discovery. In May 2024, Mubadala announced that the Tangkulo-1 exploration well had made a significant discovery on the South Andaman licence.

Harbour Energy also completed a 3-D seismic survey over the eastern part of its Andaman II PSC in the fourth quarter of 2022 to firm up prospectivity that was identified on the existing 2-D seismic data and early interpretation has confirmed further analogous prospectivity.

Net to the working interest of Harbour Energy, 2C resource associated with Andaman II and South Andaman is approximately 130 mmboe for the year ended 31 December 2023, split between 19 mmboe of liquids and 111 mmboe of gas. This does not include the Gayo and Tangkulo discoveries, both of which were drilled in 2024.

International—Vietnam

The Vietnamese operations of Harbour Energy are headquartered in Ho Chi Minh City and the Block 12W fields are its only assets in Vietnam. Net to the working interest of Harbour Energy, production from Vietnam averaged 4 kboepd for the year ended 31 December 2023, accounting for 2 per cent. of its production.

Block 12W—Production Asset

Harbour Energy holds a 53.125 per cent. operated interest in Block 12W, which contains the Chim Sáo and Dua oil fields and is located offshore southern Vietnam. The Chim Sáo field development encompassed a well head platform and FPSO and achieved production startup in 2011 while the Dua field was developed as a near-field subsea tie-back to the Chim Sáo infrastructure with first oil delivered in 2014.

In recent years, successful well intervention programs, infill wells and gas lift optimisation have helped support production levels from the Block 12W fields partially offsetting natural decline. Most recently, Harbour Energy successfully drilled two infill wells and a side track of an existing production well, with the wells coming onstream in 2023. Harbour Energy will commence the approval processes in 2024 to drill additional new wells.

Net to the working interest of Harbour Energy, production from the Chim Sáo and Dua fields in Vietnam averaged 4 kboepd, split between 3.7 kboepd of liquids and 0.6 kboepd of gas, for the year ended 31 December 2023.

In August 2023, Harbour Energy entered into sale and purchase agreements to sell its business in Vietnam to Big Energy Joint Stock Company ("**Big Energy**"). However, on 13 May 2024, Harbour Energy exercised its right to terminate these agreements in accordance with their respective terms and Harbour Energy intends to reassess its options with regards to realising the best value from its Vietnam business.

International—Mexico

Zama oil field—Pre-development Asset

Harbour Energy has a 12.39 per cent. non-operated interest in the Zama field in the Sureste basin and its partners in the block are Petróleos Mexicanos (Unit operator, 50.43 per cent.), Wintershall Dea (19.83 per cent. interest) and Talos Mexico (17.35 per cent. interest, which is owned by Talos Energy (50.1 per cent.) and Grupo Carso (49.9 per cent.)). Zama was discovered in 2017 and appraisal drilling was conducted in 2018 and 2019. Zama contains oil and associated gas. The proposed development concept includes two offshore platforms and onshore facilities at Dos Bocas.

In March 2023, the Zama Unit partners finalised the Zama Unit development plan ("**UDP**") and submitted it to the regulator. Approval of the UDP was received in June 2023 and the Zama Unit partners have formed an integrated project team to manage the delivery of the development. FEED (front end engineering design) work is planned for 2024, along with an update of project cost estimates, ahead of a potential final investment decision. This would result in approximately 75 mmboe of Harbour Energy's 2C resource moving into 2P reserves, replacing over a year's worth of its current production.

Net to the working interest of Harbour Energy, the 2C resource associated with the Zama unit is 93 mmboe for the year ended 31 December 2023, split between 90 mmboe of liquids and 3 mmboe of gas.

Kan oil discovery—Exploration and Appraisal Asset

Harbour Energy has a 30 per cent. non-operated interest in Block 30, which is operated by Wintershall Dea and located southwest of Block 7 in the Sureste Basin.

The Kan oil field was discovered in early 2023. A plan to appraise the discovery in 2024 was submitted to the regulator in October 2023 and was approved in February 2024. In parallel with the Kan appraisal programme, engineering studies are being undertaken to enable a decision on the development concept for Kan as soon as appraisal drilling is concluded.

Net to the working interest of Harbour Energy, the 2C resource associated with the Kan oil discovery is 29 mmboe for the year ended 31 December 2023, all of which is liquids.

Licence interests of Harbour Energy

Harbour Energy's business is dependent on the holding of licences and approvals from government authorities, which entitle Harbour Energy, *inter alia*, to extract oil and gas. Details of Harbour Energy's key licence interests are set out below (as at the Latest Practicable Date):

Location	Field(s)/Asset(s)	Operator	Harbour Energy Equity (per cent.) (rounded)
United Kingdom—Operated			
AELE hub	Armada Area fields	Harbour Energy	100.0
	Everest	Harbour Energy	100.0
	Lomond	Harbour Energy	100.0
Catcher Area	Catcher	Harbour Energy	50.0
	Varadero	Harbour Energy	50.0
	Burgman	Harbour Energy	50.0
Greater Britannia Area	Britannia	Harbour Energy	58.7
	Brodgar	Harbour Energy	93.8
	Callanish	Harbour Energy	83.5
	Enochdhu	Harbour Energy	50.0
J-Area hub	Jasmine	Harbour Energy	67.0
	Judy	Harbour Energy	67.0
	Joanne	Harbour Energy	67.0
	Jade	Harbour Energy	67.5
	Talbot	Harbour Energy	67.0
West of Shetland	Solan	Harbour Energy	100.0
Southern North Sea	Tolmount	Harbour Energy	50.0
	Johnston	Harbour Energy	28.8
East Irish Sea	Calder	Harbour Energy	100.0
United Kingdom—Non-operated			
West of Shetland	Clair	BP	7.5
	Schiehallion	BP	10.0
Greater Britannia Area	Alder	Ithaca Energy	26.3
AELE hub	Erskine	Ithaca Energy	32.0
Buzzard	Buzzard	CNOOC	21.7
Elgin Franklin	Elgin Franklin	TotalEnergies	19.3
	Glenelg	TotalEnergies	33.3
Central North Sea	Nelson	Shell	1.7
Beryl Area	Beryl	Apache	39.4
	Buckland	Apache	37.5
	Callater	Apache	45.0
	Ness/Nevis Central	Apache	39.4
	Nevis South	Apache	42.8
	Nevis West	Apache	49.1
	Skene	Apache	34.0
	Storr	Apache	41.0
Southern North Sea	Ravenspurn North	Perenco	28.8
	Galleon	Shell	8.4
Norway			
PL956	Block 25/8 (Ringhorne North)	Vår Energi	15.0
PL1058	Blocks 6307/1 and 6407/10	Equinor	40.0
PL1066 & PL 1066 B	Block 6507/3	Aker BP	50.0
PL1092	Blocks 15/6 and 9	Aker BP	50.0
PL1093 & PL 1093 B	Blocks 16/4, 5, 6, 8 and 9	Harbour Energy	50.0
PL1113	Blocks 6407/8, 9 and 11	Harbour Energy	40.0
PL1114	Blocks 640/7/7. 8, 10 and 11	Harbour Energy	40.0
PL 1138	Blocks 15/9, 16/4, 16/7 (Ametyst)	Harbour Energy	40.0
PL 1155 & PL 1155 B	Blocks 6407/10 and 6407/11	Wintershall Dea	20.0
PL 1162	Block 6407/2	Aker BP	30.0
PL 1190	Blocks 6507/10 and 11	Harbour Energy	50.0

Location	Field(s)/Asset(s)	Operator	Harbour Energy Equity (per cent.) (rounded)
Indonesia			
South Andaman	South Andaman (Lavaran, Tangkulo)	Mubadala Petroleum	20.0
Andaman I	Andaman I	Mubadala Petroleum	20.0
Andaman II	Andaman II (Timpan, Gayo)	Harbour Energy	40.0
Natuna Sea	Block A (Anoa, Gajah Baru, Naga, Pelikan, Bison, Iguana and Gajah Puteri)	Harbour Energy	28.7
Tuna PSC	Tuna Block (Kuda Laut, Singa Laut)	Harbour Energy	50.0
Vietnam			
Block 12W	12W (Chim Sáo, Chim Sáo North and Dua)	Harbour Energy	53.1
Mexico			
Mexico Block 7	Block 7 (which contains part of the unitised Zama field)(1)	Talos	25.0
Mexico Block 11	Block 11	Harbour Energy	100.0
Mexico Block 13	Block 13	Harbour Energy	100.0
Mexico Block 30	Block 30 (Kan)	Wintershall Dea	30.0

Notes:

(1) Harbour's interest in the Zama field is only 12.4%—as it has been unitised.

Field and Commercial Partners

The majority of the assets of Harbour Energy are owned, explored and developed through joint venture arrangements ("**JV**") with international and national oil and gas companies. When Harbour Energy evaluates whether to enter into a JV, it seeks prospective commercial partners who will complement its existing strengths. Harbour Energy conducts thorough business and financial due diligence on all its prospective commercial partners and strives to ensure partners will be able to finance its portion of any development through the full lifecycle, including decommissioning.

During the lifecycle of the JV, subject to the materiality of Harbour Energy's interest and the terms of the relevant operating agreement, Harbour Energy often has an active role in the technical, financial and administrative management of operations including in situations where it is a non-operator. Harbour Energy typically maintains involvement with many aspects of operations and provides draft compliance reports and other required government submissions. Harbour Energy works closely with its commercial partners to ensure that it remains in compliance with its ongoing obligations under the licences or agreements pursuant to which it operates. For a discussion of certain risks associated with its reliance on commercial partners, see "*—Risks relating to Harbour Energy and, following Completion, the Enlarged Group as a result of the Acquisition—Third Party Reliance Risks*" in the section entitled "*Risk Factors*".

Health, Safety, Environment and Security

Within all its operating jurisdictions, and with its joint venture partners, Harbour Energy is committed to conduct safe, environmentally responsible, and secure operations. Being active in five countries, Harbour Energy is subject to a wide range of legislative and other requirements governing health and safety matters, environmental protection, and the security of everyone affected by its operations. Consequently, Harbour Energy has established, implemented and actively maintains a comprehensive HSES business management system intended to provide safe and healthy workplaces, prevent work-related injury and ill health, avert environmental pollution, and to protect the assets of Harbour Energy including business data. To sustain focus on these critically important areas, Harbour Energy promotes a positive culture globally to ensure that health, safety, environmental, and security standards are not compromised when seeking to meet its commercial objectives. Potential risk areas for health and safety, environmental harm, and security threat are subject to rigorous assessment and Harbour Energy seeks to put appropriate risk mitigation in place.

Harbour Energy's goal is to achieve process safety excellence across all its operations. Harbour Energy bases its process safety requirements on industry best practice, including the Framework for Process Safety Management developed by the Energy Institute, and implements them through its Business Management System ("**BMS**"). Harbour Energy's process safety commitments and requirements are set out in its Corporate Major Accident Prevention Policy. Harbour Energy reports and investigates all process safety events and identifies ways to prevent recurrence, in line with the International Association of Oil and Gas Producers Tier 1, Tier 2 and Tier 3 definitions.

In 2023, for the first time in its history, Harbour Energy had no lost time injuries and reported zero Tier 1 and zero Tier 2 process safety events.

Harbour Energy's BMS holds all its mandatory policies, standards, guidelines, and procedures. The BMS provides instruction and performance expectations consistent with its core values and business principles to ensure it achieves its stated business objectives. It is the single authorised source of group-level guidance and instruction to both onshore and offshore activities within the business of Harbour Energy. For HSES, the BMS has three key policies: HSES Policy, Corporate Major Accident Prevention Policy and Sustainability Policy. Additionally, the BMS allows Harbour Energy to meet the requirements of International Standards such as ISO 14001 (Environment) and ISO 45001 (Health and Safety) for jurisdictions that hold independent accredited certifications. Harbour Energy reviews and revises the BMS on an ongoing basis to ensure its alignment with its core values, business principles and stated business and strategic objectives. Conformance with the BMS, as demonstrated through audit and assurance activities, is the principal means by which Harbour Energy conducts its activities in a manner compliant with statutory duties.

Harbour Energy has established HSES objectives and a plan to achieve them with a view to maintaining and continually improving both the HSES management system and Harbour Energy's HSES performance. Harbour Energy has established an HSES committee at the Board level with the express purpose of evaluating HSES implementation success and ongoing suitability. The HSES Committee meets at least three times per year and reports directly to the Board.

Harbour Energy seeks to develop and implement progressive HSES approaches and foster a learning culture that results in continuously improved performance. Data analytics are used to identify enterprise and asset level trends to enable focused improvement action to be taken throughout all levels of the organisation. Leading and lagging process safety, occupational health and safety, and environmental performance indicators are routinely reviewed by the Harbour Energy leadership teams. A programme of robust workforce engagement is enacted through frequent visits across the operating assets, where leadership actively engage with all levels of the workforce with a view to determining whether the HSES policies are working in practice, ensuring suitable awareness of the potential for major accident hazard and confirming controls are appropriately established. Finally, achievement of the HSES objectives of Harbour Energy is further supported by a broad ranging HSES audit and assurance programme (including the supply chain of Harbour Energy) that is completed progressively during each year. Significant achievements are recognised, including through the annual Harbour Energy CEO Safety Awards, and safety metrics are included on the Harbour Energy-wide scorecard which determines the annual cash bonus payout for all employees.

Climate and Environmental Protection

Commitment to Net Zero 2035

As the world shifts from fossil-based systems to renewable energy sources, it is anticipated that a significant proportion of future global electricity demand will be met from renewable energy sources. However, oil and gas will still have a vital role in ensuring a consistent delivery of energy and petrochemical products to businesses and households.

Harbour Energy is committed to achieving net zero greenhouse gas emissions by 2035 by reducing its own Scope 1 and Scope 2 gross operated emissions and offsetting hard to abate residual emissions with independently verified carbon credits. Harbour Energy aims to achieve its net zero goals through a combination of activities, including operational efficiencies and modifications as well as through responsibly decommissioning retired oil and gas infrastructure which cannot be repurposed for CCS. Harbour Energy's net zero goal is embedded within its investment decision-making and Harbour Energy has emissions reduction incentives incorporated into its compensation and main debt facility. In addition, one of Harbour Energy's key considerations when selecting its strategic partners, key vendors and main contractors is their respective track records and commitments to net zero and reducing their emissions.

Harbour Energy is a signatory of the World Bank's Zero Routine Flaring by 2030 initiative. The initiative brings governments, oil companies and NGOs together to work to eliminate routine flaring no later than 2030. Furthermore, Harbour Energy entered into the Oil & Gas Methane Partnership 2.0 in January 2024, which provides a reporting framework for oil and gas companies to accurately measure and report their methane emissions.

In 2023, Harbour Energy's absolute emissions across its operated assets were 1.3 mtCO_2e, a reduction of 7 per cent. from 2022, but the Company's GHG emissions intensity increased to 22.5 kgCO_2e /boe (2022: 21.2 kgCO_2e/boe), driven by lower production volumes.

Taskforce on Climate-related Financial Disclosures Compliance

As an oil and gas business, Harbour Energy supports the need for more consistent and comparable disclosure around climate-related risks and opportunities and reports against the recommendations issued by the Taskforce on Climate-related Financial Disclosures ("**TCFD**"). Harbour Energy provides information relevant to each of the four TCFD recommendations (namely governance, strategy, risk management and metrics and targets) on its website and annual report. For further details of Harbour Energy's TCFD reporting for the year ended 31 December 2023, see pages 38 to 47 (inclusive) of the Harbour Energy Annual Report 2023, which are incorporated by reference into and form part of this Prospectus.

Insurance

Harbour Energy undertakes significant and appropriate insurance programmes to minimise risk, including contingent business interruption insurance for loss of revenue following loss or damage to third party facilities identified as production bottlenecks.

Harbour Energy maintains the types and amounts of insurance coverage that it believes are consistent with customary industry practices in the jurisdictions in which it operates. The oil and gas properties and liabilities of Harbour Energy are insured within an operational energy insurance package. Coverage under the terms of this insurance package includes physical damage, operators' extra expense (including well control, seepage, pollution clean-up and redrill), contingent business interruption and third-party liabilities. Coverage is placed in respect of oil and gas exploration and production activities. Harbour Energy believes the limits and deductibles in force are in line with applicable oil industry insurance standards and believes that it has adequately provisioned for, or otherwise protected its operations against, risks consistent with customary industry practices.

Where applicable, Harbour Energy procures construction all risks insurance coverage in respect of development projects. Such coverage generally applies to works executed in performance of contracts wherein Harbour Energy is at risk including loss of, or damage to, the pipelines, risers, umbilicals, Christmas trees and completions to be installed and the related liabilities to third parties.

Harbour Energy arranges such other insurance from time to time in respect of its other operations as required and in accordance with industry practice and at levels which it feels adequately provide for its needs and the risks that it faces. Harbour Energy has not had any material claims under its insurance policies that would either make the policies void or materially increase its premiums.

There can be no assurance that the insurance coverage of Harbour Energy will adequately protect it from all risks that may arise or in amounts sufficient to prevent any material loss. For further details, see "*—Risks relating to Harbour Energy and, following Completion, the Enlarged Group as a result of the Acquisition—Other Risks—Harbour Energy's and, following Completion, the Enlarged Group's insurance and indemnities may not adequately cover all risks and expenses including losses arising from potential operational hazards and unforeseen interruptions*" in the section entitled "*Risk Factors*".

Employees

Harbour Energy believes that it has a strong and established team of highly competent workforce with deep knowledge of, among others, Subsurface, Project Management, HSES, Engineering, Operations, Assurance and Commercial disciplines. Many members of its staff in the UK, Mexico, Norway and Indonesia have experience with major oil companies or leading service companies and have direct experience of working on various production assets and field developments, both in the North Sea and globally. The business model of Harbour Energy involves using the services of the highly developed oil and gas industry supply chain both in the UK and southeast Asia to supplement its in-house capabilities, benefiting from the dedicated and highly experienced resources of contracting partners for the execution of select operational programmes. Harbour Energy believes that it has well-established working relationships with these core contracting partners. As of

31 March 2024, 31 December 2023, 31 December 2022 and 31 December 2021, Harbour Energy globally employed approximately 2,067, 2,082, 2,221 and 2,211 employees, respectively.

Harbour Energy relies on independent contractors for a variety of work related to development programmes such as drilling and logistics.

Harbour Energy believes that it has satisfactory working relationships with its employees and has not experienced any significant labour disputes or work stoppages. In 2023, Harbour Energy conducted its second global engagement survey for employees and contractors, with a response rate of 85 per cent. for employees and 57 per cent. for contractors. For the second year, safety was the highest-scoring area for both employees and contractors, where 90 per cent. surveyed indicated they were confident in challenging unsafe practices. This continued high score reflects a strong safety culture that was reinforced through 2023 with initiatives such as "Back to Basics", Harbour Energy's "HSES starts with me" campaign as well as ongoing messaging around the importance of safety.

For details of the share plans of Harbour Energy, see paragraph 17 (Employee Share Schemes) in Part XIV (*Additional Information*).

Antibribery Laws

Harbour Energy has consolidated anti-bribery and corruption policies to align with guidance from UK authorities regarding the relevant anti-bribery and corruption legislation (including, without limitation, the UK Bribery Act 2010).

Harbour Energy is committed to provide training to all relevant staff on its anti-bribery and corruption policies through a combination of workshops, e-learning and face to face training.

Decommissioning Liabilities

As of 31 December 2023, Harbour Energy had decommissioning liabilities in relation to the portfolio outlined in this document of $4.0 billion (pre-tax) with a near term focus on project execution in the UK Southern North Sea, East Irish Sea, MacCulloch, Balmoral Area, Huntington and several non-operated projects. For the year ended 31 December 2023, its decommissioning expenditures totalled $255 million (pre-tax).

PART III
INFORMATION ON THE TARGET PORTFOLIO

The following information should be read in conjunction with the information appearing elsewhere in this Prospectus, including the financial and other information in Part IX (Historical Financial Information relating to the Target Portfolio) and Part XI (Competent Person's Report on the Target Company's Portfolio).

Overview

The Target Portfolio is part of the Wintershall Dea group, one of the leading European independent gas and oil companies with full lifecycle capabilities across exploration, development and production activities, complemented by investments in midstream assets.

In the year ended 31 December 2023, the Target Portfolio produced 321 kboepd (2022: 318 kboepd), split approximately 208 and 113 kboepd between gas and liquid, respectively. Production was from a large, diversified and low-cost portfolio spanning three regions and eight countries, and extending from Northern Norway to the southern-most offshore production platform in the world in Argentina. The production, development and exploration assets of the Target Portfolio are located in Northern Europe (Norway, Germany and Denmark), North Africa (Egypt, Libya and Algeria), Mexico and Argentina and the CCS assets are located in the United Kingdom and Northern Europe (Norway, Germany and Denmark). Wintershall Dea's Russian joint ventures with Gazprom and midstream assets have been excluded from the Acquisition and are not being acquired by Harbour Energy. The Target Portfolio is operated predominantly via a partnership model with long-term joint venture arrangements with some of the world's leading oil and gas companies. A significant portion of the Target Portfolio is non-operated.

History and Development

Wintershall

Since Wintershall's inception in 1894, it completed its first discovery of crude oil in 1931 in Germany. It continued to expand its production capabilities with entries into Peru (1954), Libya (1958), Canada (1959), the Netherlands (1965), Norway (1973), Argentina (1978), Russia (1992) and the United Kingdom (2011). It was acquired by BASF in 1969. Its first major midstream investments were made in 1991. In 1998, the German upstream company Deminex (in which it held an 18.5 per cent. interest) was broken up. Following this dissolution, Wintershall retained Deminex's Argentinian, Russian and Azerbaijani assets. Wintershall completed the takeover of Clyde Netherlands B.V. in 2002 and Norwegian RevusEnergy ASA in 2008. In 2013, Wintershall further expanded its production in Norway with its acquisition of assets from Equinor Energy AS. In November 2018, Wintershall acquired a 10 per cent. interest in Ghasha, the largest gas and condensate concession to be developed in the UAE.

Dea

Since Dea's founding in 1899, it operated its first oil well in 1901 in Germany. It was taken over by Texaco in 1966 and acquired by RWE in 1988. It continued to expand its production capabilities with entries into Kazakhstan (1992), the United Kingdom (2002), Algeria (2002), Denmark (2003) and Mexico (2017). Following the dissolution of the German upstream company Deminex (of which it held an 18.5 per cent. interest), it retained all Deminex's Norwegian and Egyptian assets. In 2015, Dea was acquired from RWE by L1 Energy, and that same year, it completed the acquisition of E.ON E&P Norge, strengthening its Norwegian portfolio. In 2018, pursuant to the issuance of the relevant licence, Dea acquired participation and operatorship of the Ogarrio field in Mexico, significantly expanding its operations in the country. In 2019, Dea completed the acquisition of Sierra Oil & Gas, an independent Mexican oil and gas company with interests in several exploration and appraisal blocks including the Zama discovery.

Merger of Wintershall and Dea

On 1 May 2019, Wintershall and Dea merged to form the Wintershall Dea group.

Strengths

Harbour Energy believes that the Target Portfolio has a number of attractive features and strengths, as outlined below.

Large, attractive and diversified asset portfolio

Harbour Energy believes that the quality, scale and diversification of the Target Portfolio, in combination with Harbour Energy's existing business, will provide a foundation to compete effectively with larger U.S. and international oil and gas companies. The Target Portfolio has material production and reserves, plus undeveloped resources with asset diversity, both in terms of technical attributes as well as geographically.

The Target Portfolio includes production, development and exploration assets in Germany, Norway, Egypt, Mexico and Argentina. Each of these countries is a well-established hydrocarbon province and together they deliver material production volumes and contribute significant cash flow. The Target Portfolio also benefits from the German engineering heritage of the Wintershall Dea group and its decades of operational experience in these countries.

Production from the Target Portfolio is underpinned by a significant reserve and resource base. As at 31 December 2023, the Target Portfolio had working interest 2P reserves of 1.1 billion boe and working interest 2C resources of 1.2 billion boe.

Some material assets in the Target Portfolio located in North Africa and Mexico benefit from investment guarantees provided by the Federal Republic of Germany for direct investments made by German companies in developing and emerging countries. These investment guarantees provide protection against a number of political risks including expropriation, nationalisation, civil wars, wars or other armed conflicts and payment embargoes or moratoria, under certain conditions.

In addition to geographical diversification, the Target Portfolio also benefits from a diversified product offering, with approximately two-thirds of the total production being linked directly to spot Brent and European gas prices and the remainder priced pursuant to various contractual arrangements including formula-based, index-based and fixed price contracts (primarily in North Africa and Argentina) among others providing a natural dampening effect to earnings volatility. The Target Portfolio is primarily gas weighted, with gas volumes accounting for approximately 65 per cent. of production for the year ended 31 December 2023. As of 31 December 2023, approximately 63 per cent. of the Target Portfolio's working interest 2P reserves were gas.

Resilience through peer-leading production costs

The low-cost assets in the Target Portfolio provide it with a competitive advantage throughout the commodity price cycle, enabling resilience in a low-price environment and enhancing net cash flow when commodity prices are higher.

The combined unit production costs for the Target Portfolio (based on Wintershall Dea's definition of unit production costs) have been stable for past years with $6.6/boe for the year ended 31 December 2023, positioning it amongst the lowest unit production cost portfolios in the Enlarged Group's peer-group. For a description of the one-off effect of a commercial settlement in Germany with a third party that affected the combined unit production costs in 2022, see "*Results of Operations—Comparison of Results of Operations of the Target Portfolio for the Years Ended 31 December 2023 and 31 December 2022—Cost of operations*" in Part VII (*Operating and Financial Review relating to the Target Portfolio*).

Strong partnerships with high-quality operators

Approximately 24 per cent. of the Target Portfolio's production for the twelve months ended 31 December 2023 is operated directly by Wintershall Dea, with the balance either operated by well-established operators with deep in-country operating experience and stakeholder relationships or long-term joint venture partnerships, including with national oil companies. This includes Equinor, Aker BP and Vår Energi in Norway, BP in Egypt and TotalEnergies in Argentina. In addition, many of these joint venture partnerships have existed for multiple decades, such as in Argentina where TotalEnergies and Wintershall Dea have partnered for more than 45 years.

The Target Portfolio also benefits from long term constructive relationships with key national oil companies, including EGPC and EGAS in Egypt, YPF in Argentina, Pemex in Mexico, Sonatrach in Algeria and National Oil Corporation in Libya.

Strong ESG performance and well positioned to play an important role in the energy transition

Wintershall Dea has been recognised as a top-rated ESG performer for the fourth time by the ESG risk rating provider, Sustainalytics, in 2024. With about 65 per cent. of the Target Portfolio's production being gas, its peer group leading GHG emissions intensity and its pipeline of CCS projects in Northern Europe, Harbour Energy believes that the Target Portfolio is well positioned to play an important role in the energy transition.

Target Portfolio Assets

The following map sets forth the geographic locations of the Target Portfolio assets:

The Target Portfolio assets are located in eight countries across Northern Europe (Norway, Germany and Denmark), North Africa (Egypt, Libya and Algeria) and Latin Amercia (Argentina and Mexico). Wintershall Dea operates approximately 24 per cent. of the Target Portfolio's production for the twelve months ended 31 December 2023.

As of 31 December 2023, the Target Portfolio had working interest 2P reserves of 1.1 billion boe. As of 31 December 2023, the Target Portfolio's working interest 2P reserves consisted of 63 per cent. gas and 37 per cent. liquids, with 65 per cent. in Europe, 23 per cent. in Argentina, 5 per cent. in Mexico and 7 per cent. in North Africa. The Target Portfolio's average aggregated working interest production during the full year ended 31 December 2023 was 321 kboepd.

The Target Portfolio had working interest 2C contingent resources of approximately 1.2 billion boe, split approximately 39 per cent. and 61 per cent. between liquids and gas, respectively, as at 31 December 2023. The Target Portfolio's 2C resources are predominantly located in Northern Europe, Argentina and Mexico. The Target Portfolio includes exploration opportunities in attractive regions for growth, including Norway, Mexico and Egypt.

The following table sets forth the daily average production of the Target Portfolio for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

	Working Interest Production		
	Year ended 31 December		
Asset	**2021**	**2022**	**2023**
		(kboepd)[1]	
Norway	159	170	175
Germany	40	34	31
North Africa	55	47	46
Argentina	66	63	59
Mexico	4	4	10
Total[2]	**325**	**318**	**321**

(1) The production is presented on a working interest basis.

(2) This includes production in Denmark of 0.8 kboepd, 0.8 kboepd and 0.6 kboepd of liquids for the years ended 31 December 2021, 31 December 2022 and 31 December 2023, respectively.

The following table sets forth the daily average production for the key producing assets in the Target Portfolio for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

Asset	Working Interest (per cent.)	Operators	Production Year ended 31 December 2021	2022	2023
			(kboepd)		
Norway					
Gjøa Hub	Between 20–56.57	Vår Energi	41	43	46
Skarv Hub	Between 10–30	Aker BP	33	44	46
Njord Hub	Between 27.5–50	Equinor	0	0	12
Aasta Hansteen Hub	Between 10–30	Equinor	36	36	28
Dvalin Area	Between 40–55	Wintershall Dea	0	0	8
Maria Area	Between 38–50	Wintershall Dea	13	13	7
Edvard Grieg Hub	15	Aker BP	17	17	16
Snorre Hub	Between 1.26–8.57	Equinor	10	10	9
Snøhvit Unit	2.81	Equinor	0	2	3
Norway—Other	Between 18–35.2	Aker BP, Wintershall Dea, Equinor	9	5	0
Total (Norway)			**159**	**170**	**175**
Germany					
Mittelplatte	100	Wintershall Dea	20	18	17
Völkersen	100	Wintershall Dea	10	8	7
Total (Germany)(1)			**40**	**34**	**31**
North Africa					
West Nile Delta	17.3	BP	24	28	26
Reggane Nord	24	Groupement Reggane Nord	9	9	8
Total (North Africa)(1)			**55**	**47**	**46**
Mexico					
Ogarrio	50	Wintershall Dea	4	4	3
Hokchi	37	Hokchi Energy	0	0	7
Total (Mexico)			**4**	**4**	**10**
Argentina					
CMA-1	37.50	TotalEnergies	49	45	42
Aguada Pichana Este	Between 22.5–27.3	TotalEnergies	13	14	14
Total (Argentina)(1)			**66**	**63**	**59**
Total(2)			**325**	**318**	**321**

(1) The aggregate production amount for each of Germany, North Africa and Argentina includes production from other assets not listed here.

(2) This includes production in Denmark of 0.8 kboepd, 0.8 kboepd and 0.6 kboepd of liquids for the years ended 31 December 2021, 31 December 2022 and 31 December 2023, respectively.

The following table sets forth a summary of its 2P reserves and 2C contingent resources as of 31 December 2023:

2P (Working Interest)	2P (Net Entitlement)	2C (Working Interest)
	(mmboe)(1)	
1,117	1,064	1,238

(1) Source: Target Company CPR. Individual figures might not sum up properly due to rounding.

Norway

In the year ended 31 December 2023, Norway accounted for 175 kboepd or 55 per cent. of the Target Portfolio's aggregated production, of which approximately 58 per cent. was gas. The Target Portfolio currently participates in around 90 licences, including holding a participating interest in a number of key producing platforms with a number of tieback fields both under production and development.

During 2023, the Wintershall Dea-operated Dvalin field commenced production, and approval was received for plans to develop the operated tie back projects, Dvalin North and Maria Phase 2. Approval was also received for six additional developments where Wintershall Dea is a partner: Irpa, Solveig Phase 2, Njord Electrification, Snøhvit Future and the Skarv field satellites (Alve Nord and Idun Nord). The respective fields are expected to come into production from 2025 onwards. In 2023, Wintershall Dea continued to realise its ambitions in Carbon Management and Hydrogen and was awarded its second CO_2 storage licence in the Norwegian North Sea called 'Havstjerne'.

The working interest reserves associated with the Norwegian assets in the Target Portfolio as of 31 December 2023 are shown in the following table:

	Oil and Condensate	LPG	Sales Gas	Total
	(mmbbl)	(mmbbl)	(bcf)	(mmboe)
Proved plus probable Reserves (2P)	166	61	1,998	584

Source: Target Company CPR

The Norwegian assets that are material to the Target Portfolio's results of operations are described below.

Gjøa Hub—Production, Pre-Development, Exploration and Appraisal Assets

The Gjøa Hub is located in the northern part of the North Sea and consists of the Gjøa field (28.0 per cent. non-operated interest) and production facilities with subsea tie-backs, including the Nova (39.0 per cent. operated interest) and Vega (56.7 per cent. operated interest) fields and nearby discoveries, namely Beaujolais/ Orion/Syrah (40.0 per cent. operated interest), Hamlet (28.0 per cent. non-operated interest) and Ofelia (20.0 per cent. non-operated interest).

The Gjøa Hub fields contain a range of hydrocarbons including oil, associated and non-associated gas and gas-condensates. The Gjøa field, operated by Vår Energi, was developed with subsea wells and a semi-submersible production and processing facility, which serves as the central processing facility for the Gjøa Hub. The operated Nova and Vega fields were developed as subsea tiebacks to the Gjøa facility, which is also host to the third party Duva field (operated by Vår Energi). The Gjøa facility is partly supplied with power from shore, thereby having low emissions and a low GHG emissions intensity. Gas is exported via the Far North Liquids and Associated Gas System ("**FLAGS**") to St. Fergus in the United Kingdom, and liquids are exported via the Troll Oil II Pipeline to Mongstad in Norway. Gjøa and Vega commenced production in 2010 and were followed by Nova in 2022.

The Gjøa Hub was Wintershall Dea's largest producer in 2023 averaging 46 kboepd. The increase over 2022 (43 kboepd) was a result of the Nova field coming onstream. During 2023, a water injector was drilled on Nova to support production and a further injector is planned in 2024. A successful appraisal well was drilled by Vår Energi in 2023 on the Ofelia discovery and there was an additional gas discovery made in a shallower horizon. There are plans to drill three exploration prospects in the vicinity of the Gjøa Hub within the next two years, of which two are to be operated by Wintershall Dea. Along with the existing discoveries which continue to be matured, these additional potential developments could prolong the life of the Gjøa Hub.

Net to the interest of Wintershall Dea, the Gjøa Hub averaged 46 kboepd, split between 22 kboepd of liquids and 24 kboepd of gas, for the year ended 31 December 2023.

Skarv Hub—Production, Development, Exploration and Appraisal Assets

The Skarv Hub is located in the Norwegian Sea and consists of several oil and gas fields and is operated by Aker BP. Fields currently in production include Skarv, Idun, Ærfugl, Ærfugl Nord and Gråsel fields (28.08 per cent. non-operated interest). Fields under development include Alve Nord (20.0 per cent. non-operated interest) and Idun Nord (28.08 per cent. non-operated interest). Discoveries include Newt (10.0 per cent. non-operated interest), Nidhogg (20.0 per cent. non-operated interest) and Storjo (30.0 per cent. non-operated interest). The Adriana-Sabina discovery (38.08 per cent. operated interest) is also located in the vicinity of the Skarv Hub.

The Skarv Hub fields contain a range of hydrocarbons including oil, associated and non-associated gas and gas-condensates. The Skarv Hub fields are developed with subsea wells and an FPSO which has been upgraded by extending the gas processing capacity to enable further tie-ins and extend the lifetime of the field. The FPSO will also be host to third party subsea development Ørn (operated by Aker BP), which is being developed in parallel with Alve Nord and Idun Nord (known collectively as the "**Skarv Satellite Project**"). Gas is exported via the Åsgard Transportation System ("**ÅTS**") to Kårstø and oil is offloaded and exported via dedicated tankers.

The Skarv Hub commenced production in 2013.

The Skarv Hub was Wintershall Dea's second largest producer in Norway in 2023 averaging 45 kboepd. This increase over 2022 (44 kboepd) was driven by higher production at the Skarv field resulting from high production efficiency, the conversion of injection wells to producers and the continued effect from the gas blowdown. Two infill wells will be drilled in 2024 and further infill wells are being matured. Development of Alve Nord and Idun Nord is progressing as planned with a target to achieve first production in the second half of 2027. An appraisal well is planned at the Storjo discovery in 2024 and the potential development of other discoveries will continue to be matured. Participation in the drilling of two exploration prospects in the Skarv Hub is also planned within the next two years. These additional potential developments could prolong the life of the Skarv Hub.

Furthermore, an appraisal well on Adriana was completed in February 2024, and the results are currently being evaluated in order to determine potential future development options and whether the Skarv Hub is an appropriate host facility. Sabina appraisal is being targeted in the near term. The Adriana and Sabina discoveries primarily contain wet gas and condensate.

Net to the interest of Wintershall Dea, the Skarv Hub averaged 45 kboepd, split between 12 kboepd of liquids and 34 kboepd of gas, for the year ended 31 December 2023.

Njord Hub—Production, Development and Pre-Development Assets

Njord is an oil and gas field in the Norwegian Sea and is a production hub for the area. The Njord Hub consists of the Njord (50.0 per cent. non-operated interest), Bauge (27.5 per cent. non-operated interest) and Hyme (27.5 per cent. non-operated interest) fields, three gas-condensate discoveries in the Northern part of Njord (NWFB/NF2/NF3) and the gas-condensate discovery Noatun (45.0 per cent. non-operated interest) north of Njord, all of which are operated by Equinor.

In 2022, the field restarted production after major upgrades and refurbishment commencing in 2016. The upgrades have facilitated the continuation of Njord as an area hub for the next 20 years.

The Njord Hub fields contain oil, associated and non-associated gas and gas-condensates. Njord consists of a floating steel platform unit, Njord A, containing drilling, processing and living quarter facilities, and an oil storage vessel, Njord Bravo. Bauge and Hyme are developed as subsea tiebacks to Njord A, which is also host to the third party owned Fenja field (operated by Vår Energi). Gas is exported via the ÅTS to Kårstø and oil is offloaded via shuttle tankers. Njord commenced production in 1997 followed by Hyme in 2013. Njord resumed production in December 2022, followed by a resumption in production in Hyme and the commencement of production in Bauge in April 2023.

10 new wells at Njord were sanctioned as part of the Njord Future project, which commenced drilling in 2023 and will continue to 2027. Following issues identified with the blow-out preventer ("**BOP**") at the end of 2023 and in early 2024, the BOP was disassembled and brought to shore in January for repair and re-certification. As a result, the first new well is expected to be brought onstream in the third quarter of 2024. In addition, a water injection well at Bauge has been sanctioned. A project has also been sanctioned to provide power from shore to partly electrify the facilities from the middle of 2027. Noatun is located 15 km north of Njord and represents a future tieback opportunity, together with the NWFB/NF2/NF3 discoveries.

Net to the interest of Wintershall Dea, the Njord Hub averaged 12 kboepd, split between 8 kboepd of liquids and 4 kboepd of gas, for the year ended 31 December 2023.

Aasta Hansteen Hub—Production, Development and Appraisal Assets

The Aasta Hansteen Hub is located in the northern part of the Norwegian Sea and consists of the Aasta Hansteen field (24.0 per cent. non-operated interest), the Irpa (19.0 per cent. non-operated interest) development, and the Balderbrå (30.0 per cent. operated interest) and Obelix Upflank (10.0 per cent. non-operated interest) discoveries. The Aasta Hansteen Hub is operated by Equinor.

The Aasta Hansteen Hub contains gas-condensates and is currently the most deepwater field development on the Norwegian continental shelf, at a water depth of 1,300 metres. Aasta Hansteen was developed with subsea wells and a floating platform with a vertical cylindrical hull moored to the seabed (referred to as a "**SPAR platform**"). This was the first of its kind on the Norwegian continental shelf and the largest in the world. It is also the first in the world to have storage tanks for condensate. The SPAR platform will be host to the Irpa field which is being developed as a subsea tieback. Gas is exported via the Polarled pipeline to the Nyhamna terminal and condensate is offloaded via shuttle tankers. Aasta Hansteen commenced production in 2018.

In December 2022, the Irpa subsea tieback project entered the execution phase, with a target to achieve first production in 2026 and is expected to extend the lifetime of the Aasta Hansteen Hub. In January 2023, Wintershall Dea participated in the Equinor-operated Obelix Upflank gas discovery located 25 km south of the Irpa field development. The discovery is currently being evaluated as a potential tie-back to Irpa / Aasta Hansteen, but will likely require appraisal drilling prior to a development decision. Furthermore, a project is under evaluation to lower the inlet pressure on the Aasta Hansteen facility in order to increase field recovery.

Net to the interest of Wintershall Dea, Aasta Hansteen Hub averaged over 28 kboepd, split between 0.4 kboepd of liquids and 28 kboepd of gas, for the year ended 31 December 2023.

Dvalin—Production and Development Assets

Dvalin is located in the central part of the Norwegian Sea and consists of the Dvalin field and Dvalin North development (55.0 per cent. operated interest).

Both Dvalin and Dvalin North are high pressure high temperature gas-condensate reservoirs. The Dvalin field is developed as a subsea tieback to the Heidrun platform operated by Equinor. The Dvalin North field is being developed as a subsea tieback to Dvalin. From Heidrun, gas is exported via the Polarled pipeline to the Nyhamna terminal and liquids are offloaded via shuttle tankers. Dvalin commenced production in 2020 but was then shut in until 2023 to allow the installation of onshore mercury removal units. Dvalin started on continuous production in July 2023 and achieved plateau production in December 2023.

Dvalin North is currently under development and is expected to start production in late 2026.

Net to the interest of Wintershall Dea, Dvalin averaged 8 kboepd, split between 0.7 kboepd of liquids and 7 kboepd of gas, for the year ended 31 December 2023.

The Adriana-Sabina discoveries are also in the vicinity of Dvalin but are considered part of the Skarv Hub. For details of the Adriana-Sabina discovery, see the section entitled "*—Skarv Hub—Production, Development, Exploration and Appraisal Assets*".

Maria Area—Production, Development and Pre-Development and Appraisal Assets

The Maria Area is located in the central part of the Norwegian Sea and consists of the Maria field (50.0 per cent. operated interest) and the Bergknapp discovery (40.0 per cent. operated interest).

The Maria field contains oil and associated gas, while the Bergknapp discovery contains oil, associated and non-associated gas. Maria is developed using subsea wells, with services provided by four host facilities: production is via the Kristin Platform, water injection from the Heidrun Platform, gas lift from Åsgard B via Tyrihans and oil export is from Kristin to Åsgard C and is then further offloaded to shuttle tankers. Gas export is sent via the ATS to the Kårstø terminal. The Maria field commenced production in 2017.

The Maria Phase 2 project entered the execution phase in 2023, and comprises a new subsea template and associated wells, with first production expected 2025. A Bergknapp appraisal well was successfully drilled in late 2023, the results of which will be evaluated and used to determine the future development plan and appropriate host facility.

Net to the interest of Wintershall Dea, the Maria Area averaged 7 kboepd, split between 6 kboepd of liquids and 1 kboepd of gas, for the year ended 31 December 2023.

Edvard Grieg Hub—Production Assets

The Edvard Grieg Hub is located in the central North Sea and consists of the Edvard Grieg and Solveig fields (15.0 per cent. non-operated interest), and is operated by Aker BP.

Edvard Grieg and Solveig contains oil and associated gas, and Solveig also contains non-associated gas. Edvard Grieg is developed with a fixed platform and is host to the Solveig field which is developed as a subsea tieback. Edvard Grieg also provides processing services to the third party Ivar Aasen field (operated by Aker BP). The Edvard Grieg platform has received electric power from shore since December 2022, making the field one of the lowest CO_2 emitters on the Norwegian shelf.

Edvard Grieg commenced production in 2015 followed by Solveig in 2021. Edvard Grieg will also provide processing services to the third party Hanz and Symra fields from 2024 and 2026, respectively. These are also both operated by Aker BP and are being developed as subsea tiebacks to Ivar Aasen.

During 2023 three infill wells were brought online at Edvard Grieg, with additional wells being matured for 2025 drilling. The Solveig Phase 2 project entered the execution phase in 2023, and comprises a subsea template and associated wells, with first production expected 2026.

Net to the interest of Wintershall Dea, Edvard Grieg Hub averaged 16 kboepd, split between 14 kboepd of liquids and 2 kboepd of gas, for the year ended 31 December 2023.

Snorre Area—Production Assets

The Snorre Area is located in the northern part of the North Sea and consists of the Snorre (8.57 per cent. non-operated interest), Vigdis (2.8 per cent. non-operated interest), Tordis (2.8 per cent. non-operated interest), Statfjord Øst (1.4 per cent. non-operated interest) and Sygna (1.26 per cent. non-operated interest) fields, all of which are operated by Equinor.

Snorre Area fields contain oil and associated gas. Snorre was developed with two floating platforms and associated subsea infrastructure. Snorre A is a floating tension-leg platform located in the south of the field, while Snorre B is a semi-submersible facility, located in the north of the field. Snorre commenced production in 1992 and over 1.5 billion barrels of oil have been produced to date. Vigdis is developed as a subsea tieback to Snorre A and commenced production in 1997. Oil from Snorre A is exported to the Gullfaks A platform for storage before being loaded onto shuttle tankers, while oil from Snorre B is exported to Statfjord B for storage before being loaded onto shuttle tankers. Since 2019, all Snorre and Vigdis gas is reinjected into Snorre to increase oil recovery.

Tordis is developed as a subsea tieback to the Gullfaks C platform, where oil is stored before being loaded onto shuttle tankers and gas is exported via Gassled A to Kårstø. Tordis commenced production in 1994. The Statfjord satellites (Statfjord Øst and Sygna) are two subsea developments tied into the Statfjord C platform, adjacent to Snorre. Statfjord Øst commenced production in 1994, and has recently undergone an IOR-project, comprising the installation of gas lift capabilities to two existing subsea templates and five infill wells drilled in 2023. Sygna commenced production in 2000.

The Hywind Tampen offshore floating wind project started operations and began supplying electricity to the adjacent Gullfaks field in November 2022 and to Snorre in September 2023. With six dedicated floating wind turbines, the expected reduction in CO_2 emissions for Snorre is about 120,000 tonnes (gross) per year.

During 2023, three infill wells were completed on Snorre and one was completed on Vigdis (for development of the Lomre discovery). In 2024, a further four wells are planned on Snorre and one well on Vigdis. A significant number of potential targets remains and Equinor is continuously maturing additional infill wells for Snorre, with the ambition of continued drilling from both platforms in the future. Future infill drilling is also planned for Tordis and Vigdis. The area around Snorre is still believed to have some exploration potential with identified leads and prospects.

Net to the interest of Wintershall Dea, the Snorre Area averaged over 9 kboepd of liquids for the year ended 31 December 2023.

Snøhvit Hub—Production and Development Assets

The Snøhvit Hub (2.81 per cent. non-operated interest) is located in the Barents Sea, and is operated by Equinor.

The offshore area includes several gas-condensate fields that are being developed in phases using subsea wells. Gas and condensate are exported via a multiphase pipeline to the onshore Melkøya LNG plant near Hammerfest, which separates the hydrocarbons into sales products (LNG, LPG and condensate) for shipment via tanker. Snøhvit commenced production in 2007.

The offshore Askeladd Vest field is currently in the execution phase, with first production expected in 2025. In 2022 the 'Snøhvit Future' project entered the execution phase, and includes onshore compression and electrification of the onshore plant, which will significantly reduce the CO_2 emissions from the onshore facility as well as extend plateau production. Onshore compression is scheduled to start in 2028 and electrification is expected to start in 2030. Expected production towards 2050 is mainly dependent on the realisation of the aforementioned project, offshore compression and various infill developments.

Net to the interest of Wintershall Dea, Snøhvit Hub averaged over 3 kboepd, split between 0.4 kboepd of liquids and 3 kboepd of gas, for the year ended 31 December 2023.

Norway—Other

The Target Portfolio has decommissioning liabilities associated with a number of fields, including:

- **Brage**: The Brage field (erstwhile 35.2 per cent. operated interest) was divested to Okea in 2022 together with the Ivar Aasen field (erstwhile 6.4615 per cent. non-operated interest) and a 6 per cent. equity share in the Nova field. The Brage field is currently expected to cease production in 2030 and the Target Portfolio has decommissioning liabilities associated with the transaction. Wintershall Dea will retain responsibility for 80 per cent. of Okea's share of total decommissioning costs with a defined maximum monetary value cap related to the Brage Unit.
- **Knarr (30 per cent. non-operated interest)**: Knarr was operated by BG Group until February 2016 and then by Shell and ceased production in May 2022 and the floating production unit was removed from the field and will be repurposed by the vessel owner Altera for the Equinor operated Rosebank development in the UK. Upcoming decommissioning activities in respect of the Knarr field consist of permanent plugging of wells and the removal of subsea infrastructure and are expected to be completed by 2028.
- **Veslefrikk (18 per cent. non-operated interest)**: Veslefrikk was operated by Equinor and ceased production in February 2022. The permanent plugging of 24 wells and the towing of Veslefrikk B (a semi-submersible unit) to a disposal yard were completed in August 2022. Veslefrikk A is currently cold-stacked in field. Decommissioning activities are expected to be completed by 2027 after the removal and disposal of Veslefrikk A.

Exploration and Appraisal Assets in Norway

As of the date of this Prospectus, the Target Portfolio includes 38 exploration licences in Norway (excluding production and development assets), of which 13 are operated by Wintershall Dea. A total of 11 of these licences, including three as operator, were awarded in January 2023 by the Ministry for Energy as part of the 2022 APA licensing round. Furthermore, thirteen new licences were awarded in January 2024, following the 2023 APA licensing round, including five as operator, which became effective in March 2024. Potentially commercial discoveries on the licences include the operated Bergknapp (PL836S) and Adriana / Sabina (PL211 CS) discoveries in the Norwegian Sea, the Storjo (PL261), Nidhogg (PL1008) and Newt (PL941) discoveries in the Skarv Hub, as well as the Hamlet / Gjøa North (PL153) and Ofelia (PL929) discoveries in the vicinity of the Gjøa field.

In addition, the Target Portfolio holds shares in the operated Orion, Beaujolais and Syrah (PL248 F) oil discoveries in the Vega area, the Alta and Neiden (PL609) oil discoveries located to the north of the Snøhvit field in the Barents Sea, the Obelix Upflank (PL1128) and Balderbrå (PL894) gas discoveries, located close to the Irpa and Aasta Hansteen fields, the Oswig East (PL1100) gas-condensate discovery, located near the Oseberg field, and the PL782S Busta and PL820S Iving discoveries located close to the Balder field. Several smaller nearfield discoveries made in recent years are now included in the reserves for the relevant host fields, including the Tellus East / Jorvik Basin (PL338) and Solveig D segment (PL359) discoveries in the Edvard Grieg Hub and the Tordis Statfjord and Lomre (PL089) discoveries in the Tordis / Vigdis area.

In 2024, Wintershall Dea expects to participate in six E&A wells on the Norwegian Shelf, three of them as operator. The wells are primarily focussed on nearfield exploration and appraisal opportunities in core areas close to producing assets. A similar level of activity is expected in 2025, with a further four to six E&A wells planned.

Germany

The German assets in the Target Portfolio are in aggregate the largest oil and gas producer in Germany, with 100 per cent. working interest in the biggest oil field in Germany (Mittelplate) and 100 per cent. working interest in one of the biggest gas fields in Germany (Völkersen). In the year ended 31 December 2023, Germany accounted for 31 kboepd or approximately 10 per cent. of the aggregated production of the Target Portfolio, of which 38 per cent. was gas.

The working interest reserves associated with the German assets in the Target Portfolio as of 31 December 2023 are shown in the following table.

	Oil and Condensate	LPG	Sales Gas	Total
	(mmbbl)	(mmbbl)	(bcf)	(mmboe)
Proved plus probable Reserves (2P)	102	0	218	140

Source: Target Company CPR

Mittelplate—Production Asset

The Mittelplate field (100.0 per cent. operated interest), is located in the Elbe estuary mouth within the North Sea tidal flats of the Wadden Sea, approximately 8 kilometres offshore and also within a UNESCO World Heritage site. Mittelplate is the largest and most productive oil field in Germany, delivering more than 50 per cent. of domestic oil production.

The Mittelplate field contains oil and associated gas and was developed from both an artificial island at the offshore field location, and via extended reach wells drilled from an onshore location at Dieksand. Hydrocarbons are exported from the artificial island via pipeline to the onshore processing site at Dieksand, from which oil is then exported via pipeline to the Brunsbüttel and Heide refineries, and gas is exported to Brunsbüttel. Water extracted from the oil is sent back offshore via pipeline and re-injected into the reservoir for pressure maintenance. Mittelplate commenced production in 1987.

Wintershall Dea has operated the Mittelplate field for over 35 years. The artificial island is continuously improved by maintenance and upgrades, adhering to legal and technical requirements.

The gas turbine-driven power supply of the artificial island was switched to renewable power from shore in 2020, saving up to 36,000 tonnes of CO_2 per annum. Mittelplate is also planned to be supplied by noiseless hybrid hydrogen-powered logistic vessels in one of the world's first zero-emission marine applications. This will save 275,000 litres of diesel fuel, equal to 700 tonnes of CO_2 annually.

Mittelplate was Wintershall Dea's largest producer in Germany in 2023, averaging 17 kboepd. Operations in 2023 were dominated by further implementing efficiency measures and optimising infill development wells aimed at maintaining plateau production in the field. A focus of operations in 2024 is the drilling of two new production wells, with one planned to start production in the third quarter of 2024 and the other planned to start production in the first quarter of 2025.

Net to the interest of Wintershall Dea, Mittelplate averaged 17 kboepd, split between 16.7 kboepd of liquids and 0.2 kboepd of gas, for the year ended 31 December 2023.

Völkersen—Production Asset

Völkersen (100.0 per cent. operated interest) is an onshore gas field located in Northern Germany, approximately 30 kilometres southeast of Bremen. Völkersen is developed via several drilling sites, satellite processing plants and one central processing plant in Langwedel-Holtebüttel. Gas is exported via flowlines to the regulated transport system into the relevant market area and consumed in Lower Saxony. Völkersen commenced production in 1994, and is currently among the largest natural gas fields in Germany.

Wintershall Dea discovered the Völkersen field in 1992 and significant production started in 1994. Operations in Völkersen continue to focus on optimising production and accelerating the recovery of remaining gas reserves in a mature environment. To support efficient and safe operations, Wintershall Dea upgraded the central control room which provides state-of-the-art 24/7 plant monitoring and remote control capabilities.

Völkersen was Wintershall Dea's second largest producer in Germany in 2023, and contributes approximately half of the total gas production volumes for the Wintershall Dea group's Production District Gas Nord.

In 2023, Wintershall Dea successfully completed three coiled tubing cleanouts on Völkersen wells, as well as several smaller well interventions. Further workover and well intervention activities are planned for 2024.

Net to the interest of Wintershall Dea, Völkersen averaged 7 kboepd (exclusively gas) for the year ended 31 December 2023.

Emlichheim—Production Asset

Emlichheim (90.0 per cent. operated interest) is located onshore in the district of Grafschaft Bentheim in Lower Saxony near the Dutch border. Emlichheim is one of the oldest oil fields in Germany, commencing production in 1944 and has been producing oil for 80 years.

Emlichheim is a heavy oil reservoir that has been developed with Enhanced Oil Recovery (EOR) techniques such as hot water and steam injection. Systematically applied reservoir management, production optimisation and EOR capabilities are used to maintain production. The wells are connected to a central processing facility at Emlichheim, after which oil is exported via a pipeline owned and operated by Wintershall Dea to a third party storage tank in Osterwald. From the storage tank, the crude oil is transported via a pipeline owned by a joint venture to the BP refinery in Lingen (Lower Saxony). Associated gas is used as fuel.

In 2023, a project to revise the production technology from steam injection to hot water injection was sanctioned. Through this project, energy consumption and CO_2 emissions are expected to reduce by around three quarters from 2025. Furthermore, a geothermal project to heat the injection water is under consideration which may result in further emissions reduction from 2026/2027 onwards. Ongoing sidetracks and a drilling campaign are underway to support production levels.

Net to the interest of Wintershall Dea, Emlichheim averaged 2 kboepd for the year ended 31 December 2023.

Denmark—Production Assets, Decommissioning

Wintershall Dea is a partner in two oil producing licences in Denmark, 4/95 Nini (42.86 per cent. non-operated interest) and 16/98 Cecilie (43.59 per cent. non-operated interest), both operated by INEOS Energy. Cecilie and Nini were developed with three unmanned platforms tied back to facilities in licence 6/95 Siri (operated by INEOS Energy) for processing, storage and export via tanker. Cecilie and Nini commenced production in 2003, but are now at a late-life stage with cessation of production expected at the end of 2026.

Net to the interest of Wintershall Dea, Nini and Cecilie averaged 0.6 kboepd of liquids for the year ended 31 December 2023.

Decommissioning is planned to be carried out in a five year long campaign. With the development of the Greensand project and the accompanying CO_2 storage license IRIS, depleted oil fields of the Nini and Cecilie license will be used, including existing infrastructure. This will postpone the main parts of the Nini and Cecilie abandonment campaign to the end of the CCS activities.

North Africa

The Target Portfolio's North Africa assets are located in Egypt, Algeria and Libya. In the year ended 31 December 2023, North Africa accounted for 46 kboepd or approximately 14 per cent. of the aggregated production of the Target Portfolio, of which 84 per cent. was gas. A majority of the assets in North Africa are covered by German federal investment guarantees. See "—*Insurance*" in this Part III (*Information on the Target Portfolio*).

The working interest reserves associated with the North Africa assets as of 31 December 2023 are shown in the following table.

	Oil and Condensate	LPG	Sales Gas	Total
	(mmbbl)	(mmbbl)	(bcf)	(mmboe)
Proved plus probable Reserves (2P)	12	0.3	388	82

Source: Target Company CPR

Egypt

Nile Delta Offshore Area—Production, Development and Exploration Assets

The Nile Delta Offshore Area is located offshore Egypt and includes both the North Alexandria and West Mediterranean offshore West Nile Delta ("**WND**") project and the North West Abu Qir exploration block (both 17.25 per cent. non-operated interest), and is operated by BP.

WND is one of the largest assets in the Mediterranean Sea and provides critical gas supply to the domestic market. The project offers unique governance terms, with no traditional joint venture operation involving an NOC or cost recovery structure and is the first production asset in Egypt to be operated by an international oil company. Development operations are carried out under the supervision of a joint development committee formed pursuant to the terms of the PSC.

The WND project includes five fields containing gas-condensates: Giza, Fayoum, Libra, Raven and Taurus. The fields are developed with subsea wells and connected via multiphase pipelines to onshore processing facilities. The Taurus and Libra fields are connected via an offshore tie-in to the third-party Burullus subsea and onshore infrastructure. The Fayoum and Giza fields are connected via pipeline to the onshore Rosetta processing facility, and are also using the Burullus onshore facility to ensure higher efficiency. The Raven field is connected via pipeline to a new processing facility, the Raven plant, adjacent to the existing Rosetta facility. Gas and condensate is exported via pipeline to the domestic market. Production commenced from the Taurus and Libra fields in 2017, followed by Giza and Fayoum fields in 2019, and Raven in 2021.

WND was Wintershall Dea's largest producer in Egypt in 2023 averaging 26 kboepd. The Raven field continued to produce at plateau level throughout the majority of 2023. Meanwhile, production optimisation activities were conducted to extend the production of the remaining fields. In 2023, a project to drill two wells in Raven West and to tie-back to the existing Raven subsea infrastructure entered the execution phase with first production expected in 2025. A further exploration opportunity is being evaluated which in the event of success could be tied back via the existing Fayoum infrastructure. In the North West Abu Qir block, a number of prospects are under evaluation, and a potential exploration well is expected in 2025/2026.

Net to the interest of Wintershall Dea, the Nile Delta Offshore Area averaged 26 kboepd, split between 4 kboepd of liquids and 22 kboepd of gas, for the year ended 31 December 2023.

Nile Delta Onshore Area—Production Asset

The Nile Delta Onshore Area is located onshore Egypt approximately halfway between Alexandria and Damietta, and includes the Disouq concession (100.0 per cent. non-operated interest), which is operated by DISOUCO, a joint venture between Wintershall Dea and the Egyptian Natural Gas Company (EGAS), and East Damanhour (40.0 per cent. non-operated interest, with operations managed by DISOUCO via a service agreement).

The Disouq concession includes several dry gas and gas condensate fields connected to a central processing facility, which delivers gas and condensate into Egypt's national pipeline system. East Damanhour is a gas field that is developed via a single well tieback to the Disouq infrastructure. Disouq commenced production in 2013 followed by East Damanhour in 2023.

Within the Disouq concession, the North West Sidi Ghazi ("**NWSG**") development project is under execution. The project's focus is to expand the capacity of the central treatment plant to cater for extra volumes of condensate. The first stage of the upgrade was completed in December 2023 and the second stage is expected to be completed by mid-2024. The NWSG rich-gas production helps to enhance production from the Disouq fields and to continue to maximise utilisation of gas ullage in the central processing facility. A number of exploration prospects within the Disouq concession are being matured for potential future drilling.

Net to the interest of Wintershall Dea, the Nile Delta Onshore Area averaged 9 kboepd, split between 1 kboepd of liquids and 8 kboepd of gas, for the year ended 31 December 2023.

Algeria

Reggane Nord—Production and Development Asset

Reggane Nord (24.0 per cent. non-operated interest) is located in south-western Algeria in the Sahara desert, approximately 1,500 kilometres from the capital, Algiers, and the Mediterranean coast. Reggane Nord is operated by Groupement Reggane, representing its partners Sonatrach, Repsol and Wintershall Dea.

Reggane Nord includes several dry gas fields connected to a central processing facility, with gas export via a pipeline connecting to the Algerian national pipeline network. Reggane Nord commenced production in 2017.

The 2023 and 2024 operations mainly focus on the ongoing third drilling campaign. In May 2023, a second drilling rig was mobilised and started drilling. Drilling operations currently focus on the four (Reggane, Azrafil-SE, Kahlouche and Kahlouche-S) producing fields. Two (Tiouliline and Sali) currently undeveloped fields are to be drilled from 2025 onwards. In addition, several business development opportunities are being evaluated to continue growth in the area.

Net to the interest of Wintershall Dea, Reggane Nord averaged 8 kboepd, of gas, for the year ended 31 December 2023.

Libya

The target portfolio's main asset in Libya is the offshore Al-Jurf production asset. In addition, onshore exploration blocks Area 69, 70, 86, 87 (NC 193), Area 88, 89 (NC 195) and Area 58 are part of the Target Portfolio. These are exploration blocks (EPSA IV) that are currently the subject of certain force majeure events.

Al-Jurf—Production Asset

Al-Jurf (12.5 per cent. non-operated interest) is located in the Mediterranean Sea, about 100 kilometres off Libya's western coast, and is operated by Mabruk Oil Operations, the Libyan National Oil Corporation (50 per cent.) and TotalEnergies (37.5 per cent.) holds the remaining equity.

Net to the interest of Wintershall Dea, Al-Jurf averaged 2 kboepd of liquids for the year ended 31 December 2023.

Argentina

The Wintershall Dea group has been active in Argentina since 1978. Today, the Argentinian assets in the Target Portfolio constitute in aggregate one of the largest gas producers in Argentina. They include a 37.5 per cent. non-operated interest in the mainly offshore CMA-1 fields in southern Argentina as well as interests in the large Vaca Muerta play. Wintershall Dea's Argentinian assets produced 59 kboepd for the year ended 31 December 2023, of which 92 per cent. was gas.

The working interest reserves associated with the Argentinian assets in the Target Portfolio as of 31 December 2023 are shown in the following table.

	Oil and Condensate	LPG	Sales Gas	Total
	(mmbbl)	(mmbbl)	(bcf)	(mmboe)
Proved plus probable Reserves (2P)	12	9	1,331	259

Source: Target Company CPR

Cuenca Marina Austral—Production and Development Assets

Cuenca Marina Austral 1 ("**CMA-1**") (37.5 per cent. non-operated interest) is located in southern Argentina in Tierra del Fuego, and is operated by TotalEnergies. It includes several fields and discoveries, all of which are located offshore except for the Cañadon Alfa complex, which produces from both onshore and offshore reservoirs. Approximately 16 per cent. of the gas produced in Argentina comes from CMA-1.

CMA-1 fields include a range of hydrocarbons including oil, condensate, associated and non associated gas. The fields were developed with five offshore platforms connected via pipeline to onshore processing facilities at Cañadón Alfa and Rio Cullen. Gas is exported via the national pipeline network. Oil and gasoline are exported via tanker, and other liquids produced in the Turbo Expander facilities of Cañadón Alfa-LPG are exported to Chile through an onshore pipeline. Onshore production from CMA-1 commenced in 1972 from Cañadon Alfa, with first offshore production starting in 1989 from the Hidra field.

CMA-1 was Wintershall Dea's largest producer in Argentina in 2023, averaging 42 kboepd which represents 71 per cent. of Wintershall Dea's overall production in the country.

The Fénix project is currently in the execution phase and involves development of an offshore gas field with a new platform and connection to the existing offshore and onshore infrastructure. The offshore platform was successfully installed in February 2024 and first production is expected in the fourth quarter of 2024. The contribution from Fénix is expected to extend the production plateau of CMA-1. Fénix is the sixth offshore platform installed in CMA-1 and will become the eighth field on production. The joint venture partners are evaluating various projects in CMA-1 which plan to optimise hydrocarbon recovery and reduction of the environmental impact of operations in Tierra del Fuego.

Net to the interest of Wintershall Dea, CMA-1 averaged 42 kboepd, split between 4 kboepd of liquids and 38 kboepd of gas for the year ended 31 December 2023.

Aguada Pichana Este—Production Assets

Aguada Pichana Este ("**APE**", non-operated interest) is located in the Neuquén Province in central Argentina and is operated by TotalEnergies.

APE comprises two separate licences: (i) the residual licence (27.27 per cent. interest), under which conventional gas has been produced since 1996 and also encompasses gas production from tight developments and exploratory and pilot wells from Vaca Muerta shale drilled before the unconventional exploitation concession over APE was granted; and (ii) the Vaca Muerta licence (22.5 per cent. interest), for the production of dry and rich gas from the shale formation since 2017. APE comprises several fields connected via a gathering system to a central processing facility. Gas and liquids are exported in separate pipelines to Loma La

Lata, after which gas is exported via pipelines to Buenos Aires and liquids are exported via pipeline to the EBYTEM terminal at Bahía Blanca.

In APE Vaca Muerta, 10 wells were brought on stream in 2022 and 13 in 2023. Productivity of new wells showed an increase associated with the continuous enhancement of the completion design.

Production in 2023 was similar to 2022 due to external and non-controllable factors, such as market constraints associated to demand and weather conditions.

Future development activities on the APE Vaca Muerta licence are focusing on the Vaca Muerta shale formation, which holds significant contingent resources and currently has 76 wells in production. 12 more wells in APE Vaca Muerta are planned in 2024. Nevertheless, the decision on the amount of activity for the year is dynamic and will be adjusted according to market conditions. Future phases of drilling are being matured in order to maintain plateau production, and studies are underway to increase the capacity of the central processing plant.

Net to the interest of Wintershall Dea, APE averaged 14.2 kboepd, split between 0.3 kboepd of liquids and 13.9 kboepd of gas, for the year ended 31 December 2023.

San Roque—Production and Pre-development Assets

San Roque (24.71 per cent. non-operated interest) is located in the Neuquén Province in central Argentina and is operated by TotalEnergies.

San Roque comprises several mature oil and gas fields connected via a gathering system to a central processing facility. Gas and liquids are exported in separate pipelines to Loma La Lata, after which gas is exported via pipelines to Buenos Aires and liquids are exported via pipeline to the EBYTEM terminal at Bahía Blanca.

Production started in 1981 from conventional plays which are now fully developed. In 2018, exploratory and pilot projects targeting Vaca Muerta formation were conducted which demonstrated significant potential, with oil and/or volatile oil as the primary hydrocarbon phase.

During 2023, activities were focused on maintaining current production and minimising natural field decline. No additional development investments were performed nor are any future investments expected in the conventional plays.

The joint venture partners for San Roque are evaluating options to proceed with the development of the Vaca Muerta formation.

Net to the interest of Wintershall Dea, San Roque averaged 3 kboepd, split between 0.3 kboepd of liquids and 2.7 kboepd of gas, for the year ended 31 December 2023.

Mexico

In Mexico, the Target Portfolio includes the Hokchi and Ogarrio fields, which, in the year ended 31 December 2023, had production of about 7 kboepd and 3 kboepd, respectively, of which gas constituted 7 per cent. and 27 per cent., respectively. The interest in the Hokchi field was acquired in March 2023.

In addition, the Target Portfolio includes material interests in eight offshore exploration blocks located in the Tampico-Misantla and the Sureste basins in the Gulf of Mexico. In the Sureste Basin, the Target Portfolio includes a participation in Block 7, through which it holds an interest in the Zama discovery, one of the world's largest shallow-water discoveries in recent times. It also has a participation in Block 29, which includes the Polok and Chinwol discoveries. In 2023, Wintershall Dea made a material oil discovery on the Kan exploration prospect in Block 30.

The working interest reserves associated with the Mexican assets in the Target Portfolio as of 31 December 2023 are shown in the following table.

	Oil and Condensate	LPG	Sales Gas	Total
	(mmbbl)	(mmbbl)	(bcf)	(mmboe)
Proved plus probable Reserves (2P)	46	0	36	52

Source: Target Company CPR

Ogarrio—Production Asset

Ogarrio (50.0 per cent. operated interest) is a mature onshore oil field located 107 kilometres west of Villahermosa, in the state of Tabasco.

To date more than 500 wells have been drilled on the field, with 80 wells currently active. Surface infrastructure includes a gathering system and two processing facilities: the Ogarrio 2 processing facility is operated by Wintershall Dea, while the Ogarrio 5 processing facility is operated by PEMEX. Oil is subsequently exported to the La Venta processing facility operated by PEMEX and then onwards to the Palomas Crude Oil Commercialisation Centre. Gas is routed through a compression station located at Ogarrio operated by PEMEX, before being exported to the La Venta processing facility. Ogarrio commenced production in 1957.

In the near term, contemplated development activities in Ogarrio include drilling one development well, 20 major workovers, 45 minor workovers, installing additional gas compression capacity in the Ogarrio 2 facility and Front-end engineering design ("**FEED**") for waterflood facilities.

In 2023, Ogarrio production was impacted by downtime related to the PEMEX operated compression facility. Many wells depend on a steady supply of compressed gas from this facility for gas lift production. As a result, the asset is transitioning suitable wells to sucker rod pump systems, and enhancing compression capacity. Based on the results of a water injection test conducted in the central southern area of the field, a waterflood project has been initiated and will be matured with FEED commencing in 2024. The project is expected to improve the overall recovery and primarily aims to utilise existing wells and plans to reinject produced water from the field.

Net to the interest of Wintershall Dea, Ogarrio averaged 3 kboepd, split between 2 kboepd of liquids and 1 kboepd of gas, for the year ended 31 December 2023.

Hokchi—Production Asset

The Hokchi oil field (37.0 per cent. non-operated interest) is located in shallow water in the Sureste basin and is operated by Hokchi Energy, the Mexican subsidiary of Pan American Energy.

The Hokchi field is developed with two offshore platforms connected via pipeline to an onshore processing facility, where oil and gas are separated and treated for further sale to PEMEX.

Hokchi commenced production in 2020 and it is the Target Portfolio's largest producing asset in Mexico.

Three workovers are planned in 2024 and 2025 to replace electrical submersible pumps as well as modifications to the water injection plan to boost injection capacity. In the longer term, additional infill wells (producers and injectors), may be considered to optimize recovery efficiency.

Net to the interest of Wintershall Dea, Hokchi averaged over 9 kboepd, split between 8.5 kboepd of liquids and 0.6 kboepd of gas, for the part of the year ended 31 December 2023.

Zama—Pre-Development Asset

Wintershall Dea holds a 19.83 per cent. non-operated Interest in Zama. Harbour Energy is also a JV partner in Zama. For further details, see "*Harbour Energy's Assets—International—Mexico—Zama oil field—Pre-development Asset*" in Part II (*Information on Harbour Energy*).

Exploration and Appraisal Assets in Mexico

The Target Portfolio also includes eight exploration/appraisal blocks in Mexico, with three exploration blocks located in the Tampico-Misantla Basin and five blocks located in the Sureste Basin.

The Kan oil field (40 per cent. operated interest) was discovered in 2023, in which Harbour Energy are also a JV partner. See "*Harbour Energy's Assets—International—Mexico—Kan oil discovery—Exploration and Appraisal Asset*" in Part II (*Information on Harbour Energy*).

The Polok and Chinwol discoveries in Block 29 (25 per cent. non-operated interest) are operated by Repsol and following the appraisal of the Polok discovery in 2021, the partners are maturing the Polok project and are in the process of starting the detailed engineering phase. The proposed development concept is based on subsea wells and a leased FPSO, the identified vessel candidate was reserved in early March 2024 and is being inspected. Plans for further drilling on Block 29 will be evaluated by the partners during 2024.

In 2023, in the deep water Block 4 (50 per cent. non-operated interest), the Naajal well (operated by Petronas) was drilled resulting in a technical discovery. An appraisal plan for the discovery will be prepared during 2024, including an evaluation of the wider Naajal area, with further drilling dependent on the outcome of that evaluation.

CCS Projects—Pre-Development Assets

Overview

The carbon management and hydrogen team at Wintershall Dea is developing a portfolio of projects that has the potential to store 20 to 30 million tonnes of CO_2 per year by 2040. Wintershall Dea's CCS-related activities in Europe are concentrated in the North Sea where it has acquired a total of five licences in Denmark, Norway and the United Kingdom. In 2022, Wintershall Dea also launched a hydrogen project in Northern Germany called BlueHyNow.

Infrastructure and Project of Common Interest (PCI)

Wintershall Dea is evaluating the options for infrastructure projects to connect the sources of CO_2 capture in Europe to the Wintershall Dea existing CO_2 storage licences in the North Sea. In this process, Wintershall Dea is engaging with emitters and pipeline projects such as Nor-Ge and appraising the future CO_2-hub CO_2nnectNow. The future H_2-hub BlueHyNow has the potential to supply a significant amount of blue hydrogen. Taken together, these Wintershall Dea projects form part of the project EU2NSEA which was recently envisaged by the European Commission to be granted the status of a 'Project of Common interest' ("**PCI**"). Projects selected as PCIs can automatically benefit from many advantages stemming from the Trans-European Network—Energy (TEN-E) Regulations, including an accelerated permit granting and improved regulatory treatment. Projects on the list can also apply for financial support under the CEF Energy programme.

Denmark

Greensand

Wintershall Dea International GmbH holds a 40 per cent. non-operated share in the Greensand CCS-project operated by INEOS E&P A/S. The project involves repurposing depleted Danish oil fields, which are located in the Danish Sector close to the Norway-Denmark border. It is one of the most advanced CCS projects in the EU and the first project that has demonstrated a cross-border CO_2 transport based on bilateral agreements between Belgium and Denmark. First CO_2 injection was achieved in March 2023 as part of a pilot project in which CO_2 was captured from an emitter in Belgium, transported by ship in special containers to the Nini West platform and safely stored in the depleted Nini West oil field.

The Greensand CO_2-storage licence (C2023/01—Iris) was awarded in early February 2023 to Wintershall Dea International GmbH (40 per cent. non-operated interest), INEOS E&P A/S (40 per cent. operated interest) and Nordsøfonden (20 per cent. non-operated interest). As part of the licence work program, the consortium submitted the storage site application in February 2024 for Nini West. With the expansion of the project, Greensand CCS can store a considerable part of Denmark's total annual emissions and other un-abatable sectors in Europe may add to the stream. The project is targeting a total storage potential of up to 8 mtpa of CO_2.

The Greensand development concept is to re-use existing infrastructure around the depleted oilfields, with CO_2 being transported to the site via ship or pipeline.

Greensand has received independent certification, via DNV, for its pilot phase and the site endorsement is targeted in 2024 according to ISO 27914.

Greenport Scandinavia

Wintershall Dea is evaluating the future development of the port of Hirtshals to become a pivotal part of a CCS network in the North of Denmark with partners along a Denmark CCS value chain. Greenport Scandinavia has the potential to become one of the largest CO_2 hubs in North-West Europe. In 2023, the project received funding from the EU and, in the first phase, plans to utilise the Greensand offshore storage (Wintershall Dea 40 per cent. non-operated interest), operated by INEOS and collecting biogenic CO_2 from local emitters, as these emissions are biogenic in origin this would develop an overall negative CO_2 emissions potential. In parallel, the maturation of a new value chain of capture and transport will be designed via a future pipeline network for industrial CO_2 emitters in Denmark. In an extended phase, Greenport Scandinavia has the potential for expansion to facilitate a central collection hub serving as an import and export location for CO_2.

Germany

Wintershall Dea's current CCS and hydrogen projects in Germany are at an early stage and limited to memoranda of understanding and other contracts with limited commitments.

Wilhelmshaven ENERGY HUB

BlueHyNow and CO2nnectNow are part of the Wilhelmshaven ENERGY HUB, a group of project developers and stakeholders developing the city of Wilhelmshaven on Lower Saxony's coast into a new centre for supplying Germany with energy and supporting the Energy Transition. Wintershall Dea is involved in the Wilhelmshaven ENERGY HUB through the CO2nnectNow and BlueHyNow projects. Wilhelmshaven features two landing stages for natural gas from Norway, a direct connection to Germany's planned hydrogen network, existing cavern storage facilities that can be converted to hydrogen storage and a deep-water port.

CO_2nnectNow

This project aims to develop Wilhelmshaven into a logistical hub and collection point for CO_2 emissions from gas-based hydrogen production and energy intensive industries that plan to utilise CCS to decarbonise. Wilhelmshaven can act as a key hub for cross-border export of CO_2 based on connection to the future German CO_2 pipeline network. A draft legal framework for pipeline transport has been launched by the Federal Government of Germany as part of its carbon management strategy. For further details, see "*Germany*" in Part IV (*Regulatory Overview*). From Wilhelmshaven, the CO_2 could be transported by ship or pipeline to CCS storage sites in the North Sea. CO2nnectNow will benefit from funding options and accelerated permitting due to the status as a project of common interest.

BlueHyNow

The BlueHyNow project aims to produce environmentally friendly blue hydrogen from Norwegian natural gas. The project's development concept evaluates the potential for the hydrogen-generation to utilise the provision of electricity from green wind power from the North Sea. The German and Norwegian governments have signalled their intent to secure a significant supply of hydrogen from Norwegian natural gas for Germany. The project will benefit from funding options and accelerated permitting due to the status as a project of common interest.

United Kingdom

Camelot

Wintershall Dea Carbon Management Solutions B.V. ("**WDCMS**") holds a 50 per cent. non-operated share in carbon storage licence CS019, Camelot, located in the Southern Gas Basin, which is operated by Synergia Energy. The licence was granted to WDCMS by the North Sea Transition Authority in August 2023. It has a total storage potential of up to 6 mtpa of CO_2 in a combination of depleted Rotliegend reservoirs (Camelot fields) and a Bunter saline aquifer structure (BC-18). The notional development concept foresees CO_2 transport via a shuttle tanker concept delivering to a floating injection storage and offloading unit moored in the shallow water of the Southern North Sea.

Poseidon

In November 2023, Wintershall Dea joined its second CCS project in the UK, Poseidon, after acquiring a 10 per cent. stake in the licence CS009 from Carbon Catalyst. The Poseidon CCS project is operated by Perenco and is also located in the Southern Gas Basin. The Poseidon storage potential is currently estimated at approximately 1,000 million tonnes (gross) of CO_2, primarily in depleted Rotliegend reservoirs of the large, depleted Leman gas fields.

The Poseidon joint venture is currently appraising development concepts including pipeline and CO_2 shipping transport options. The Poseidon joint venture is targeting CO_2 injection of up to 40 mtpa once fully at scale. A CO_2 injectivity test is planned for the fourth quarter of 2024 and would be the first of its kind in the UK.

The Netherlands

In addition to its UK activities, WDCMS is party to several CCS cooperation agreements which provide for engineering studies and potential for, if concluded beneficial, joint licence-application with respect to permanent storage of CO_2 in designated depleted gas-reservoirs offshore The Netherlands. The agreements concern the following interests:

- K14-FA K14-FB Pre-FEED (3.6 per cent. non-operated interest, operated by Shell);
- K14-FA K14-FB FEED and application (3.6 per cent. non-operated interest, operated by Shell);
- Q1-B Pre-FEED, FEED and application (40 per cent. operated interest); and
- P6-A Pre-FEED, FEED and application (45 per cent. operated interest).

WDCMS has applied for two storage exploration licenses for several other areas in the K-blocks offshore The Netherlands, which are currently pending.

Norway

Havstjerne

Havstjerne (Carbon Storage Exploration Licence (EXL006), 60.0 per cent. operated interest) was awarded in May 2023 and is located in the southern part of the Norwegian Sea, approximately 100 km southeast of Egersund, offering an attractive sailing distance to ports located in Northern Europe. The licence work commitments include drilling of an exploration well planned to be drilled within the first quarter of 2025.

Concept selection for the development of the saline aquifer storage reservoir is targeted for 2025. Thereafter, a field development plan would need to be submitted to the Norwegian Ministry of Energy ("**MoE**") together with an application for an exploitation licence.

Appraisal of the Havstjerne development concepts include evaluation for CO_2 ship-based transport to an offshore injection unit and is targeting an injection rate of five mtpa of CO_2.

Luna

Luna (Carbon Storage Exploration Licence (EXL004), 60.0 per cent. operated interest) is located in the Norwegian Sea, approximately 120 km west of Bergen, and was awarded in November 2022. The licence work commitments include an exploration well.

Concept selection for the development of the storage reservoir is targeted for the first quarter of 2026. Thereafter, a field development plan would need to be submitted to the MoE together with an application for an exploitation licence. Development concepts for Luna are under evaluation including CO_2 transport via the Nor-Ge pipeline project, with the project targeting an annual injection capacity of five mtpa of CO_2.

The Nor-Ge pipeline project

The Nor-Ge pipeline project is a jointly operated pipeline project between Wintershall Dea and Equinor ASA, with each company having a 50 per cent. participating interest. The project consists of a CO_2 pipeline and associated compression facilities from Wilhelmshaven in Germany to the storage licences Smeaheia (EXL002—Equinor 100 per cent. operated interest) and Luna (EXL004—Wintershall Dea 60 per cent. operated interest) in the Norwegian sea. The Nor-Ge project is in the planning phase and has PCI status.

In parallel, Wintershall Dea and Equinor along with five other CCS companies in Norway are funding a transportation system study carried out by Gassco AS, comprising a similar CO_2 pipeline transportation system called CO_2T. Wintershall Dea is participating with a 14.3 per cent. non-operated interest, subject to participation by the various companies in the next phase.

Nor-Ge and CO2T are planned to be assessed for a future potential combined CO2T project.

Licence interests related to the Target Portfolio

The Target Portfolio's business is dependent on the holding of licences and approvals from government authorities, which entitle the Target Portfolio, *inter alia*, to extract oil and gas. Details of the key licences relating to the Target Portfolio are set out below (as at the Latest Practicable Date):

Country	Asset(s)	Operator	Wintershall Dea Group Equity (per cent.)
Algeria	Reggane Nord	Groupement Reggane Nord	24
Argentina	Aguada Pichana Este Residual	TotalEnergies	27.27
	Aguada Pichana Este Vaca Muerta	TotalEnergies	22.5
	San Roque	TotalEnergies	24.71
	CMA-1	TotalEnergies	37.5
Egypt	West Nile Delta	BP	17.25
	Disouq	DISOUCO	100
	East Damanhour	DISOUCO	40
Germany	Emlichheim	Wintershall Dea	90
	Mittelplate	Wintershall Dea	100
	Völkersen	Wintershall Dea	100
Libya	Contract areas 15, 16, 32 (Al-Jurf)	Mabruk Oil Operations	12.5
Mexico	Hokchi Block	Hokchi Energy	37
	Ogarrio	Wintershall Dea	50
	Block 7 (Zama)	PEMEX	19.83
	Block 29 (Polok, Chinwol)	Repsol	25
	Block 30 (Kan)	Wintershall Dea	40
	Block 4 (Naajal)	Petronas	50
Norway	Aasta Hansteen	Equinor	24
	Ærfugl Nord	Aker BP	28.08
	Edvard Grieg	Aker BP	15
	Gjøa	Vår Energi	28
	Maria	Wintershall Dea	50
	Njord	Equinor	50
	Nova	Wintershall Dea	39
	Skarv	Aker BP	28.08
	Snorre	Equinor	8.57
	Vega	Wintershall Dea	56.7
	Bauge	Equinor	27.5
	Dvalin	Wintershall Dea	55
	Dvalin North	Wintershall Dea	55
	Hyme	Equinor	27.5
	Havstjerne CO_2	Wintershall Dea	60
	Luna CO_2	Wintershall Dea	60
	Snøhvit (CO_2 and Petroleum)	Equinor	2.81
United Kingdom	Camelot CO_2	Synergy Energy	50
	Poseidon CO_2	Perenco	10
Denmark	Greensand CO_2	Ineos	40

Field and Commercial Partners

Non-operated joint ventures represent a large portion of the Target Portfolio. With respect to such assets, the business units of the Wintershall Dea group track the performance of the assets and their respective operator. A workflow has been established to secure a consistent approach to joint venture influencing. This approach includes operator assessments, stakeholder analyses, opportunities and risks and their mitigation. On this basis, the responsible asset team determines key focus areas that are deemed significant and can be influenced by the Wintershall Dea group. These areas are followed up regularly.

Health, Safety, Environment and Security

In relation to the Target Portfolio, the Wintershall Dea group actively manages the safety of all personnel working in its operations, including through the application of health and safety standards, the implementation of security measures at its facilities and internal and external audits of health and safety risks. Pursuant to its health and safety principles, it endeavours to:

- shape a health, safety, environment, and quality culture through its own behaviour by promoting cross-unit learning, exchanges and collaboration and driving cultural development;
- provide a safe and healthy working environment for those working on its behalf;
- drive a strong reporting culture to enable transparent follow up and communication of incidents, near misses and observations;
- identify, understand and manage risks worldwide to protect the company, its colleagues and ensure business continuity; and
- implement and maintain robust barriers for known risks as well as practices to create awareness of early signals to prevent incidents from happening.

The Wintershall Dea group has established safety cases for all operated production facilities and has robust emergency preparedness and incident management in place as well as regular training for employees and contractors. Its management systems are in line with the international ISO standard for occupational health and safety (ISO 45001) and it pursues regional certification of ISO 14001 (environmental management) and 50001 (energy management).

In relation to the Target Portfolio, the Wintershall Dea group uses a range of measures to track its HSE performance, such as lost time injury rate per million hours worked ("**LTIR**").

Climate and Environmental Protection

The methane emissions in exploration and production of the Target Portfolio are quantified and published according to OGMP 2.0 standards with a very low methane intensity below 0.2 per cent. Action plans are derived by the Wintershall Dea group to further reduce them. As some of the Target Portfolio assets operate in ecologically sensitive shallow water zones, such as the North German Wadden Sea (Mittelplate), risk assessments and studies are conducted to ascertain the potential environmental impact of Wintershall Dea's activities. For instance, at the Mittelplate asset, environmental-friendly measures including zero discharges and zero flaring, supplying via low draught ships, dimmed lighting, low noise levels and adhering to environmentally sensitive pipeline construction guidelines have been employed and there have not been any oil-related incidents at Mittelplate for more than 30 years. The electricity supply is 100 per cent. certified electricity from renewable energies. This made Mittelplate the first oilfield in Germany to be produced solely with green electricity. In addition, the Wintershall Dea group also performed water risk assessments on several of its sites and engages in platform recycling in the North Sea.

Insurance

The Wintershall Dea group maintains a number of separate insurance policies to protect its core businesses against loss and liability to third parties, including general liability, physical damage, operators' extra expense (which includes the cost of regaining control of wells, re-drilling, seepage, pollution, clean-up and contamination) and third party liability. These policies are arranged for the Wintershall Dea Group as a whole and therefore provide coverage for the Target Portfolio.

Certain material assets located in North Africa and Mexico, namely the Ogarrio, Reggane Nord, West Nile Delta and Disouq fields, benefit from investment guarantees provided by the Federal Republic of Germany for direct investments made by German companies in developing and emerging countries. These guarantees provide protection against certain political risks, including expropriation, nationalisation, civil wars, wars or other armed conflicts and payment embargoes or moratoria, under certain conditions. The coverage of the guarantees is limited by the general terms and conditions. Compensation paid under such guarantees is limited to the lower of: (i) 95 per cent. of the nominal guarantee amount; and (ii) 95 per cent. of the market value of the project at the time the event of loss occurs.

Employees

As of 31 March 2024, 31 December 2023, 31 December 2022 and 31 December 2021, the Wintershall Dea group employed approximately 1,307, 1,325, 1,280 and 1,475 employees, respectively, in relation to the Target Portfolio.

Antibribery Laws

The Wintershall Dea group has, including in relation to the Target Portfolio, laid down a code of conduct which prescribes a company-internal zero tolerance policy for bribery and corruption in global business activity and implemented internal regulations on how to address the risks of corruption.

Decommissioning Liabilities

As of 31 December 2023, The Target Portfolio had decommissioning provision of $2.2 billion, including in relation to fields that are no longer producing, such as the Knarr and Veslefrikk fields. For the year ended 31 December 2023, the Target Portfolio's decommissioning expenditures totalled $41 million.

PART IV
REGULATORY OVERVIEW

The operations of Harbour Energy and the Target Portfolio are subject to various laws and regulations administered by local, national, supranational and other government entities and similar agencies in the United Kingdom, Norway and in the other jurisdictions in which they operate. These laws and regulations have a significant impact on oil and gas exploration, development, production and marketing activities, and accordingly can materially affect the operations of Harbour Energy and the Target Portfolio.

This section is intended to give an overview of the regulatory framework that currently applies to the material assets of Harbour Energy and the Target Portfolio.

United Kingdom

Summary of the Regulatory Regime and Licence Terms in the UK

The Petroleum Act governs oil and gas exploration and production activities in the UK. The Petroleum Act provides for a licensing regime, whereby, following an application process, exploration and production licences are granted to oil and gas companies. The Petroleum Act is supplemented by various environmental and health and safety laws and regulations.

The main type of licence which Harbour Energy holds is a Seaward Production Licence, which is granted in relation to offshore fields. Seaward Production Licences are valid for a sequence of terms. Each licence expires automatically at the end of each term, unless the licensee makes an application to continue the licence and can demonstrate that sufficient progress has been made under the licence to warrant moving into the next term. The exploration period (the "**initial term**") is usually set at four years. The licence expires at the end of the initial term unless the licensee has applied to continue the licence and completed the work programme. At this stage, the licensee must also relinquish a fixed amount of acreage covered by the applicable licence.

The appraisal and development period is usually four years for Seaward Production Licences. The licence expires at the end of the second term unless licensee has applied to continue the licence and the Secretary of State has approved a development plan. The production period is usually 18 years for Seaward Production Licences unless extended by the Secretary of State in exceptional circumstances (such as continuing production). The terms and conditions of every licence are prescribed in a series of model clauses (the "**Model Clauses**"), which are set out in statutory instruments deriving from the Petroleum Act (for Seaward Production Licences, the Petroleum Licensing (Production) (Seaward Areas) Regulations 2008). The Model Clauses applicable to a particular licence are those which are in force at the time the licence was granted, save for recent amendments to all existing and future licences by the Energy Act 2023. The Model Clauses govern the operation of the licence and deal with matters such as: (i) the exploration, appraisal, development and production periods; (ii) extension of the licence by agreement; (iii) the licensee's obligations to carry out the work programme during the initial term, to obtain approval for a development and production programme and to obtain consent before drilling a well; (iv) an indemnity by licensees for the benefit of the Secretary of State for any third party claims; (v) joint and several liability of licensees; (vi) restrictions on and consent for assignment; (vii) consent for change of control; and (viii) a power to revoke the licence in certain circumstances, including insolvency of a licensee, a transfer of the licence or change of control without approval or breach of any of the licence terms.

The Secretary of State may serve a notice under the Petroleum Act to a wide variety of persons including the operator of the field and each of the licensees (and potentially a holding or associated company) requiring them to prepare, submit and (once approved) carry out a decommissioning programme in relation to offshore oil and gas installations and pipelines (a "**Decommissioning Notice**"). Each licensee remains liable for decommissioning obligations until the Decommissioning Notice is withdrawn.

From 1 April 2016, the Oil and Gas Authority ("**OGA**") replaced the UK Department for Energy and Climate Change ("**DECC**") as the entity responsible for petroleum licensing and regulation of the upstream oil and gas sector in the UK. On 14 July 2016, the UK Department for Business, Energy and Industrial Strategy ("**DBEIS**") was created as the result of a merger between the DECC and the Department for Business, Innovation and Skills. On 1 October 2016, the OGA was granted greater regulatory powers, including some powers which had previously belonged to the Secretary of State of Energy and Climate Change. On 21 March 2022, the OGA adopted the trading name of North Sea Transition Authority ("**NSTA**"). On 7 February 2023, the UK Department for Energy Security and Net Zero ("**DESNZ**") was created and it took over the energy policy responsibilities of the DBEIS.

Summary of the Economic and Fiscal Regime in the UK

The primary amounts which Harbour Energy must pay to the UK government comprise taxation arising from the production of oil and gas. There are currently four main elements of taxation to which UK oil companies may be subject in relation to their 'upstream' activities (i.e. exploration, development and production), namely: (i) petroleum revenue tax ("**PRT**") (at 0 per cent. from 1 January 2016 as explained below); (ii) ring fence corporation tax ("**RFCT**"); (iii) a supplementary charge (the "**Supplementary Charge**"); and (iv) until 31 March 2028, unless prices fall between certain floors ahead of that, an energy profits levy ("**EPL**"). On 7 March 2024, the Chancellor of the Exchequer announced that this period would be further extended to 31 March 2029. There are currently no tax stabilisation measures in place, although qualifying companies may apply for a contractual undertaking from the UK government to maintain the current UK decommissioning tax relief regime (see below on decommissioning relief deeds).

Royalties are no longer payable under licences. Licences carry a small annual rental charge which is calculated at an escalating rate on each square kilometre the licence covers at that date. There are no signature or production bonuses or other fiscal terms.

PRT is a field-based tax charged on the profits made by each participant from the production of oil under a licence. It only applies to fields which received development consent prior to 16 March 1993 (including twenty of Harbour Energy's fields). The previous PRT tax rate was 50 per cent. on profits after certain deductions and allowances. The current rate is 0 per cent. PRT is, therefore, effectively abolished. The reason for keeping PRT as a 0 per cent. tax (rather than abolishing the tax completely) is to ensure companies can still obtain PRT refunds (to which they may be entitled from a carry-back of decommissioning losses).

RFCT applies to profits from oil and gas extraction activities and rights in the UK and UKCS instead of corporation tax as calculated under the normal corporation tax rules. It applies regardless of when development consent was given and is intended to prevent profits from these activities being reduced for tax purposes by the setting off of losses from other activities. The current RFCT rate is 30 per cent. The profits from oil and gas extraction activities are 'ring fenced' for RFCT purposes so that, broadly, only losses derived from these activities can be set off against profits from these activities. RFCT is charged on taxable profits, which are profits after certain deductions for items such as capital expenditure, plant and machinery allowances, research and development, expenditure on mineral exploration and access and decommissioning. There are restrictions on the use of interest on borrowings to reduce ring fence profits.

The Supplementary Charge is also imposed on profits arising from any ring fenced activities. The current rate is 10 per cent. Broadly speaking, it applies to the same taxable profits base as RFCT, the key difference being that financing expenses are generally not deductible for Supplementary Charge purposes. In addition, there is a basin-wide investment allowance, currently 62.5 per cent., applicable to investment expenditure incurred on or after 1 April 2015 in both new and existing fields and infrastructure within the ring fence tax regime. The new allowance exempts a proportion of a company's adjusted ring fence profits from the Supplementary Charge.

In 2022, the UK Government introduced the EPL in response to windfall prices. It was originally introduced at 25 per cent. until 31 December 2025 but was increased to 35 per cent. and extended to 31 March 2028 with effect from 1 January 2023 with scope for early removal if prices fall below both an oil and a gas price floor. It is also imposed on profits arising from any ring fenced activities. Broadly speaking, it applies to the same taxable profits base as RFCT, the key difference being that financing and decommissioning expenses are generally not deductible for EPL purposes. In addition brought forward RFCT tax losses cannot be used to offset EPL profits. There is a basin-wide investment allowance, currently 29 per cent. (80 per cent. for decarbonisation spend), applicable to investment expenditure incurred. The allowance exempts a proportion of a company's adjusted ring fence profits from the EPL.

Certain aspects of the UK oil and gas tax regime are designed to provide certainty about the availability of, and importantly the ability to utilise, tax relief in respect of decommissioning expenditure. Decommissioning expenditure can generate RFCT or PRT losses for oil and gas companies to the extent the costs exceed current year profits (decommissioning costs are not deductible for the purposes of the EPL).

These losses can be carried forward if the company is still trading or carried back and set off against past profits as far back as 2002 (or indefinitely for PRT purposes). The carry back of losses can generate valuable tax refunds to the extent the company incurring the losses has paid tax historically. To address concerns that a future government might seek to restrict or limit such refunds, and to enable security for future decommissioning expenditure under decommissioning security agreements to be posted on a 'net of tax' basis, the Finance Act 2013 introduced the decommissioning relief deed ("**DRD**").

The DRD is a contract entered into by participators in North Sea oil and gas fields with the UK government which effectively guarantees participators the benefit of the tax rules as they stood at the time of the Finance Act 2013, by giving DRD holders the right to claim payment from the government for any shortfall in tax relief due to a subsequent change in law. DRDs also allow participators who are required to meet the decommissioning expenditure of a fellow participator in default to claim tax relief notwithstanding that the participator may not itself have sufficient historic profits.

Agreements for Petroleum Activities in the UK

The UK government grants licences for exploration and production in respect of geographic blocks. Licences can be held by more than one company and all companies named on the licence share joint and several liability for operations conducted under it and obligations in respect of the licence (including decommissioning obligations).

Typically, licences in the UK are continuously extended so far as they relate to the producing part of the licence area where production is continuing, subject to the licensee continuing to observe the terms and conditions and the Minister agreeing to such extension.

Co-licence holders will enter into a Joint Operating Agreement ("**JOA**"), which provides the contractual arrangements under which they explore for and produce petroleum under the licence. Harbour Energy is a party to a number of JOAs in respect of its jointly held UK assets. JOAs typically continue for as long as the licence relating to the JOA is in force or until all joint property has been disposed and final settlement has been made between the parties. A JOA will typically set out, among other things, respective shares in the beneficial interest in the relevant licence, all joint property, all joint petroleum and all rights, benefits, costs and obligations incurred in, under or derived from the licence or the JOA. Generally, each party to a JOA may nominate a representative to a joint operating committee established under the JOA, charged with making certain decisions on behalf of the licensees.

If a petroleum deposit extends over more than one production licence and such licences are held by different licensees with unequal equity shares in each respective licence then, the affected licensees must enter into a unitisation and unit operating agreement ("**UUOA**") prior to approval of a development plan in respect of the relevant petroleum deposit. The UUOAs of Harbour Energy include the Armada Area, Britannia, Brodgar, Buzzard, Callanish, Clair, Elgin Franklin, Erskine, Galleon, Nevis South, Johnston, Ravenspurn North, Schiehallion, Storr, Tolmount and Nelson fields. A UUOA regulates the unitisation of each participant's rights and the joint exploration, development and production of petroleum from the production licences applicable to the unit area. UUOAs create a new joint venture and management committee, consisting of all licensees in the respective production licences over which the deposit extends. The UUOAs in respect of UK assets are approved by the NSTA, and regulate commercial provisions such as the scope of the unit area and unit interest split and voting rules. The production from the field or fields covered by a UUOA are typically allocated to the unit participants in accordance with its unit interest share.

Voting rules in the JOAs and UUOAs for Harbour Energy's UK assets usually require certain thresholds to be met based on a combination of the number of licensees and the level of participating interest they represent for a decision to be passed. However, these thresholds may vary depending on how many licensees are party to the agreement at the time of the vote. Under the majority of JOAs and UUOAs to which Harbour Energy is a party, a licensee's voting interest is aligned with their respective working interest in the licence or area subject to the agreement. The number of licensees and the level of participating interest required to pass decisions varies on a case by case basis under the applicable terms of the relevant JOA or UUOA. Some decisions require unanimous approval by all participating parties and such decisions are set out in the agreements. In general, costs and obligations arising out of the JOAs and UUOAs are borne by the parties in proportion to their respective interests.

Summary of the regulatory regime and licence terms in the United Kingdom for offshore storage of CO_2

The UK government has set in law a target to be Net Zero by 2050 compared to 1990 levels. Developing carbon capture usage and storage ("**CCUS**") is important for delivering this target. The Net Zero Strategy aims to create four clusters by 2030, capturing and storing 20-30 megatonnes of carbon dioxide ("**$MtCO_2$**") per year by 2030 and up to 50 $MtCO_2$ per year by 2035.

The North Sea Transition Deal was finalised in late March 2021 by the UK government and offshore oil and gas industry aimed at balancing continued development of hydrocarbon resources on the UKCS with the country's target of Net Zero by 2050. The upstream sector has committed to cut emissions from hydrocarbon production by 10 per cent. by 2025, 25 per cent. by 2027, and 50 per cent. by 2030 (all targets are relative to the 2018 baseline of 18.3 MMt of CO_2e). Both, government and industry have committed to invest jointly up to GBP 16 billion in new energy technologies by 2030, including up to GBP 3 billion for CCUS, and up to GBP 10 billion for hydrogen projects. CCUS developments will receive state finance through the Carbon Capture and Storage Infrastructure Fund, created in 2020, and the UK Government will establish revenue mechanisms for carbon transportation and storage as well as hydrogen production to encourage investment.

Key Regulations

The Energy Act 2008, adopted in line with EU Directive 2009/31/EC on the geological storage of carbon dioxide (the "**CCS Directive**"), established a regime for the regulation of CO_2 storage and introduced a licensing requirement for offshore CCUS. In 2011, the Storage of Carbon Dioxide (Amendment of the Energy Act 2008 etc.) Regulations 2011 extended the licensing regime to onshore and the adjacent internal waters in the United Kingdom. Carrying out regulated CCS operations without a licence is prohibited.

The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010, as amended, regulate the issuance of CO_2 appraisal and storage licences (each, a "**CS Licence**") and storage permits and set out a number of requirements for CCS operations, including in respect of financial security and state inspections (which were introduced by the Storage of Carbon Dioxide (Inspections etc.) Regulations 2012). The liability for a closed CCS site upon termination of a CS Licence is regulated by the Storage of Carbon Dioxide (Termination of Licences) Regulations 2011.

Further, the permitting regime for CO_2 capture and discharges to groundwater is regulated by the Environmental Permitting (England and Wales) (Amendment) Regulations 2011.

Licensing authority, CS licence application and terms

The NSTA, is the licensing and permitting authority for offshore carbon dioxide storage in an offshore UK controlled place or English controlled place (as set out in the Energy Act 2008 (the "**Act**")), approving and issuing CS Licence and storage permits.

Anyone who wishes to explore for or use a geological feature for the long-term storage of carbon dioxide in a UK offshore area must hold a CS Licence, pursuant to section 18 of the Act, issued by the NSTA. A storage permit may later be applied for and is required for the storage of carbon dioxide in a storage site with a view to its permanent disposal during the operational phase of the CS Licence. The CS Licence will expire at the end of the appraisal/initial term if an application for a storage permit is not made before that date or if the storage permit application is not approved.

In addition to a CS Licence, a Crown Lease from The Crown Estate ("**TCE**") or Crown Estate Scotland ("**CES**") is also required to undertake any intrusive exploration or appraisal (inclusive the drilling of a well) or storage activities for all offshore areas, including the territorial sea adjacent to Scotland, as the right to store gas (including carbon dioxide) in the offshore area is vested in the Crown by virtue of Section 1 of the Energy Act 2008. TCE and CES are statutory bodies which act on behalf of the Crown in its role as landowner within the area of the territorial sea and as owner of the sovereign rights of the UK seabed beyond territorial waters. TCE and CES operate as a commercial landowner under the provisions of the Crown Estate Act 1961.

Applications for CS Licences can only be made in response to a formal invitation from the NSTA. The NSTA will decide when and which areas (if any) to offer for application after considering a number of factors including, but not limited to: (i) matters to which the NSTA is to have regard under s. 8 Energy Act 2016; and (ii) input from the DESNZ's Offshore Petroleum Regulator for Environment and Decommissioning on the Strategic Environmental Assessment and other regulatory requirements. Should the NSTA decide to invite applications for CS Licences in respect of a particular area or areas, it will publish details on its website indicating the opening of a period for application and including any specific details on the application process, application fee and closing date and time.

The NSTA has discretion to decide whether to issue a CS Licence. The general terms and conditions will normally be set out in a CS Licence document ("**CS Licence Clauses**"). While the CS Licence Clauses show the general terms and conditions on which the NSTA is likely to award a CS Licence, pursuant to section 20 of the Act, the NSTA has the right to grant a CS Licence on the terms and conditions that it considers appropriate in any specific circumstances and in accordance with The Storage of Carbon Dioxide (Licensing etc.) Regulations 2010 (the "**Storage Regulations**") and other applicable law.

A CS Licence grants exclusive rights for the exploration and appraisal of potential storage sites, and storage (if a storage permit is granted in respect of a storage site) of carbon dioxide and the establishment or maintenance of installations for those purposes.

A CS Licence is required for the whole duration of a carbon storage development and covers three distinct periods, each consisting of multiple phases leading to the termination of the licence, and the post-transfer period:

1. Initial or Appraisal Term: the period during which exploration, appraisal, and project "assess" and "define" phase activities may be carried out to evaluate the potential for a storage project and/or an application for a storage permit is made. This term ends with either the grant of a storage permit (if applied for) or the expiry of the CS Licence either because no storage permit was applied for or because such application was refused.
2. Operational Term: the period beginning with the date on which the storage permit is granted and ending with the closure of the storage site.
3. Post-Closure Period: the period beginning immediately after the closure of the storage site and continuing until the CS Licence is terminated pursuant to The Storage of Carbon Dioxide (Termination of Licences) Regulations 2011.
4. Post-Transfer Period: the period after the licence is terminated and transferred to government, which involves a financial contribution to be paid by the Storage Operator to cover at least the anticipated cost of monitoring for a subsequent period of 30 years.

The duration of the Initial/Appraisal Term, per Regulation 4(1) of the Storage Regulations, may not exceed the time required to make an application for a storage permit. In practical terms, the Initial/Appraisal Term of the CS Licence will be the period to complete any work programme and/or, if appropriate, submit and have approved a storage permit application. Failure to submit the storage permit application before the end of the Initial/Appraisal Term, or a refusal of the application by the NSTA, will result in the expiry of the CS Licence.

Where a work programme has been included in the Appraisal term of a CS Licence, that work programme is binding and is the minimum amount of work that the licensee must carry out within the stipulated timeframes. Failure to deliver a work programme may result in the revocation of the CS Licence. A CS Licence may not be granted for the purpose of storing CO_2 in the water column (ocean storage). If a CS Licence is granted, the licensee will not be able to undertake any intrusive exploration work (including the drilling of a well) under the CS Licence without having the corresponding Crown lease from TCE/CES, as appropriate.

An application may be made by one or more companies ("**Applicant**"). The Applicant (where the Applicant is more than one company, each of those companies) must be able to demonstrate financial capability and meet the NSTA's criteria in this regard. Applicants must satisfy the NSTA that they have a place of business in the UK. Only Applicants who fully meet the NSTA's criteria and its assessment of "fitness" can be considered for award of a CS Licence. Where a CS Licence is held by more than one company, each company bears full joint and several liability for any obligations and commitments arising under the licence.

The Act gives the NSTA discretion in deciding whether to issue a CS Licence and, if so, to whom and on what conditions. However, under Regulation 5(A1) of the Offshore Petroleum Activities (Conservation of Habitats) Regulation 2001 (as amended), the NSTA cannot grant a CS Licence unless it first has the agreement of the Secretary of State. In deciding whether to award a CS Licence and if so, to whom, the NSTA considers whether the Applicant is able to effectively and appropriately undertake the appraisal, analysis and planning over the licenced area, and their capability to utilise the available resources to carry out carbon storage effectively and be in a position to submit a credible Storage Permit application. The NSTA will also take into account (amongst other matters) the need to collaborate with DESNZ and to assist the Secretary of State in meeting the government's net zero target. Where two or more Applicants have applied for the same storage site(s) and meet the NSTA criteria, a recommendation to award a CS Licence (or otherwise) will be made after evaluation of the applications and respective supporting information. The NSTA may suggest a combination between competing Applicants where their interests and expertise are complementary, and their applications cannot be separated geographically. However, it remains up to the Applicants to agree to the combination and its terms. If Applicants are unable or unwilling to do so, the NSTA will proceed to make a decision. There are occasions where the NSTA may decide that no application for award of a CS Licence would best serve the NSTA's general objective.

The NSTA will normally interview all Applicants before deciding whether to recommend an award. The main purposes of the interview are to enable the Applicant to present the technical rationale for the application, review the work already carried out and outline the proposed work programme associated with the Appraisal Term, and for the NSTA to assess the Applicant's technical capability and competence and ask questions and seek any clarifications, before final evaluation.

Storage Permit Application

From the issue of a CS Licence to a licensee submitting a Storage Permit Application, the Licensee must complete the work programme set out in its CS Licence. Before granting a storage permit, the NSTA must be satisfied of certain matters in accordance with Regulations 6 and 7 of the Storage Regulations. These include, but are not limited to:

1. the storage complex and surrounding area having been sufficiently characterised and assessed in accordance with the criteria set out in Annex I of the CCS Directive;
2. no part of the storage complex being beyond the territory of the United Kingdom;
3. under the proposed conditions of use of the storage site, there being no significant risk of leakage or of harm to the environment or human health;
4. the proposed operator being technically competent (including in the operation of environmental management systems), financially sound, and capable of being relied upon to carry out the functions of an operator; and
5. the proposed operator having in place an appropriate programme of professional and technical development and training.

In relation to CO_2 that is to be contained within the storage site, the following information has to be provided for in the Storage Permit Application: (i) the total quantity that is to be injected and stored; (ii) a proposed date on which injection is to commence; (iii) the prospective sources and transport methods; (iv) the composition of the CO_2 streams; (v) the proposed injection rates and pressures; and (vi) the proposed location of the injection facilities. The Licensee will also need to submit to the NSTA, for its approval, a monitoring plan, and a corrective measures plan. A provisional post-closure plan must also be drawn up in accordance with Regulation 13(1) of the Storage Regulations. As mentioned above, also for storage activities a Crown Lease from TCE or CES is required.

Latest developments

The NSTA launched the UK's first carbon storage licensing round, based on the process described above, on 14 June 2022 and closed on 13 September 2022, inviting applications for a number of areas across the UKCS including the Northern North Sea, Central North Sea, East Irish Sea and Southern North Sea. On 18 May 2023, the NSTA offered for award 20 carbon storage licences at offshore sites, expecting first CO_2 injection into subsurface stores within a decade. On 15 September 2023, the NSTA announced the list of companies which have accepted licences.

Norway

Summary of the regulatory regime and licence terms in Norway

The Norwegian Petroleum Act 1996 (the "**NPA**") governs oil and gas exploration and production activities in Norway. Under the NPA, the rights to the petroleum resources on the Norwegian continental shelf ("**NCS**") are vested in the Norwegian State. The regulatory regime for the Norwegian petroleum activities is based on a licensing system, under which companies can be granted exclusive rights to produce petroleum within a specified geographical area ("**Licences**"). The NPA is supplemented by further petroleum regulations, including regulations in respect of health, safety and the environment. The parent company of any licensee on the NCS is required to issue a parent company guarantee in favour of the Norwegian state covering any liability incurred when the affiliate company is acting as a licensee.

Licences supplement the requirements in the NPA and set out the terms and conditions for each individual Licence. The terms and conditions of each Licence are stipulated by the Ministry of Energy ("**MoE**"). Each Licence is usually initially awarded to a group of qualified companies for a period of up to 10 years. During this period, the licensees must complete the mandatory work obligations specified in the Licence. If these work obligations have been satisfied by the end of the initial term, the licensees are entitled to apply for an extension. The extension period is stipulated in each individual Licence and the extension period is typically up to 20–30 years.

As a condition for the award of a Licence, the licensees will have to enter into an agreement for petroleum activities that regulates their joint activities in the Licence. This agreement is in a non-negotiable format stipulated by the MoE. By means of this agreement, the licensees form an unincorporated joint venture. The participants in the joint venture are liable towards each other primarily on a *pro rata* basis but, secondarily jointly and severally liable for all obligations arising by virtue of the joint venture's activities. The joint venturers' liability towards third parties will depend on the applicable agreement with the third party or the applicable law for tort liability. The operator is only liable for losses sustained by the other participants in the joint venture to the extent such losses are a result of wilful misconduct or gross negligence by the management or supervisory personnel of the operator or any of its Affiliated companies.

The Licence and the Agreement on Petroleum Activities, read together with the NPA, generally include provisions dealing with matters such as: the exploration, appraisal and production periods; extension of the Licence; the licensees' obligations to carry out the work programme during the initial term to obtain approval for its development and production programme and to obtain consent before drilling any wells; a requirement for the appointment of the operator to be approved by the MoE; liability of licensees and the operator; restrictions on and government consent for assignment of a Licence or change of control of a licensee; and a power of revocation of the Licence in certain circumstances, including where there have been serious or repeated violations of the legislation or the terms of the Licence. Under the current legislation, licensees must submit a decommissioning plan to the MoE between two and five years before a Licence expires or is relinquished, or the use of a facility is terminated permanently.

Sellers of interests in producing Licences (i.e. asset transactions) retain secondary liability to the remaining licence partners and the state for potential defaults of future decommissioning costs by their buyer, limited to the after-tax value of such default amounts. From 2017, the MoE may also require parent companies divesting their Norwegian E&P affiliates (i.e. share sale transactions) to issue a guarantee for the benefit of the Norwegian state and affected licence partners for costs related to a potential future default of decommissioning costs by the divested affiliate.

The licensees have a strict liability for pollution damage caused by petroleum emanating from a well or a facility as well as reasonable expenses incurred to avoid or limit such damage or loss. The possibility for recourse against contractors is limited to cases where a contractor has caused or contributed to the damage by gross negligence or wilful misconduct.

Summary of the economic and fiscal regime in Norway

Taxation under the Petroleum Tax Act

The Norwegian petroleum tax system is based on the ordinary income tax rules for companies set out in the Tax Act 1999. However, these rules are superseded in important areas by the Norwegian Petroleum Tax Act 1975 ("**PTA**").

The exploration and production companies on the Norwegian continental shelf are subject to two income taxes: Special petroleum tax ("**SPT**") and ordinary company tax ("**CT**"). The SPT, which is levied on activities related to oil and gas exploration, development, production and upstream processing (E&P) and pipeline transportation, is the dominant income tax.

The Norwegian petroleum tax system was reformed in 2022. Following this reform, the most important petroleum tax features are:

(a) 71.8 per cent. SPT in addition to 22 per cent. CT.

(b) Deduction of a calculated CT in the SPT base, preserving a high aggregate tax rate of 78 per cent. and reducing the effective CT rate from 22 per cent. to 6.2 per cent.

(c) Direct SPT expensing of investments in production and processing facilities, production wells and pipelines.

(d) Annual cash refund of the tax value of SPT losses.

(e) Taxable income from oil sales stipulated at norm prices.

(f) Rapid phase-out of deduction for finance costs in the SPT base.

No capital gains taxation on transfers of production licence interests.

The petroleum tax applies on a company's total E&P income in Norway and is hence not based on ring-fenced taxation of separate oil and gas fields.

The Target Portfolio is in a full tax paying position in Norway, in respect of both offshore corporate tax and offshore special tax. As of 31 December 2023, the Target Portfolio had an onshore loss carry forward of NOK 2.2 billion.

Exploration costs

Exploration costs are immediately deductible both in the SPT and CT bases.

Capex

Production and processing facilities, oil and gas pipelines and production wells are the major fixed assets of an E&P company. In the petroleum tax system prior to the 2022 tax reform, such investments were subject to depreciation over six years, i.e. 16.67 per cent. per year straight line, both for SPT and CT purposes. The 2022 tax reform implemented direct expensing (i.e. 100 per cent. depreciation in the year the investment is incurred) of such investments in the SPT base. Depreciation of production and upstream processing facilities and pipelines in the CT base is still 16.67 per cent. per year straight line, starting with the year of investment.

In the petroleum tax system prior to the 2022 reform, net taxable SPT income was reduced by a special allowance called "uplift" to shelter normal CT profits from SPT. Uplift was generated by investments in E&P production, processing and pipeline facilities. The 2022 tax reform abolished uplift on investments incurred from 1 January 2022. However, uplift will still be generated on certain investment projects eligible for temporary tax relief introduced as a result of the oil price crisis in the spring of 2020. Such uplift is expected to continue for a period of several years, depending on the planned start-up of the relevant project. The uplift is deductible in the SPT base at a rate determined annually. For 2024, this rate is 12.4 per cent. of eligible investment costs incurred during the year.

Financial costs

Financial items, such as interest income and expenses and currency losses and gains, etc are taxable/deductible. However, PTA allocates only a portion of the taxpayer's finance costs related to interest bearing debt to the offshore tax regime (i.e. 78 per cent. tax rate). All other financial cost and all income items are allocated to the onshore tax regime (i.e. 22 per cent. tax rate).

When field facilities and pipeline capex is directly expensed for SPT purposes, the SPT value per year end will be zero for such assets. The effect is therefore that the formula will allocate nearly all net financial costs to the onshore tax regime when the pre-2022 capex has been fully depreciated.

General tax avoidance limitations, such as thin capitalisation reclassification of debt to equity or transfer pricing scrutiny of interest rates, apply to intra group borrowing or lending.

Tax losses

Prior to the 2022 tax reform, the PTA tax loss rules made the following deviations from general tax law:

(a) interest compensation on losses carried forward;

(b) right to transfer tax losses to third parties in the event of a sale of taxpayer's business or a merger;

(c) right to claim cash refund from the state of the nominal value of tax losses upon exit from E&P operations in Norway; and

(d) right to claim annual cash refunds from the state for tax losses attributable to exploration activities.

The 2022 tax reform changed this by introducing the annual refund of the tax value of SPT losses together with cancellation of all favourable treatment of CT losses. Tax losses are recorded separately for CT and SPT due to the different tax treatment.

All SPT losses, irrespective of cost source, will be settled in cash by the State as part of the annual tax assessments, normally in the fourth quarter of the year following the income year. The claim for refund may be pledged as security for loan financing. CT losses may be carried forward for an indefinite period, but no interest compensation applies.

The right to transfer tax losses to third parties in the event of business sales or mergers was repealed. The same applied to the cash refunds of annual exploration tax losses or uncovered tax loss at the final exit from the NCS.

Area Fees

Licensees are required to pay an area fee after the initial period, which is regarded as rent for the Licence area and is intended to ensure that awarded areas are explored efficiently. The fee is a deductible cost for CT and SPT purposes No royalty is charged for petroleum activities.

Agreements for Petroleum Activities in Norway

In Norway, the MoE awards a Licence with a condition that the prospective licensees enter into an agreement for petroleum activities in respect of such Licence. Harbour Energy's Norwegian subsidiary, Harbour Energy Norge AS, is therefore a party to an agreement for petroleum activities in respect of each licence on the NCS in which it has a participating interest. Such agreements have a standardised and non-negotiable format and consist of: (i) certain specific provisions stipulated by the MoE which set out, among other things, the voting rules in the Licence; and (ii) the standard JOA and a standard Joint Accounting Agreement ("**JAA**").

The agreement for petroleum activities, including the JOA, establishes certain joint venture principles and governs the relationship between the licensees on matters such as, amongst others, the day-to-day management of the activities, allocation of costs, decision-making processes and the operators' duties. A management committee is established as the supreme body of the Licence joint venture, in which all licensees are represented and have a vote pursuant to their participating interest, which is specifically determined for each Licence and corresponding JOA. The standard JAA regulates the accounting and financial aspects of the Licence joint venture.

Voting rules in JOAs for Norwegian Licences usually require that a combination of the number of licensees and the level of participating interest they represent must vote in favour, in order for a decision to be passed. A typical threshold is a majority of the participants and a majority of participating interests. Votes in Licences with only two parties require approval by both parties. There are, however, deviations from this majority rule. For example, decisions related to the relinquishment of acreage or the Licence require unanimity. Development decisions are subject to ordinary majority vote, but each licensee must in addition explicitly adhere to the agreed plan for development to be bound to participate.

If a hydrocarbon deposit extends over more than one production licence, the licensees must enter into a unitisation agreement. The unitisation agreements are typically based on terms similar to the JOA whilst the main commercial provisions, such as the scope of the unit, unit interest share and voting rules, are negotiated. Unitisation agreements create a new joint venture and a new management committee, consisting of all licensees in the respective production Licences over which the deposit extends. The petroleum produced is allocated to the unit partners in accordance with their unit interest share. Pursuant to some unit agreements, tract participation and unit interest may be re-determined from time to time on the basis of the underlying licensees' contribution to reserves, production or other agreed criteria and procedures. The economic interest in developments subject to unitisation agreements may therefore vary over time.

Use of existing production facilities and oil transportation pipelines are based on negotiated agreements. A regulatory framework is, however, in place in Norway to ensure the right to use available capacity and reasonable tariffs and cost coverage. If the owner plans to cease operation of the existing infrastructure, the tie-in agreements may, subject to certain terms, be terminated by the owner. If no agreement on third-party access is reached through negotiations by the owner and user groups, the MoE can impose a solution on the parties, including the commercial terms for third-party use, such as tariffs.

Summary of the regulatory regime and licence terms in Norway for offshore storage of CO_2

The Norwegian Storage Regulations 2014 (the "**Norwegian Storage Regulations**"), which relate to the exploitation of subsea reservoirs on the NCS for storage of CO_2 and relating to transportation of CO_2 on the NCS, governs offshore carbon CO_2 storage activities on the NCS. The right to store CO_2 on the NCS is vested in the Norwegian State and, similar as for petroleum activities, the regulatory regime for offshore carbon CO_2 storage is based on a licensing system, under which companies are granted rights to explore for and inject CO_2 within a specified geographical area and for a limited period. The State (King in Council) can in the first stage award an exploration licence that grants the licensees an exclusive right to explore for suitable CO_2 storages locations within the licence area. In order to develop and operate a reservoir for injection and storage of CO_2 a subsequent exploitation licence is required which grants an exclusive right for exploitation of a subsea reservoir for injection and storage of CO_2 in the area comprised by the licence. The licensees of an exploration licence in the relevant geographical location shall, on certain conditions, be preferred in the granting of such an exploitation licence (both licences hereinafter collectively referred to as the "**Storage Licence**").

The granting of a Storage Licence is discretionary and conditional upon, amongst other things, the licensees having the financial strength, technical and geological competence, and the reliability deemed necessary to operate and control the storage site. The applicant must also document its ability and willingness to provide a financial guarantee, which guarantee shall be valid and effective before CO_2 injection starts.

The MoE therein stipulates the terms and conditions for each individual licence and the licensees must fulfil the work commitments and milestones stipulated by the MoE within the given licence period. The exploitation licence is not in itself sufficient for the licensees to execute the CO_2 storage development project. Such development requires a Plan for Development and Operation approved by the MoE.

As a condition for the award of a Storage Licence, the licensees will have to enter into an agreement for storage activities regulating the joint activities under the Storage Licence (the "**Agreement for Storage Activities**"). This Agreement for Storage Activities contains appendices for a JOA and an accounting agreement, and is made on a non-negotiable format set forth by the MoE. A key feature of the Agreement for Storage Activities is that the licensees are liable to each other principally on a *pro rata* basis, and secondarily are jointly and severally liable for all obligations arising by virtue of the joint activities.

By award of a Storage Licence to two or more companies, the licensees together form an incorporated partnership regulated by the Norwegian Partnership Act 1985. The licensees must agree on a company agreement and register the partnership in the Norwegian Business Register. Contrary to the Agreement for Storage Activities there is no standardised company agreement.

There is a general comprehension in the industry that the Agreement for Storage Activities is not fully adapted to the Norwegian Partnership Act, and a general expectation that the Agreement for Storage Activities will be revised by the MoE, upon which revision the licensees may be required to replace the existing Agreement for Storage Activities. It is currently not publicly known if and when such a revision will be implemented.

The Storage Licence and the Agreement for Storage Activities, together with the Norwegian Storage Regulations and other applicable legislation, regulates the exploration, development, injection and decommission phase of the licensees' storage activities, including comprehensive regulation concerning the licensees' liability for pollution and leakage of CO_2 and their obligation to provide financial guarantees for such liability prior to start-up of injection. It should be noted that the legislative framework for offshore storage of CO_2 is still under development.

During the injection phase and the post-shutdown phase, the licensees are required to establish monitoring programs to track the behaviour and impact of stored CO_2, including potential leaks or migration. Following shutdown of a storage location, all obligations concerning monitoring and corrective measures in case of leakage shall be transferred to the State; some key conditions being that after a period of minimum 20 years, it is documented that the CO_2 injected will remain completely and permanently contained and that the injected CO_2 is behaving in stable manner, in accordance with technically modelled expectations. Before transfer of responsibility to the State take effect, the operator of the Storage Licence shall make a financial contribution available to the State to cover at least the anticipated monitoring expenses for a period of 30 years.

Indonesia

Summary of regulatory regime and licence terms in Indonesia

Oil and gas exploration and production activities in Indonesia are mainly regulated by the Oil and Gas Law 2001 and its subordinate legislation and regulations. In addition, various environmental and health and safety laws and regulations apply.

Harbour Energy's activities in Indonesia are governed by the production sharing contract ("**PSC**") regime. Harbour Energy is party to five PSCs with differing terms. Under the PSCs, the maximum total term is 30 years subject to a possible extension approved by the Minister of Energy and Mineral Resources ("**MEMR**"). The exploration period is six years subject to possible extensions approved by the MEMR through Special Task Force for Upstream Oil and Gas Business Activities Republic of Indonesia ("**SKKMIGAS**"). The development and production period begins from the date when the first plan of development is approved by MEMR and continues until the expiry of the PSC.

The PSCs deal with matters such as: (i) confirming that ownership of the natural resources remain vested in the Government of Indonesia until such natural resources have reached the delivery point; (ii) SKKMIGAS' approval rights with respect to work programs and/or budgets and subsequent plan of developments plus SKKMIGAS' rights to monitor the approved work programs and budgets and plan of developments; (iii) the capital and financial risks of the contractor; (iv) the exploration, development and production periods; (v) obligations to carry out the work programme during the initial term and to obtain approval for its development and production programme; (vi) the automatic transfer of assets acquired by the contractor in connection with the PSC to the Government of Indonesia if charged as petroleum costs upon import into Indonesia; (vii) the requirement to offer a regionally owned business a 10 per cent. participating interest in the PSC upon the approval of the first plan of development by the MEMR; (viii) restrictions on, and government consent for, assignment of participating interest in the PSC or change of control of a contractor or change of operatorship; and (ix) the power of SKKMIGAS to revoke the PSC where a party fails to remedy a major breach of the PSC.

MEMR Regulation 23/2021 deals with the expiry of current PSCs and contemplates three options for operation of a contract area following the expiry of the current PSC: (i) extension of the PSC granted to one or more of the existing PSC contractors; (ii) management of operations to be carried out by PT Pertamina (Persero); or (iii) joint operations between PT Pertamina (Persero) and one or more of the existing PSC contractors. If MEMR does not approve any of the options, the relevant contract area will be put up for offer through a bid process. Applications for the future rights to manage a contract area can be made by both PT Pertamina (Persero) or the current PSC contractors no earlier than 10 years before the expiry of the PSC and no later than two years before its expiry, with the exception for a contractor that already has a gas sales arrangement (in the form of a letter of intent, a head of agreement, an MOU or a gas sales agreement). The maximum term of any extension granted to the existing PSC contractors is 20 years. Evaluation of the current management of PSCs will be undertaken by the Directorate General of Oil & Gas ("**DGOG**") with final approval given by MEMR. Furthermore, the terms of the extension may include amendment to the previous PSC terms or the execution of a new PSC on new terms and conditions as determined by the MEMR funding procedure, to be included within a plan of development. Contractors are required to establish a decommissioning fund and start contributing to such decommissioning fund from first production. Such financial funding shall be made annually in accordance with the annual work programme and budget, and such funding costs are recoverable under cost recovery PSCs or calculated as a deduction to PSC contractors' taxable income under gross split PSCs. Furthermore, MEMR Regulation 15/2018 concerning abandonment and site restoration provides that all PSC contractors, regardless of their PSC's provisions, are required to set aside abandonment and site restoration funds and conduct the abandonment and site restoration activities upon expiry of their PSC, unless the Government appoints a new contractor (PT Pertamina (Persero) or PSC contractor) to manage the expired PSC. In case the Government appoints a new contractor, the obligation to conduct abandonment and site restoration obligations that have not been carried out prior to the expiry of a PSC shall be carried out by PT Pertamina (Persero) and/or other PSC contractors under the new or extended PSC, who may utilise abandonment and site restoration funds that were deposited by the previous PSC contractor under the expired PSC.

Summary of economic and fiscal regime in Indonesia

The contractual structures in Indonesia are either production-sharing or gross-splits. Each asset is the subject of an individual contract with a unique formula for calculating the production split between the Indonesian Government and the contractor.

In cases of production-sharing some PSCs require first tranche petroleum ("**FTP**"), up to 20 per cent. of the production each year (before any deduction for cost recovery), to be allocated either to the Government of Indonesia or between the Government of Indonesia and the contractor based on the profit allocation percentage split prescribed in the PSC. Under certain PSCs, a share of petroleum production in each year up to a maximum percentage of production ("**Cost Recovery Petroleum**") after FTP is allocated to cover certain permitted petroleum costs incurred by the contractors. Petroleum costs which are not recovered from the allocation of Cost Recovery Petroleum in a year may be carried forward to the next succeeding years without interest and time limit until fully recovered. Only petroleum costs defined in the relevant PSC and Government Regulation are eligible for cost recovery. Profit petroleum (being net production after the deduction of FTP and Cost Recovery Petroleum) is allocated between the Government of Indonesia and contractors in accordance with the production split as prescribed in the PSC. A bonus or commission is paid as a lump sum by the contractor on signing the PSC, and upon cumulative production reaching certain thresholds.

In cases of gross-splits the gross revenue is split between the Government of Indonesia and the contractor based on the profit allocation percentage split prescribed in the contract. The contractor bears all of the costs.

The income tax rate applicable to both production-sharing and gross-split contracts are the rate prevailing when the PSC was signed, and rates range from 25 per cent. to 45 per cent. The after tax profits of a PSC contractor are subject to a further tax of 20 per cent. on branch profits remittances, which may be reduced by a tax treaty. Some PSCs include tax stabilisation clauses. The Oil and Gas Law 2001 and subsequent Government implementing regulations require a PSC contractor to supply up to 25 per cent. of its portion of hydrocarbon allocation to the domestic market at a defined percentage market price depending on the contract. Contractors are required to give preference to Indonesian goods and services in accordance with competitive standards. The specific percentage of local content is varied upon the types of goods or services rendered.

Agreements for Petroleum Activities in Indonesia

In Indonesia, all oil and gas activities fall under the remit of the MEMR, which implements and regulates the country's energy policy. The MEMR is divided into several directorates, with the DGOG responsible for all oil and gas industry activities.

Exploration and exploitation (upstream) activities are regulated through a joint cooperation contract in the form of a PSC between the corporate entity and SKKMIGAS, which acts on behalf of the Government of Indonesia. DGOG manages the tender process for a working area. A PSC for a working area will be executed by SKKMIGAS and approved by the Minister. SKKMIGAS maintains exclusive control of petroleum operation management including approving the contractor's budget, work programmes, manpower plan, expenditure scheme and procurement of good and services.

Indonesia currently utilises two types of PSCs: gross split PSCs and cost recovery PSCs. Gross split PSCs require gross production to be shared between SKKMIGAS and the contractor and therefore the contractor cannot recover its costs. Conversely the cost recovery PSCs allow a contractor to recover a portion of its costs after FTP has initially been shared with the government, the remaining profit oil and gas after cost recovery is then shared between the contractor and the government. Unlike the cost recovery PSCs, through which SKKMIGAS is able to exert a tight control on work programme and budget, under gross split PSCs, SKKMIGAS retains control over the work programme but has no control over the budget and less control over the contracting of services. Although the two types of PSCs operate differently, the ultimate split in production under both models is similar.

Both cost recovery PSCs and gross split PSCs have: (i) a duration of 30 years with a possible extension of 20 years; (ii) a 10 per cent. (local) state participation requirement; (iii) a local content obligation; and (iv) a domestic market obligation. Harbour Energy's subsidiaries, Premier Oil Natuna Sea B.V., Premier Oil Tuna B.V., Premier Oil Andaman Limited, Premier Oil South Andaman Limited and Premier Oil Andaman I Limited, each of which is party to both cost recovery PSCs and gross split PSCs with respect to the assets of Harbour Energy in Indonesia.

Mexico

Summary of regulatory regime and licence terms in Mexico

The Mexican oil and gas industry opened to private investors in 2014. Following these reforms, exploration and extraction contracts were tendered and entered into with contractors by the National Hydrocarbon Commission (the "**CNH**"). The Government placed a moratorium on the tender process in 2018. For those tenders carried out prior to the moratorium, the Ministry of Energy, with the opinion of CNH and SHCP (Ministry of Finance and Public Credit) determined the type of contract offered in each bid round, with contractual forms including profit sharing contracts, licences, services and PSCs. Harbour Energy is party to four PSCs and the Target Portfolio is party to seven PSCs and four licenses.

Under each PSC or license ("**E&P Contracts**"), a percentage of production is allocated to a contractor who assumes all costs and risks related to the activities. The initial term of an E&P Contract ranges from twenty-five to thirty-five years (based on executed E&P Contracts) from the effective date which is extendable, at the request of the contractor, for two additional periods ranging from five to ten years, subject to the approval of the CNH. Regarding E&P Contracts which entitles the contractor to conduct exploration activities, the initial exploration period is four years from the effective date, with the possibility of having one or two additional exploration periods, each of between two to six additional contractual years following the termination of the initial exploration period (depending on the terms of the relevant E&P Contract). In the event of a discovery during the initial exploration period, or any additional exploration period, the contractor may submit an appraisal programme for the evaluation of the relevant discovery for a period as set out in the E&P Contract. In certain circumstances, this period can be extended with the approval of CNH. The development and production period begins after the declaration of commercial discovery and its duration extends to the rest of the term of the E&P Contract. The E&P Contracts deal with matters such as: (i) the exploration, appraisal, development and production periods; (ii) extension of the E&P Contract; (iii) the contractor's obligation to carry out the minimum work commitment during the exploration period; (iv) the procedure to obtain approval for its production programme; (v) the submission of annual work programmes to the CNH; (vi) the submission of budgets to the CNH, with respect to PSCs, and the eligibility of costs for costs recovery; (vii) the automatic transfer to the Mexican Government of materials provided or acquired by the contractor in connection with the operations upon termination of the PSC; (viii) payment and, with respect to PSCs, production split procedures; (ix) the liability of contractors; and (x) termination provisions.

Contractors are obliged to carry out all operations related to abandonment of the contract area. The development plan and each work programme submitted to the CNH must provide for provisions related to abandonment. Contractors are obliged to set up an investment trust as an abandonment fund, which depending on the terms of the E&P Contract may be under the control of the contractor or under the joint control of the contractor and the CNH at a Mexican financial institution authorised by, or with the favourable opinion of, the CNH.

There is a requirement that exploration and production of hydrocarbons activities in Mexico should reach a minimum percentage of local content in stages (exploration and development period) and should be increased progressively up to 38 per cent. in 2025. For these purposes, local content refers to the amount of locally produced materials, labour, training personnel, local and regional infrastructure, goods and services rendered to the oil industry.

Summary of economic and fiscal regime in Mexico

The fiscal regime in Mexico for the hydrocarbon sector is set out in the Hydrocarbons Revenue Law. The Mexican Petroleum Fund is required to compute and pay consideration to the Mexican State and the contractor when regular commercial production starts and delivery of hydrocarbon exists at the measurement points.

Consideration will be paid based on the information received from the contractor, the National Hydrocarbons Commission, SHCP (i.e. Ministry of Finance and Public Credit) and the computation performed by the Mexican Petroleum Fund in accordance with the terms of the relevant.

E&P Contract. E&P Contracts must pay the fees during the exploration phase and, once in production, royalties, and: (i) under a license, a consideration to be determined considering the value of hydrocarbons, or (ii) under a PSC, the operating profit. The PSCs use a formula for calculating the operating profit based on subtracting royalties and Cost Recovery Oil (as defined below) from the actual crude oil output. The relevant PSC indicates explicitly the formula for calculating the percentage of the operating profit for each period allocated to the Mexican Government, the remainder being allocated to the relevant contractor. Under the PSCs, a share of net petroleum production in each period to a maximum percentage of net production ("**Cost Recovery Oil**") is allocated to cover certain permitted petroleum costs incurred by the contractors.

Contractors are required to pay royalties based on the gross income derived from production, calculated by applying a formula to the contractual spot price of hydrocarbons produced in a given month. The mechanism to determine the royalties is adjusted each year in the month of January in accordance with the United States Consumer Price Index calculated by the US Bureau of Labour Statistics. Profit petroleum (being net production after the deduction of Cost Recovery Oil) is allocated between the Mexican Government and contractors after deductions for royalties, whilst the profit petroleum owed to the Mexican Government is subject to an adjustment mechanism contained within the PSCs which is designed to capture additional profits for the Mexican Government, based on the monthly internal rate of return of contractors. Additionally, contractors are required to pay a fee for the exploration phase at a rate charged per square kilometre assigned to the contractor, for the contract area that does not have a development plan approved by CNH, and a further monthly tax on exploration and extraction of hydrocarbon activities at rates charged per square kilometre assigned to the contractor. The corporate income tax rate is 30 per cent.

Employers are required to distribute 10 per cent. of their pre-tax profit each year among all employees, with certain exceptions (namely, board members, directors, administrators and general managers, as well as temporary employees who worked less than 60 days). The amount of profit sharing will be limited to the greater of: (a) three months of the relevant employee's salary or (b) the average of the profit sharing received during the last three years (whichever is most favourable for the employee).

Germany

In Germany, the exploration and production of oil and gas is generally governed by the German Federal Mining Act 1980 (the "**GFMA**"). The GFMA is federal law, but executed by the mining authorities of the 16 Federal States and supplemented by special regulations of the Federal States.

The exploration and production of public mineral resources, such as hydrocarbons, require an exploration licence or production licence, respectively, and such licences are issued by the mining authority of the Federal State in whose territory the resources are located. The production of such public mineral resources is subject to royalties that are set by the Federal States. Such exploration and production licences can only be granted to an individual person, a legal entity or a commercial partnership. In Germany, onshore licences are commonly held by one partner of a joint venture.

Production licences can be granted for a period of time that is reasonable for the exploitation of the deposit and generally not exceeding 50 years and production licences can be prolonged if production is ongoing until the expected depletion of the deposit. Exploration licences can be granted for a period of up to five years and may be prolonged by three years if the exploration field has not yet been properly explored. Further extensions are possible if the aforementioned requirements are met.

In general, exploration and production activities in Germany may only be executed in line with operational plans (*Betriebsplänen*), in which the respective activities, as approved by the competent mining authority, are described in detail. The operator has to prepare such operational plans and to file them with the respective mining authority for approval. The mining authority's approval of the operational plan is the operating permit (*Betriebsplanzulassung*) required for exploration and production activities in Germany. Additional specific permits by different governmental bodies may be required for specific activities and installations.

The operator is responsible for the execution of the operational plan, and for the compliance of exploration and production operations with the operating permit and applicable laws and regulations. The operator is the legal entity that is responsible to carry out the exploration and/or production activities or the entity that controls another legal entity's execution of exploration and/or production activities at its own account with decisive influence on the operations. In practice, one of the joint venture partners is appointed as operator. The operator need not be the entity that holds the exploration or production licence nor the entity with the highest participation in the joint venture. Whilst the operator may make use of contractors for the execution of all or part of the operations, the operator is responsible for the proper organisation and implementation of proper processes in respect of the operations and remains liable to the mining authority for compliance with all legal requirements in respect of the operations.

The consortium agreements govern the relationship between the joint venture partners and form the basis for day-to-day management of the activities among these partners, including particularly the allocation of costs, decision making processes and the determination of the operator and its duties. Produced hydrocarbons are allocated to the joint venture partners in accordance with their shares in the consortium agreement.

Summary of the regulatory regime and licence terms in Germany for storage of CO_2

In Germany, the legal framework for carbon storage is mainly laid down in the Federal Carbon Dioxide Storage Act ("**KSpG**").

Based on the two-step-approach of the CCS Directive, it provides for two different kinds of permits: An exploration permit and a storage permit. The requirements for the application and the procedural steps to obtain a permit are laid down in detail in the KSpG. Generally, the legal and procedural requirements to obtain an exploration permit are fewer compared to the ones applicable for a storage permit. Obtaining an exploration permit requires engagement and consulting with relevant members of the public to some extent whereas the procedure to obtain a storage permit is strongly formalized (*Planfeststellungsverfahren*, Plan Approval Procedure) including extensive public participation. For the time being, the KSpG does not allow for CCS in Germany.

The KSpG does not provide for a tender process and permits for the exploration of a certain site are granted based on applications. If there are competing applications for the same site, the application that fulfils the most amount of legal requirements will be considered and if both applications are equally compliant, the first complete application will be considered and the successful applicant will receive the exploration permit.

The permits will be granted to one specific entity. This might be one company or a project consortium involving more companies founded for the purpose of constituting a project proponent. German law does not require a JOA.

The KSpG lays down further legal requirements for CCS projects. Like the CCS Directive, it concentrates on the phases of operation, post-closure and post-transfer of responsibility. The requirements for the operations of a storage site will typically be set out in the relevant permit and compliance will be monitored by the supervisory authority. Closure is subject to the receipt of an individual permit which will be granted subject to conditions, including a closure and post-closure monitoring program.

During injection and until transfer of responsibility, sufficient financial security must be presented to ensure that all obligations including closure and post-closure-monitoring can be met. Such security may be in the form of insurance or bank guarantees (*Bürgschaft*) in certain circumstances. The competent authority determines the means of financial security (e.g. by insurance or guarantee), how to substantiate it and when it must be submitted. Different means of financial security may be combined.

Responsibility may be transferred 40 years after site closure. In this regard, the CCS Directive is less strict; it allows for the responsibility to be transferred after 20 years. In Germany, the competent authority is empowered to decide the terms of a transfer. An earlier transfer of responsibility is only possible upon an individual decision of the competent authority if all requirements are met. Monitoring continues post-transfer but it may be reduced to a level which allows for detection of leakages or significant irregularities. For the transfer of responsibility, onerous requirements apply, including presentation of evidence of long-term safety and a financial contribution from the operator with respect to post-transfer obligations, which shall cover at least the anticipated cost of monitoring for a period of 30 years after the transfer of responsibility.

Latest developments

On 26 February 2024, the German Government launched the milestones of its future Carbon Management Strategy, including a draft new KSpG ('Gesetz zur dauerhaften Speicherung und zum Transport von Kohlendioxid', Kohlendioxid-Speicherungs- und -Transportgesetz, KSpTG). According to the draft, CCS projects in the German Exclusive Economic Zone will be possible outside marine protected areas. The application process for exploration as well as storage permits shall remain as outlined above. The competent authorities will be based in the German Federal States. Germany endeavours to store first CO_2 by 2030. Moreover, the draft provides for a robust legal framework for CO_2 transport, including considerable permit-acceleration measures. The new law is expected to enter into force in the third quarter of 2024. The focus of the Carbon Management Strategy is mainly on industries with hard-to-abate emissions. The application of CCUS shall be possible for other industry processes, though, as long as electrification or switch to hydrogen is not possible in a cost-efficient way in the foreseeable future. CCUS may also be deployed for gas-fired power plants but without state support. Coal-fired power plants are not granted access to CO_2 pipelines. Germany will ratify the relevant amendment of the London Protocol to allow for offshore cross-border transport.

Egypt

The Egyptian assets of the Target Portfolio are governed by concession agreements (which have the force of law), between it, the Arab Republic of Egypt and the Egyptian General Petroleum Corporation ("**EGPC**") or the Egyptian Natural Gas Holding Company ("**EGAS**"), as applicable. EGPC or EGAS, as applicable, controls and performs executive activities in many aspects of the Egyptian hydrocarbon industry, including exploration, production, refining, transportation and marketing.

The PSCs govern, among other things, the operation of the asset following commercial discovery, recovery of operating costs and expenses and production sharing between the Group and EGPC or EGAS, as applicable. Usually, the concession agreement contains the definitions, the grant of rights, the licence holder's obligations, time frames and relinquishment rules during the initial exploration period and its extension, the applicable rules in case of a commercial discovery and the production sharing terms during the production phase. Subject to these agreements, the licensee funds all costs and expenses in respect of exploration, development and related operations but is entitled to recover these costs and expenses through production up to an annual cost recovery cap of all hydrocarbons produced. These agreements also govern the proportion of profit production split between the Group and EGPC and EGAS. The West Nile Delta is a unique fiscal regime where there is no cost recovery mechanism, but rather a price review to address cost overruns. Under this regime, the contractor may request a review to increase the gas price if the actual capex required to deliver the development plan of the underlying reserves exceeds the agreed estimates. In addition, title to all gas and condensate of the initial reserves vests in the contractor. However, incremental reserves and other reserves to be discovered are subject to the standard production sharing mechanism as per the respective shares provided for therein.

However, economically the costs and expenses in respect of exploration, development and operations are reflected in the gas price and production entitlement agreed with EGPC. The WND gas is priced based on a formula provided for in the PSC which factors in Henry Hub, Brent and NBP price indices with a cap and a floor.

Argentina

The National Law on Hydrocarbons is the primary law governing the hydrocarbon industry, which sets forth two types of licences granted by the provinces, or, in the case of offshore blocks under Federal jurisdiction, the Federal Government: (i) exploration permits and (ii) exploitation concessions.

Exploration permits can be granted for periods of up to: (i) six years for conventional exploration onshore; (ii) eight years for non-conventional exploration onshore; and (iii) eight years for offshore exploration. Extensions for up to five years are admissible in all types of exploration. The holder of an exploration permit is entitled to an exploration concession for the development and production of hydrocarbons discovered in the area of the permit, and to a transport concession enabling the concession operator to exploit the area.

With respect to exploitation concessions, the terms are: (i) 25 years for conventional hydrocarbon exploitation; (ii) 35 years for unconventional hydrocarbon exploitation, a term which includes a "pilot plan" period of up to five years, to be defined by the concession operator in order to determine the marketability of the field; and (iii) 30 years for the exploitation of the continental shelf and the territorial sea. A concession grants the holder the exclusive right to exploit oil and natural gas within a defined concession area. The concession gives rise to the duty to pay royalties on the production, and an annual fee over the area being exploited, per square kilometre of the concession or permit area. A concession operator has the right to apply for successive extensions, each for the maximum term of ten years. The granting authority may determine, for the extension of the exploitation concession, the payment of an "extension bonus".

In Argentina, oil and gas exploration and exploitation activities are normally operated through joint venture agreements. Under Argentine law, these agreements are framed as a temporary union of companies (the "**UT**") Regulated by Articles 1463 et. seq. of the Argentine Civil and Commercial Code. The UT does not constitute a separate legal entity with respect to the parties that comprise it, except with respect to accounting and tax matters. The UT must be registered before the Public Registry of Commerce and needs to appoint a representative to establish a domicile and to constitute a minimum operative fund for the purpose of registration. The UT governs the relationship between the parties and forms the basis for day-to-day management of the activities, including allocation of costs, decision making processes and the operators' duties. A management committee is established as the supreme body of the UT, in which all parties are represented, and have a vote pursuant to their participating interest.

Companies incorporated in Argentina are subject to income tax on their worldwide income. Any profits, including capital gains, are taxable at a rate ranging from 25 per cent. to 35 per cent. Tax losses may be carried forward for five tax periods. The dividend withholding tax rate is 7 per cent. for profits accrued in fiscal years started from 1 January 2018. At federal level, other significant taxes are value-added tax, tax on financial transactions, social security taxes and tax on personal assets and export and import duties. At the local level, companies are subject to turnover tax, amongst others. Applicable turnover tax rates for production of oil and gas in Neuquén and Tierra del Fuego is 3 per cent. Moreover, companies that hold producing oil and gas licences in Argentina are subject to a royalty regime at rates ranging between 12 per cent. to 18 per cent. The Fénix project is subject to the special federal tax regime set forth under Law 19.640, which includes, amongst others, income tax exemption and certain benefits on value added tax. The special regime has been granted pursuant to Resolution N° 630/2022 within the framework of Decree N° 1049/2018.

Denmark

In recent years, a number of political agreements have been concluded concerning CCS, and new legislation has been adopted, creating an improved regulatory framework for the deployment of CCS in Denmark also implementing the CCS Directive.

The Subsoil Act 2019 (the "**Subsoil Act**") provides the legal framework for onshore and offshore CO_2 exploration and storage licences. Chapter 6A of the Subsoil Act stipulates special conditions regarding geological storage and piped transport of CO_2, such as maintaining a register, setting up and applying monitoring programme, criteria regarding the quality of the CO_2 stream, closure of CO_2 storage and post-closure plans and transfer of all legal obligations to the Minister of Climate, Energy and Utilities (the "**Minister**").

Act no. 803 of 7/6 2022 amending the Subsoil Act introduces a fast track process regarding geological storage of CO_2 below 0.1 megatonnes for research, development or testing of new products and processes and ensures state participation in CO_2 storage permits.

Executive Order 1425/2016 on Geological Storage of CO_2 specifies the details regarding: licence application requirements including financial security, the operations of CO_2 storage sites, criteria regarding quantity, properties and composition of the CO_2 flow, requirements regarding monitoring, reporting and supervision of the storage site and conditions for closure and transfer of responsibilities and liabilities of the storage site. The executive order also outlines the special conditions regarding consultation and notification of the European Commission regarding draft storage permits and withdrawal of storage permits. Chapter 11 stipulates principles for negotiating access to CO_2 transport networks and CO_2 storage sites.

On 15 August 2022, the Danish Energy Agency published the first tender and the conditions for applying for licences for geological storage of CO_2 with a deadline for applications to be received no later than 1 October

2022. Following this first tender process, applications can now be submitted to the Danish Energy Agency every year in the period of 15 August to 1 October of the same year.

On 13 December 2023, the onshore licence round was announced and included five licences with an application date on 24 January 2024. The state-owned entity Nordsøfonden will participate in all awarded licences with a 20 per cent. owner share. The Danish authorities have announced that award of licences will take place before summer 2024. The award includes permission to start exploration of the given licence area. Expected exploration periods granted are six years followed by a 30-year storage licence.

On 28 February 2024, the Minister presented a bill on CO_2 pipelines to the Danish parliament. The purpose of the bill is to implement parts of the 'Agreement on strengthened framework conditions for CCS in Denmark from September 2023', where it was agreed, amongst other things, that a new main law on piped transport of CO_2 should be prepared. The proposal entails creating a clear and uniform framework for the establishment and operation of a comprehensive CO_2 infrastructure that will support the realisation of Denmark's CO_2 reduction targets. The bill proposes to gather all Danish regulation on CO_2 pipelines including third-party access and the legal basis for expropriation. The law is intended to enter into force from 1 July 2024.

Applications can be submitted by groups of companies as well as individual companies. Applications from groups must indicate which company will function as the operator. The operator must possess the necessary technical and financial capacity. In this connection, the Danish Energy Agency involves the Danish Working Environment Authority to assess the operator's qualifications, including capacity to meet safety and environmental requirements stipulated in the Danish Offshore Safety Act. In the event of disagreement about the choice of operator among the applying companies, the Minister may appoint the operator on the basis of the applicants' qualifications.

It will also be possible for a licensee of an existing oil or gas field to apply for a CO_2 storage licence provided that this activity does not become a means of extracting more oil and gas than without the CO_2 storage activity.

The decision to award a licence is at the discretion of the Minister after having presented a report to the Climate, Energy and Utilities Committee of the Danish Parliament explaining which licences the Minister intends to issue.

Award of licences is conditional upon the applicant having the required technical and financial capacity to operate geological storage of CO_2 in accordance with the Danish Subsoil Act and Executive Order 1425/2016. The Danish Energy Agency reviews the applications and evaluates the technical and financial capacity as well as the technical content of the work programs presented by the companies in their applications and issues a recommendation to the Minister. The technical and financial capacity requirements can be characterised as minimum requirements to be met in order to be considered for a licence at all, whereas the evaluation of the applicants' work programmes will be the determining criteria if there are several applicants for the same area.

The licences for geological storage of CO_2 give the companies exclusive rights to a defined geographic area of the North Sea for the purpose of carrying out exploration activities defined in the detailed licence work program with the aim of demonstrating the presence of suitable geological structures to store CO_2. If such suitable structures are detected and the work program is satisfactorily implemented, the licence holder will have a right to extend the licence in order to carry out storage activities for up to 30 years (the storage phase) following issuance of an application for approval of a plan for the storage activities containing, amongst others, the organisation of operations and the facilities for its use. The licences thus basically follow the system used for Danish hydrocarbon licences, where the licence is divided into two phases.

A licence for the storage of CO_2 does not formally preclude awarding licences for other use. Possible interfaces with other licences are considered case by case prior to a licence award.

Nordsøfonden will represent the interest of the Danish state and participate with a share of 20 per cent. in each of the CO_2 licences.

A standard licence (the so-called model licence) has been prepared, which is used in connection with the tenders licence award. A standard JOA and standard Accounting Procedures are also available and part of the tender documentation and conditions. The Danish Energy Agency recognises that amendments to these standards can be necessary due to specific circumstances. Any amendments must however be approved by the Danish Energy Agency.

The standard JOA stipulates that an abandonment agreement must be entered into between the joint venture parties prior to submission of a development plan, providing a framework in relation to the decommissioning of any joint property and ensuring that each party in relation to its percentage licence interest shall provide the security required in respect of its liability to contribute to abandonment costs, including monitoring cost for the benefit of the other joint venture parties. The abandonment agreement is subject to approval by the Danish Energy Agency. The security must be provided no later than 20 working days after said party is deemed to participate in a development of a CO_2 storage.

In order to ensure that the licensee fulfils all obligations and liabilities related to the licence (including abandonment) each participant shall, within 30 days after the licence award, provide security to the Danish State equalling the amount and nature of the obligations as may be approved by the Danish Energy Agency. For licensees who are a subsidiary or a branch of a subsidiary, a guarantee from the ultimate parent company is generally required. The Danish Energy Agency has prepared a model parent company guarantee for all E&P activities in Denmark and prefers to use this standard for CO_2 licences as well.

The Netherlands

In the Netherlands, the Dutch Mining Act (the "**Dutch Mining Act**") provides the legal framework for the exploration, production, and storage of minerals and other substances, including CO_2. With respect to CO_2, the Dutch Mining Act covers activities relating to the exploration for, injection and storage in, monitoring of and closure of CO_2 storage complexes. The Dutch Mining Act applies to both onshore and offshore activities. Details for the implementation of the Dutch Mining Act are specified in the Mining Decree and Mining Regulation.

Any party wishing to engage in either the exploration for a storage complex or the permanent storage of CO_2 must obtain a licence under the Dutch Mining Act. These licences are granted by and at the discretion of the Minister of Economic Affairs and Climate, and a grant is based on complying with certain financial, technical, organisational, safety and environmental requirements as specified in the Dutch Mining Act. The Minister of Economic Affairs and Climate has discretionary powers to add conditions precedent or subsequent to a licence and a licence can be withdrawn should the licensee fail to comply with any conditions and also if leakages occur or financial security provided in relation to the licence appears to be insufficient.

The Dutch Mining Act emphasises the need to evaluate potential storage sites based on geological suitability, storage capacity and the absence of significant risks to human health and the environment. Ongoing monitoring and reporting are crucial aspects of CO_2 storage under the Dutch Mining Act. A licensee is required to establish monitoring programs to track the behaviour and impact of stored CO_2, including potential leaks or migration. Regular reporting to the competent authorities is mandatory to demonstrate compliance with safety and environmental standards. Furthermore, the Dutch Mining Act requires a licensee to post financial security for the cost of abandonment and removal of storage facilities.

PART V
CAPITALISATION AND INDEBTEDNESS STATEMENT

Harbour Energy

The following tables show the capitalisation of Harbour Energy as at 31 March 2024 and the indebtedness of Harbour Energy as at 31 March 2024.

Capitalisation

	As at 31 March 2024
	($ million)
Current debt (including current portion of non-current debt)	
Guaranteed	—
Secured	—
Unguaranteed/Unsecured(1)	238
Total current debt	**238**
Non-current debt (excluding current portion of non-current debt)	
Guaranteed	—
Secured	—
Unguaranteed/Unsecured(2)	1,038
Total non-current debt	**1,038**
Shareholders' equity	
Share capital	171
Other reserves(3)	256
Total shareholders' equity	**427**

Indebtedness

	As at 31 March 2024
	($ million)
Cash and cash equivalents(4)	360
Other current financial assets	—
Liquidity	**360**
Current financial debt(1)	(238)
Current other debt	—
Current financial indebtedness	**(238)**
Net current liquidity	**122**
Non-current financial debt(2)	(1,038)
Non-current other debt	—
Non-current financial indebtedness	**(1,038)**
Total financial indebtedness	**(916)**

Notes

(1) Unguaranteed/Unsecured current debt comprises the interest payable on the bond of $13 million as well as current lease liabilities of $225 million.

(2) Unguaranteed/Unsecured non-current financial debt comprises the bond principal of $500 million net of unamortised fees of $6 million, as well as non-current lease liabilities of $544 million.

(3) Other reserves comprise the merger reserve, capital redemption reserve, cash flow hedge reserve, cost of hedging reserve and currency translation reserve.

(4) Cash and cash equivalents comprise both short-term fixed deposits and cash balances that earn interest at floating rates based on daily bank deposit rates plus joint venture account balances.

(5) The lease liability balances included within current and non-current financial debt exclude Vietnam lease liabilities of $91 million classified as assets held for sale.

As of 31 March 2024, Harbour Energy had no indirect indebtedness and no contingent indebtedness.

There has been no material change in the capitalisation or indebtedness of Harbour Energy since 31 March 2024.

Target Portfolio

The following tables show the capitalisation of the Target Portfolio as at 31 March 2024 and the indebtedness of the Target Portfolio as at 31 March 2024. The information in the tables has been extracted from the Wintershall Dea consolidation schedules and adjusted to align with the Company's accounting policies and presentational currency to represent the Target Portfolio's capitalisation and indebtedness (the "**Unaudited Combined Carve Out**").

Capitalisation

	As at 31 March 2024 ($ million)
Current debt (including current portion of non-current debt)	
Guaranteed[(1)]	40
Secured	—
Unguaranteed/Unsecured	—
Total current debt	**40**
Non-current debt (excluding current portion of non-current debt)	
Guaranteed[(2)]	4,878
Secured	—
Unguaranteed/Unsecured	—
Total non-current debt	**4,878**
Shareholders' equity[(3)]	
Share capital	—
Share premium	—
Other reserves	—
Retained earnings	—
Total shareholders' equity	**—**

Notes

(1) Guaranteed current debt comprises the interest payable on the Senior Notes and Subordinated Notes as extracted in the Unaudited Combined Carve Out as at 31 March 2024.

(2) Guaranteed non-current financial debt comprises the outstanding Senior Notes and the Subordinated Notes balances as set out in the Unaudited Combined Carve Out as at 31 March 2024. In the consolidated group financial statements of Wintershall Dea the Subordinated Notes, as included in the Target Portfolio, are classified as equity. For the purposes of the historical financial information relating to the Target Portfolio as set out in Part IX (Historical Financial Information relating to the Target Portfolio), the Subordinated Notes have been classified as liabilities in line with IAS 32 Financial Instruments on the basis that the guarantor of the Subordinated Notes is Wintershall Dea (outside the Target Portfolio), and therefore the cash flows are outside the control of the entities within the perimeter. Going forward, it is probable that the Subordinated Notes will be treated as equity within the consolidated group financial statements of the Company because on 21 February 2024 the bondholders approved a change in guarantor from Wintershall Dea to the Company which will be effective upon Completion. As at 31 March 2024, the value of the Senior Notes and the Subordinated Notes is $3.2 billion and $1.7 billion, respectively.

(3) The Target Portfolio is not a legal group for the purposes of consolidated financial statement reporting in accordance with IFRS 10 "Consolidated Financial Statements". The Target Portfolio aggregation data does not disclose any shareholders equity as well as ordinary share capital, legal reserves and other reserves and the balances have not been calculated for the purposes of the capitalisation of the Target Portfolio as at 31 March 2024.

Indebtedness

	As at 31 March 2024
	($ million)
Cash and cash equivalents(4)	616
Other current financial assets	0
Liquidity	**616**
Current financial debt(5)	40
Current other debt	0
Current financial indebtedness	**40**
Net current financial indebtedness	**576**
Non-current financial debt(6)	4,878
Non-current other debt	—
Non-current financial indebtedness	**4,878**
Total financial indebtedness(7)	**(4,302)**

Notes

(4) Cash and cash equivalents comprises both short-term fixed deposits and cash balances that earn interest at floating rates based on daily bank deposit rates. The Target Portfolio only deposits cash with major banks of high-quality credit standing. Restricted cash and cash equivalents include amounts in Egypt and Argentina that are subject to foreign currency transfer and legal restrictions. The restricted cash balance at 31 March 2024 is $137 million.

(5) Current portion of non-current financial debt comprises the interest payable on the Senior Notes and Subordinated Notes as set out in the Unaudited Combined Carve Out as at 31 March 2024.

(6) Non-current financial debt comprises the outstanding Senior Notes and the Subordinated Notes balances as set out in the Unaudited Combined Carve Out as at 31 March 2024. In the consolidated group financial statements of Wintershall Dea, the Subordinated Notes, as included in the Target Portfolio, are classified as equity. For the purposes of the historical financial information relating to the Target Portfolio as set out in Part IX (Historical Financial Information relating to the Target Portfolio), the Subordinated Notes have been classified as liabilities in line with IAS 32 Financial Instruments on the basis that the guarantor of the Subordinated Notes is Wintershall Dea (outside the Target Portfolio), and therefore the cash flows are outside the control of the entities within the perimeter. Going forward, it is probable that the Subordinated Notes will be treated as equity within the consolidated group financial statements of the Company because on 21 February 2024 the bondholders approved a change in guarantor from Wintershall Dea to the Company which will be effective upon Completion. As at 31 March 2024, the value of the Senior Notes and the Subordinated Notes is $3.2 billion and $1.7 billion, respectively.

(7) The Target Portfolio's lease liabilities are not included in the table above as they do not represent borrowings. The value of current lease liabilities is $27 million and non-current lease liabilities is $97 million as at 31 March 2024.

As of 31 March 2024, the Target Portfolio had no indirect indebtedness and no contingent indebtedness.

There has been no material change in the capitalisation or indebtedness of the Target Portfolio since 31 March 2024.

PART VI
OPERATING AND FINANCIAL REVIEW RELATING TO HARBOUR ENERGY

The following discussion and analysis is intended to assist in providing an understanding of Harbour Energy's financial position and results of operations as at and for the years ended 31 December 2021, 31 December 2022 and 31 December 2023. The financial information as at and for each of the years ended 31 December 2021, 31 December 2022 and 31 December 2023 has been derived from the historical financial information relating to Harbour Energy included in Part VIII (Historical Financial Information relating to Harbour Energy) of this Prospectus.

Where gross amounts are indicated, they are presented on a total project basis—i.e., the total interest of all relevant licence holders in the relevant fields and licence areas without deduction for the economic interest of Harbour Energy's commercial partners, taxes or royalty interests or otherwise.

The following discussion contains forward-looking statements that involve risks and uncertainties that could cause the actual results of Harbour Energy to differ from those expressed or implied by such forward looking statements. These risks and uncertainties are discussed in the section entitled "Risk Factors" and elsewhere in this document. Also see "—Forward-looking Statements" in the section entitled "Important Information".

Overview

Harbour Energy is an independent oil and gas company which is building a large-scale, geographically diverse asset base, mainly through acquisition of high quality, cash generative producing portfolios.

Critical to Harbour Energy's success is safe and responsible operations, and safety remains the number one priority at every level of the business. Harbour Energy is also committed to playing an important role in the energy transition through reducing the emissions associated with its own operations and by deploying its skills and infrastructure to deliver CCS.

For the year ended 31 December 2023, Harbour Energy delivered 186 kboepd, with over 90 per cent. of its production coming from its diverse UK asset base and split broadly equally between liquids and gas. The remaining balance of Harbour Energy's production comes from assets in South East Asia. Harbour Energy has identified numerous short cycle, high return infrastructure-led investment opportunities within its producing portfolio to help offset natural decline and underpin future cash flow.

Harbour Energy has a portfolio of international growth opportunities in Indonesia and in Mexico which have the potential to materially add to its reserves and diversify its portfolio over time. These include a potential major gas development in the Andaman Sea in Indonesia and the Zama oil field offshore Mexico. In addition, Harbour Energy has an interest in two UK CCS projects, including Harbour Energy's flagship Viking CCS project which has the potential to provide Harbour Energy with a long-term, stable income stream.

As at 31 December 2023, Harbour Energy has 361 mmboe and 519 mmboe of oil and gas 2P reserves and 2C resources, respectively, and 222 million tonnes of independently-certified net 2C contingent storage resources.

For the year ending 31 December 2023, Harbour Energy generated significant free cash flow of $1 billion, which enabled the Board to approve $439 million of shareholder returns and the Company to reduce its net debt to $0.2 billion. This is consistent with Harbour Energy's disciplined approach to capital allocation which, together with sustained operational and financial delivery, has enabled Harbour Energy to reduce its net debt by $2.7 billion, return $1 billion to shareholders and retain flexibility to agree a transformational $11.2 billion acquisition since becoming a public company in April 2021.

The Company is a premium-listed, FTSE 250 company headquartered in London with approximately 2,000 staff and contractors across its offshore platforms and offices.

Key Factors Affecting Harbour Energy's Historical and Future Results of Operations

Price of Oil and Gas

The prevailing price of crude oil and gas significantly affects Harbour Energy's operations and has also affected and continues to affect the levels of Harbour Energy's oil and gas reserves estimates, which in turn impact Harbour Energy's depreciation, depletion and amortisation. Harbour Energy's oil and gas reserves estimates are also a key estimate in the value-in-use calculation for a field when considering whether there are any indicators of impairment and in performing impairment assessments of property, plant and equipment. The impact of a reduction in oil and gas prices on Harbour Energy's reserves estimates occurs when oil and gas reserves become no longer profitable to develop or produce at the reduced prices for oil and gas. A significant reduction in Harbour Energy's entitlement reserves estimates could lead to an impairment of property, plant and equipment, including exploration and evaluation assets.

Crude oil and gas prices have historically been volatile, dependent upon the balance between supply and demand and particularly sensitive to OPEC production levels. In 2020, global markets experienced significant oil price volatility resulting from a series of factors including: the impact of the COVID-19 pandemic; geopolitical developments between key oil producing nations, including market competition between Saudi Arabia and Russia; and the decision taken in April 2020 by OPEC and its allies to cut oil supply. By April 2020, the average Brent crude oil quoted price fell to a low of $19.3/bbl. Continual under investment in oil and gas globally drove higher oil and gas prices in late 2021 as the world economy emerged from the pandemic. The Russian-Ukraine conflict in 2022 intensified these existing inflationary pressures, in particular with regard to European gas prices and accelerated the tightening of monetary policies globally. Furthermore, production from U.S. shale oil producers and increased production from Russia have further increased volatility in commodity prices. More recently, the Israel—Gaza conflict that started in October 2023, the activities of the Houthi rebel group from Yemen in disrupting the trade through the Red Sea and Suez Canal and the risk of a wider conflict in the Middle East following the Israeli and Iranian attacks and counter-attacks in April 2024 have further added to this volatility.

Harbour Energy's European oil sales and the majority of Harbour Energy's Asian oil sales are priced against the average Platts Dated Brent crude oil benchmark price during the month of entitlement, with a premium or discount by grade to account for crude quality. Harbour Energy's oil sales from Indonesia are priced against Indonesian Official Selling prices ("**ICP**"), a government issued monthly official selling price.

The following table sets forth the average, highest and lowest Platts Dated Brent crude oil benchmark prices for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

	Year ended 31 December		
	2021	2022	2023
		(in $/bbl)	
Average price for the period	70.91	101.32	82.64
Highest price for the period	86.12	137.64	97.92
Lowest price for the period	50.34	76.36	71.71

Source: Platts Dated Brent Crude Oil settlement prices, Platts Crude Oil Marketwire.

The following table sets forth the average, highest and lowest ICP Anoa benchmark prices for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

	Year ended 31 December		
	2021	2022	2023
		(in $/bbl)	
Average price for the period	69.89	99.67	80.45
Highest price for the period	83.79	122.07	92.50
Lowest price for the period	53.48	79.22	70.88

Source: Government issued monthly official selling price.

Harbour Energy's UK gas sales are priced against the Heren Day-ahead UK National Balancing Point ("**UK NBP**") benchmark bid price published in the ICIS European Spot Gas Market report, with daily balancing against National Grid intraday prices.

The following table sets forth information on UK NBP gas prices for the years ended 31 December 2021, 31 December 2022 and 31 December 2023.

	Year ended 31 December		
	2021	2022	2023
		(in pence/therm)	
Average price for the period	113.45	197.87	99.07
Highest price for the period	449.90	515.98	173.50
Lowest price for the period	39.40	10.00	56.30

Source: ICIS UK NBP Gas settlement prices, ICIS European Spot Gas Market Report.

Harbour Energy's Indonesian gas sales are priced against the month average of Platts HSFO 180 3.5s Singapore FOB Cargo benchmark price, as published in Platts Asia Pacific/Arab Gulf Marketscan, with a formula attached to give a final price in \$/mmbtu. The realised gas prices in Indonesia for the years ended 31 December 2021, 31 December 2022 and 31 December 2023 were \$13/mscf, \$14/mscf and \$12/mscf, respectively.

The following table sets forth information on HSFO 180 3.5s Singapore FOB Cargo prices for the years ended 31 December 2021, 31 December 2022 and 31 December 2023.

	Year ended 31 December		
	2021	2022	2023
		(in \$/mt)	
Average price for the period	409.63	521.63	456.39
Highest price for the period	518.78	739.13	563.20
Lowest price for the period	301.68	354.99	360.37

Source: Platts HSFO 180 3.5s Singapore FOB Cargo settlement prices, Platts Asia Pacific/Arab Gulf Marketscan.

Production Volumes

In addition to oil and gas prices, production volumes are a primary revenue driver and are impacted by a number of factors, including maturity of field, managed and natural decline rates and uptime and operational efficiency. Harbour Energy's production levels also affect the level of reserves and depreciation, depletion and amortisation. In addition, certain of Harbour Energy's interests are in mature fields with declining production. See "*Harbour Energy and, following Completion, the Enlarged Group may be unable to replace its proved plus probable reserves as they are produced which could lead to a decline in its reserves, production and revenue*" in the section entitled "*Risk Factors*".

The following table sets forth information on Harbour Energy's oil and gas production and sales volumes for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

	Year ended 31 December		
	2021	2022	2023
Total average daily oil and NGL production for the period (kboepd)	96	103	90
Total average daily gas production for the period (kboepd)	79	105	96
Total average daily production for the period (kboepd)	175	208	186

Reserves

Harbour Energy estimates reserves using standard recognised evaluation techniques and reviews its internal estimates at least annually. In addition, Harbour Energy engages independent consultants to review its reserve estimates annually. Harbour Energy estimates future development costs by taking into account the costs required to produce the reserves and by referencing these costs to similar operations where applicable, and then engages external engineers to conduct reviews of these estimates. See "*—Presentation of Reserves and Resources*" in the section entitled "*Important Information*". The volume of Harbour Energy's oil and gas reserves and production volumes may be lower than estimated or expected because many of the factors in respect of which assumptions are made when estimating reserves and resources (including production history, quality and quantity of available data and future oil and gas prices) are beyond Harbour Energy's control and therefore these estimates may prove to be incorrect over time. See "*Harbour Energy and, following Completion, the Enlarged Group may be unable to replace its proved plus probable reserves as they are produced which could lead to a decline in its reserves, production and revenue*" in the section entitled "*Risk Factors*".

Separately, the depletion of oil and gas assets charged within cost of sales in Harbour Energy's income statement is dependent on its estimate of its oil and gas reserves. An increase in estimated reserves will cause a reduction to Harbour Energy's annual income statement charge because a larger base exists on which to depreciate the asset. Correspondingly, a decrease in estimated reserves will cause an increase to Harbour Energy's annual income statement charge. The estimate of oil and gas reserves also underpins the net present value of a field used for impairment calculations, and a significant reduction to the reserves estimate for a given field can lead to an impairment charge. Similarly, an increase to the reserves estimate can lead to a reversal of a previous impairment charge. These impairment charges or credits will not impact Harbour Energy's cash flow and cash taxes.

Exploration and Appraisal Success and Exploration Costs Written Off or Impaired

Harbour Energy faces inherent risks in connection with exploration and appraisal activities. The success or failure of Harbour Energy's exploration and appraisal activities affects the level of resources recognised and future development plans for a particular licence area. Pre-licensing costs are expensed in the period in which they are incurred. After the acquisition of an exploration licence, exploration and evaluation costs, such as seismic purchase and evaluation and exploration drilling, are capitalised as intangible non-current assets until the exploration is complete and the results are evaluated. The value of Harbour Energy's intangible assets is reviewed at least annually and, when appropriate, values are and have been impaired or written off if the asset is not expected to make a sufficient economic return from the investment, such as when an exploration well is dry or has insufficient reserves to be commercial.

For the years ended 31 December 2021, 31 December 2022 and 31 December 2023, Harbour Energy wrote off costs totaling $255 million, $64 million and $57 million, respectively, in relation to Harbour Energy's intangible exploration and evaluation assets following unsuccessful exploration and appraisal activities and licence relinquishments.

Harbour Energy's oil and gas assets are analysed into Cash Generating Units ("**CGUs**") for impairment review purposes, in accordance with the IAS 36 Impairment of Assets accounting standard, with Exploration and Evaluation ("**E&E**") asset impairment testing being performed at a grouped CGU level. When reviewing E&E assets for impairment, the combined carrying value of the grouped CGU is compared with the grouped CGU's recoverable amount. The recoverable amount of a grouped CGU is determined as the higher of its fair value less costs to sell and value in use. When the carrying amount of an asset or CGU exceeds its recoverable amount, the difference is recognised in the income statement as an impairment charge. Write-offs and impairments of intangible exploration and evaluation assets are expensed through the exploration costs written-off from Harbour Energy's income statement. Harbour Energy accounts for such write offs using the successful efforts method of accounting. In line with the successful efforts method of accounting, all licence acquisition, exploration and evaluation costs are initially capitalised as intangible oil and gas assets in cost centers by field or exploration area, as appropriate, pending determination of the commerciality of the relevant property. Directly attributable administration costs are capitalised in so far as they relate to specific exploration activities. Pre-licence costs and general exploration costs not specific to any particular licence or prospect are expensed as incurred. If prospects are deemed to be impaired or unsuccessful on completion of the evaluation, the associated costs are charged to the income statement. If the field is determined to be commercially viable, the attributable costs are transferred to property, plant and equipment. These costs are then depreciated on a unit of production basis. All field development costs are capitalised as property, plant and equipment. Property, plant and equipment related to production activities are amortised in accordance with Harbour Energy's depletion and amortisation accounting policy. See "*—Critical Accounting Estimates and Judgments*" and "*—Critical Accounting Estimates and Judgments—Exploration and Evaluation Expenditure*" in this Part VI (*Operating and Financial Review relating to Harbour Energy*).

Development and Production Success and Impairment

Harbour Energy faces inherent risks in connection with development and production activities. These risks include the difference between estimated and actual reserves, its cost efficiency in development, timing of production activities and level of production. Harbour Energy reviews development and production projects at least annually for indicators of impairment. In the event that such an indicator exists, Harbour Energy compares the expected value of the asset (based on discounted cash flows) with the carrying value on its balance sheet. If the expected value is lower than the carrying value, Harbour Energy records any impairment to its income statement.

For the year ended 31 December 2021, Harbour Energy's pre-tax impairment charges in respect of tangible oil and gas assets were $117 million. For the year ended 31 December 2022, Harbour Energy's pre-tax impairment reversals in respect of tangible oil and gas assets previously impaired were $170 million, driven by higher gas price assumptions for UK natural gas and reductions of $82 million in decommissioning provisions related to non-producing assets or assets with no remaining book value. For the year ended 31 December 2023, Harbour Energy's pre-tax impairment charges in respect of tangible oil and gas assets were $214 million.

Acquisitions and Disposals

An election to divest an asset could impact several items in Harbour Energy's income statement depending, in part, on the stage of the asset's life in which the disposal occurs. For example, a farm-out during the development phase is likely to result in a gain or loss. When Harbour Energy enters the development phase of a project with a high equity stake and decide to farm-out a portion of the equity in that licence in return for cash consideration and a carry of all, or a portion of, its share of development costs, the cash consideration and/or the fair value of the carry will be assessed against the carrying value of the percent of the equity disposed to calculate the gain or loss on disposal. Further, any acquisition of or sale of interests in producing assets will affect Harbour Energy's production volumes and revenues.

Harbour Energy's results may also be positively affected by successful acquisitions and dispositions, although the extent of the impact largely depends on the mix of assets acquired or sold.

Acquisitions and disposals affecting the periods presented include, among others, those set forth below:

(a) On 31 March 2021, Chrysaor and Premier Oil completed an all share merger creating Harbour Energy plc (the "**Merger**"). As a result, Premier Oil is fully consolidated in the Company's financial statements with effect from 31 March 2021, and all results prior to this date represent those of Chrysaor only.

(b) On 10 August 2023, Harbour Energy entered into sale and purchase agreements with Big Energy to sell its Vietnam business. However, on 13 May 2024, Harbour Energy exercised its right to terminate these agreements in accordance with their respective terms and Harbour Energy intends to reassess its options with regards to realising the best value from its Vietnam business.

As of 31 December 2023, Harbour Energy had no appraisal and or/pre-development or development assets held for sale and, save for its Vietnam business, no production assets held for sale.

For further details, see "*Information on Harbour Energy—History and Development*".

Underlying Operating Costs

Underlying operating costs are operating expenses that are either variable or fixed. The variable element of operating costs will increase (or decrease) with the level of production, therefore an increase (or decrease) in production will result in an increase (or decrease) in underlying variable operating costs. The main variable operating costs that affect Harbour Energy's results include the costs associated with the use of production consumables, such as chemicals and fuel. Fixed operating costs are substantially independent from production levels and therefore do not increase (or decrease) with an increase (or decrease) of Harbour Energy's level of production. Fixed operating costs include, for example, routine and non-routine maintenance costs, any element of fixed FPSO lease payments and both offshore and onshore personnel costs. Certain significant maintenance programmes result in the shut in of production for a period of time. An increase in fixed operating costs will result in an increase in operating cost per barrel due to higher costs with no associated increase in production.

Derivative Financial Instruments

Harbour Energy's results are affected by movements in commodity prices and foreign currency exchange. Harbour Energy's oil and gas hedging policy is to hedge predominantly by way of swaps and collar instruments. Harbour Energy's ability to hedge by way of instruments with an uncapped contingent credit exposure is subject to the following limits (based on a percentage of Harbour Energy's internal production forecasts):

Commodity swap hedging limits	Min Volume	Max Volume
	(per cent.)	
From 31 December 2024 for a period of 12 months	40	70
12–24 months from 31 December 2024	30	60
24–36 months from 31 December 2024	0	50
36–48 months from 31 December 2024	0	40

Harbour Energy's foreign currency hedging policy is to monitor Harbour Energy's exposure by entering into hedging arrangements with agreement from Harbour Energy's board of directors.

For further details, see "*—Qualitative and Quantitative Disclosures About Market Risk—Commodity Price Risk Management*" and "*—Qualitative and Quantitative Disclosures About Market Risk—Foreign Currency Risk Management*" in this Part VI (*Operating and Financial Review relating to Harbour Energy*).

Interest Rates

Harbour Energy's exposure to the risk of changes in market interest rates relates primarily to borrowings under the existing RBL Facility which has USD LIBOR-linked interest rate. Under Harbour Energy's interest rate hedging policy, Harbour Energy manages this risk by monitoring Harbour Energy's exposure to fluctuations in interest rates and may use interest rate derivatives to manage the fixed and floating composition of Harbour Energy's borrowings. Harbour Energy may be affected by changes in market interest rates at the time Harbour Energy refinances any of its indebtedness.

For further details, see "*Qualitative and Quantitative Disclosures About Market Risk—Interest Rate Risk Management*" in this Part VI (*Operating and Financial Review relating to Harbour Energy*).

Currency Exchange Rates

Harbour Energy's presentational currency is the U.S. dollar.

Each entity in Harbour Energy determines its own functional currency, this being the currency of the primary economic environment in which the entity operates, and items included in the financial statements of each entity are measured using that functional currency. The functional currencies of entities in Harbour Energy's entities include U.S. dollar, pound sterling, Norwegian krone and Mexican pesos. A significant amount of Harbour Energy's operating, staffing and other administration costs are, and were, denominated in pound sterling which determines the functional currencies of the operating entities incurring these costs.

Transactions recorded in foreign currencies are initially recorded in the entity's functional currency by applying an average rate of exchange. Monetary assets and liabilities denominated in foreign currencies are retranslated at the functional currency rate of exchange ruling at the reporting date. All differences are taken to the income statement, except when hedge accounting is applied. Non-monetary assets and liabilities denominated in foreign currencies are measured at historic cost based on exchange rates at the date of the transaction and subsequently not retranslated.

On consolidation, Harbour Energy's assets and liabilities are translated at exchange rates prevailing on the balance sheet date. Income and expense items are translated at the average monthly exchange rates for the year. Equity is held at historic costs and are not retranslated. The resulting exchange differences are recognised as other comprehensive income or expense and are transferred to Harbour Energy's translation reserve. As a result, Harbour Energy's results are affected by changes in the U.S. dollar/pound sterling exchange rate.

For further details, see "*Qualitative and Quantitative Disclosures About Market Risk—Foreign Currency Risk Management*" in this Part VI (*Operating and Financial Review relating to Harbour Energy*).

Emissions

Harbour Energy adheres to the regulatory requirements of the UK Emissions Trading Scheme ("**UK ETS**") for Harbour Energy's UK operations. Under the UK ETS, Harbour Energy is exposed to the cost of purchasing emissions allowances to cover any regulatory emissions shortfall. To manage this price exposure, Harbour Energy may seek to hedge a portion of any shortfall in advance through the purchase of fixed price physical or financial contracts. For more information, see "*Harbour Energy's and, following Completion, the Enlarged Group's failure to deliver on its stated climate change commitments and to adapt its strategy in the context of evolving external requirements and expectations, coupled with the effects of climate change and political and societal perception of the production and use of fossil fuels, may have a material adverse effect on the hydrocarbon industry, Harbour Energy and, following Completion, the Enlarged Group*" in the section entitled "*Risk Factors*".

Taxation

Taxation can have a significant impact on Harbour Energy's results of operations.

In 2022, the UK government first introduced and then subsequently extended the UK Energy Profits Levy ("**EPL**"). It initially applied at a rate of 25 per cent. in 2022 and then was increased to 35 per cent. for the period from 1 January 2023 to 31 March 2028. On 7 March 2024, the Chancellor of the Exchequer announced that this period would be further extended to 31 March 2029. This tax has resulted in Harbour Energy's headline UK tax rate being 75 per cent., which reduces Harbour Energy's profits and cashflows. On 9 June 2023, the UK government proposed the introduction of the Energy Security Investment Mechanism ("**ESIM**") which would end the imposition of EPL earlier than 31 March 2028 where certain conditions are met. Under the proposed ESIM, if both average oil and gas prices fall to, or below, $71.40 per barrel for oil and £0.54 per therm for gas adjusted annually for inflation, for six consecutive months, then EPL will be repealed and the headline tax rate on UK oil and gas profits will return to 40 per cent. Prices are not currently expected to fall to, or below, the quoted triggers before the existing EPL end date of 31 March 2029. ESIM is therefore not expected to have a material impact on the Company.

Harbour Energy's UK taxation is also affected by tax incentive programmes such as investment allowances. An uplift called Investment Allowance is available for capital investment and certain types of operating and leasing expenses for supplementary charge and EPL purposes. With the application of these incentives there is scope for the rate of tax relief across all levels of UK tax to be 91 per cent. (109 per cent. for certain types of decarbonisation expenditure).

In the year to 31 December 2023, Harbour Energy's effective rate was tax was 95 per cent. compared to 100 per cent. for the year to 31 December 2022.

Deferred tax assets are recognised to the extent that the future benefit from the underlying tax losses and tax deductions is probable. Relevant tax law is considered as to the ability of the tax losses and deductions to offset income. To determine the future taxable income from which losses may be deducted, reference was made to Harbour Energy's profit forecasts using corporate assumptions which are consistent with Harbour Energy's impairment assessment and Harbour Energy's business combination accounting.

As of 31 December 2023, Harbour Energy recognised a net deferred tax liability of $1,284 million, primarily in respect of balance sheet plant property and equipment value offset by decommissioning obligations. This compares to an asset of $1,009 million as of 31 December 2022 with the change being driven by changes in fair value of derivative instruments in the year.

Harbour Energy is subject to various tax claims which arise in the ordinary course of business, including tax claims from tax authorities in the jurisdictions in which Harbour Energy operates. Harbour Energy assesses all such claims in the context of the tax laws of the countries in which it operates and, where applicable, makes provision for any settlements which it considers to be probable and disclosure of those that are possible.

Harbour Energy may also be affected by how taxes impact its counterparties and contracts.

Seasonality

Seasonal weather conditions and lease stipulations can limit the drilling and production activities of Harbour Energy and other oil and natural gas operations in certain areas. These seasonal conditions can increase competition for equipment, supplies and personnel during the spring and summer months, which can lead to shortages, increase costs or delay its operations.

Description of Key Line Items

Revenue

Harbour Energy's revenue consists of crude oil, gas and condensate sales including realised hedging gains or losses, and tariff and other revenue. Oil, gas, and condensate revenues associated with the sale of these products to customers are recognised when Harbour Energy satisfies a performance obligation by transferring a good or service to a customer. A good or service is transferred when the customer obtains control of that good or service. The transfer of control of oil, natural gas liquids and other items sold by Harbour Energy occurs when title passes at the point the customer takes physical delivery. Harbour Energy principally satisfies its performance obligations at this point in time. Revenues from the production sale of oil and natural gas properties in which Harbour Energy has an interest with joint venture partners are recognised on the basis of its working interest in those properties.

Other Income

Other income represents the recovery from joint venture partners of their equity share of lease costs charged to operated ventures under IFRS 16 Leases, mark to market losses on UK Allowance emissions hedges, and research and development expenditure credits.

Cost of Operations

Harbour Energy's cost of operations consists of field operating costs and underlying operating costs such as transportation tariffs, depreciation, depletion and amortisation and movements in over/underlift and in hydrocarbon inventories.

Harbour Energy's movement in hydrocarbon inventories arises due to differences between volumes produced and sold. Inventories of hydrocarbons are stated at market value. Harbour Energy's movement in overlift and underlift arises due to differences between the production sold and Harbour Energy's share of production of oil and gas properties in which it has an interest with partners. Overlift and underlift are valued at market value and included within payables or receivables respectively.

Impairment of Property, Plant and Equipment

Harbour Energy assesses at each reporting date, whether there is an indication that an asset may be impaired. If any indication exists, Harbour Energy estimates the recoverable amount of the associated asset or cash generating unit, being the higher of the fair value less costs of disposal and value-in-use. When the carrying amount of an asset or cash generating unit exceeds its recoverable amount, the difference is recognised in the income statement as an impairment charge.

Impairment of Goodwill

Harbour Energy tests goodwill annually for impairment, or more frequently if there are or were indications that goodwill might be impaired. Impairment is determined for goodwill by assessing the recoverable amount of each CGU to which the goodwill relates. Where the recoverable amount of the CGU is less than its carrying amount, an impairment loss is recognised in the income statement. Impairment losses relating to goodwill cannot be reversed in future periods.

Provision for Onerous Service Contracts

A provision is recognised when Harbour Energy has a legal or constructive obligation as a result of a past event. The expense relating to any provision is presented in the income statement net of any reimbursement.

Other provisions may include provision for onerous service contracts in respect of contracts where there are reduced or no future planned activities under a contract. In such situations, a provision is recognised for the outstanding contractual obligations not covered by planned activities.

Exploration and Evaluation Expenses (E&E) and New Ventures

Harbour Energy's E&E expenses include pre-licence costs before the legal right to explore has been acquired, licence and property acquisition costs paid in connection with a right to explore in an existing exploration area, and farm outs in the E&E phase. Such costs also include early project costs incurred on new ventures, including carbon capture and storage and electrification projects.

Exploration Costs Written-Off

Exploration costs written-off consist of write offs of costs for explorations evaluated to be uncommercial, including licence relinquishments and uncommercial well evaluations.

Once the legal right to explore has been acquired, costs directly associated with the exploration are capitalised as exploration and evaluation intangible non-current assets until the exploration is complete and the results have been evaluated. The application of Harbour Energy's accounting policy for exploration and evaluation expenditure requires judgement to determine whether future economic benefits are likely, from either exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves. The determination of reserves and resources is itself an estimation process that requires varying degrees of uncertainty depending on how the resources are classified.

If no potential commercial resources are discovered, the exploration asset is written off. All such capitalised costs are subject to technical, commercial and management review, as well as review for indicators of impairment at least annually. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off through the income statement. When proved and probable reserves of oil or natural gas are identified and development is sanctioned by management, the relevant capitalised expenditure is first assessed for impairment and (if required) any impairment loss is recognised, then the remaining balance is transferred to oil and gas properties within development and production assets. No amortisation is charged during the exploration and evaluation phase.

Gain on Disposal

Harbour Energy presents a gain on disposal in 2022, which is related to the release of a provision associated with Premier's sale of its legacy Pakistan assets in 2019 after the expiry of the deadline in the period for tax claims to be submitted. The calculation of this gain is specific to the situation. No other gains have been recognised.

General and Administrative Expenses

Harbour Energy's general and administration costs consist of costs for the head office staff and other costs net of the recharge of costs to Harbour Energy's asset activities, commercial partners and therefore reflects the net costs associated with corporate activities. With respect to certain operated assets, Harbour Energy's commercial partnership agreements allow it to charge back Harbour Energy's expenses as operator to the field partners at specified percentages and subject to certain conditions. These agreements typically allow Harbour Energy to charge to its commercial partners an additional amount up to a specified percentage of the total costs to compensate for parent company overhead.

Finance Income

Finance income includes bank interest receivable, lease finance income, finance income on deferred revenue, realised gains on interest rate swaps, realised gains on foreign exchange forward contracts, gains on derivatives and foreign exchange gains.

Finance Expenses

Finance expenses include interest expense on the existing RBL Facility and the bond, other interest, foreign exchange loss, bank and financing fees, unwinding of discount on contingent consideration and unwinding of discount on decommissioning, leases and other provisions.

Income Tax Expense

Current Tax

Current tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and laws used to compute the amount are those that are enacted or substantively enacted at the reporting date in the countries where Harbour Energy operates and generates taxable income.

Current income tax related to items recognised directly in other comprehensive income or equity is recognised in other comprehensive income or directly in equity not in the income statement.

Deferred Tax

Deferred taxation is recognised in respect of all timing differences arising between the tax bases of the assets and liabilities and their carrying amounts in the financial statements with the following exceptions: (i) deferred income tax assets are recognised only to the extent that it is probable that the taxable profit will be available against which the deductible temporary difference, carried forward tax credits or tax losses can be utilised; (ii) deferred income tax assets and liabilities are measured on an undiscounted basis at the tax rates that are expected to apply when the related asset is realised or liability is settled, based on tax rates and laws enacted or substantively enacted at the reporting date. The carrying amount of the deferred income tax asset is reviewed at each reporting date; and (iii) deferred income tax assets and liabilities are offset, only if a legally enforceable right exists to offset current assets against current tax liabilities, the deferred income tax relates to the same tax authority and that same tax authority permits Harbour Energy to make a single net payment and there is an intention to do so.

Results of Operations

The following tables set forth Harbour Energy's historical revenue, expense items and production and operating data for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

	Year ended 31 December		
	2021	2022	2023
		($ million)	
Revenue	**3,479**	**5,390**	**3,715**
Other income	139	41	36
Revenue and other income	**3,618**	**5,431**	**3,751**
Cost of operations	(2,453)	(2,845)	(2,357)
(Impairment)/impairment reversal of property, plant and equipment	(117)	170	(214)
Impairment of goodwill	—	—	(25)
Exploration and evaluation expenses and new ventures	(50)	(42)	(36)
Exploration costs written-off	(255)	(64)	(57)
Gain on disposal	—	12	—
General and administrative expenses	(103)	(121)	(149)
Operating profit	**640**	**2,541**	**913**
Finance income	49	279	104
Finance expenses	(374)	(358)	(420)
Profit before taxation	**315**	**2,462**	**597**
Income tax expense	(214)	(2,454)	(565)
Profit for the year	**101**	**8**	**32**

Comparison of Results of Operations of Harbour Energy for the Years Ended 31 December 2023 and 31 December 2022

Revenue and Other Income

Harbour Energy's revenue decreased by $1,675 million, or 31 per cent., to $3,715 million for the year ended 31 December 2023 from $5,390 million for the year ended 31 December 2022. This decrease was primarily driven by lower production which fell by 11 per cent. from 208 kboepd for the year ended 31 December 2022 to 186 kboepd for the year ended 31 December 2023. In addition, realised UK gas prices fell by 37 per cent. from 86 pence per therm for the year ended 31 December 2022 to 54 pence per therm for the year ended 31 December 2023.

Harbour Energy's other income decreased by $5 million, or 12 per cent., to $36 million for the year ended 31 December 2023 from $41 million for the year ended 31 December 2023.

Harbour Energy's crude oil sales, including realised hedging results, decreased to $2,086 million for the year ended 31 December 2023 as compared to $2,792 million for the year ended 31 December 2022. This decrease was primarily driven by lower production with post-hedging realised oil prices broadly flat year-on-year.

Harbour Energy's gas revenues decreased to $1,415 million for the year ended 31 December 2023 as compared to $2,322 million for the year ended 31 December 2022. This decrease was primarily driven by lower post-hedging realised gas prices and lower production.

Harbour Energy's NGL sales decreased to $179 million for the year ended 31 December 2023 as compared to $238 million for the year ended 31 December 2022. Harbour Energy's tariff income and other revenue was unchanged at $30 million for the year ended 31 December 2023 as compared to the year ended 31 December 2022.

Cost of Operations

Harbour Energy's cost of operations, including field operating costs, transportation tariffs and depreciation, depletion and amortisation, decreased by $488 million, or 17 per cent., to $2,357 million for the year ended 31 December 2023 from $2,845 million for the year ended 31 December 2022. Part of this decrease was a result of lower production driving lower depreciation, depletion and amortisation charges. In addition, there was a movement in over/underlift of $225 million credit for the year ended 31 December 2023 as compared to a $181 million charge for the year ended 31 December 2022.

Impairment of Property, Plant and Equipment

Harbour Energy recognised an impairment expense of $214 million for the year ended 31 December 2023 compared to an impairment reversal of property, plant and equipment of $170 million for the year ended 31 December 2022.

Within this, for the year ended 31 December 2023, there was a pre-tax impairment charge of $214 million representing a write-down of property, plant and equipment assets of $108 million (2022: $163 million), across two CGUs in the UK of $70 million, one driven primarily by a significant reduction in the gas price forward curve, and the other by a revised decommissioning cost profile, in addition to a Vietnam fair value adjustment on the held for sale asset of $38 million plus a pre-tax impairment charge of $106 million in respect of revisions to decommissioning estimates on mainly non-producing assets with no remaining net book value.

In addition, there was a goodwill impairment of $25 million in the international CGU related to the Vietnam business being classified as asset held for sale.

Exploration and Evaluation Expenses and New Ventures

Harbour Energy's E&E expenses and new ventures decreased by $6 million to $36 million for the year ended 31 December 2023 from $42 million for the year ended 31 December 2022. This decrease is primarily related to lower ongoing pre-licence expenditure.

Exploration Costs Written-Off

Harbour Energy's exploration costs written-off decreased by $7 million to $57 million for the year ended 31 December 2023 from $64 million for the year ended 31 December 2022. For the year ended 31 December 2023, the charges related to the Ix-1EXP well in Mexico and the JDE well in Norway and also include costs associated with licence relinquishments and uncommercial well evaluations.

General and Administrative Expenses

Harbour Energy's general and administrative expenses increased by $28 million, or 23 per cent., to $149 million for the year ended 31 December 2023 from $121 million for the year ended 31 December 2022. The increase in general and administrative expenses was primarily due to increased consultancy fees.

Finance Income

Harbour Energy's finance income decreased by $175 million, or 63 per cent., to $104 million for the year ended 31 December 2023 from $279 million for the year ended 31 December 2022. For the year ended 31 December 2023, finance income amounted to $104 million and included derivative gains of $68 million, compared to a $48 million loss for the year ended 31 December 2022, which related to changes in the fair value of an embedded derivative within one of Harbour Energy's gas contracts. In addition, for the year ended 31 December 2022, there were unrealised foreign exchange gains of $202 million which predominately arose on the revaluation of open sterling denominated gas hedges as a result of the weakening of sterling against the US dollar in the period.

Finance Expenses

Harbour Energy's finance expenses increased by $62 million, or 17 per cent., to $420 million for the year ended 31 December 2023 from $358 million for the year ended 31 December 2022. Finance expenses amounted to $420 million (2022: $358 million). This included interest expense incurred on debt facilities of $42 million compared to $98 million for the year ended 31 December 2022. The reduction reflects the impact of lower drawn down debt partially offset by higher interest rates. Other financing expenses, bank and financing fees, include the unwinding of the discount on provisions of $156 million for the year ended 31 December 2023 compared to $65 million for the year ended 31 December 2022, which increased due to higher cost estimates and interest rates, and $57 million of foreign exchange losses as compared to gains of $202 million for the year ended 31 December 2022 as a result of the strengthening of sterling in the year.

Income Tax Expense

Harbour Energy's income tax expense decreased by $1,889 million, or 77 per cent., to $565 million for the year ended 31 December 2023 from $2,454 million for the year ended 31 December 2022. The 2022 charge included a one-off non-cash charge of $1,469 million as a result of the revaluation of the deferred tax position on the balance sheet following the introduction of the EPL in the UK. The tax expense is split between a current tax expense of $677 million for the year ended 31 December 2023 compared to $706 million for the year ended 31 December 2022, and includes an EPL current tax charge of $525 million and a deferred tax credit of $112 million.

Comparison of Results of Operations of Harbour Energy for the Years Ended 31 December 2022 and 31 December 2021

Revenue and Other Income

Harbour Energy's revenue increased by $1,911 million, or 55 per cent., to $5,390 million for the year ended 31 December 2022 from $3,479 million for the year ended 31 December 2021. This increase was primarily driven by increased production, especially U.K. gas production which was 34 per cent. higher compared to 2021, and higher post-hedging realised prices.

Harbour Energy's other income decreased by $98 million, or 70 per cent., to $41 million for the year ended 31 December 2022 from $139 million for the year ended 31 December 2021. This decrease was primarily driven by mark-to-market gains on European Union Agency emissions hedges of $51 million and a consideration adjustment of $40 million received from ConocoPhillips, both included in other income for the year ended 31 December 2021.

Harbour Energy's crude oil sales, including realised hedging results, increased to $2,792 million for the year ended 31 December 2022 as compared to $2,023 million for the year ended 31 December 2021. This increase was primarily driven by higher post-hedging realised prices.

Harbour Energy's gas revenues have increased to $2,322 million for the year ended 31 December 2022 as compared to $1,264 million for the year ended 31 December 2021. This increase was primarily driven by higher post-hedging realised prices and higher production.

Harbour Energy's NGL sales increased to $238 million for the year ended 31 December 2022 as compared to $164 million for the year ended 31 December 2021. This increase was primarily driven by higher realised prices. Harbour Energy's tariff income and other revenue increased by $10 million, or 36 per cent., to $38 million for the year ended 31 December 2022 as compared to $28 million for the year ended 31 December 2021. This increase was primarily driven by higher realised prices.

Cost of Operations

Harbour Energy's cost of operations, including field operating costs, transportation tariffs and depreciation, depletion and amortisation, increased by $392 million, or 16 per cent., to $2,845 million for the year ended 31 December 2022 from $2,453 million for the year ended 31 December 2021. This increase was primarily driven by a full year contribution from the Premier Oil assets and the addition of the Tolmount field. This increase was partially offset by a foreign exchange benefit from the pound sterling weakening against the US dollar.

Impairment Reversal of Property, Plant and Equipment

Harbour Energy recognised a net impairment reversal of property, plant and equipment of $170 million for the year ended 31 December 2022 from an impairment expense of $117 million for the year ended 31 December 2021. The impairment reversal consisted of $251 million on North Sea gas assets, which was driven by higher gas price assumptions for U.K. natural gas. In addition, an impairment credit of $82 million in respect of revisions to decommissioning estimates on Harbour Energy's non-producing assets was also recognised. This was partially offset by a $163 million impairment expense relating to one of Harbour Energy's North Sea producing fields as a result of the contracted price which it realised for its crude sales being negatively impacted by the pricing differential between Urals and Brent crude, and a revised operating cost profile for the field.

Exploration and Evaluation Expenses and New Ventures

Harbour Energy's E&E expenses and new ventures decreased by $8 million, or 16 per cent., to $42 million for the year ended 31 December 2022 from $50 million for the year ended 31 December 2021. This decrease is primarily related to lower ongoing pre-licence expenditure.

Exploration Costs Written-Off

Harbour Energy's exploration costs written-off decreased by $191 million to $64 million for the year ended 31 December 2022 from $255 million for the year ended 31 December 2021. The decrease in exploration costs written-off mainly relates to write-offs incurred in 2021 associated with the exit from exploration acreage in Brazil and the Sea Lion project in the Falklands Islands of $134 million, and relinquishments of UK licences and uncommercial drilling results on the UK Dunnottar well and Norwegian PL973 Jerv and Ilder prospects of $121 million.

Gain on Disposal

Harbour Energy had a gain on disposal of $12 million for the year ended 31 December 2022. This gain was due to the release of a provision associated with Premier's sale of its legacy Pakistan assets in 2019 after the expiration of the deadline in the period for tax claims to be submitted.

General and Administrative Expenses

Harbour Energy's general and administrative expenses increased by $19 million, or 18 per cent., to $121 million for the year ended 31 December 2022 from $102 million for the year ended 31 December 2021. The increase in general and administrative expenses was primarily due to a full 12 months of an enlarged organisation following the merger with Premier in March 2021.

Finance Income

Harbour Energy's finance income increased by $230 million, or 472 per cent., to $279 million for the year ended 31 December 2022 from $49 million for the year ended 31 December 2021. This increase was primarily due to foreign exchange gains of $202 million reflecting the weakening of pound sterling against the US dollar. In particular, this included unrealised foreign exchange gains arising predominantly on the revaluation of open sterling denominated U.K. gas hedges using a significantly lower sterling US dollar exchange rate. It also includes additional gains of $38 million on interest rate and foreign currency derivatives.

Finance Expenses

Harbour Energy's finance expenses decreased by $17 million, or 5 per cent., to $358 million for the year ended 31 December 2022 from $375 million for the year ended 31 December 2021. This decrease was primarily driven by no foreign exchange losses in the year compared to $65 million in 2021, a reduction in interest expense reflecting lower drawn debt under the existing RBL Facility, partially offset by higher losses on derivatives of $33 million related to changes in the value of an embedded derivative within one of Harbour Energy's gas contracts.

Income Tax Expense

Harbour Energy's income tax expense increased by $2,241 million to $2,454 million for the year ended 31 December 2022 from $213 million for the year ended 31 December 2021. The increase in Harbour Energy's income tax expense is primarily due to the U.K. government's introduction of the EPL. Specifically it includes a one off non-cash deferred tax charge of $1,469 million due to the revaluation of the deferred tax position to reflect the 35 per cent. EPL which will apply until 31 March 2029.

Liquidity and Capital Resources

Harbour Energy's liquidity requirements arise principally from capital investment, working capital demands and debt servicing requirements. For the periods presented, Harbour Energy met its liquidity requirements primarily from ongoing cash flow generation from its producing assets and debt financing through ongoing drawings under the existing RBL Facility and other loans.

In addition to amounts available under its debt facilities, Harbour Energy also held cash and cash equivalents of $699 million, $500 million and $280 million as of 31 December 2021, 31 December 2022 and 31 December 2023, respectively.

Cash Flow

The following table sets forth Harbour Energy's consolidated cash flow information for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

	Year Ended 31 December		
	2021	2022	2023
		($ million)	
Net cash inflow from operating activities	1,614	3,130	2,144
Net cash outflow from investing activities	(571)	(629)	(693)
Net cash outflow from financing activities	(787)	(2,674)	(1,667)
Cash and cash equivalents as of end of period	699	500	280

Net Cash Inflows From Operating Activities

Net cash flows from operating activities consist of:

	Year Ended 31 December		
	2021	2022	2023
		($ million)	
Profit before taxation	315	2,462	597
Adjustments to reconcile profit before tax to net cash flows:			
—Finance cost, excluding foreign exchange	309	358	363
—Finance income, excluding foreign exchange	(49)	(77)	(104)
—Depreciation, depletion and amortisation	1,371	1,546	1,430
—Fair value movement in unrealised carbon swaps	—	2	—
—Net impairment of property, plant and equipment	117	(170)	214
—Impairment of goodwill	—	—	25
—Taxes paid	(280)	(552)	(438)
—Share-based payments	8	17	20
—Decommissioning payments	(245)	(217)	(268)
—Onerous contract provision	(2)	—	—
—Exploration costs written-off	255	64	57
—Write-off of non-oil and gas assets	5	—	—
—Pre-merger costs	7	—	—
—Onerous contract payments	(9)	(2)	—
—Increase in royalty consideration receivable	(1)	—	—
—(Gain)/loss on disposal	—	(12)	—
—Movement in realised cash flow hedges not yet settled	362	(104)	(207)
—Unrealised foreign exchange loss/(gain)	57	(238)	49
Working capital adjustments:			
—(Increase)/decrease in inventories	(13)	65	(52)
—(Increase)/decrease in trade and other receivables	(607)	(75)	519
—Increase/decrease in trade and other payables	14	63	(61)
Net cash inflow from operating activities	**1,614**	**3,130**	**2,144**

Harbour Energy's net cash inflow from operating activities was $2,144 million for the year ended 31 December 2023 compared to $3,130 million for the year ended 31 December 2022. This decrease was primarily due to decreased production volumes in addition to lower realised commodity prices.

Harbour Energy's net cash inflow from operating activities was $3,130 million for the year ended 31 December 2022 compared to $1,614 million for the year ended 31 December 2021. This increase was primarily due to increased production volumes in addition to higher realised commodity prices.

Net Cash Outflow From Investing Activities

	Year Ended 31 December		
	2021	2022	2023
		($ million)	
Expenditure on exploration and evaluation assets	(176)	(127)	(202)
Expenditure on property, plant and equipment	(437)	(477)	(496)
Expenditure on non-oil and gas intangible assets	(30)	(30)	(20)
Expenditure on other intangible assets	—	—	(81)
Cash acquired on business combinations	97	—	—
Receipts for sub-lease income	7	10	10
Payments relating to disposal of oil and gas properties	—	(6)	3
Expenditure on business combinations—deferred consideration	(46)	(19)	—
Finance income received	14	20	93
Net cash outflow from investing activities	**(571)**	**(629)**	**(693)**

Harbour Energy's net cash outflows from investing activities was $693 million for the year ended 31 December 2023 compared to $629 million for the year ended 31 December 2022. This increase was primarily due to higher capital investment in 2023 compared to 2022.

Harbour Energy's net cash outflows from investing activities was $629 million for the year ended 31 December 2022 compared to $571 million for the year ended 31 December 2021. This increase was primarily due to the 2021 cash outflow being reduced because of $97 million of cash acquired as part of the Merger.

For a more detailed description of Harbour Energy's recent capital expenditure, see "—*Capital Investment*" in this Part VI (*Operating and Financial Review relating to Harbour Energy*).

Net Cash Outflow From Financing Activities

	Year Ended 31 December		
	2021	2022	2023
		($ million)	
Repurchase of shares	—	(361)	(249)
Proceeds from new borrowings—reserves-based lending facility	1,618	—	660
Proceeds from new borrowings—bond	500	—	—
Proceeds from new borrowings—exploration financing facility	46	11	—
Lease liability payments	(160)	(254)	(259)
Repayment of short-term debt arising on business combination	(1,276)	—	—
Repayment of hedging liabilities arising on business combination	(49)	—	—
Repayment of reserves-based lending facility	(698)	(1,663)	(1,435)
Repayment of junior debt	(400)	—	—
Repayment of exploration financing facility	(15)	(38)	(11)
Repayment of financing arrangement	(9)	(15)	(21)
Redemption of loan notes	(136)	—	—
Purchase of ESOP Trust shares	(3)	(21)	(12)
Interest paid and bank charges	(205)	(142)	(150)
Dividends paid	—	(191)	(190)
Net cash outflow from financing activities	**(787)**	**(2,674)**	**(1,667)**

Harbour Energy's net cash outflows from financing activities was $1,667 million for the year ended 31 December 2023, compared to $2,674 million for the year ended 31 December 2022. This decrease was primarily due to lower net repayments of the reserves based lending facility of $775 million.

Harbour Energy's net cash outflows from financing activities was $2,674 million for the year ended 31 December 2022, compared to $787 million for the year ended 31 December 2021. This increase was primarily due to higher repayments of the reserves based lending facility of $965 million, share repurchases of $361 million and dividends paid of $191 million.

For a more detailed description of Harbour Energy's recent financing activities, see "—*Financing*" in this Part VI (*Operating and Financial Review relating to Harbour Energy*).

Cash and Cash Equivalents

As of 31 December 2023, Harbour Energy held $280 million of cash and cash equivalents.

Capital Investment

The primary objective of Harbour Energy's capital management is to optimise the return on investment, by managing its capital structure to achieve capital efficiency while maintaining flexibility for future acquisitions. Harbour Energy regularly monitors the capital requirements of the business over the short, medium and long term, in order to enable it to better anticipate the timing of requirements for additional capital. All capital investment opportunities are screened to achieve attractive risk-adjusted returns at conservative commodity prices.

Harbour Energy's capital investment represents expenditure on oil and gas assets incurred during a period through all lifecycle phases. Currently the portfolio is weighted towards producing assets so the majority of expenditure is spent on development and producing wells plus associated infrastructure. Capital investment primarily comprises expenditures on property, plant and equipment and other intangible assets. The following table sets forth Harbour Energy's capital investments for the years ended 31 December 2021, 31 December 2022 and 31 December 2023.

	Year ended 31 December		
	2021	**2022**	**2023**
		($ million)	
Property, plant and equipment expenditure	465	532	482
Non-oil and gas expenditure	34	42	29
Other intangible assets expenditure	210	111	210
Capital investment	**709**	**685**	**721**

Harbour Energy's capital investment in the year ended 31 December 2023 was $721 million. The capital investments in 2023 mainly consisted of, for operated assets, development drilling in the J-Area, including at Talbot, the tie in of Tolmount East to Tolmount, the appraisal of the Leverett discovery which is close to the Britannia discovery (part of the Greater Britannia Area), and long lead items for the Callanish and North Seymour infill wells at the GBA and AELE hubs, respectively. For partner operated assets, capital investment consisted primarily of the tie in of two subsea wells at Beryl, and drilling at Buzzard, Clair and Schiehallion. In international operations, exploration wells were drilled at Layaran-1 in Indonesia, the JDE well in Norway and the Kan and Ix-1EXP wells in Mexico.

Harbour Energy's capital investment in the year ended 31 December 2022 was $685 million. The capital investments in 2022 mainly consisted of operated drilling on the J-Area at the Jade, Judy and Jill fields, Catcher development wells and non-operated drilling programmes on the Clair Ridge platform. The decommissioning expenditure mainly relates to activity in the Southern North Sea and Balmoral area in the UK Central North Sea.

Harbour Energy's capital investment in the year ended 31 December 2021 was $709 million. The 2021 investment programme was focused on operated assets in the J-Area (Jasmine West Limb development, Talbot appraisal and Jade South and Dunnottar exploration wells), Tolmount development drilling and Everest LAD well. Non-operated capital expenditure included drilling programs at Beryl, Elgin Franklin and Clair Ridge.

Future Capital Investment

Harbour Energy's capital investments are driven largely by full phase expenditure on existing producing fields, new development projects and exploration and appraisal. As of 31 December 2023, Harbour Energy had commitments for future capital expenditure amounting to $389 million. The key components of this relate to Harbour Energy's UK operated hubs and non-operated assets as well as international assets.

Contractual Obligations and Contingent Liabilities

The following table sets forth Harbour Energy's remaining contractual maturity for its non-derivative financial liabilities with contractual repayment periods as of 31 December 2023. The table reflects the undiscounted cash flows of financial liabilities based on the earliest date on which Harbour Energy could be required to pay.

(in $ million)	Total	Less than 1 year	1 to 2 years	2 to 5 years	Over 5 years
Bond	584	28	28	528	—
Other loans[1]	16	16	—	—	—
Trade and other payables	838	825	13	—	—
Lease obligations	897	250	186	340	121
Total	**2,335**	**1,119**	**227**	**868**	**121**

Notes

(1) Includes commercial financing arrangement with Baker Hughes, a GE company, covering a multi-year work programme for drilling, completion and subsea tie-in of development wells on Harbour Energy's legacy operated assets. Interest has been calculated using the effective interest method with reference to the expected cash flows, using an estimated reserve case.

Harbour Energy also has certain liabilities for future decommissioning activities on some of Harbour Energy's oil and gas assets. Harbour Energy calculates total future decommissioning liability based on Harbour Energy's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon wells and facilities and the estimated timing of the costs to be incurred in future periods. The provisions Harbour Energy makes represent the present value of decommissioning costs which are expected to be incurred assuming no further development of Harbour Energy's assets. As of 31 December 2023, Harbour Energy used a risk-free rate between 4.3 per cent. and 5.2 per cent. and an inflation rate of 2.5 per cent. over the varying lives of the assets to calculate a present value of Harbour Energy's decommissioning liabilities of $4,021 million, which qualify for decommissioning tax relief. These decommissioning costs are expected to be incurred at various intervals over the next 40 years, the majority of which are anticipated to be incurred between the next 10 to 20 years. The payment dates of expected decommissioning costs are uncertain and are based on economic assumptions of the fields concerned.

These provisions relating to decommissioning liabilities have been created based on internal and third-party estimates. Assumptions based on the current economic environment have been made which Harbour Energy believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to consider any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon market prices for the necessary decommissioning work required, which will reflect market conditions at the relevant time. In addition, the timing of decommissioning liabilities will depend upon the dates when the fields become economically unviable, which in itself will depend on future commodity prices, which are inherently uncertain. See "—*Critical Accounting Estimates and Judgments*" in this Part VI (*Operating and Financial Review relating to Harbour Energy*).

Financing

Harbour Energy's liquidity requirements arise principally from Harbour Energy's capital investment, working capital demands and debt servicing requirements. For the periods presented, Harbour Energy met its capital investment, working capital and debt servicing requirements primarily from cash flows from operations and the proceeds of debt financing. Harbour Energy's actual financing requirements will depend on a number of factors, many of which are beyond Harbour Energy's control.

For further details of Harbour Energy's financing arrangements, see paragraph 15 (Harbour Energy Material Contracts) in Part XIV (*Additional Information*).

Letters of Credit and Surety Bonds

Harbour Energy enters into letters of credit for Harbour Energy's obligations, in respect of certain future abandonment liabilities including certain bilateral decommissioning credit arrangements with ConocoPhillips. As of 31 December 2023, Harbour Energy had $1,186 million in letters of credit outstanding relating to security obligations under certain decommissioning security agreements. Furthermore, as of 31 December 2023, Harbour Energy had $400 million of surety bond capacity for the purposes of posting decommissioning security, which is effective from 1 January 2024.

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 to us. The majority of Harbour Energy's accounts receivable balance is with customers and commercial partners in the international oil and gas industry. Harbour Energy has a credit policy that governs the management of credit risk, including the establishment of counterparty credit limits and specific transaction approvals. Harbour Energy limits credit risk by assessing creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness after transactions have been initiated.

Harbour Energy only sells hydrocarbons to recognised and creditworthy parties, typically the trading arm of large, international oil and gas companies. The credit risk on liquid funds and derivative financial instruments is limited because the counterparties are internationally recognised banking institutions and are considered to represent minimal credit risk. Harbour Energy has no significant concentrations of credit risk unless otherwise disclosed, and credit losses are expected to be near zero. The maximum credit risk exposure relating to financial assets is represented by carrying value as of the balance sheet date.

Liquidity Risk Management

Liquidity and refinancing risks refer to the risk that Harbour Energy will not be able to obtain sufficient financing from lenders and the capital markets to meet its working capital and project financing and refinancing requirements. Harbour Energy monitors the liquidity risk by reviewing its cash flow requirements on a regular basis relative to its funding sources, cash flow generation from its producing asset base and its existing RBL Facility. Specifically, Harbour Energy ensures that it has sufficient liquidity or committed facilities to meet its operational funding requirements and service its debt and adhere to its financial covenants. Harbour Energy closely monitors and manages its 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 run for different scenarios including, but not limited to, changes in commodity prices, different production rates from Harbour Energy's portfolio of producing fields and potential delays in development projects. In addition to Harbour Energy's operating cash flows, portfolio management opportunities are reviewed to potentially enhance its financial capacity and flexibility. Ultimate responsibility for liquidity risk management rests with Harbour Energy's board of directors, which has built a liquidity risk management framework which the Company believes to be appropriate for the management of all its funding and liquidity management requirements. As of 31 December 2023, Harbour Energy was in compliance with all applicable financial covenant ratios under the existing RBL Facility.

As of 31 December 2023, Harbour Energy had total commitments of $2.75 billion under the existing RBL Facility. For further details of the existing RBL Facility, see paragraph 15.9 (Reserve Base Lending Facility) in Part XIV (*Additional Information*). Harbour Energy held cash and cash equivalents of $280 million and $500 million as of 31 December 2023 and 31 December 2022, respectively.

Foreign Currency Risk Management

Whilst Harbour Energy has subsidiaries with various local functional currencies, it generally conducts and manages its business in U.S. dollars and pound sterling, which are the operating currencies of the industry in the geographic areas where the majority of Harbour Energy's operations are located. To mitigate exposure to movements in exchange rates, wherever possible financial assets and liabilities are held in currencies that match the functional currency of the relevant entity. For instance, Harbour Energy has the ability to draw in U.S. dollars and pounds sterling under the existing RBL Facility agreement, which assists in foreign currency risk management. From time to time, Harbour Energy will undertake certain transactions denominated in other currencies. These exposures are monitored and managed by executing financial derivatives relating to that currency with agreement from the board of directors.

As of 31 December 2023, Harbour Energy's open foreign exchange contracts were as follows:

Foreign exchange contracts	Term	Volume	Average price
Forwards Sterling versus U.S. Dollar	Up to 10 months	£212 million	$1.2182–$1.2742

As of 31 December 2023, Harbour Energy's material monetary assets or liabilities that were not denominated in the functional currency of the respective subsidiaries involved were non-U.S. dollar denominated cash, joint venture billing receivables and third-party suppliers. The carrying amount of Harbour Energy's foreign currency denominated monetary assets and monetary liabilities as of 31 December 2023 was, net of liabilities, $777 million.

Harbour Energy is mainly exposed to fluctuations in other currencies against the U.S. dollar, in particular pound sterling. Harbour Energy measures its market risk exposure by running various sensitivity analyses including assessing the impact of reasonably possible movements in key variables. The sensitivity analyses include only outstanding non-U.S. dollar denominated monetary items and adjusts their translation at the period end for a 10 per cent. change in such non-U.S. dollar rates. As of 31 December 2023, Harbour Energy's open foreign exchange contracts were £212 million hedged at a forward rate of between $1.2182 and $1.2742:£1 for the period January 2024 to October 2024. As of 31 December 2023, a 10 per cent. increase or decrease in currency exchange rates against the functional currency of Harbour Energy's entities would not have resulted in a decrease or increase, respectively, in non-U.S. dollar denominated equity.

Commodity Price Risk Management

Harbour Energy is exposed to the impact of changes in oil and gas prices on its revenue and profits. On a rolling basis, Harbour Energy's policy is to hedge the commodity price exposure associated with 40 per cent. to 70 per cent. of the next 12 months' production, between 30 per cent. and 60 per cent. in the next 12-month period, up to 50 per cent. in the following 12-month period, and up to 40 per cent. in the subsequent 12-month period.

The following table summarises the commodity hedges in place at 31 December 2023:

Derivative	Term	Volume	Average Price
Oil	January 2024–December 2025	11,700,000 bbls	$82/bbl
Gas Swaps	January 2024–March 2026	980,150,000 therms	69 pence/therm
Gas Collars	January 2024–March 2026	296,450,000 therms	105–244 pence/therm

Interest Rate Risk Management

Interest rate risk refers to the risk that market interest rates will increase, resulting in higher borrowing costs under the existing RBL Facility, which has a floating interest rate. Harbour Energy manages interest rate risk using interest rate swaps from time to time.

As of 31 December 2023, Harbour Energy had the following interest rate swaps in place under Harbour Energy's existing RBL Facility in the year ended 31 December 2023:

Date	Derivative	Currency	Period of hedge	Terms
31 December 2023	Interest rate swaps	$nil million	n/a	n/a
31 December 2022	Interest rate swaps	$545 million	June 2020–June 2025	Average 0.55 per cent.

Harbour Energy may be affected by changes in market interest rates at the time Harbour Energy need to refinance any of its indebtedness.

Critical Accounting Estimates and Judgments

This section discusses Harbour Energy's consolidated financial statements, which have been prepared in accordance with UK-adopted 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 UK-adopted 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 Harbour Energy's current judgments and estimates.

This listing of critical accounting policies is not intended to be a comprehensive list of all Harbour Energy's accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by UK-adopted IFRS, with no need for management's judgment regarding accounting policy. Harbour Energy believes that of Harbour Energy's significant accounting policies, the following policies may involve a higher degree of judgment and complexity.

Exploration and Evaluation Expenditure

Harbour Energy held a balance relating to expenditure on unproved hydrocarbon resources within other intangible assets which represent active exploration and evaluation activities as of 31 December 2023 and 2022 of $1,016 million and $817 million, respectively. The application of Harbour Energy's accounting policy for exploration and evaluation expenditure requires judgement to determine whether future economic benefits are likely, from either exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves. The determination of reserves and resources is itself an estimation process that requires varying degrees of uncertainty depending on how the resources are classified. If, after expenditure is capitalised, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalised amount is written off in the income statement in the period when the new information becomes available.

Recoverability of Oil and Gas Assets

For impairment review purposes, Harbour Energy's oil and gas assets are analysed into CGUs as identified in accordance with IAS 36 Impairment of Assets. A review is carried out at each reporting date for any indicators that the carrying value of Harbour Energy's assets may be impaired. 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 of disposal and value-in use, then compared to the carrying value of the asset or CGU. The assessments of fair value less cost of disposal, generally referenced by the present value of the future net cash flows expected to be derived from production of reserves, requires the use of estimates and assumptions on uncontrollable parameters such as long-term oil prices (considering current and historical prices, price trends and related factors), foreign exchange rates and discount rates. Harbour Energy's estimate of the recoverable value of its assets is sensitive to commodity prices and discount rates. A change in the long-term price assumptions of 10 per cent. and a 1 per cent. change in the post-tax discount rate are considered to be reasonably possible for the purposes of sensitivity analysis.

Decommissioning Costs

Harbour Energy recognises decommissioning costs in full when the related facilities are installed. Harbour Energy assesses Harbour Energy's decommissioning provision at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors including the expected timing, extent and amount of expenditure. On the basis that all other assumptions in the calculation remain the same, a 10 per cent. increase in the cost estimates, and a 1 per cent. decrease in the discount rates used to assess the final decommissioning obligation at 31 December 2023, would result in increases to the decommissioning provision of $456 million and $440 million, respectively. This change would be principally offset by a change to the value of the associated asset unless the asset is fully depreciated, in which case the change in estimate is recognised directly within the income statement.

Goodwill

Harbour Energy tests goodwill annually for impairment or more frequently if there are indications that goodwill might be impaired. Impairment is determined for goodwill by assessing the recoverable amount of each CGU to which the goodwill relates. Where the recoverable amount of the CGU is less than its carrying amount, an impairment loss is recognised in the income statement.

The recoverable amount of goodwill is based on estimates and assumptions regarding in particular the expected market outlook (including future commodity prices) used for the measurement of cash flows and estimates of the volume of commercially recoverable.

Impairment losses relating to goodwill cannot be reversed in future periods.

Merger Reserve

On 31 March 2021, Harbour Energy plc (formerly Premier Oil plc) acquired Chrysaor Holdings Limited as part of a reverse acquisition. Under the terms of the Merger, Premier Oil plc legally acquired Chrysaor Holdings Limited through the issuance of consideration shares while Chrysaor was the acquirer for accounting purposes, primarily as a result of its ability to appoint the board of directors of the Company. The merger reserve primarily represents Premier's opening balance on the legal reserve plus the fair value of the assets and liabilities acquired by Chrysaor.

Deferred Tax Assets

Deferred taxation is recognised in respect of timing differences arising between the tax bases of the assets and liabilities and their carrying amounts in the financial statements. Deferred tax assets are recognised only to the extent that it is probable that future taxable profits will be available against which the deductible temporary difference, carried forward tax credits or tax losses can be utilised. The estimation of future taxable profits requires management's judgment with the use of appropriate assumptions (including, amongst other items, oil and gas prices, production forecasts and cost estimates), assessment of tax history and other relevant information. These parameters can change from period to period and as such can lead to derecognition of a deferred tax asset, with a corresponding charge to the income statement, or recognition of a previously unrecognised deferred tax asset, with a corresponding credit to the income statement in the period.

Climate Change

Harbour Energy recognises that there may be potential financial implications in the future from climate change risk. Harbour Energy expects that climate change policies, legislation and regulation will increase, likely on accelerating timelines. Whilst this will result in intended benefits, it is likely to increase associated costs and administration requirements as well as potentially limiting the investment capital available to the industry in which Harbour Energy operates. These in due course may well have an impact across a number of areas of accounting including impairment, fair values, increased costs, onerous contracts, contingent liabilities. However, as of 31 December 2023, Harbour Energy believes there is no material impact on balance sheet carrying values of assets or liabilities. Although this is an estimate, it is not considered a critical estimate, as management's view is that at the end of the current reporting period there is no significant risk of climate change resulting in a material adjustment to the carrying amounts of assets and liabilities, within the next financial year.

Recent Accounting Pronouncements

Amendments to IAS 1, Presentation of Financial Statements—classification of liabilities as current or non-current

On 23 January 2020, the International Accounting Standards Board ("**IASB**") issued a narrow-scope amendment to IAS 1 to clarify that liabilities are classified as either current or non-current depending on the rights that exist at the end of the reporting period. Liabilities are classified as non-current if the entity has a substantive right to defer settlement for at least 12 months at the end of the reporting period. Harbour Energy does not consider this amendment to have significant impact on the classification of its liabilities as either current or non-current and applied these amendments starting with the year ended 31 December 2023.

Amendments to IAS 8—Definition of Accounting Estimates

In February 2021, the IASB issued "Definition of Accounting Estimates", which amended "IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors". The amendments introduced the definition of accounting estimates and included other amendments to IAS 8 to help entities distinguish changes in accounting estimates from changes in accounting policies, with the distinction important because changes in accounting estimates are applied prospectively only to future transactions and other future events, but changes in accounting policies are generally also applied retrospectively to past transactions and other past events. Harbour Energy applied these amendments starting with the year ended 31 December 2023.

Amendments to IAS 1 and IFRS Practice Statement 2—Disclosure of Accounting Policies

In February 2021, the IASB issued amendments to "IAS 1 Presentation of Financial Statements" and "IFRS Practice Statement 2 Making Materiality Judgements". The amendments to IAS 1 require companies to disclose their material accounting policy information rather than their significant accounting policies. The amendments to IFRS Practice Statement 2 provides guidance on how to apply the concept of materiality to accounting policy disclosures. Harbour Energy applied these amendments starting with the year ended 31 December 2023.

Amendments to IAS 12—Deferred Tax related to Assets and Liabilities arising from a Single Transaction

On 7 May 2021, the IASB issued amendments to "IAS 12 Income Taxes". The amendments require companies to recognise deferred tax on transactions that, on initial recognition, give rise to equal amounts of taxable and deductible temporary differences. According to the amended guidance, a temporary difference that arises on initial recognition of an asset or liability is not subject to the initial recognition exemption if that transaction gave rise to equal amounts of taxable and deductible temporary differences. These amendments were expected to typically apply to transactions such as leases for the lessee and decommissioning obligations. Harbour Energy applied these amendments starting with the year ended 31 December 2023.

IFRS 17 Insurance Contracts

IFRS 17 Insurance Contracts is a comprehensive new accounting standard for insurance contracts covering recognition and measurement, presentation and disclosure. IFRS 17 replaces IFRS 4 Insurance Contracts. IFRS 17 applies to all types of insurance contracts (i.e. life, non-life, direct insurance and re-insurance), regardless of the type of entities that issue them as well as to certain guarantees and financial instruments with discretionary participation features; a few scope exceptions will apply. The overall objective of IFRS 17 is to provide a comprehensive accounting model for insurance contracts that is more useful and consistent for insurers, covering all relevant accounting aspects. IFRS 17 is based on a general model, supplemented by:

- a specific adaptation for contracts with direct participation features (the variable fee approach); and
- a simplified approach (the premium allocation approach) mainly for short-duration contracts.

The new standard had no impact on Harbour Energy's consolidated financial statements.

PART VII
OPERATING AND FINANCIAL REVIEW RELATING TO THE TARGET PORTFOLIO

The following discussion and analysis is intended to assist in providing an understanding of the financial position and results of operations of the Target Portfolio on a combined basis as at and for the years ended 31 December 2021, 31 December 2022 and 31 December 2023. The financial information as at and for each of the years ended 31 December 2021, 31 December 2022 and 31 December 2023 has been derived from the Historical Financial Information relating to the Target Portfolio included in Part IX of this Prospectus.

Where gross amounts are indicated, they are presented on a total project basis—i.e., the total interest of all relevant licence holders in the relevant fields and licence areas without deduction for the economic interest of the Target Portfolio's commercial partners, taxes or royalty interests or otherwise.

The following discussion contains forward-looking statements that involve risks and uncertainties that could cause the actual results of the Target Portfolio to differ from those expressed or implied by such forward looking statements. These risks and uncertainties are discussed in the section entitled "Risk Factors" and elsewhere in this document. Also see "—Forward-looking Statements" in the section entitled "Important Information".

Overview

The Target Portfolio is part of the Wintershall Dea group, one of the leading European independent gas and oil companies with full lifecycle capabilities across exploration, development and production activities, complemented by investments in midstream assets.

In the year ended 31 December 2023, the Target Portfolio produced 321 kboepd (2022: 318 kboepd), split approximately 208 and 113 kboepd between gas and liquid, respectively. Production was from a large, diversified and low-cost portfolio spanning three regions and eight countries, and extending from Northern Norway to the southern-most offshore production platform in the world in Argentina. The production, development and exploration assets of the Target Portfolio are located in Northern Europe (Norway, Germany and Denmark), North Africa (Egypt, Libya and Algeria), Mexico and Argentina and the CCS assets are located in the United Kingdom and Northern Europe (Norway, Germany and Denmark). Wintershall Dea's Russian joint ventures with Gazprom and midstream assets have been excluded from the Acquisition and are not being acquired by Harbour Energy. The Target Portfolio is operated predominantly via a partnership model with long-term joint venture arrangements with some of the world's leading oil and gas companies. A significant portion of the Target Portfolio is non-operated.

Key Factors Affecting the Target Portfolio's Historical and Future Results of Operations

Price of Oil and Gas

The prevailing price of crude oil and gas significantly affects the Target Portfolio's operations and has also affected and continues to affect the levels of the Target Portfolio's oil and gas reserves estimates, which in turn impact the Target Portfolio's depreciation, depletion and amortisation. The Target Portfolio's oil and gas reserves estimates are also a key estimate in the fair value less cost of disposal calculation for a field when considering whether there are any indicators of impairment and in performing impairment assessments of property, plant and equipment. The impact of a reduction in oil and gas prices on the Target Portfolio's reserves estimates occurs when oil and gas reserves become no longer profitable to develop or produce at the reduced prices for oil and gas. A significant reduction in the Target Portfolio's working interest reserves estimates could lead to an impairment of property, plant and equipment, including exploration and evaluation assets. Crude oil and gas prices have historically been volatile, dependent upon the balance between supply and demand and particularly sensitive to OPEC production levels. Continual under investment in oil and gas globally drove higher oil and gas prices in late 2021 as the world economy emerged from the pandemic. The Russian-Ukraine conflict in 2022 intensified these existing inflationary pressures, in particular with regard to European gas prices and accelerated the tightening of monetary policies globally. Furthermore, production from U.S. shale oil producers and increased production from Russia have further increased volatility in commodity prices. More recently, the Israel—Gaza conflict that started in October 2023, the activities of the Houthi rebel group from Yemen in disrupting the trade through the Red Sea and Suez Canal and the risk of a wider conflict in the Middle East following the Israeli and Iranian attacks and counter-attacks in April 2024 have further added to this volatility.

Approximately one-third of the Target Portfolio's oil sales is priced against the average Platts Dated Brent crude oil benchmark price during the month of entitlement, with a premium or discount by grade to account for crude quality, and one-third of the Target Portfolio's gas sales is priced against the UK NBP benchmark bid price published in the ICIS European Spot Gas Market report and the Dutch Title Transfer Facility ("**TTF**") gas prices. For details of the Platts Dated Brent crude oil benchmark and UK NBP prices for the years ended 31 December 2021, 31 December 2022 and 31 December 2023, see "*—Key Factors Affecting Harbour Energy's Historical and Future Results of Operations—Price of Oil and Gas*" in Part VI (*Operating and Financial Review relating to Harbour Energy*).

The following table sets forth the average, highest and lowest TTF prices for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

	Year ended 31 December		
	2021	2022	2023
		(in $/mscf)	
Average price for the period	15.69	36.97	12.85
Highest price for the period	60.53	91.18	23.18
Lowest price for the period	5.59	6.93	7.36

Source: Heren/Argus; FX conversion according to ECB.

The average pre-hedging realised prices for international gas, European gas and liquids produced by the Target Portfolio for the year ended 31 December 2023 was $4/mscf, $15/mscf and $74/bbl, respectively.

Production Volumes

In addition to oil and gas prices, production volumes are a primary revenue driver. The Target Portfolio's production levels also affect the level of reserves and depreciation, depletion and amortisation.

The following table sets forth information on the Target Portfolio's oil and gas production volumes for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

	Year ended 31 December		
	2021	2022	2023
Total average daily oil, condensate and NGL production for the period (kboepd)	120	111	113
Total average daily gas production for the period (kboepd)	205	207	208
Total average daily production for the period (kboepd)	325	318	321

Reserves

The Target Portfolio's reserves are estimated using standard recognised evaluation techniques and the Wintershall Dea group reviews its internal estimates at least annually. In addition, the Wintershall Dea group engages independent consultants to review its reserve estimates on a regular basis. The Wintershall Dea group estimates future development costs by taking into account the costs required to produce the reserves and by referencing these costs to similar operations where applicable, and engages external engineers to conduct reviews of these estimates. See "*—Presentation of Reserves and Resources*" in the section entitled "*Important Information*". The volume of the Target Portfolio's oil and gas reserves and production volumes may be lower than estimated or expected because many of the factors in respect of which assumptions are made when estimating reserves and resources (including production history, quality and quantity of available data and future oil and gas prices) are beyond the Target Portfolio's control and therefore these estimates may prove to be incorrect over time.

Separately, the depletion of oil and gas assets charged within cost of operations in the Target Portfolio's income statement is dependent on the estimate of its oil and gas reserves. An increase in estimated reserves will cause a reduction to the Target Portfolio's annual income statement charge because a larger base exists on which to depreciate the asset. Correspondingly, a decrease in estimated reserves will cause an increase to the Target Portfolio's annual income statement charge. The estimate of oil and gas reserves also underpins the net present value of a field used for impairment calculations, and a significant reduction to the reserves estimate for a given field can lead to an impairment charge. Similarly, an increase to the reserves estimate can lead to a reversal of a previous impairment charge. These impairment charges or credits will not impact the Target Portfolio's cash flow and actual tax charges.

Exploration and Appraisal Success and Exploration Costs Written Off or Impaired

The Target Portfolio faces inherent risks in connection with exploration and appraisal activities. The success or failure of the Target Portfolio's exploration and appraisal activities affects the level of resources recognised and future development plans for a particular licence area. Pre-licensing costs are expensed in the period in which they are incurred. After the acquisition of an exploration licence, exploration and evaluation costs, such as seismic purchase and evaluation and exploration drilling, are capitalised as intangible non-current assets until the exploration is complete and the results are evaluated. The value of the Target Portfolio's intangible assets is reviewed at least annually and, when appropriate, values are and have been impaired or written off if the asset is not expected to make a sufficient economic return from the investment, such as when an exploration well is dry or has insufficient reserves to be commercial.

For the years ended 31 December 2021, 31 December 2022 and 31 December 2023, the Target Portfolio wrote off exploration costs totalling $193 million, $28 million and $72 million, respectively, in relation to the Target Portfolio's intangible exploration and evaluation assets following unsuccessful exploration and appraisal activities.

The Target Portfolio's oil and gas assets are analysed into Cash Generating Units ("**CGUs**") for impairment review purposes, in accordance with the IAS 36 Impairment of Assets accounting standard, with Exploration and Evaluation ("**E&E**") asset impairment testing being performed at licence level. When reviewing E&E assets for impairment, the carrying value is compared with the recoverable amount. The recoverable amount is determined as the higher of its fair value less costs to sell and value in use. When the carrying amount of an asset or CGU exceeds its recoverable amount, the difference is recognised in the income statement as an impairment charge. Write-offs and impairments of intangible exploration and evaluation assets are expensed through the exploration costs written off in the Target Portfolio's income statement. For further details, see "*Note 7*" in Part IX (*Historical Financial Information relating to the Target Portfolio*) of this Prospectus. The Target Portfolio accounts for such write offs using the successful efforts method of accounting. In line with the successful efforts method of accounting, all licence acquisition, exploration and evaluation costs are initially capitalised as intangible oil and gas assets by field or exploration area, as appropriate, pending determination of the commerciality of the relevant property. Directly attributable administration costs are capitalised insofar as they relate to specific exploration activities. Pre-licence costs and general exploration costs not specific to any particular licence or prospect are expensed as incurred. If prospects are deemed to be impaired or unsuccessful on completion of the evaluation, the associated costs are charged to the income statement. If the field is determined to be commercially viable, the attributable costs are transferred to property, plant and equipment. These costs are then depreciated on a unit of production basis from the start of production onwards. All field development costs are capitalised as property, plant and equipment. Property, plant and equipment related to production activities are amortised in accordance with the Target Portfolio's depletion and amortisation accounting policy. See the section entitled "*—Critical Accounting Estimates and Judgments*" in this Part VII (*Operating and Financial Review relating to the Target Portfolio*).

Development and Production Success and Impairment

The Target Portfolio faces inherent risks in connection with development and production activities. These risks include the difference between estimated and actual reserves, its cost efficiency in development, timing of production activities and level of production. The Target Portfolio reviews development and production projects at least annually for indicators of impairment or reversals of impairment. In the event that such an indicator exists, the Target Portfolio compares the expected value of the asset (based on discounted cash flows) with the carrying value on its balance sheet. If the expected value is lower than the carrying value, the Target Portfolio records any impairment to its income statement.

For the year ended 31 December 2021, the Target Portfolio's pre-tax impairment reversal in respect of tangible oil and gas assets was $6 million. For the year ended 31 December 2022, the Target Portfolio's impairment charge in respect of tangible oil and gas assets was $188 million. For the year ended 31 December 2023, the Target Portfolio's pre-tax impairment reversal in respect of tangible oil and gas assets was $111 million.

Acquisitions

Any acquisition of interests in producing assets will affect the production volumes and revenues of the Target Portfolio for the periods presented. Acquisitions undertaken by Wintershall Dea affecting the periods presented include, among others, those set forth below:

- In October 2022, Wintershall Dea agreed to acquire a 37 per cent. stake in the Hokchi Block in the Gulf of Mexico. The acquisition completed in March 2023. Following completion of the acquisition, Wintershall Dea acquired a 37 per cent. share in the Hokchi Block, with the operator Hokchi Energy holding 59.4 per cent. and Ainda, Energía & Infraestructura, SAPI de CV holding 3.6 per cent.

- In May 2022, Wintershall Dea agreed to acquire the stake of Edison in the Reggane Nord project in Algeria. The acquisition completed in October 2023. Following completion of the acquisition, Groupement Reggane Nord, the operator of the project, consisted of Sonatrach (40 per cent.), Repsol (36 per cent.) and Wintershall Dea (24 per cent.).

Underlying Operating Costs

Underlying operating costs are operating expenses that are either variable or fixed. The variable element of operating costs will increase (or decrease) with the level of production, therefore an increase (or decrease) in production will result in an increase (or decrease) in underlying variable operating costs. The main variable operating costs that affect the Target Portfolio's results include the costs associated with the use of production consumables, such as chemicals and fuel. Fixed operating costs are substantially independent from production levels and therefore do not increase (or decrease) with an increase (or decrease) of the Target Portfolio's level of production. Fixed operating costs include, for example, routine and non-routine maintenance costs, any element of fixed FPSO lease payments (unless capitalised as a right of use assets) and both offshore and onshore personnel costs. Certain significant maintenance programmes result in the shut in of production for a period of time. An increase in fixed operating costs will result in an increase in operating cost per barrel due to higher costs with no associated increase in production.

Derivative Financial Instruments

The Target Portfolio's results are affected by movements in commodity prices and foreign currency exchange. The Wintershall Dea group's oil and gas hedging policy is to hedge by way of forward gas sales, oil swaps and zero cost collar instruments. The Wintershall Dea group's foreign currency hedging policy is to fully hedge booked positions, where feasible, without undue delay through linear instruments. See "—*Qualitative and Quantitative Disclosures About Market Risk*" in this Part VII (*Operating and Financial Review relating to the Target Portfolio*).

Currency Exchange Rates

The Target Portfolio's presentational currency is the U.S. dollar.

Each entity in the Target Portfolio determines its own functional currency, this being the currency of the primary economic environment in which the entity operates, and items included in the financial statements of each entity are measured using that functional currency. The functional currencies of entities in the Target Portfolio's entities include the U.S. dollar, Euro and Mexican peso.

Transactions recorded in foreign currencies are initially recorded in the entity's functional currency by applying the exchange rates prevalent at the time of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated at the functional currency rate of exchange ruling at the reporting date. Non-monetary assets and liabilities denominated in foreign currencies are measured at historic cost based on exchange rates at the date of the transaction and subsequently not retranslated.

The financial statements of the Target Portfolio's companies with functional currencies other than the presentation currency of the Target Portfolio are translated using the closing rate method. The Target Portfolio's assets and liabilities are translated at exchange rates prevailing on the balance sheet date. Income and expense items are translated at the average annual exchange rates for the year. Equity is held at historic costs and are not retranslated. The resulting exchange differences are recognised as other comprehensive income or expense and are transferred to the Target Portfolio's translation reserve.

Emissions

In Norway and Germany, five assets of the Target Portfolio are subject to the statutory EU Emission trading system. Required emission allowances are purchased and traded on the market according to a determined procurement strategy.

Taxation

The assets of the Target Portfolio are located in a number of countries. It is therefore exposed to a wide range of tax environments that are subject to change in a manner that may be materially adverse for the Target Portfolio, which can include changes and uncertainty surrounding subsidies, royalties or taxation (including policies relating to the granting of advance rulings on taxation matters), for example, excess profit taxes in EU countries to absorb windfall profits generated from high prices. Favourable changes to subsidies, royalties or taxes may also serve as an opportunity.

Seasonality

Seasonal weather conditions and lease stipulations can limit the drilling and production activities of the Target Portfolio and other oil and natural gas operations in certain areas. These seasonal conditions can increase competition for equipment, supplies and personnel during the spring and summer months, which can lead to shortages, increase costs or delay its operations.

Description of Key Line Items

The historical financial information relating to the Target Portfolio set out in Part IX (*Historical Financial Information relating to the Target Portfolio*) of this Prospectus has been prepared in accordance with accounting policies consistent with those applied by Harbour Energy in its audited financial statements as at and for the year ended 31 December 2023. For details of the key line items reported by Harbour Energy in its income statement, see "*—Description of Key Line Items*" in Part VI (*Operating and Financial Review relating to Harbour Energy*).

Results of Operations

The following tables set forth the Target Portfolio's historical revenue, expense items and production and operating data for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

	2021	2022	2023
		($ million)	
Revenue	4,892	7,984	6,337
Other income	66	57	43
Revenue and other income	**4,958**	**8,041**	**6,380**
Cost of operations	(2,927)	(2,942)	(3,128)
Net impairment reversal/(impairment) of property, plant and equipment, goodwill and other intangible assets	6	(188)	111
Exploration and evaluation expenses	(46)	(56)	(78)
Exploration cost written off	(193)	(28)	(72)
Gain/losses on disposal	25	(128)	(10)
General and administrative expenses	(348)	(367)	(412)
Operating profit	**1,475**	**4,332**	**2,791**
Finance income	292	301	497
Finance expenses	(465)	(518)	(713)
Profit before taxation	**1,302**	**4,115**	**2,575**
Income tax expense	(1,357)	(3,334)	(2,028)
(Loss)/profit for the year	**(55)**	**781**	**547**

Comparison of Results of Operations of the Target Portfolio for the Years Ended 31 December 2023 and 31 December 2022

Revenue and Other Income

The Target Portfolio's revenue decreased by $1,647 million, or 21 per cent., to $6,337 million for the year ended 31 December 2023 from $7,984 million for the year ended 31 December 2022. This decrease was primarily driven by lower commodity prices.

The Target Portfolio's crude oil sales decreased by $351 million, or 14 per cent., to $2,223 million for the year ended 31 December 2023 from $2,574 million for the year ended 31 December 2022. This decrease was primarily driven by lower oil prices (Brent) which declined by 18 per cent. to $82.6/bbl for the year ended 31 December 2023 from $101.2/bbl for the year ended 31 December 2022. The existence of hedges in both periods reduced the relative decline in realisations compared to the decline in Brent prices.

The Target Portfolio's gas sales decreased by $1,133 million, or 24 per cent., to $3,664 million for the year ended 31 December 2023 from $4,797 million for the year ended 31 December 2022. This decrease was primarily driven by lower TTF gas prices which declined by 65 per cent. to $12.85/mscf for the year ended 31 December 2023 from $36.97/mscf for the year ended 31 December 2022. The existence of hedges as well as domestic gas price and formula price contracts in certain non-European jurisdictions of the Target Portfolio reduced the relative decline compared to decline in TTF prices.

The Target Portfolio's condensate sales (comprising condensate, NGL and LPG) decreased by $96 million, or 18 per cent., to $448 million for the year ended 31 December 2023 from $544 million for the year ended 31 December 2022. This decrease was primarily driven by lower prices for condensate, NGL and LPG. The decrease was partially offset by higher sales volumes which increased by 8 per cent.

The Target Portfolio's tariff income decreased by $67 million, or 97 per cent., to $2 million for the year ended 31 December 2023 from $69 million for the year ended 31 December 2022. This decrease was primarily driven by lower sales of unused pipeline capacity in Norway.

The Target Portfolio's other income decreased by $14 million, or 25 per cent., to $43 million for the year ended 31 December 2023 from $57 million for the year ended 31 December 2022. This decrease was primarily driven by lower government grants in Argentina.

Cost of operations

The Target Portfolio's cost of operations increased by $186 million, or 6 per cent., to $3,128 million for the year ended 31 December 2023 from $2,942 million for the year ended 31 December 2022. This increase was primarily driven by higher gas purchases which increased by $271 million to $465 million for the year ended 31 December 2023 from $194 million for the year ended 31 December 2022, mainly due to additional trading volumes in Germany. In addition, production, insurance and transportation cost increased to $1,134 million for the year ended 2023 from $1,007 million for the year ended 31 December 2022, mainly driven by the acquisition of a 37 per cent. non-operating interest in the oil producing Hokchi-block, a one-off effect from a provision for a commercial settlement with a third-party in Germany, inflationary pressures as well as higher cost allocations. This increase was partially offset by a positive effect from the change of over/underlift, relating to sales volumes in Latin America and Northern Europe not corresponding to the respective production volumes, lower royalties as well as lower depreciation charges on oil and gas assets.

Net impairment reversal/(impairment) of property, plant and equipment and other intangible assets

The Target Portfolio recognised a net impairment reversal of $111 million for the year ended 31 December 2023, compared to a net impairment expense of $188 million for the year ended 31 December 2022. This net impairment reversal consisted of reversal of impairments totalling $209 million for assets in Mexico due to higher oil prices and Algeria related to an increase in interest in the asset, which was partially offset by impairments on assets in the amount of $98 million, relating to assets in Egypt and Mexico, based on operational updates. The net impairments for the year ended 31 December 2022 consisted of impairments for assets amounting to $322 million and relating to assets in Mexico due to changed technical concepts, in Norway due to disposal of Brage and in Egypt due to operational updates as well as reversal of impairments on assets, totalling to $134 million, in Egypt, Algeria and Germany due to improved economics of the projects.

Exploration and evaluation expenses

The Target Portfolio's E&E expenses increased by $22 million, or 39 per cent., to $78 million for the year ended 31 December 2023 from $56 million for the year ended 31 December 2022. This increase was primarily driven by higher exploration expenses in Mexico and Norway.

Exploration costs written off

The Target Portfolio's Exploration costs written off increased by $44 million, or 157 per cent., to $72 million for the year ended 31 December 2023 from $28 million for the year ended 31 December 2022. The exploration costs written off in the year ended 31 December 2023 consisted of two dry wells in Mexico as well as one dry well in Norway and one in Egypt. The exploration costs written off in the year ended 31 December 2022 included a total of five dry wells in Norway and one dry well in Mexico.

Net gains and losses on disposal

The Target Portfolio had net losses on disposal of $10 million for the year ended 31 December 2023. The losses were due to losses from disposals for various projects in Norway and Germany, partially offset by gains from purchase price adjustments in Germany. The Target Portfolio recorded a net loss on disposals of

$128 million for the year ended 31 December 2022, which mainly related to the disposal of the Brage field in Norway.

General and administrative expenses

The Target Portfolio's general and administrative expenses increased by $45 million, or 12 per cent., to $412 million for the year ended 31 December 2023 from $367 million for the year ended 31 December 2022. This increase was primarily driven by additions to restructuring provisions ($78 million for the year ended 31 December 2023) as well as higher integration and transformation costs ($75 million for the year ended 31 December 2023; $17 million for the year ended 31 December 2022). In addition, the expenses for the carbon management and hydrogen activities increased and amounted to $25 million for the year ended 31 December 2023 (up from $15 million for the year ended 31 December 2022). This was partially offset by higher allocations into the Target Portfolio's general and administrative expenses in the year ended 31 December 2022.

Finance income

The Target Portfolio's finance income increased by $196 million, or 65 per cent., to $497 million for the year ended 31 December 2023 from $301 million for the year ended 31 December 2022. This increase was primarily driven by higher interest income in Argentina, and by interest income from related parties, driven by higher interest on cash pooling receivables. This was partially offset by lower net foreign exchange gains which turned into net foreign currency losses for the year ended 31 December 2023.

Finance expenses

The Target Portfolio's finance expenses increased by $195 million, or 38 per cent., to $713 million for the year ended 31 December 2023 from $518 million for the year ended 31 December 2022. This increase was primarily driven by higher net foreign exchange losses for the year ended 31 December 2023 mainly attributable to the devaluation of the Argentinian Peso. This was partially compensated by lower net losses on derivatives.

Income tax expense

The Target Portfolio's income tax expense decreased by $1,306 million, or 39 per cent., to $2,028 million for the year ended 31 December 2023 from $3,334 million for the year ended 31 December 2022. This decrease was primarily driven by the lower profit before taxation due to lower commodity prices. The tax rate for the year ended 31 December 2023 amounted to 79 per cent. (81 per cent. for the year ended 31 December 2022).

Comparison of Results of Operations of the Target Portfolio for the Years Ended 31 December 2022 and 31 December 2021

Revenue and Other Income

The Target Portfolio's revenue increased by $3,092 million, or 63 per cent., to $7,984 million for the year ended 31 December 2022 from $4,892 million for the year ended 31 December 2021. This increase was primarily driven by higher commodity prices.

The Target Portfolio's crude oil sales increased by $428 million, or 20 per cent., to $2,574 million for the year ended 31 December 2022 from $2,146 million for the year ended 31 December 2021. This increase was primarily driven by higher oil prices (Brent) which increased by 43 per cent. to $101.2/bbl for the year ended 31 December 2022 from $70.9/bbl for the year ended 31 December 2021. The existence of hedges in both periods as well as a decline in sales volumes by 10 per cent. reduced the relative increase compared to the increase in Brent prices.

The Target Portfolio's gas sales increased by $2,459 million, or 105 per cent., to $4,797 million for the year ended 31 December 2022 from $2,338 million for the year ended 31 December 2021. This increase was primarily driven by higher TTF gas prices which increased by 136 per cent. to $36.97/mscf for the year ended 31 December 2022 from $15.69/mscf for the year ended 31 December 2021. The increase in TTF prices was partially offset by the existence of hedges as well as domestic gas price and formula price contracts in certain non-European jurisdictions of the Target Portfolio.

The Target Portfolio's condensate sales (comprising condensate, NGL and LPG) increased by $144 million, or 36 per cent., to $544 million for the year ended 31 December 2022 from $400 million for the year ended

31 December 2021. This increase was primarily driven by higher prices for condensate, NGL and LPG. In addition, sales volumes increased by 15 per cent.

The Target Portfolio's tariff income increased by $61 million, or 763 per cent., to $69 million for the year ended 31 December 2022 from $8 million for the year ended 31 December 2021. This increase was primarily driven by higher sales of unused pipeline capacity in Norway.

The Target Portfolio's other income decreased by $9 million, or 14 per cent, to $57 million for the year ended 31 December 2022 from $66 million for the year ended 31 December 2021. This decrease was primarily driven by lower government grants in Argentina.

Cost of operations

The Target Portfolio's cost of operations remained stable at $2,942 million for the year ended 31 December 2022 compared with $2,927 million for the year ended 31 December 2021. This is due to several opposing effects: increases in tariff costs (mainly in Norway), in costs for gas purchases (mainly in Germany due to the optimization of a storage), higher royalties (mainly in Germany due to higher gas prices) as well as a negative effect from changes in over/underlift were offset by lower production costs in Egypt after the relinquishment of the concessions in the Gulf of Suez, lower restructuring and integration costs, lower depreciation charges in Germany, Argentina and Norway as well as a one-off effect from a provision for a commercial settlement with a third-party in Germany in the year ended 31 December 2021.

Net impairment reversal/(impairment) of property, plant and equipment and other intangible assets

The Target Portfolio recognised a net impairment on assets of $188 million for the year ended 31 December 2022 compared to a net impairment reversal of $6 million for the year ended 31 December 2021. The net impairments for the year ended 31 December 2022 consisted of impairments for assets, amounting in total to $322 million, in Norway due to disposal of Brage, in Mexico due to changed technical concepts and in Egypt due to operational updates as well as reversal of impairments on assets amounting to $134 million, relating to assets in Egypt, Algeria and Germany due to improved economics of the projects. The net reversal of impairments for the year ended 31 December 2021 consisted of impairments on assets amounting to $402 million relating to assets in Mexico, Egypt and Germany due to operational updates and in Argentina due to inorganic measures, as well as reversal of impairments amounting to $409 million relating to assets in Norway and Mexico due to increased service potential after significant increase of commodity prices.

Exploration and evaluation expenses

The Target Portfolio's E&E expenses increased by $10 million, or 22 per cent., to $56 million for the year ended 31 December 2022 from $46 million for the year ended 31 December 2021. This increase was primarily driven by higher charges from non-operated concessions in Norway and in Egypt.

Exploration costs written off

The Target Portfolio's Exploration costs written off decreased by $165 million, or 85 per cent., to $28 million for the year ended 31 December 2022 from $193 million for the year ended 31 December 2021. The exploration costs written off in the year ended 31 December 2022 included a total of five dry wells in Norway and one dry well in Mexico. The exploration costs written off in the year ended 31 December 2021 consisted of three dry wells in Norway, losses from relinquishment of a licence in Norway, one dry well in Mexico as well as one dry well in Egypt. In addition, the exploration costs written off in the year ended 31 December 2021 included impairment losses on exploration assets in Egypt, Mexico and Norway.

Net gains and losses on disposal

The Target Portfolio had a net loss on disposal of $128 million for the year ended 31 December 2022. This loss was mainly due to the loss related to the sale of the Brage field in Norway. In addition, losses occurred in Algeria and Germany. This was partially offset by gains from disposal of certain assets in Germany. The Target Portfolio recorded a net gain on disposal of $25 million for the year ended 31 December 2021. This net gain consisted of gains from disposal of certain assets in Germany, farm-downs in Norway and Egypt as well as the sale of an office building in Germany, offset by losses from disposal related to the relinquishment of the concessions in the Gulf of Suez as well as related to farm-outs in Germany.

General and administrative expenses

The Target Portfolio's general and administrative expenses increased by $19 million, or 5 per cent., to $367 million for the year ended 31 December 2022 from $348 million for the year ended 31 December 2021. This increase was primarily driven by higher service charges from related parties as well as cost for the new carbon management and hydrogen function, partially offset by lower restructuring and integration costs. The allocation remained nearly stable in the years ended 31 December 2022 and 31 December 2021.

Finance income

The Target Portfolio's finance income increased by $9 million, or 3 per cent., to $301 million for the year ended 31 December 2022 from $292 million for the year ended 31 December 2021. The increase was primarily driven by higher net foreign exchange gains which were only partially offset by lower interest income.

Finance expenses

The Target Portfolio's finance expenses increased by $53 million, or 11 per cent., to $518 million for the year ended 31 December 2022 from $465 million for the year ended 31 December 2021. This increase was primarily driven by higher net losses from foreign currency derivatives.

Income tax expense

The Target Portfolio's income tax expense increased by $1,977 million, or 146 per cent., to $3,334 million for the year ended 31 December 2022 from $1,357 million for the year ended 31 December 2021. This increase was primarily driven by the higher profit before taxation due to significantly higher commodity prices. In addition, the Covid-Uplift allowance in Norway ceased in 2022. The tax rate for the year ended 31 December 2022 amounted to 81 per cent. (104 per cent. for the year ended 31 December 2021). The decrease in the tax rate is primarily due to a lower share of Norway in the overall profit before taxation of the Target Portfolio.

Liquidity and Capital Resources

The Target Portfolio's liquidity requirements arise principally from capital expenditures in its business, including in the areas of exploration, development, production and acquisition of oil and natural gas reserves and resources (for example, to offset declines in its key production assets) and to meet its obligations under changing environmental laws and regulations. For the periods presented, the Target Portfolio met its liquidity requirements primarily from ongoing cash flow generation from its producing assets.

The Target Portfolio also held cash and cash equivalents of $149 million, $324 million and $244 million as of 31 December 2021, 31 December 2022 and 31 December 2023, respectively.

Cash Flow

The following table sets forth the Target Portfolio's consolidated cash flow information for the years ended 31 December 2021, 31 December 2022 and 31 December 2023:

	Year Ended 31 December		
	2021	2022	2023
		($ million)	
Net cash inflow from operating activities	3,108	3,655	1,597
Net cash outflow from investing activities	(3,871)	(3,147)	(164)
Net cash inflow / (outflow) from financing activities	802	(305)	(1,212)
Cash and cash equivalents at 31 December	149	324	244

Net cash (outflow)/inflow from operating activities

Net cash flows from operating activities consist of:

	Year ended 31 December		
	2021	2022	2023
		($ million)	
Profit before tax for the year	1,302	4,115	2,575
Adjustments to reconcile profit before tax to net cash flows:			
Finance income	(224)	(198)	(497)
Finance expense	182	192	281
Depreciation and amortisation	1,670	1,464	1,400
Impairment (reversal)/expense of property, plant and equipment	(23)	176	(111)
Impairment goodwill	17	12	—
Net loss/(gain) on disposal	(25)	128	10
SIR 2000 adjustment	131	132	11
Exploration costs written-off	193	28	72
Decommissioning costs paid	(38)	(68)	(41)
Fair value movement of derivatives not yet settled	29	15	(41)
Unrealised foreign currency movement	(231)	(309)	367
Decrease / (Increase) in inventories	(23)	(32)	43
(Increase) in trade and other receivables	(276)	(133)	(68)
Increase in trade and other payables	151	111	228
Increase/(decrease) in provisions	176	66	(26)
Other operating cash flows	(123)	(34)	(91)
Tax paid	220	(2,010)	(2,515)
Net cash inflow from operating activities	**3,108**	**3,655**	**1,597**

The Target Portfolio's net cash inflow from operating activities was $1,597 million for the year ended 31 December 2023 compared to $3,655 million for the year ended 31 December 2022. This change was primarily due to lower commodity prices and higher income tax payments mainly due to the high tax payment schedule in Norway for the year 2022.

The Target Portfolio's net cash inflow from operating activities was $3,655 million for the year ended 31 December 2022 compared to $3,108 million for the year ended 31 December 2021. This increase was primarily due to higher commodity prices. This was partially offset by significantly higher income tax payments in Norway.

Net Cash Outflow From Investing Activities

	Year Ended 31 December		
	2021	2022	2023
		($ million)	
Cash pooling with related parties	(2,693)	(2,608)	(80)
Proceeds from financial receivables—related parties	1,342	104	975
Issuance of financial receivables—related parties	(1,797)	—	—
Proceeds from financial liabilities—related parties	846	—	—
Issuance of financial liabilities—related parties	(716)	—	(17)
Net cashflow with related parties	**(3,018)**	**(2,504)**	**878**
Expenditure on exploration and evaluation assets	(125)	(119)	(116)
Expenditure on property, plant and equipment	(1,021)	(893)	(1,382)
Expenditure on other intangible assets	(2)	(6)	(21)
Expenditure on financial assets	(4)	(2)	—
Proceeds from disposal of financial assets	6	—	—
Proceeds from the disposal of exploration and evaluation assets	13	—	—
Proceeds from the disposal of property, plant and equipment	90	225	34
Interest received	190	152	443
Net cash outflow from investing activities	**(3,871)**	**(3,147)**	**(164)**

The Target Portfolio's net cash outflow from investing activities was $164 million for the year ended 31 December 2023 compared to $3,147 million for the year ended 31 December 2022. This decrease was primarily due to a positive impact from net cash flows from investing activities with related parties which turned into a net cash inflow in 2023 compared to a net cash outflow in 2022. This was partially compensated by higher capital expenditures.

The Target Portfolio's net cash outflow from investing activities was $3,147 million for the year ended 31 December 2022 compared to $3,871 million for the year ended 31 December 2021. This decrease was primarily due to lower cash outflows from investing activities with related parties as well as lower capital expenditures and higher proceeds from the sale of assets.

For a more detailed description of the Target Portfolio's recent capital expenditure, see "—*Capital Investment*" in this Part VII (*Operating and Financial Review relating to the Target Portfolio*).

Net cash inflow/(outflow) from financing activities

	Year Ended 31 December		
	2021	**2022**	**2023**
		($ million)	
Repayment of bonds	—	(106)	(979)
Proceeds from debt to banks	62	12	—
Repayment of debt to banks	(862)	(12)	—
Lease liability payments	(69)	(35)	(28)
Interest paid	(87)	(164)	(205)
Proceeds from Subordinated Notes	1,758	—	—
Net cash inflow / (outflow) from financing activities	**802**	**(305)**	**(1,212)**

The Target Portfolio's net cash outflow from financing activities was $1,212 million for the year ended 31 December 2023 compared to $305 million for the year ended 31 December 2022. This increase was primarily due to higher repayments of bonds.

The Target Portfolio's net cash outflow from financing activities was $305 million for the year ended 31 December 2022 compared to a net cash inflow of $802 million for the year ended 31 December 2021. The change was primarily due to the fact that proceeds from Subordinated Notes were included in 2021, which were partially offset by corresponding repayments of debt to banks.

For a more detailed description of the Target Portfolio's recent financing activities, see "—*Financing*" in this Part VII (*Operating and Financial Review relating to the Target Portfolio*).

Cash and Cash Equivalents

As of 31 December 2023, the Target Portfolio held $244 million of cash and cash equivalents.

Capital Investment

As at 31 December 2023, the Target Portfolio has obligations based on based on firm orders for property, plant and equipment, as well as from field development projects, exploration wells and seismic surveys in the amount of $2,017 million (2022: $866 million and 2021: $490 million).

Contractual Obligations and Contingent Liabilities

Contingent liabilities

Contingent liabilities relate to legal disputes and potential tax risks. The Target Portfolio is regularly involved as a defendant or other party in judicial and arbitration proceedings, as well as in official proceedings. Based on the present knowledge, these proceedings have no significant impact on the Target Portfolio's economic situation.

The Target Portfolio is also subject to statutory liability related to participations in various joint ownerships. Based on the present knowledge, these proceedings have no significant impact on Target Portfolio's economic situation.

Financing

For details of the Target Portfolio's liquidity requirements, see "—*Liquidity and Capital Resources*" in this Part VII (*Operating and Financial Review relating to the Target Portfolio*). The Target Portfolio's actual financing requirements will depend on a number of factors, many of which are external factors and are therefore beyond the control of the Target Portfolio.

For further details of the Target Portfolio's financing arrangements, see paragraph 16 (*Target Portfolio Material Contracts*) in Part XIV (*Additional Information*).

Qualitative and Quantitative Disclosures About Market Risk

Foreign currency risk

Changes in exchange rates could lead to losses in the value of financial instruments and adverse changes in future cash flows. Foreign currency risks from financial instruments arise from the translation of financial receivables, cash and cash equivalents and financial liabilities into the functional currency of the respective Target Portfolio company at the closing rates. The Target Portfolio's foreign currency exposures are monitored and managed with the aim to eliminate the effect of currency fluctuations on the statement of income.

Exposure and sensitivity per currency:

	31 December 2023			31 December 2022			31 December 2021		
	Exposure	–10%	+10%	Exposure	–10%	+10%	Exposure	–10%	+10%
					($ million)				
EGP	10	(1)	1	71	(6)	6	—	—	—
GBP	—	—	—	148	(13)	13	206	(19)	19
USD	(2,295)	209	(209)	(150)	13	(13)	81	(7)	7
ARS	176	(16)	16	208	(19)	19	20	(2)	2
NOK	49	(4)	4	(337)	31	(31)	(186)	17	(17)
MXN	(128)	11	(11)	(99)	9	(9)	29	(3)	3
Total	**(2,188)**	**199**	**(199)**	**(159)**	**15**	**(15)**	**150**	**(14)**	**14**

Interest rate risks

Interest rate risks arise due to potential changes in prevailing market interest rates, which can lead to changes in the fair value of fixed-rate instruments and interest payment fluctuations for variable-rate instruments. Even though the interest rates for the subordinated bonds are currently fixed, this will change over time, in line with the respective first option for the issuer to call one of the bonds for redemption in the year 2026, and the other in the year 2029. Following these dates the interest rate for the respective subordinated bond will be reset to become a variable interest rate, based on a benchmark rate and a spread. These risks are not of material significance for the Target Portfolio's operating activities.

Commodity price risks

The Target Portfolio's revenue, cash flows and profitability depend to a large extent on prevailing international and local commodity prices. Any resulting adverse changes in market prices could have a negative impact on the Target Portfolio's net result and equity.

Commodity price risks related to production are assessed and mitigated regularly using systematic risk management. The principles of this approach are defined in the commodity hedging policy.

All hedging transactions are entered into for the sole purpose of reducing risks from planned transactions exposed to commodity price risks that have a high probability of occurrence. Part of the oil and gas price risks are hedged. The volumes to be hedged depend on the economic exposure and the current level of oil and gas prices.

The target hedge volumes are 50 per cent. and 25 per cent. of economic exposure after tax, capped by 75 per cent. and 37.5 per cent. of effectively hedgeable volumes, for a one-year and two-year horizon, respectively.

Existing hedges as at 31 December 2023 include forward gas sales and zero cost collars to stabilise portions of gas revenues until 2025 as well as Dated Brent oil swaps and zero cost collars to stabilise portions of oil sales until 2025.

For the Dated Brent oil swaps and the zero cost collars, German and Norwegian oil production currently serves as a hedged item. The contracted price is defined via a price formula. Regression analyses show a high correlation between Dated Brent oil prices and contracted prices and provide the basis for determining optimal hedge ratios. In the case of fixed-price gas sales agreements, to which the hedge accounting regulations are applicable, the critical terms match method is applied to assess hedge effectiveness.

Commodity price risks also arise in the ordinary course of business for contracted gas purchase and supply agreements. The specific price risk, which results from the valuation of the gas agreements concluded in the event of an adverse change in market prices, is mitigated by imposing and constantly monitoring the limits on the type and scope of the transactions concluded.

The following table summarises the impact on the Target Portfolio's pre-tax profit and other comprehensive income from a reasonably foreseeable movement in commodity prices on the fair value of commodity based derivative instruments held:

	As of 31 December					
	2021		2022		2023	
	Effect on profit before tax	Effect on OCI	Effect on profit before tax	Effect on OCI	Effect on profit before tax	Effect on OCI
	($ million)					
Brent crude oil						
$10/bbl increase	—	(157)	—	(123)	—	(96)
$10/bbl decrease	—	157	—	123	—	96
Natural gas						
$1.5/MMBtu increase	(47)	(644)	(64)	(514)	(11)	(155)
$1.5/MMBtu decrease	47	644	64	514	11	155

Credit Risk

Default and credit risks arise when contractual partners do not fulfil their obligations. The Target Portfolio is exposed to credit risks from its operating activities (primarily trade accounts receivable) and its financing activities, including deposits with banks and financial institutions, favourable derivative financial instruments (positive fair value) and other financial receivables.

If customers are independently rated, these ratings are used for assessment. If there is no independent rating, the risk management function assesses customers' credit quality based on their financial position or bases the assessment on past experience and other factors. Individual risk limits are set based on internal or external ratings in accordance with set limits. There are no significant concentrations of credit risks through the exposure to individual customers or regions. Country-specific payment risks are within the limits stipulated by the management and closely monitored.

A default event occurs if there is good reason to believe that a customer will not repay its liability to the Target Portfolio, usually due to the customer's financial difficulty. A payment delay in the course of regular business practice does not alone indicate a customer default.

An assessment of the overall situation is required on a case-by-case basis.

The maximum risk of default corresponds to the carrying amounts of the financial assets.

Financial assets are written off when there is no reasonable expectation of recovery of the contractual cash flows. Losses from financial assets that have been written off were not material in 2023, 2022 and 2021.

Liquidity risks

The liquidity risk management ensures that the required liquidity to meet financial obligations is available at all times and that the liquidity position of the Target Portfolio is optimised. Centralised financial planning is the basis for liquidity risk management. Financial planning is performed for the following twelve months on a monthly basis and for the following month on a daily basis.

Wintershall Dea AG has a revolving credit facility that was available to the Target Portfolio in the total amount of €900 million, with an initial tenor of five years and additional extension options of up to two years were agreed with a bank consortium and can be utilised if necessary. The first and second one-year extensions were confirmed for the full amount. This facility is available until March 2026 remains undrawn, however it will no longer be available on completion of the transaction.

The Target Portfolio's cash flow requirements are monitored on a regular basis, taking into consideration the funding sources, existing bank facilities and cash flow generation from the producing asset base. Specifically, it is ensured that there is sufficient liquidity to meet operational funding requirements and debt servicing.

Maturity Analysis

	≤1 year	1-5 years	>5 years	Total Payment Amount
		($ million)		
As at 31 December 2023				
Non-derivative financial liabilities				
Bond	12	2,207	1,104	3,323
Subordinated notes	34	—	1,656	1,690
Trade and other payables (excluding related party financial liabilities)	949	7	—	956
Lease obligations	34	81	41	156
Related party financial liabilities	568	—	—	568
Total non-derivative financial liabilities	1,597	2,295	2,801	6,693
Derivative financial liabilities				
Foreign currency derivatives	585	—	—	585
Commodity derivatives (settled in cash)	44	3	—	47
Total	**2,226**	**2,298**	**2,801**	**7,325**
As at 31 December 2022				
Non-derivative financial liabilities				
Bond	967	1,061	2,121	4,149
Subordinated notes	33	—	1,591	1,624
Trade and other payables (excluding related party financial liabilities)	603	12	—	615
Lease obligations	21	52	37	110
Related party financial liabilities	809	—	1,302	2,111
Total non-derivative financial liabilities	2,433	1,125	5,051	8,609
Derivative financial liabilities				
Foreign currency derivatives	1,112	—	—	1,112
Commodity derivatives (settled in cash)	119	42	—	161
Total	**3,664**	**1,167**	**5,051**	**9,882**
As at 31 December 2021				
Non-derivative financial liabilities				
Bond	13	2,274	2,274	4,561
Subordinated notes	36	—	1,706	1,742
Trade and other payables (excluding related party financial liabilities)	559	11	—	570
Lease obligations	27	45	41	113
Related party financial liabilities	604	—	1,372	1,976
Total non-derivative financial liabilities	1,238	2,330	5,393	8,962
Derivative financial liabilities				
Foreign currency derivatives	749	—	—	749
Commodity derivatives (settled in cash)	132	78	—	210
Total	**2,119**	**2,408**	**5,393**	**9,921**

Impairment on financial assets

In order to determine the impairment of financial assets, the Target Portfolio uses either a general three-stage approach or the simplified approach, according to IFRS 9, as applicable. In the case of financial assets for which the simplified approach does not apply, their assessment takes place as at each reporting date to determine whether the credit risk on a financial instrument has increased significantly since its initial recognition.

Trade accounts receivable, other receivables, financial receivables and deposits with banks are subject to the expected credit loss model. This is generally based on either externally provided or internal ratings for each debtor which, in certain cases, are updated based on recently available information.

To measure the expected credit losses on trade accounts receivable, the Target Portfolio applies the simplified approach according to IFRS 9. Accordingly, the loss allowance is measured at an amount equal to the lifetime expected credit losses. For trade accounts receivable, the contractual payment term is usually 30 days. In deviation to this general rule, terms of up to one year are considered for the calculation of expected credit losses due to different regional payment practices, especially in Egypt and Mexico.

The loss allowance for other receivables, financial receivables and deposits with banks is measured at an amount equal to the twelve-month expected credit loss. If the term of the financial instrument is shorter than 12 months, the lifetime expected credit loss is applied.

The valuation loss allowances are determined as follows for the years ended 31 December 2021, 2022 and 2023:

	As at 1 January 2023	Additions	Reversals	Currency translation adjustments	As at 31 December 2023
			$ million		
Trade accounts receivable					
of which Stage 2	(2)	(49)	3	(1)	(49)
of which Stage 3	(9)	—	5	—	(4)
	(11)	**(49)**	**8**	**(1)**	**(53)**
Other receivables					
of which Stage 3	(6)	(5)	—	—	(11)
	(6)	**(5)**	**—**	**—**	**(11)**
Financial receivables					
of which Stage 1	—	(8)	8	—	—
Total	**(17)**	**(62)**	**16**	**(1)**	**(64)**

	As at 1 January 2022	Additions	Reversals	Disposals	Transfer	Currency translation effects	As at 31 December 2022
				$ million			
Trade accounts receivable							
of which Stage 2	(3)	(4)	4	—	—	—	(3)
of which Stage 3	(14)	—	5	—	—	—	(9)
	(17)	**(4)**	**9**	**—**	**—**	**—**	**(12)**
Other receivables							
of which Stage 2	(4)	—	—	—	4	—	—
of which Stage 3	—	(3)	—	—	(3)	—	(6)
	(4)	**(3)**	**—**	**—**	**1**	**—**	**(6)**
Financial receivables							
of which Stage 3	—	—	—	—	—	—	—
Total	**(21)**	**(7)**	**9**	**—**	**1**	**—**	**(18)**

	As at 1 January 2021	Additions	Reversals	Disposals	Currency translation effects	As at 31 December 2021
				$ million		
Trade accounts receivable						
of which Stage 2	(3)	(6)	6	—	1	(2)
of which Stage 3	(16)	(1)	3	—	—	(14)
	(19)	**(7)**	**9**	**—**	**1**	**(16)**
Other receivables						
of which Stage 3	—	(3)	—	—	(1)	(4)
	—	**(3)**	**—**	**—**	**(1)**	**(4)**
Financial receivables						
of which Stage 3	(27)	—	—	24	1	(2)
Total	(46)	(10)	9	24	1	(22)

Critical Accounting Estimates and Judgments

The preparation of the combined historical financial information in conformity with UK-adopted IFRS requires management to make judgements, estimates and assumptions at the date of the combined historical financial information. Combined historical financial information estimates and assumptions are continuously evaluated and are based on management 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 the assets or liabilities affected in future periods. In particular, the Target Portfolio has identified the following areas where significant judgement, estimates and assumptions are required.

Critical accounting judgements

- *Functional currency of Norway component:* Judgment is required in determining the functional currency on inception of an entity and whether there has been a change to that functional currency. In respect to the Norway component, management have considered the currency of both cash inflows and outflows that the component is subject to, as well as the currency in which its funding is received. This component receives the majority of its cash inflows in US dollars. However, it does also receive some inflows in both Euro and Norwegian Krone. Similarly, with its outflows, these include both US dollars and Norwegian Krone denominated amounts. Management also note that the majority of funding, which is received from entities outside the perimeter, is received in US dollars. Taking all these factors into account and recognising that it is a judgment, management determined that US dollars was its functional currency reflecting the primary economic environment in which it operates. In addition, management considered whether these indicators had moved during the historical financial information period and determined that no change had been noted, on this basis US dollars has been applied as the functional currency throughout.

Key sources of estimation uncertainty

- *Gas and oil reserves*: Natural gas and oil reserves are used to determine the recoverable amount within the scope of an impairment test, as well as for production-related depreciation and amortisation using the unit-of-production method, and the year of abandonment assumption used to determine decommissioning provision. Reserves are estimated by Wintershall Dea AG's own qualified engineers and geoscientists based on standardised valuation methods and are classified in line with international industry standards. This process is subject to specific guidelines. Furthermore, the estimates are audited by independent consultants on a regular basis.
- *Impairment of property, plant and equipment*: Assumptions used in impairment testing for property, plant and equipment relate to estimated reserves, price assumptions for natural gas and crude oil, consumer price indices and exchange rates, CO_2 prices, production forecasts and discount rates as well as production costs. For further details on inputs and sensitivities, see "*Note 11*" in Part IX (*Historical Financial Information relating to the Target Portfolio*) of this Prospectus.
- *Decommissioning cost and provisions*: Decommissioning provisions require estimates and assumptions, with regards to terms, costs to be considered and discount rates. Future actual cashflows may differ due to changes in relation to these items. For further details on inputs and sensitivities, see "*Note 22*" in Part IX (*Historical Financial Information relating to the Target Portfolio*) of this Prospectus.
- *Oil and Gas Depreciation*: Depreciation is generally calculated on the units of production methodology using proven reserves. If the approach was changed to use proven and probable reserves, the value of total assets would increase by $1.1 billion (2022: $764 million, 2021: $523 million) and have an impact of $329 million (2022: $241 million, 2021: $529 million) on the income statement of the Target Portfolio, thereby increasing profit.

Recent Accounting Pronouncements

For details of recent amendments to IFRS Standards and Interpretations that have been applied to the financial information of the Target Portfolio, see "*Note 3*" in Part IX (*Historical Financial Information relating to the Target Portfolio*) of this Prospectus.

PART VIII
HISTORICAL FINANCIAL INFORMATION RELATING TO HARBOUR ENERGY

1. BASIS OF FINANCIAL INFORMATION

The Company's audited consolidated financial statements for the years ended 31 December 2023, 2022 and 2021 included in the Harbour Energy Annual Reports 2023, 2022 and 2021, respectively, together with the respective audit reports thereon, are incorporated by reference into and form part of, this Prospectus.

The Company's consolidated financial statements for the years ended 31 December 2023, 2022 and 2021 were prepared in accordance with IFRS as adopted by the United Kingdom and in accordance with the Companies Act, were audited and the audit report was unqualified.

2. DOCUMENTS INCORPORATED BY REFERENCE

Certain sections, as set out below, of the Harbour Energy Annual Reports for the years ended 31 December 2023, 2022 and 2021 are incorporated by reference into this Prospectus.

The following cross-reference list is intended to enable investors to identify easily specific items of information which have been incorporated by reference into this Prospectus.

For the year ended 31 December 2023

Information incorporated by reference into this Prospectus	Page number in Harbour Energy Annual Report 2023
Independent auditor's report	109 to 117 (inclusive)
Consolidated income statement	118
Consolidated statement of comprehensive income on page	119
Consolidated balance sheet	120
Consolidated statement of changes in equity	121
Consolidated statement of cash flows	122
Notes to the consolidated financial statements	123 to 171 (inclusive)

For the year ended 31 December 2022

Information incorporated by reference into this Prospectus	Page number in Harbour Energy Annual Report 2022
Independent auditor's report	108 to 117 (inclusive)
Consolidated income statement	118
Consolidated statement of comprehensive income on page	119
Consolidated balance sheet	120
Consolidated statement of changes in equity	121
Consolidated statement of cash flows	122
Notes to the consolidated financial statements	123 to 172 (inclusive)

For the year ended 31 December 2021

Information incorporated by reference into this Prospectus	Page number in Harbour Energy Annual Report 2021
Independent auditor's report	103 to 113 (inclusive)
Consolidated income statement	114
Consolidated statement of comprehensive income on page	115
Earnings per share	115
Consolidated balance sheet	116
Consolidated statement of changes in equity	117
Consolidated statement of cash flows	118
Notes to the consolidated financial statements	119 to 165 (inclusive)

PART IX
HISTORICAL FINANCIAL INFORMATION RELATING TO THE TARGET PORTFOLIO

SECTION A:
ACCOUNTANT'S REPORT IN RESPECT OF THE HISTORICAL FINANCIAL INFORMATION RELATING TO THE TARGET PORTFOLIO

KPMG LLP
15 Canada Square
London E14 5GL
United Kingdom

Tel +44 (0) 20 7311 1000
Fax +44 (0) 20 7311 3311

The Directors
Harbour Energy plc
23 Lower Belgrave Street
London
SW1W 0NR

12 June 2024

Ladies and Gentlemen

The Target Portfolio

We report on the financial information of the Target Portfolio set out in Section B of part IX of the Prospectus dated 12 June 2024 of Harbour Energy plc for the years ended 31 December 2021, 31 December 2022 and 31 December 2023 (the "**Historical Financial Information**"). This report is required by Item 18.3.1 of Annex 1 of the UK version of Commission Delegated Regulation (EU) 2019/980 (the "**PR Regulation**") and is given for the purpose of complying with that item and for no other purpose.

Opinion on financial information

In our opinion, the Historical Financial Information gives, for the purposes of the Prospectus dated 12 June 2024 of Harbour Energy plc, a true and fair view of the state of affairs of the Target Portfolio as at 31 December 2021, 31 December 2022 and 31 December 2023 and of its profits/losses, other comprehensive income, cash flows and statement of changes in equity for the years then ended in accordance with the basis of preparation set out in note 2 of the Historical Financial Information.

Responsibilities

The Directors of Harbour Energy plc are responsible for preparing the Historical Financial Information on the basis of preparation set out in note 2 to the Historical Financial Information.

It is our responsibility to form an opinion on the Historical Financial Information and to report our opinion to you.

Save for any responsibility arising under Prospectus Regulation Rule 5.3.2R (2)(f) to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Item 1.3 of Annex 1 of the PR Regulation, consenting to its inclusion in the prospectus.

Basis of Preparation

The Historical Financial Information has been prepared on the basis of the accounting policies set out in note 2 of the Historical Financial Information.

Basis of Opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Financial Reporting Council in the United Kingdom (the "**FRC**"). We are independent, and have fulfilled our other ethical responsibilities, in accordance with the relevant ethical requirements of the FRC's Ethical Standard as applied to Investment Circular Reporting Engagements.

Our work included an assessment of evidence relevant to the amounts and disclosures in the Historical Financial Information. It also included an assessment of the significant estimates and judgments made by those responsible for the preparation of the Historical Financial Information and whether the accounting policies are appropriate to the Target Portfolio's circumstances, consistently applied and adequately disclosed.

KPMG LLP
15 Canada Square
London E14 5GL
United Kingdom

Tel +44 (0) 20 7311 1000
Fax +44 (0) 20 7311 3311

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the Historical Financial Information is free from material misstatement whether caused by fraud or other irregularity or error.

Conclusions Relating to Going Concern

The Directors of Harbour Energy plc (the "**Directors**") have prepared the Historical Financial Information on the going concern basis as they do not intend to liquidate the Target Portfolio or to cease its operations, and as they have concluded that the Target Portfolio's financial position means that this is realistic. They have also concluded that there are no material uncertainties that could have cast significant doubt over its ability to continue as a going concern for at least a year from the date of approval of the Historical Financial Information (the "**going concern period**").

Our conclusions based on this work:

- we consider that the Directors' use of the going concern basis of accounting in the preparation of the entity's Historical Financial Information is appropriate; and
- we have not identified, and concur with the Directors' assessment that there is not, a material uncertainty related to events or conditions that, individually or collectively, may cast significant doubt on the Target Portfolio's ability to continue as a going concern for the going concern period.

However, as we cannot predict all future events or conditions and as subsequent events may result in outcomes that are inconsistent with judgments that were reasonable at the time they were made, the above conclusions are not a guarantee that the Target Portfolio will continue in operation.

Declaration

For the purposes of Prospectus Regulation Rule 5.3.2R (2)(f) we are responsible for this report as part of the prospectus and declare that, to the best of our knowledge, the information contained in this report is in accordance with the facts and that the report makes no omission likely to affect its import. This declaration is included in the prospectus in compliance with Item 1.2 of Annex 1 of the PR Regulation.

Yours faithfully

KPMG LLP

SECTION B:
HISTORICAL FINANCIAL INFORMATION RELATING TO THE TARGET PORTFOLIO

Combined Statement of other Comprehensive Income for the years ended 31 December

	Note	2023	2022	2021
			$ million	
Revenue	6	6,337	7,984	4,892
Other income	6	43	57	66
Revenue and other income		**6,380**	**8,041**	**4,958**
Cost of operations	7	(3,128)	(2,942)	(2,927)
Net impairment reversal/(impairment) of property, plant and equipment, goodwill and other intangible assets	7	111	(188)	6
Exploration and evaluation expenses	7	(78)	(56)	(46)
Exploration costs written-off	7	(72)	(28)	(193)
Net (losses)/gains on disposal	7	(10)	(128)	25
General and administrative expenses	7	(412)	(367)	(348)
Operating profit		**2,791**	**4,332**	**1,475**
Finance income	9	497	301	292
Finance expenses	9	(713)	(518)	(465)
Profit before taxation		**2,575**	**4,115**	**1,302**
Income tax expense	10	(2,028)	(3,334)	(1,357)
Profit/(loss) for the year		**547**	**781**	**(55)**
Other comprehensive profit/(loss)				
Items that will not be subsequently reclassified to income statement:				
Actuarial gains and losses	21	(24)	67	52
Tax (expense)/credit on actuarial gains and losses	10	10	(22)	(15)
Items that may be subsequently reclassified to income statement:				
Unrealised gains and losses on currency translation		11	(53)	(151)
Fair value gains on cash flow hedges	17	3,493	(748)	(2,735)
Tax (expense)/credit on cash flow hedges	10	(2,560)	617	2,090
Other comprehensive profit/(loss) for the period, net of tax		**930**	**(139)**	**(759)**
Total comprehensive profit/(loss) for the year		**1,477**	**642**	**(814)**

The results relate to continuing operations.

Comprehensive income is attributable to the Target Portfolio, as per note 29.

Combined Balance Sheet as at 31 December

	Note	2023	2022	2021
		As at 31 December		
			$ million	
Assets				
Non-current assets				
Goodwill	11	2,304	2,287	2,353
Other intangible assets	12	374	285	206
Property, plant and equipment	13	10,491	10,422	12,178
Right-of-use assets	14	131	93	80
Deferred tax assets	10	312	246	256
Other receivables and assets	16	33	3,675	4,624
Derivative financial assets	17	134	7	3
Total non-current assets		**13,779**	**17,015**	**19,700**
Current assets				
Inventories	15	195	239	207
Trade and other receivables	16	2,082	8,125	5,496
Derivative financial assets	17	234	97	16
Cash and cash equivalents	18	244	324	149
Assets held for sale	27	—	—	146
Total current assets		**2,755**	**8,785**	**6,014**
Total assets		**16,534**	**25,800**	**25,714**
Invested capital				
Invested capital	24	792	6,690	6,651
Total invested capital attributable to the Target Portfolio investors		**792**	**6,690**	**6,651**
Liabilities				
Non-current liabilities				
Borrowings	23	4,963	4,766	6,241
Provisions	21, 22	2,238	2,259	3,082
Deferred tax	10	4,641	2,097	2,670
Trade and other payables	20	27	1,325	1,399
Lease creditor	14	107	78	75
Derivative financial liabilities	17	42	1,293	1,072
Total non-current liabilities		**12,018**	**11,818**	**14,539**
Current liabilities				
Trade and other payables	20	1,642	1,582	1,333
Lease creditor	14	29	19	25
Borrowings	23	46	1,000	49
Provisions	22	453	375	471
Current tax liabilities		1,296	1,895	716
Derivative financial liabilities	17	258	2,421	1,924
Liabilities directly associated with asset classified as held for sale	27	—	—	6
Total current liabilities		**3,724**	**7,292**	**4,524**
Total liabilities		**15,742**	**19,110**	**19,063**
Total liabilities and invested capital		**16,534**	**25,800**	**25,714**

Combined Statement of Changes in Equity for years ended 31 December

	Note	**Invested capital**
Balance at 1 January 2021		**7,490**
Loss for the year		(55)
Other comprehensive loss for the period, net of tax		(759)
Total comprehensive loss		**(814)**
Capital reduction	24	(25)
Balance at 31 December 2021		**6,651**
Profit for the year		781
Other comprehensive loss for the period, net of tax		(139)
Total comprehensive income		**642**
Capital reduction	24	(603)
Balance at 31 December 2022		**6,690**
Profit for the year		547
Other comprehensive profit for the period, net of tax		930
Total comprehensive income		**1,477**
Capital reduction	24	(7,375)
Balance at 31 December 2023		**792**

Combined Statement of Cash Flows for the years ended 31 December

		Year ended 31 December		
		2023	**2022**	**2021**
	Note		*$m*	
Net cash inflow from operating activities	26	**1,597**	**3,655**	**3,108**
Investing activities				
Cash pooling with related parties		(80)	(2,608)	(2,693)
Proceeds from financial receivables—related parties		975	104	1,342
Issuance of financial receivables—related parties		—	—	(1,797)
Proceeds from financial liabilities—related parties	23	—	—	846
Issuance of financial liabilities—related parties	23	(17)	—	(716)
Net cashflow with related parties		**878**	**(2,504)**	**(3,018)**
Expenditure on exploration and evaluation assets		(116)	(119)	(125)
Expenditure on property, plant and equipment		(1,382)	(893)	(1,021)
Expenditure on other intangible assets		(21)	(6)	(2)
Expenditure on financial assets		—	(2)	(4)
Proceeds from disposal of financial assets		—	—	6
Proceeds from the disposal of exploration and evaluation assets		—	—	13
Proceeds from the disposal of property, plant and equipment		34	225	90
Interest received		443	152	190
Net cash outflow from investing activities		**(164)**	**(3,147)**	**(3,871)**
Financing activities				
Repayment of bonds	23	(979)	(106)	—
Proceeds from debt to banks	23	—	12	62
Repayment of debt to banks	23	—	(12)	(862)
Lease liability payments	23	(28)	(35)	(69)
Interest paid		(205)	(164)	(87)
Proceeds from subordinated notes	23	—	—	1,758
Net cash inflow / (outflow) from financing activities		**(1,212)**	**(305)**	**802**
Net increase in cash and cash equivalents		**221**	**203**	**39**
Net foreign exchange difference		(301)	(28)	(6)
Cash and cash equivalents at 1 January		324	149	116
Cash and cash equivalents at 31 December	18	**244**	**324**	**149**

1. GENERAL INFORMATION

The principal activities of the Target Portfolio are the exploration, development and production of natural gas and oil and resulting by-products in Northern Europe, Latin America, North Africa and Other.

2. BASIS OF PREPARATION

2.1 The Perimeter

The transaction includes the purchase of shares in a limited liability company ("**Target Company**") which will be created to head the group comprising of the legal entities included in the Target Portfolio. As well as the acquisition of the Target Company, the Target Portfolio also comprises certain licenses, hedge arrangements and other trade agreements held in the Wintershall Dea AG group.

The Combined Carved-Out Historical Financial Information ("**Combined HFI**") of the Target Portfolio comprises the portfolio of assets and liabilities to be acquired, as described in the Business Combination Agreement ("**BCA**") signed by the selling shareholders (BASF SE, BASF Handels—Und Exportgesellschaft Mit Beschrankter Haftung, Letterone Holdings S.A., L1 Energy Capital Management Services S. À R. L.) and the buyer (Harbour Energy plc). These comprise of:

a) Certain legal entities and the assets they hold—all of Wintershall Dea AG's upstream assets in Norway, Germany, Denmark (excluding Ravn field), Argentina, Mexico, Egypt, Libya (excluding Wintershall AG) and Algeria as well as Wintershall Dea AG's CO2 Capture and Storage licences in Europe. These upstream asset concessions and Carbon Capture and Storage ("**CCS**") licences are summarised as follows:

Entity	Country of operations	Country of registration	Asset	Nature	Operating interest
Wintershall Dea Norge AS .	Norway	Norway	Njord	Production	50%
			Snorre	Production	8.57%
			Vega	Production	56.70%
			Aasta Hansteen	Production	24%
			Æfugl Nord	Production	25%
			Bauge	Production	27.50%
			Dvalin	Production	55%
			Edvard Grieg	Production	15%
			Gjøa	Production	28%
			Hyme	Production	27.50%
			Maria	Production	50%
			Nova	Production	39%
			Skarv	Production	28.08%
			Dvalin North	Development	55%
			Maria Phase 2	Development	50%
			Irpa	Development	19%
			Alve Nord	Development	20%
			Idun Nord	Development	40%
			Luna	CCS	60%
			Havstjerne	CCS	60%
83 other Norway licences across production, development and exploration within Wintershall Dea Norge AS					
Wintershall Dea Deutschland GmbH	Germany	Germany	Emlichheim	Production	90%
			Mittelplate	Production	100%
			Völkersen	Production	100%
385 other Germany licences across production, development, exploration and other rights within Wintershall Dea Deutschland GmbH					
Wintershall Dea International GmbH—Branch Denmark . .	Denmark	Denmark	Cecilie	Production	43.60%
			Greensand	CCS	40%
Wintershall Dea Argentina S.A.	Argentina	Argentina	Aguada Pichana Este Residual	Production	27.27%
			Aguada Pichana Este Vaca Muerta	Production	22.50%
			CMA-1	Production	37.50%

Entity	Country of operations	Country of registration	Asset	Nature	Operating interest
			Fénix	Development	37.50%
9 other Argentina licences across production and exploration within Wintershall Dea Argentina S.A.					
Wintershall Dea México, S. de R.L. de C.V.	Mexico	Mexico	Ogarrio	Production	50%
			Block 30	Exploration	40%
			Block 2	Exploration	30%
2 other exploration licences within Wintershall Dea México, S. de R.L. de C.V					
Sierra Nevada E&P, S. DE R.L. DE C.V.	Mexico	Mexico	Block 29	Exploration	25%
Sierra O&G Exploración Y Producción, S. DE R.L. DE C.V.	Mexico	Mexico	Zama	Development	19.83%
Sierra Coronado E&P, S. DE R.L. DE C.V. /Sierra Offshore Exploration/ Sierra Perote E&P/ Sierra Blanca P&D	Mexico	Mexico	Hokchi	Production	37%
Sierra Coronado E&P	Mexico	Mexico	Block 4	Exploration	50%
Sierra Offshore Exploration, S. DE R.L. DE C.V.	Mexico	Mexico	Block 5	Exploration	30%
Wintershall Dea Nile GmbH	Egypt	Germany	Disouq	Production	100%
			East Damanhour	Production	40%
Wintershall Dea WND GmbH	Egypt	Germany	West Nile Delta	Production	17.25%
Wintershall Dea Suez GmbH[1]	Egypt	Germany	Ras Budran Zeit Bay	Production	100%
5 other Egypt licences across production, development and exploration within Wintershall Dea WND GmbH					
Wintershall Petroleum (E&P) B.V	Libya	Netherlands	Contract area 15, 16, 32 (Al-Jurf)	Production	12.50%
DEA North Africa/Middle East GmbH	Libya	Germany	NC193 NC195	Development	100%
DEA Cyrenaica GmbH	Libya	Germany	Area 58	Exploration	100%
Wintershall Dea Algeria GmbH	Algeria	Germany	Reggane Nord	Production	24%
Wintershall Dea Carbon Management Solution BV . .	The Netherlands	United Kingdom	Camelot	CCS	50%
Wintershall Dea Carbon Management Solution BV . .	The Netherlands	United Kingdom	Poseidon	CCS	10%
Wintershall Dea Middle East GmbH*	UAE	UAE	Ghasha	Development	10%

* *Wintershall Dea Middle East GmbH historically includes the Ghasha concession which Wintershall Dea AG owns a 10 per cent. working interest. There is a condition precedent in the BCA that states that the Ghasha concession will be sold from the aforementioned entity in line with the Ghasha SPA by day 1. The Ghasha concession and Wintershall Dea Middle East GmbH have therefore been excluded from the Combined HFI, as Wintershall Dea Middle East GmbH will become a shell following the sale of the Ghasha concession , and all the cash in the entity will be distributed to the selling shareholders. Prior to the publication of the prospectus and circular Ghasha will be sold.*

b) The legal entities holding interests in the following Technology participations:

Entity	Country of operations	Country of registration	Asset	Nature	Operating interest
Wintershall Dea Technology Ventures GmbH	Norway	Norway	Soiltech AS	Technology participation	13.60%
Wintershall Dea Technology Ventures GmbH	Norway	Norway	Earth Science Analytics AS	Technology participation	13.50%
Wintershall Dea Technology Ventures GmbH	Norway	Norway	Wellstarter AS	Technology participation	24.40%
Wintershall Dea Deutschland GmbH	Germany	Germany	Erdgas Münster GmbH	Technology participation	33.70%

[1] Wintershall Dea Suez GmbH relinquished its assets with effective date 1 January 2022, thus only includes assets in FY21.

Entity	Country of operations	Country of registration	Asset	Nature	Operating interest
Wintershall Dea Technology Ventures GmbH	Germany	Germany	AMBARtec AG	Technology participation	24.40%
Wintershall Dea Argentina S.A.	Argentina	Argentina	Gas Link S.A	Technology participation	5%
Wintershall Dea Argentina S.A.	Argentina	Argentina	Gasoducto Cruz del Sur S.A.	Technology participation	10%
Wintershall Dea Technology Ventures GmbH	United Kingdom	United Kingdom	HiiROC Limited	Technology participation	9.60%

In addition to the entities above, there are also a number of entities that are part of the Target Portfolio which do not contain upstream assets, these are shown in note 29 and also interests in joint operations as detailed in note 4.18.

c) Certain hedge arrangements, transactions and balances held at Wintershall Dea AG:

- all outstanding physical commodity hedge transactions relating to the business of the Target Portfolio companies including intercompany arrangements that relate to those commodity hedge transactions. These relate to certain hedge arrangements entered into by Wintershall Dea AG on behalf of entities in the Target Portfolio. The effect of these arrangements is included in the Combined HFI; and

- the hedge agreement entered into between Wintershall Dea AG and Wintershall Dea Norge AS as of 1 January 2020 and all outstanding transactions thereunder. This relates to a hedge arrangement entered into by Wintershall Dea AG on behalf of Wintershall Dea Norge AS, an entity in the Target Portfolio. The effect of this arrangement is included in the Combined HFI.

d) Certain other agreements held by Wintershall Dea AG which relate to the business of the Target Portfolio. These agreements have no effect on the preparation of the Combined HFI.

2.2 **Basis of Combination**

The Combined HFI has been prepared in accordance with the Listing Rules and Prospectus Directive Regulation, and the requirements of UK adopted international accounting standards ("**UK-adopted IFRS**") except as noted below.

- UK adopted IFRS does not explicitly provide guidance for the preparation of the Combined HFI, therefore certain accounting conventions permitted for the preparation of historical financial information for inclusion in investment circulars, as described in the Standards for Investment Reporting Annexure (the "**Annexure**") to SIR 2000 (Investment Reporting Standard applicable to public reporting engagements on historical financial information) issued by the Financial Reporting Council, have been applied where IFRS does not provide specific accounting treatments.

- The carved-out basis was applied, whereby the Combined HFI has been prepared by extracting and aggregating the historical financial information for the Target Portfolio from the Wintershall Dea AG IFRS-based consolidated group financial statements issued under IFRS. No adjustments have been made to opening balances or estimates and an opening balance sheet has not been presented.

- The Combined HFI is not prepared on a consolidated basis and therefore does not comply with the requirements of IFRS 10 'Consolidated Financial Statements'. However, the Combined HFI information has been prepared on a Combined HFI basis applying the aggregation principles underlying the consolidation procedures of IFRS 10.

- Relevant goodwill and corresponding fair value allocations recognised in the Wintershall Dea AG consolidation, which relate to the Target Portfolio have also been included in the Combined HFI. This is on the basis that the historical PPA from which these amounts arose relates to the underlying assets of the entities within the Target Portfolio.

- The Target Portfolio was not a separate group sitting under a legal entity during the three years ended 31 December 2023 and has no share capital. Therefore, invested capital represents a combination of the funding balances with equity holders, retained earnings and other reserves from entities in the Target Portfolio and debt instruments from allocation of central costs. Capital distributions represent the transfer of profits or dividends outside of the Target Portfolio. See Note 24 for more detail.

- All intercompany transactions have been eliminated between entities of the Target Portfolio. Transactions and balances with the Wintershall Dea AG group companies outside of the Target Portfolio represent third-party transactions for the purposes of the Combined HFI and have been disclosed as related party transactions.
- Whilst the concessions, interests and joint operations are under common control, the Target Portfolio has not previously constituted a single legal group which has prepared consolidated financial results. Accordingly, the Combined HFI has been prepared by management specifically for the purposes of the Prospectus and Circular and reflects the income, expenses, assets and liabilities of the entities and interests in joint operations in the Target Portfolio, and the allocations of direct and indirect costs and expenses related to the operations. Such allocations have been made on a reasonable basis based on all available information and but does not necessarily reflect what the operating results and cash flows would have been had the Target Portfolio been a standalone group for all periods presented.
- The Combined HFI also includes central general and administrative costs allocated firstly using an intercompany transfer pricing methodology and further additional costs to recognise the Target Portfolio's overall share of central general and administrative costs allocated through full time employee, entity count or reserve-based assumptions.
- In 2021 and 2022, Wintershall Dea AG undertook hedging transactions linked to the sale of gas produced by entities in the Target Portfolio. Relevant oil and gas hedging positions to the Target Portfolio have been included within the Combined HFI recognised either in the underlying Target Portfolio entities or through adjustments in 2021 and 2022 to the Combined HFI to recognise Norway (2021 only) and Germany hedging positions recognised at Wintershall Dea AG head office.
- Prior to October 2023, cash generated by the Target Portfolio was swept on a daily basis into a cash pooling arrangement with Wintershall Dea AG, an entity outside of the transaction perimeter. Subsequent to this time, cash was swept daily to Wintershall Dea Global Holding Gmbh ("**WDGH**"). A number of transactions were settled through the cash pooling arrangements, rather than through physical cash flows, including where sales income has been received by Wintershall Dea AG on behalf of entities in the Target Portfolio. Therefore, a number of cashflows present within the Combined Statement of Cashflows are not true cashflows into the Target Portfolio but are notional cash movements representing the cashflows that would have occurred had there not been a cash pooling arrangement with Wintershall Dea AG.
- Related party cashflows reflect long term financing, together with movements on the cash pooling arrangement, which are internal the Wintershall Dea AG group but comprise inflows and outflows reflecting movements between the Target Portfolio and the wider group. Under IAS 7, each of these cashflows would be classified as investing and financing activities, however, on account of these all being part of an integrated cash management and reflecting a net receivable position, have instead been grouped together and classified as investing activities in the Combined Statement of Cashflows to provide a clearer picture of the underlying cashflows. The Target Portfolio has three primary revenue streams, 1/ gas and oil sales; 2/ revenue from strategic purchases and resale of gas and oil; and 3/ trading activities for the purpose of margin improvement. Revenue derived from production by trading entities in the Target Portfolio which was invoiced to third parties by Wintershall Dea AG (less an administrative fee charged by Wintershall Dea AG) is recognized in revenue in the Target Portfolio. Revenue from trading activities for the purpose of margin improvement is only recognised in the Target Portfolio where it has been mandated by the producing entity.

The taxation expense and movements to other comprehensive income included in the Combined HFI has been calculated based at an individual country level and adjusted for any pre-tax Combined HFI adjustments. Following the updates for the pre-tax Combined HFI adjustment, the current and deferred tax balances at each balance sheet date were reviewed to determine whether any areas of judgement and estimate needed to be amended.

For the year ended 31 December 2023 post balance sheet events have been considered to the date of signing this Combined HFI. For years ended 31 December 2021 and 2022, post balance sheet events have only been considered up to the respective dates that the Wintershall Dea AG consolidated group financial statements were signed.

The principal accounting policies applied in the preparation of the Combined HFI are set out below. These policies have been consistently applied to all the periods presented, unless otherwise stated and are consistent with the accounting policies used to prepare the latest audited financial statements of Harbour

Energy plc. In respect of oil and gas depreciation, the Target Portfolio calculates this on the units of production methodology using proven reserves, while Harbour Energy uses proven and probable reserves. This is an estimation difference and not an accounting policy difference. See the '*Significant accounting judgements and estimates*' section for the potential impact of this.

The Combined HFI is presented in US Dollar ("**USD**", "**$**") and all values are stated in millions of USD ("**$m**"), except where otherwise indicated, and have been prepared on the historical cost basis, unless otherwise indicated in the accounting policies.

As the Combined HFI Information has been prepared on a combined and carved-out basis, it may not be indicative of the future performance of the Target Portfolio and does not necessarily reflect what its results of operations, financial position and cash flows would have been had the Target Portfolio operated as an independent entity during the periods presented.

The Combined HFI does not constitute statutory accounts within the meaning of section 434(3) of the Companies Act 2006.

2.3 Going Concern

The financial position of the Target Portfolio, its cash flows, liquidity position and borrowing facilities are set out in this Combined HFI.

The Combined HFI has been prepared on a going concern basis which the Target Portfolio believe to be appropriate for the reasons described below. The Target Portfolio meets its day to day working capital requirements through cash from operations.

The Target Portfolio has prepared pre-acquisition cash flow forecasts for a period of at least 12 months from the date of approval of the Combined HFI ("**the going concern assessment period**") in order to assess going concern. These forecasts consider only the activity of those entities included in the Target Portfolio , which continue to utilise the wider financing arrangements that the broader Wintershall Dea AG group is subject to in its normal course of business up until the point when the transaction completes. The financing arrangements include cash and cash equivalents and a committed undrawn revolving credit facility.

The forecasts comprise estimates of key variables, including production, gas and oil prices, continued development of reserves, operating costs, capital expenditure and are subject to a number of risks and uncertainties, in particular gas and oil prices. In all scenarios modelled, including the severe but plausible downside scenario, the Target Portfolio continues to have satisfactory liquidity headroom throughout the going concern period.

As described in note 23, on 22 February 2024, the Wintershall Dea AG subordinated noteholders approved a change in guarantor from Wintershall Dea AG to Harbour Energy plc, which will be effective upon Completion meaning Target Portfolio will continue to have access to this capital post transaction, together with the financing arrangements available to Harbour Energy plc.

Based on this assessment, the Directors of Harbour Energy plc have a reasonable expectation that the Target Portfolio has adequate resources to continue operating for the going concern assessment period and hence the directors consider that the application of the going concern basis for the preparation of the Combined HFI to be appropriate.

3. NEW STANDARDS AND AMENDMENTS—APPLICABLE DURING THE PERIOD

The Target Portfolio has applied the below amendments to IFRS Standards and Interpretations issued by the Board that are effective for an annual period that begins on or after 1 January 2021 (unless otherwise stated). Their adoption has not had any material impact on the disclosures or on the amounts reported in the Combined HFI.

- Amendments to IAS 1 "Presentation of Financial Statements" and IFRS Practice Statement 2 "Making Materiality Judgements"
- Amendments to IAS 1 "Disclosure of Accounting Policies"
- Amendments to IAS 12 "Deferred Tax related to Assets and Liabilities arising from a Single Transaction"
- Amendments to IAS 12 "International Tax Reform—Pillar Two Model Rules"

- Amendments to IAS 8 "Definition of Accounting Estimates"
- Amendments to IFRS 3 "Reference to the Conceptual Framework"
- Amendments to IAS 16 "Proceeds before Intended Use"
- Amendments to IAS 37 "Cost of Fulfilling a Contract"
- Annual Improvements to IFRS Accounting Standards 2018-2020 Cycle
- Amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16 "Interest Rate Benchmark Reform—Phase 2"
- Amendment to IFRS 16 "COVID-19-Related Rent Concessions beyond 30 June 2021"

3.1 **New standards, interpretations and amendments issued but not effective for the Combined HFI Period**

At the date of authorisation of the Combined HFI, the Target Portfolio has not applied the following new and revised IFRS Accounting Standards that have been issued but are not yet in effect. The effective date for these amendments is for annual periods that begins on or after 1 January 2024 (unless otherwise stated). Their future adoption is not expected to have any material impact on the disclosures or on the amounts reported in the Combined HFI.

- Amendments to IAS 1 "Classification of Liabilities as Current or Non-current"
- Amendments to IAS 1 "Non-current Liabilities with Covenants"
- Amendments to IAS 7 "Statement of Cash Flows" and IFRS 7 "Supplier Finance Arrangements"
- Amendments to IAS 21 "The Effects of Changes in Foreign Exchange Rates: Lack of Exchangeability" (effective date for annual periods that begins on or after 1 January 2025)
- Amendments to IFRS 16 "Lease Liability in a Sale and Leaseback"
- Amendments to IFRS 18 "Presentation and Disclosure in Financial Statements" (effective date for annual periods that begins on or after 1 January 2027)
- Amendments to IFRS 19 "Subsidiaries without Public Accountability: Disclosures" (effective date for annual periods that begins on or after 1 January 2027)

4. **SIGNIFICANT ACCOUNTING POLICIES**

The principal accounting policies applied in the preparation of these Combined HFI are set out below. These policies have been consistently applied unless otherwise stated.

4.1 **Foreign currency translation**

Each entity in the Target Portfolio determines its own functional currency, being the currency of the primary economic environment in which the entity operates, and items included in the Combined HFI of each entity are measured using that functional currency. The functional currencies in use by the Target Portfolio and included in the Combined HFI are; Euros, Mexican pesos and US dollars.

The Combined HFI is presented in USD, which is also Harbour Energy plc's reporting currency.

Foreign currency transactions are initially recorded in the entity's functional currency by applying the exchange rates prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated at the functional currency rate of exchange ruling at the reporting date. All differences are taken to the income statement.

Non-monetary assets and liabilities denominated in foreign currencies are measured at historic cost based on exchange rates at the date of the initial transaction and subsequently not retranslated.

On combination, the assets and liabilities of the Target Portfolio's operations are translated into the reporting currency, USD, at exchange rates prevailing on the balance sheet date. Income and expense items are translated at the average exchange rate for the year. Invested capital is held at translated historic cost and is not retranslated. The resulting exchange differences are recognised as other comprehensive income and are transferred to the Target Portfolio's currency translation reserve.

When an operation with a functional currency other than USD is disposed of, such translation differences relating to it are recognised as income or expense.

4.2 **Segment reporting**

The Target Portfolio's activities consist of one class of business being the acquisition, exploration, development and production of oil and gas reserves and related activities.

The Target Portfolio's business is conducted in four segments:

- Northern Europe
- Latin America
- North Africa
- Other (representing head office and other costs)

The accounting policies for the segments are the same as the Target Portfolio's accounting policies.

4.3 **Goodwill**

In the event of a business combination or acquisition of an interest in a joint operation in which the activity constitutes a business, as defined in IFRS 3 Business Combinations, the acquisition method of accounting is applied. Goodwill represents the difference between the aggregate of the fair value of purchase consideration transferred at the acquisition date and the fair value of the identifiable assets, liabilities and contingent liabilities acquired. If however, the fair value of the purchase consideration transferred is lower than the fair value of the identifiable assets and liabilities acquired, the difference is recognised in the income statement as a gain on bargain purchase. Goodwill is initially measured at cost. Following initial recognition, goodwill is measured at cost less any accumulated impairment. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Target Portfolio's cash-generating units ("**CGUs**"), or groups of CGUs, that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units. Goodwill is treated as an asset of the relevant entity to which it relates and accordingly non-US dollar goodwill is translated into USD at the closing rate of exchange at each reporting date.

Goodwill, as disclosed in note 11, is not amortised but is reviewed for impairment at least annually by assessing the recoverable amount of the CGUs to which the goodwill relates. Where the carrying amount of each respective CGU and related goodwill is higher than the recoverable amount of the respective CGU, an impairment loss is recognised in the income statement. The recoverable amounts of the CGUs have been determined on a fair value less costs of disposal basis. Impairment losses relating to goodwill cannot be reversed in future periods. Goodwill acquired through business combinations has been allocated to separate CGUs, as per note 11, being Norway, Germany, Argentina, and the Netherlands.

4.4 **Interests in joint arrangements**

A joint arrangement is an arrangement where two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control. Joint arrangements where the Target portfolio has the rights to assets and obligations for liabilities of the arrangement are classified as joint operations and are accounted for by recognising the Target portfolio's share of assets, liabilities, income and expenses.

Joint arrangements where the Target portfolio has the rights to the net assets of the arrangement are classified as joint ventures and are accounted for using the equity method of accounting.

4.5 **Oil and gas assets**

Intangibles

Pre-licence costs

Pre-licence costs are expensed in the period in which they are incurred.

Licence and property acquisition costs

Licence and property acquisition costs paid in connection with a right to explore in an existing exploration area are capitalised as exploration and evaluation costs within intangible assets. Licence acquisition costs related to the production and development phase are capitalised under property, plant and equipment.

Licence and property acquisition costs are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount and should be impaired. Also if no future activity is planned or the related licence has been relinquished or has expired, the carrying value of the property acquisition costs is written off through the income statement. Upon recognition of proved reserves and internal approval for development, the relevant expenditure is transferred to oil and gas properties within development and production assets, under property, plant and equipment.

Exploration and evaluation costs

Once the legal right to explore has been acquired, costs directly associated with the exploration are capitalised as exploration and evaluation ("**E&E**") intangible non-current assets until the exploration is complete and the results have been evaluated. If no potential commercial resources are discovered, the exploration asset is written off.

All such capitalised costs are subject to technical, commercial and management review, as well as review for indicators of impairment at least annually. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off through the income statement.

When proved reserves of oil or natural gas are identified and development is sanctioned by management, the relevant capitalised expenditure is first assessed for impairment and, if required, any impairment loss is recognised, then the remaining balance is transferred to oil and gas properties within development and production assets, under property, plant and equipment. No amortisation is charged during the exploration and evaluation phase.

Property, plant and equipment—oil and gas assets

Oil and gas development and production assets are accumulated generally on a field-by-field basis. This represents expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including E&E expenditures incurred in finding commercial reserves transferred from intangible E&E assets, as outlined in the intangible asset policy above, which is capitalised as oil and gas properties within development and production assets.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation and, for qualifying assets borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

An item of development and production expenditure and any significant part initially recognised is derecognised upon disposal or when no future economic benefits are expected. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in the income statement.

Expenditure on major maintenance includes refits, inspections or repairs comprising the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset, or part of an asset, that was separately depreciated and is now written off is replaced and it is probable that future economic benefits associated with the item will flow to the Target Portfolio, the expenditure is capitalised. All other day-to-day repairs and maintenance costs are expensed as incurred.

Depreciation and amortisation of oil and gas assets

All costs relating to a development are accumulated and not depreciated until the commencement of production. Gas and oil assets are generally depreciated using the unit-of-production method. In principle, depreciation of capitalised wells is based on the current production for the period in relation to proven developed producing reserves.

When there is a change in the estimated total proven developed producing reserves of a field, that change is accounted for in the depreciation charge over the revised remaining proven developed producing reserves.

For the following assets which is depreciated on a straight-line basis, the useful lives are as follows:

- Technical plant and machinery: one to 33 years.

Acquisitions, and disposals

Acquisitions of oil and gas properties are accounted for using the acquisition method when the assets acquired, and liabilities assumed constitute a business.

Proceeds on disposal are applied to the carrying amount of the specific intangible asset or oil and gas property disposed of and any surplus is recorded as a gain on disposal in the income statement.

Decommissioning

A provision for decommissioning is recognised in full when the related facilities are installed. The amount recognised is the present value of the estimated future expenditure. A corresponding amount equivalent to the provision is also recognised as part of the cost of the related oil and gas property. This is subsequently depreciated as part of the capital costs of the production facilities. Any change in the present value of the estimated expenditure is adjusted in the decommissioning provision and the oil and gas property. The unwinding of the discount is included as a finance cost.

4.6 Non-oil and gas assets

Property, plant and equipment—fixtures and fittings and office equipment, buildings and land

Non-oil and gas assets are comprised of land and buildings, fixtures, fittings and office equipment. Depreciation is provided for on a straight-line basis at rates sufficient to write off the cost of the assets less any residual value over their estimated useful economic lives. The depreciation periods for the principal categories of assets are as follows:

- Buildings: four to 50 years.
- Fixtures, fittings and office equipment: one to 23 years.

Intangible assets

Intangible assets, which principally comprise IT software/licences, are carried at cost less any accumulated amortisation. These assets are amortised on a straight-line basis over their useful economic lives of between two and three years.

4.7 Impairment of non-current assets (excluding goodwill)

Impairment and reversal indicators

In accordance with IAS 36 Impairment of Assets, property, plant and equipment and intangible assets with finite useful lives are only tested for impairment when there is an indication that they may be impaired. This is generally the result of significant changes to the environment in which the assets are operated or when asset performance is significantly lower than expected.

The main impairment indicators used by the Target Portfolio are described below:

- External sources of information:
  - Significant changes in the economic, technological, political or market environment in which the entity operates or to which an asset is dedicated;
  - Fall in demand; and
  - Changes in commodity prices, inflation rates and exchange rates.
- Internal sources of information:
  - Evidence of obsolescence or physical damage;
  - Significantly lower than expected production or cost performance;
  - Reduction in reserves and resources, including as a result of unsuccessful results of drilling operations;

- Pending expiry of licence or other rights;
- In respect of capitalised exploration and evaluation costs, lack of planned future activity on the prospect or licence; and
- For reversals, plausible downside sensitivity scenarios are run to test the robustness of the asset carrying values typically against changes in production and commodity prices.

Measurement of recoverable amount

The CGU applied for impairment test purposes is generally the field, except that a number of field interests may be grouped as a single CGU where the cash inflows of each field are interdependent. The carrying value of each CGU is compared against the expected recoverable amount of the asset, which is primarily determined based on the fair value less cost of disposal method, where the fair value is determined from the estimated present value of the future net cash flows expected to be derived from production of commercial reserves. Standard valuation techniques are used based on the discount rates that reflect the specific characteristics of the operating entities concerned; discount rates are determined on a post-tax basis and applied to post-tax cash flows.

Any impairment loss (or reversal) is recorded in the income statement under Impairment of property, plant and equipment or intangible assets. Impairment losses recorded may be subsequently reversed if the recoverable amount of the assets subsequently increases above carrying value. The increased carrying amount of an item of property, plant or equipment attributable to a reversal of an impairment loss may not exceed the carrying amount that would have been determined (net of depreciation/amortisation) had no impairment loss been recognised in prior periods.

4.8 **Financial instruments**

Financial instruments are recognised and measured in accordance with IFRS 9 Financial Instruments.

Financial assets

The Target Portfolio uses two criteria to determine the classification of financial assets: the Target Portfolio's business model and contractual cash flow characteristics of the financial assets. Where appropriate the Target Portfolio identifies three categories of financial assets: amortised cost, fair value through profit or loss ("**FVTPL**"), and fair value through other comprehensive income ("**FVOCI**").

Financial assets held at amortised cost

Financial assets held at amortised cost are initially measured at fair value except for trade debtors without a significant financing component, which are initially measured at cost. Both are subsequently carried at amortised cost using the effective interest rate ("**EIR**") method, less impairment. The EIR amortisation is presented within finance income in the income statement.

Cash and cash equivalents

Cash and cash equivalents comprise cash at bank and other short-term highly liquid investments that are readily convertible to a known amount of cash and are subject to an insignificant risk of changes in value.

Impairment of financial assets

The Target Portfolio recognises an allowance for expected credit losses ("**ECL**") for all debt instruments not held at FVTPL. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Target Portfolio expects to receive, discounted at the effective interest rate.

ECLs are recognised in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit losses that result from default events that are possible within the next 12 months (a 12-month ECL).

Default events could include:

- Payment default, i.e. the failure to pay principal or interest when it falls due for payment;
- Prospective default, when payment is not yet due, but it is clear that it will not be capable of being paid when it does fall due; and

- Covenant default, when the borrower fails to keep a promise (a covenant) that it has made in the contract.

For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit losses expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL).

For trade receivables and contract assets, the Target Portfolio applies a simplified approach in calculating ECLs as allowed under IFRS 9. Provision rates are calculated based on estimates including the probability of default by assessing counterparty credit ratings, as adjusted for forward-looking factors specific to the debtors, the economic environment and the Target Portfolio's historical credit loss experience.

Credit impaired financial assets

At each reporting date, the Target Portfolio assesses whether financial assets carried at amortised cost and debt financial assets carried at FVOCI are credit impaired. A financial asset is credit impaired when one or more events that have a detrimental impact on the estimated future cash flows of the financial asset have occurred.

Evidence that a financial asset is credit impaired includes the following observable data:

- Significant financial difficulty of the borrower or issuer;
- A breach of contract such as default or past due event;
- The restructuring of a loan or advance by the Target Portfolio on terms that the Target Portfolio would otherwise not consider;
- It is becoming probable that the borrower will enter bankruptcy or other financial reorganisation; and
- The disappearance of an active market for a security because of financial difficulties.

Financial liabilities

Financial liabilities are classified, at initial recognition, as financial liabilities at FVTPL, loans and borrowings, payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate. All financial liabilities are recognised at either amortised cost, FVTPL, or FVOCI.

Borrowings and loans

Interest-bearing bank loans and overdrafts are recorded at the proceeds received, net of direct issue costs. Finance charges, including premiums payable on settlement or redemption and direct issue costs, are accounted for on an accruals basis in the income statement using the EIR method and are added to the carrying amount of the instrument to the extent that they are not settled in the year in which they arise.

Derecognition

A financial liability is derecognised when the obligation under the liability is discharged, cancelled, or expires. 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 income statement.

Derivative financial instruments

The Target Portfolio uses foreign currency derivatives including cross-currency-swaps, oil swaps, zero cost collars and certain fixed-price gas sales agreements to hedge its foreign currency risks and commodity price risks, respectively. Derivative financial instruments are initially recognised at fair value and subsequently remeasured to fair value at each reporting date. Certain derivative financial instruments are designated as cash flow hedges in line with the Target Portfolio's risk management policies. When derivatives do not qualify for hedge accounting or are not designated as hedging instruments, changes in the fair value of the derivative are recognised within the income statement.

Cash flow hedges

The effective portion of gains and losses arising from the remeasurement of derivative financial instruments designated as cash flow hedges are deferred within other comprehensive income, subsequently transferred to the income statement in the period the hedged transaction is recognised in the income statement and accumulated in invested capital in the statement of changes in equity. When a hedging instrument is sold or expires, any cumulative gain or loss previously recognised in other comprehensive income remains deferred until the hedged item affects profit or loss or is no longer expected to occur. Any gain or loss relating to the ineffective portion of a cash flow hedge is immediately recognised in the income statement. Hedge ineffectiveness arises e.g., as a result of the difference between Dated Brent oil swaps and production being sold at contracted price formulas (linked to Brent, but slightly adjusted), or where the creditworthiness of the counterparty is significant and may dominate the transaction and lead to losses. In the case of fixed-price gas sales agreements, to which the hedge accounting regulations are applicable, the critical terms match method is applied to assess hedge effectiveness.

Fair values

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It is determined by reference to quoted market prices adjusted for estimated transaction costs that would be incurred in an actual transaction, or by the use of established estimation techniques such as option pricing models and estimated discounted values of cash flows.

For financial instruments not traded in an active market, the fair value is determined using appropriate valuation techniques.

4.9 **Inventory**

All inventories, except for petroleum products, are stated at the lower of cost and net realisable value. The cost of materials is the purchase cost, determined at weighted average costs. Petroleum products, as well as underlift and overlift positions are measured at net realisable value using an observable year-end oil or gas market price. Petroleum products are included in inventory, with underlift and overlift in trade and other receivables or payables, respectively.

4.10 **Leases**

Leases are recognised as a right-of-use asset and a corresponding liability at the date at which the leased asset is available for use by the Target Portfolio. The finance cost is charged to the income statement over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period.

Right-of-use assets and lease liabilities arising from a lease are initially measured on a present value basis reflecting the net present value of the fixed lease payments and amounts expected to be payable by the Target Portfolio assuming leases run to full term. The Target Portfolio has applied judgement to determine the lease term for some lease contracts in which it is a lessee that include renewal options. The assessment of whether the Target Portfolio is reasonably certain to exercise such options impacts the lease term, which impacts the amount of lease liabilities and right-of-use assets recognised.

The lease payments are discounted using the Target Portfolio's incremental borrowing rates, being the rate that the Target Portfolio would have to pay to borrow the funds necessary to obtain an asset of similar value in a similar economic environment with similar terms and conditions.

To determine the incremental borrowing rate, the Target Portfolio where possible:

- Uses recent third-party financing received by the individual lessee as a starting point, adjusted to reflect changes in financing conditions since third party financing was received; and
- Makes adjustments specific to the lease, for example term, country, currency and security.

When adjustments to lease payments based on an index or rate take effect, the lease liability is reassessed and adjusted against the right-of-use asset.

Lease payments are allocated between principal and finance cost.

Right-of-use assets are measured at cost comprising the following:

- The amount of the initial measurement of lease liability;
- Any lease payments made at or before the commencement date less any lease incentives received; and
- Any initial direct costs and restoration costs.

Right-of-use assets are generally depreciated over the shorter of the asset's estimated useful life and the lease term on a straight-line basis. Right-of-use assets that are allocated to the asset category 'gas and oil assets', are depreciated either on a straight-line basis or according to the unit-of-production method.

Payments associated with short-term leases and leases of low value assets are recognised on a straight-line basis as an expense in the income statement. Short-term leases are leases with a lease term of 12 months or less.

4.11 **Provisions for liabilities**

A provision is recognised when the Target Portfolio has a legal or constructive obligation as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

The expense relating to any provision is presented in the income statement net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risk specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognised as part of finance costs in the income statement.

The estimated cost of dismantling and restoring the production and related facilities at the end of the economic life of each field is recognised in full when the related facilities are installed. The amount provided is the present value of the estimated future restoration cost. Any changes to estimated costs or discount rates are dealt with prospectively.

4.12 **Retirement benefit plan**

The Target Portfolio operates defined contribution retirement benefit plans for all qualifying employees which requires contributions to be made to a separately administered fund. Payments to defined contribution retirement benefit plans are charged as an expense as they fall due. Payments made to state-managed retirement benefit schemes are dealt with as payments to defined contribution plans where the Target Portfolio's obligations under the schemes are equivalent to those arising in a defined contribution retirement benefit plan.

The Target Portfolio sponsors defined benefit plans for qualifying employees. The defined benefit plans are administered by a separate fund that is legally separated from the Target Portfolio. The trustees of the pension fund are required by law to act in the interest of the fund and of all relevant stakeholders in the plans. The trustees of the pension fund are responsible for the investment policy with regard to the assets of the fund. The cost of providing benefits is determined using the projected unit credit method, with actuarial valuations being carried out at each balance sheet date. Actuarial gains and losses are recognised immediately in the statement of comprehensive income.

The retirement benefit obligation recognised in the balance sheet represents the present value of the defined benefit obligation as reduced by the fair value of plan assets. Any asset resulting from this calculation is limited to the present value of available refunds and reductions in future contributions to the plan.

The Target Portfolio still participates in a legally independent multiemployer plan provided by BASF Pensionskasse VVaG, which is financed by employer and employee contributions as well as the return on plan assets. Since sufficient information is not available for this multi-employer plan, the Target Portfolio accounts for the plan as if it was a defined contribution plan.

In the case of contribution-based defined benefit pension plans, the Target Portfolio makes contribution payments to special-purpose funds as well as to life insurances. These contribution payments are recorded as expenses. Furthermore, for some of the Target Portfolio's contribution-based defined benefit pension plans, benefit obligations are recognised at the fair value of these funds, so far as the assets exceed the guaranteed minimum benefit amount.

If the assets do not exceed the guaranteed minimum benefit amount, benefit obligations for these contribution-based benefit plans are recognised in the amount of the guaranteed minimum benefit amount.

4.13 **Trade payables**

Initial recognition of trade payables is at fair value. Subsequently they are stated at amortised cost.

4.14 **Taxes**

Current tax

The tax currently payable is based on taxable profit for the year. Taxable profit differs from net profit as reported in profit or loss because it excludes items of income or expense that are taxable or deductible in other years and it further excludes items that are never taxable or deductible. The Target Portfolio's liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the end of the reporting period.

IFRIC 23 clarifies the application of the recognition and measurement regulations of IAS 12 if there are uncertainties with regard to the income tax treatment. For recognition and measurement, estimates and assumptions have to be made, such as whether the assessment should be made separately or together with other uncertainties, whether to use a probable or expected value for the uncertainty and whether changes have occurred in comparison to the previous reporting period. The risk of detection is not relevant for the accounting treatment of uncertain balance sheet items. The accounting is based upon the assumption that the tax authorities consider the issue in question and that they have all relevant information.

Deferred tax

Deferred taxation is recognised in respect of all timing differences arising between the tax bases of the assets and liabilities and their carrying amounts in the Combined HFI.

Deferred income tax assets are recognised only to the extent that it is probable that the taxable profit will be available against which the deductible temporary difference, carried forward tax credits or tax losses can be utilised.

Deferred income tax assets and liabilities are measured on an undiscounted basis at the tax rates that are expected to apply when the related asset is realised or liability is settled, based on tax rates and laws enacted or substantively enacted at the reporting date. The carrying amount of the deferred income tax asset is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered. The Target Portfolio reassesses any unrecognised deferred tax assets each year taking into account changes in oil and gas prices, the Target Portfolio's proven developed producing reserves and resources profile and forecast capital and operating expenditures.

Deferred income tax assets and liabilities are offset if the deferred income tax relates to the same tax authority.

Changes in deferred taxes in the balance sheet are recognised as deferred tax expense/income if the underlying transaction is also recognised in profit or loss. For those effects that have been recognised in equity or other comprehensive income ("**OCI**"), changes to deferred tax assets and tax liabilities are also recognised directly in equity or OCI.

4.15 **Revenue from contracts with customers**

Revenue from contracts with customers is recognised when the Target Portfolio satisfies a performance obligation by transferring a good or service to a customer. Revenue associated with the sale of crude oil and natural gas is measured based on the consideration specified in contracts with customers with reference to quoted market prices in active markets, adjusted according to specific terms and conditions as applicable according to the sales contracts.

Revenues and expenses from gas and oil concessions are often allocated based on defined formulas set out in exploration and production sharing agreements between the state and one or more development and production companies. The proceeds to be received under these contracts are reported as revenue. Revenues of the Target Portfolio originate primarily from gas and oil sales. Gas and oil revenues are recognised at the time of delivery to the contractual delivery point. This is generally the case when the oil passes the vessel's rail or, in the case of gas and oil supply via pipeline, when passing agreed delivery points. The Target Portfolio applies the simplification rule set out in IFRS 15. It therefore does not adjust the agreed amount of consideration to reflect the effects of a material financing component if, at the contract start date, the period between the transfer to the customer of the promised goods or services and the date the customer is expected to pay for those goods or services is expected to be one year or less.

Over/underlift

Differences between the production sold and the Target Portfolio's share of production result in an overlift or an underlift. Overlift and underlift are valued at net realisable value using an observable oil or gas market price as at each reporting date, and included within payables or receivables, respectively. Movements during the accounting period are recognised within cost of operations.

4.16 **Interest income**

Interest income is recognised on an accruals basis, by reference to the principal outstanding and at the effective interest rate applicable.

4.17 **Borrowing costs**

Borrowing costs directly attributable to the acquisition, construction or production of an asset that necessarily takes a substantial period of time to get ready for its intended use or sale (a qualifying asset) are capitalised as part of the cost of the respective assets. Where the funds used to finance a project form part of general borrowings, the amount capitalised is calculated using a weighted average of rates applicable to relevant general borrowings of the Target Portfolio during the period. All other borrowing costs are recognised in the income statement in the period in which they are incurred.

4.18 **Joint operations**

A large part of the activities in the exploration and production business area is carried out in the context of joint operations, some of which are managed through separate companies.

There are also joint operations in the context of CCS activities. In 2023, the jointly controlled license holding companies Luna Carbon Storage ANS and Havstjerne ANS were newly established legal entities due to local legislation requirements and accounted for as joint operations based on the outcome of the review of contractual arrangements and other facts and circumstances in accordance with IFRS 11.

The following joint operations are structured as separate entities:

Name	Nature of the joint operation	Principal place of business	Ownership interest/voting rights (%)
Disouq Petroleum Company (DISOUCO)	Operating company for the development and production phases	Cairo, Egypt	50
Groupement Reggane	Operating company for the development and production phases	Algiers, Algeria	24
Luna Carbon Storage ANS . . .	License holding company for CCS storage activities	Stavanger, Norway	60
Havstjerne ANS	License holding company for CCS storage activities	Stavanger, Norway	60

Joint operations that are not managed through separate companies are mainly located in Germany, Norway, Mexico and Argentina.

The Target Portfolio's shares in joint operations are accounted for by recognising its respective share in assets and liabilities as well as its income and expenses.

4.19 **Estimates made in assessing the impact of climate change and the energy transition**

The Target Portfolio monitors global climate change and energy transition developments and plans accordingly. Management recognises there is a general high level of uncertainty about the speed and scale of impacts which, together with limited historical information, provides significant challenges in the preparation of forecasts and plans with a range of possible future scenarios.

As a result, climate change and the energy transition have the potential to impact the accounting estimates adopted by management and therefore the valuation of assets and liabilities reported on the balance sheet. On an ongoing basis management continues to assess the potential impacts on the significant judgements and estimates used in the Combined HFI. Estimates adopted in the preparation of the Combined HFI reflect management's best estimate of future market conditions where, in particular, commodity prices can be volatile. There are no significant judgements and/or critical estimation uncertainty related to climate change factors.

This note provides insight into how the Target Portfolio has considered the impact on valuations of key line items in the Combined HFI:

Gas and oil reserves

Reduction in the demand for oil and gas and increasing regulation due to the energy transition reduces the value of the reserves and increases the future development expenditures necessary to bring those reserves into production. This has the potential to impact the calculation of the useful economic life of oil and gas property plant and equipment and create uncertainty in the estimation of the useful economic life and therefore the depreciation charge to be suffered.

Intangible assets—exploration and evaluation assets

The energy transition has the potential to affect the future development or viability of exploration and evaluation prospects. There is a judgement in relation to whether commercial determination of an exploration prospect has been reached. Climate change and energy transition could potentially impact the calculation of when an exploration is deemed to be commercial as they create uncertainty around the inputs into the judgement.

Impairment of property, plant and equipment, and goodwill

The in-house assumptions on the long-term development of gas and oil prices are based on empirically sound analyses of global gas and oil supply and demand, taking into account possible impacts of climate policies, the energy transition and energy efficiency gains. External sources such as consultant data, consensus views, forwards data, as well as peer estimates, are frequently assessed. Local price assumptions are derived depending on global market dynamic as well as the regulations and contractual terms in place.

Discount rates are based on the weighted average cost of capital, taking into consideration specific country risks.

The energy transition has the potential to impact future commodity and carbon prices which would, in turn, affect the recoverable amount of property, plant and equipment and goodwill. Oil and gas price forecasts are based on the Target Portfolio's current oil and gas price scenario taking into account management's estimates and available market data.

Decommissioning cost and provisions

The energy transition may accelerate the decommissioning of assets which would result in an increase in the carrying value of associated decommissioning provisions. The Target Portfolio currently expects to incur decommissioning costs over the next 30 years, the majority of which are anticipated to be incurred between the next 10 to 20 years. Decommissioning cost estimates are based on country specific factors in the regulatory and external environment.

These cost estimates and recoverability of associated deferred tax may change in the future, including as a result of the energy transition.

4.20 **Significant accounting judgements and estimates**

The preparation of the Combined HFI in conformity with UK-adopted IFRS requires management to make judgements, estimates and assumptions at the date of the Combined HFI. Combined HFI estimates and assumptions are continuously evaluated and are based on management 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 the assets or liabilities affected in future periods. In particular, the Target Portfolio has identified the following areas where significant judgement, estimates and assumptions are required.

Critical accounting judgements

- *Functional currency of Norway component*; Judgement is required in determining the functional currency on inception of an entity and whether there has been a change to that functional currency. In respect to the Norway component management have considered the currency of both cash inflows and outflows that the component is subject to, as well as the currency in which its funding is received. This component receives the majority of its cash inflows in US$, however, it does also receive some inflows in both Euro and Norwegian Krone; similarly with its outflows these include both USD and Norwegian Krona denominated amounts. Management also note that the majority of funding, which is received from entities outside the perimeter, is received in USD. Taking all these factors into account and recognising that it is a judgement, management determined that USD was its functional currency reflecting the primary economic environment in which it operates. In addition, management considered whether these indicators had moved during the HFI period and determined that no change had been noted, on this basis USD has been applied as the functional currency throughout.

Key sources of estimation uncertainty

- *Gas and oil reserves*; natural gas and oil reserves are used to determine the recoverable amount within the scope of an impairment test, as well as for production-related depreciation and amortisation using the unit-of-production method, and the year of abandonment assumption used to determine decommissioning provision. Reserves are estimated by Wintershall Dea AG's own qualified engineers and geoscientists based on standardised valuation methods and are classified in line with international industry standards. This process is subject to specific guidelines. Furthermore, the estimates are audited by independent consultants on a regular basis.
- *Impairment of property, plant and equipment*; assumptions used in impairment testing for property, plant and equipment relate to estimated reserves, price assumptions for natural gas and crude oil, consumer price indices and exchange rates, CO2 prices, production forecasts and discount rates as well as production costs. Inputs and sensitivities are shown in note 11.
- *Decommissioning cost and provisions*; decommissioning provisions require estimates and assumptions, with regards to terms, costs to be considered and discount rates. Future actual cashflows may differ due to changes in relation to these items. Please refer to note 22 provisions.
- *Oil and Gas Depreciation;* depreciation is generally calculated on the units of production methodology using proven reserves. If the approach was changed to use proven and probable reserves the value of total assets would increase by $1.1bn (FY22 $764m, FY21 $523m) and have an impact of $329m, (FY22 $241m, FY21 $529m) on the Income Statement increasing profit.

5. **SEGMENT INFORMATION**

The Target Portfolio's business is conducted in four segments:

- Northern Europe
- Latin America
- North Africa
- Other

Income statement

	Year ended 31 December		
	2023	2022	2021
		$m	
Revenue			
Northern Europe	5,233	6,843	3,774
North Africa	521	531	558
Latin America	583	610	549
Other	—	—	11
Total Target Portfolio sales revenue	**6,337**	**7,984**	**4,892**
Other income			
Northern Europe	1	6	4
North Africa	—	—	—
Latin America	34	44	55
Other	8	7	7
Total Target Portfolio revenue and other income	**6,380**	**8,041**	**4,958**
Operating profit			
Northern Europe	2,443	4,230	1,591
North Africa	88	410	96
Latin America	290	(165)	(94)
Other	(30)	(143)	(118)
Target Portfolio operating profit	**2,791**	**4,332**	**1,475**
Finance income	497	301	292
Finance expenses	(713)	(518)	(465)
Profit before income tax	**2,575**	**4,115**	**1,302**

Other information

	Year ended 31 December		
	2023	2022	2021
		$m	
Depreciation and amortisation			
Northern Europe	(1,045)	(1,099)	(1,310)
North Africa	(209)	(168)	(156)
Latin America	(142)	(194)	(199)
Other	(4)	(3)	(5)
Total depreciation and amortisation	**(1,400)**	**(1,464)**	**(1,670)**
Exploration and evaluation expenses (including costs written off)			
Northern Europe	(49)	(41)	(113)
North Africa	(11)	(5)	(48)
Latin America	(95)	(38)	(78)
Other	5	—	—
Total exploration and evaluation expenses (including costs written off)	**(150)**	**(84)**	**(239)**

Balance sheet

	Year ended 31 December		
	2023	2022	2021
		$m	
Segment non-current assets			
Northern Europe	10,429	10,709	11,935
North Africa	476	630	677
Latin America	2,380	1,752	2,193
Other	49	3,671	4,637
Deferred tax	312	246	256
Derivative assets	133	7	2
Total non-current assets	**13,779**	**17,015**	**19,700**
Segment current assets			
Northern Europe	969	5,126	3,064
North Africa	391	434	353
Latin America	584	490	507
Other	811	2,735	2,090
Total current assets	**2,755**	**8,785**	**6,014**
Total assets	**16,534**	**25,800**	**25,714**
Segment liabilities			
Northern Europe	(8,961)	(10,926)	(10,162)
North Africa	(248)	(208)	(242)
Latin America	(820)	(625)	(973)
Other	(5,713)	(7,351)	(7,686)
Total liabilities	**(15,742)**	**(19,110)**	**(19,063)**

The reduction in total assets in 2023 headquarter and other relates to the debt pushdown. Refer to Note 24 for details.

6. REVENUE FROM CONTRACTS WITH CUSTOMERS AND OTHER INCOME

	Year ended 31 December		
	2023	2022	2021
		$m	
Type of goods:			
Crude oil sales	2,223	2,574	2,146
Gas sales	3,664	4,797	2,338
Condensate sales	448	544	400
Total revenue from contracts with customers	**6,335**	**7,915**	**4,884**
Tariff income	2	69	8
Total revenue	**6,337**	**7,984**	**4,892**
Other income	43	57	66
Total revenue and other income	**6,380**	**8,041**	**4,958**

Tariff income mainly comprises revenues from the marketing of unused pipeline capacity in Norway.

Other income principally comprises of government subsidies in Argentina.

	Year ended 31 December		
	2023	2022	2021
		$m	
Revenue by region:			
Norway	4,155	5,990	3,059
Germany	1,059	833	700
Argentina	476	505	476
Mexico	107	105	74
North Africa	521	531	558
Other regions	19	20	25
Total revenue	**6,337**	**7,984**	**4,892**

The Target Portfolio sells all oil and gas to Wintershall Dea AG, a related party, and subsequently onwards to a third party. No individual third party represents more than 10 per cent. of the total of the Target Portfolio's revenue.

7. OPERATING PROFIT

	Year ended 31 December		
	2023	2022	2021
		$m	
Cost of operations:			
Production, insurance and transportation costs	(1,134)	(1,007)	(1,049)
Gas purchases	(465)	(194)	(84)
Royalties	(170)	(233)	(145)
Depreciation of oil and gas assets	(1,378)	(1,444)	(1,647)
Other cost of operations	(78)	(84)	(65)
Movement in over/underlift balances and hydrocarbon inventories	97	20	63
Total cost of operations	**(3,128)**	**(2,942)**	**(2,927)**
Net impairment reversal/(expense) of property, plant and equipment, goodwill and intangible assets	111	(188)	6
Exploration and evaluation expenditure	(78)	(56)	(46)
Exploration costs written-off	(72)	(28)	(193)
Net (loss)/gain on disposal	(10)	(128)	25
General and administrative expenses:			
Depreciation of non-oil and gas assets	(20)	(18)	(21)
Amortisation of non-oil and gas intangible assets	(2)	(2)	(2)
Allocation of Wintershall Dea AG head-office costs, in line with SIR2000	(11)	(132)	(131)
Other administrative costs	(379)	(215)	(194)
Total general and administrative expenses	**(412)**	**(367)**	**(348)**

The Target Portfolio recognised a net impairment reversal of $111 million for the year ended 31 December 2023, compared to a net impairment expense of $188 million for the year ended 31 December 2022. This net impairment reversal consisted of the reversal of impairments totalling $209 million for assets in Mexico due to higher oil prices and in Algeria (increase in interest in the asset) offset by impairments on assets in the amount of $98 million, relating to assets in Egypt and Mexico, based on operational updates.

The net impairments for the year ended 31 December 2022 mainly consisted of impairments for assets amounting to $322 million and relating to assets in Norway due to disposal of Brage, in Mexico due to changed technical concepts and in Egypt due to operational updates as well as reversal of impairments on assets, totalling to $134 million, in Egypt, Algeria and Germany due to improved economics of the projects.

The net reversal of impairments for the year ended 31 December 2021 consisted of impairments on assets amounting to $402 million and relating to assets in Mexico, Egypt and Germany due to operational updates and in Argentina due to inorganic measures, as well as reversal of impairments amounting to $409 million and relating to assets in Norway and Mexico due to increased service potential after significant increase of commodity prices.

The exploration costs written off in the year ended 31 December 2023 consisted of expenditure previously capitalised in respect of two wells in Mexico, one well in Norway and one in Egypt, all of which were dry. The costs written off in the year ended 31 December 2022 included expenditure capitalised of five dry wells in Norway and one well in Mexico. The exploration costs written off in the year ended 31 December 2021 consisted of three dry wells in Norway, losses from relinquishment of a licence in Norway, one well in Mexico and one well in Egypt, both of which were dry. In addition, this position includes impairment losses on exploration assets in Egypt, Mexico and Norway.

During 2023 administrative expenses increased due to one-off restructuring and related transformation costs plus systems integration costs related to deployments in certain HFI entities.

8. STAFF COSTS

	Year ended 31 December		
	2023	**2022**	**2021**
		$m	
Wages and salaries and other staff costs	212	223	224
Social security costs	28	26	27
Pension costs	14	17	22
Total staff costs	**254**	**266**	**273**

The staff costs have been appropriately allocated to the relevant cost function and included within the Combined Statement of Other Comprehensive Income as part of operating profit.

Please refer to note 21 for the pension provision reconciliation.

9. FINANCE INCOME AND FINANCE EXPENSES

	Year ended 31 December		
	2023	**2022**	**2021**
		$m	
Finance income:			
Bank interest	148	28	8
Interest income from related parties	298	163	206
Foreign currency exchange gains	—	103	68
Investment income from related parties	2	3	10
Other interest and finance gains	49	4	—
Total finance income	**497**	**301**	**292**
Finance expenses:			
Interest payable on bond and subordinated notes	(108)	(106)	(113)
Interest payable on debt to banks	—	—	(3)
Other interest and finance expenses	(90)	(51)	(38)
Lease interest	(4)	(3)	(3)
Losses from financial derivatives, net	(48)	(348)	(304)
Foreign currency exchange losses	(387)	—	—
Unwinding of discount on decommissioning and other provisions	(79)	(32)	(25)
	(716)	**(540)**	**(486)**
Finance costs capitalised during the year	3	22	21
Total finance expense	**(713)**	**(518)**	**(465)**

Interest income from related parties comprise interest from the loans as well as from the cash pooling arrangement with Wintershall Dea AG.

Investment income from related parties comprise of dividend payments and profit transfers from investments in other financial assets as well as income on the disposals of investments.

10. INCOME TAX

	Year ended 31 December		
	2023	2022	2021
		$m	
Current income tax (expense)/credit:			
German corporation tax	(92)	(67)	(32)
Overseas tax	(1,993)	(3,319)	(824)
Adjustments in respect of prior years	28	14	(49)
Total current income tax expense	**(2,057)**	**(3,372)**	**(905)**
Deferred tax (expense)/credit			
German corporation tax	28	36	(35)
Overseas tax	1	2	(417)
Adjustments in respect of prior years	—	—	—
Total deferred tax (expense)/credit	**29**	**38**	**(452)**
Total tax expense reported in the income statement	**(2,028)**	**(3,334)**	**(1,357)**
The tax (expense)/credit in the statement of comprehensive income is as follows:			
Tax (expense)/credit in other comprehensive income	**(2,550)**	**595**	**2,075**

In Germany, a uniform corporate income tax rate of 15 per cent. and a solidarity surcharge of 5.5 per cent. across all three HFI periods are levied on all distributed and retained earnings. In addition to corporate income tax, income generated in Germany is subject to a trade tax that varies depending on the municipality in which the company is represented. The weighted average corporate income and trade tax rate for 2023 was 30 per cent. (2022: 30 per cent., 2021: 30 per cent.). The income of foreign Target Portfolio companies is assessed using the tax rates applicable in their respective countries, in particular for Norway at 78 per cent. (2022: 78 per cent., 2021: 78 per cent.). In 2022, Germany enacted the EU regulation of a temporary mandatory solidarity contribution of 33 per cent. for excess profits generated from activities in the oil, gas, coal and refinery sectors. The Target Portfolio expensed an additional $12m EU solidarity contribution for its oil and gas excess profits generated in its German operations in 2022.

For group tax purposes, Wintershall Dea AG (entity outside of the perimeter) is located in Germany, which has enacted new legislation prescribing a global minimum top-up tax in 2024. The Target Portfolio does not expect to be affected by the global minimum top-up tax. The Target Portfolio's operations are generally located in countries with statutory tax rates of considerably more than 15 per cent., and so the Target Portfolio expects immaterial future impacts resulting from the global minimum top-up tax on its operations. If the global minimum top-up tax had been applied in 2023, the simplified calculated global minimum top-up tax for Target Portfolio's activities in the segments North Africa and Northern Europe would have an immaterial impact on the effective tax rate of Target Portfolio's operations.

Reconciliation to the effective tax expense and the tax rate

	Year ended 31 December		
	2023	2022	2021
		$m	
Income – before taxes	2,575	4,115	1,302
Expected income taxes based on German weighted average corporate and trade income tax rate (30%)	(773)	(1,235)	(390)
Effect of overseas tax rate differences	(1,220)	(2,110)	(796)
Adjustments in respect of prior years	28	14	(49)
Tax effects on:			
Changes in tax loss carryforwards	—	(31)	(45)
Intangible and fixed asset impairments and reversal of impairments	(17)	39	—
Goodwill impairments and disposal losses	—	(10)	(8)
Future dividends from subsidiaries and associates	6	(8)	(9)
Miscellaneous	(52)	7	(60)
Effective income tax (expense)/credit	**(2,028)**	**(3,334)**	**(1,357)**
Effective income tax rate %	**79%**	**81%**	**104%**

Income tax assets and liabilities

Income tax assets and liabilities consist primarily of income taxes for the respective current year and prior-year periods.

Deferred tax

	Year ended 31 December		
	2023	2022	2021
		$m	
Deferred tax assets	312	246	256
Deferred tax liabilities	(4,641)	(2,097)	(2,670)
Total deferred tax	**(4,329)**	**(1,851)**	**(2,414)**

The following are the major deferred tax liabilities and assets recognised by the Target Portfolio group and movements thereon during the current and prior reporting periods:

Deferred Tax Asset/(Liability) in $m	Intangible assets, property, plant and equipment	Inventories, receivables and financial assets	Pension provisions	Cash flow hedges and other financial instruments	Tax loss carry-forwards	Total
As at 1 January 2021	(5,839)	(42)	84	1,756	107	(3,934)
Deferred tax income/(expense)	(193)	(99)	(5)	(187)	32	(452)
Comprehensive income	—	21	(15)	2,069	—	2,075
Foreign exchange	(21)	3	(2)	(74)	(9)	(103)
As at 31 December 2021	**(6,053)**	**(117)**	**62**	**3,564**	**130**	**(2,414)**
Deferred tax income/(expense)	370	79	(10)	(450)	49	38
Comprehensive income	—	(2)	(22)	619	—	595
Foreign exchange	78	6	(3)	(143)	(8)	(70)
As at 31 December 2022	**(5,605)**	**(34)**	**27**	**3,590**	**171**	**(1,851)**
Deferred tax income/(expense)	(95)	15	(3)	(42)	154	29
Comprehensive income	—	(8)	10	(2,552)	—	(2,550)
Foreign exchange	(36)	(2)	—	71	10	43
As at 31 December 2023	**(5,736)**	**(29)**	**34**	**1,067**	**335**	**(4,329)**

Deferred tax assets result from domestic and foreign activities. Deferred tax assets comprise capitalised tax credit claims resulting from the expected utilisation of loss carry forwards in subsequent years, and unrealised gains/losses on cash flow hedges. Deferred tax assets are recognised on the basis that it is probable that taxable profits will be available against which the deferred tax asset can be utilised. In the reporting period, there were tax loss carry forwards of $1,023m (2022: $569m; 2021: $435m) in Mexico, $0m (2022: $3m; 2021: $0m) in the Netherlands, $87m (2022: $0m; 2021: $0m) in Argentina, for which deferred taxes of $335m (2022: $171m; 2021: $130m) were recognised.

The amount of tax loss carry forwards not covered by deferred tax assets totals $924m (2022: $863m and 2021: $753m). A total amount of $586m (2022: $526m and 2021: $453m) will not expire. An amount of $41m (2022: $41m, 2021: $36m) will expire in 2–3 years, $125m (2022: $81m, 2021: $32m) will expire in 3–5 years and $172m (2022: $215m, 2021: $232m) after 5 years.

No deferred tax liabilities were recognised for temporary differences associated with investments in subsidiaries and branches in the amount of approximately $362m (2022: $300m; 2021: $334m) because the Target Portfolio will remain in a position to control the timing of the reversal of the temporary differences, and it is probable that such differences will not reverse in the foreseeable future.

The Target Portfolio has applied the temporary exception, introduced in May 2023, from the accounting requirements for deferred taxes in IAS 12, so that the group neither recognises nor discloses information about deferred tax assets and liabilities related to Pillar Two income taxes.

11. GOODWILL

Goodwill represents the difference between the aggregate of the fair value of purchase consideration transferred at the acquisition date and the net fair value of the identifiable assets acquired and liabilities assumed.

	Year ended 31 December		
	2023	2022	2021
		$m	
Cost and net book value			
At 1 January	2,287	2,353	2,400
Disposals	—	(22)	(11)
Impairment charge	—	(12)	(17)
Currency translation adjustment	17	(32)	(19)
At 31 December	**2,304**	**2,287**	**2,353**

Goodwill is allocated as follows to the group of CGUs:

	Year ended 31 December		
	2023	2022	2021
		$m	
Norway	1,827	1,824	1,865
Germany	335	322	345
Argentina	130	130	131
The Netherlands	12	11	12
	2,304	**2,287**	**2,353**

Goodwill is subject to an annual impairment test, which was carried out as at year-end, at the level of groups of CGUs. An impairment is recognised when the carrying amount of the CGU exceeds the recoverable amount. The recoverable amount corresponds to the fair value less cost of disposal (level 3 in fair value hierarchy). For goodwill, producing licences and licences in the development phase, the recoverable amount is estimated based on discounted future cash flows after tax.

Macroeconomic parameters (applicable to all asset impairment tests)

Oil and gas prices

Oil and gas price forecasts are based on the current oil and gas price scenario taking into account management's estimates and available market data. The oil and gas price scenario includes a Brent price of $75/bbl and a European gas price of $16/mmbtu for the year 2024. In the long-term, respective prices of $75/bbl (after 2024) and of $9/mmbtu (after 2026) in real terms are assumed.

Discount rates

The discount rates applied are based on the weighted average cost of capital, taking into consideration the individual functional currency and specific country risks. The Target Portfolio applies after-tax discount rates. The beta factor is based on publicly available market data about the identified peer group. For the impairment test in 2023, the after-tax discount rates applied per functional currency ranged between 8.4 per cent. and 33.9 per cent.. After-tax discount rates for the goodwill impairment test for 2023 of 8.4 per cent. and 8.5 per cent. (2022: 7.9 per cent. and 7.6 per cent.; 2021: 6.7 per cent. and 6.6 per cent.) were used for the business units Norway and Germany respectively, to which a significant portion of the goodwill was allocated.

Goodwill impairment test

Oil and gas prices, production volumes, and discount rates are considered to be the most critical input parameters and assumptions for goodwill impairment testing. A sensitivity analysis was carried out for these items. In accordance with IAS 36.134 f, the analysis focused solely on the Norway and Germany business units.

After determining the corresponding recoverable amounts of the business units by assessing considerable deviations (-20 per cent. on prices, -20 per cent. on production and +1 per cent. on discount rates), there was no indication that the carrying amount would exceed the recoverable amount and trigger goodwill impairment with regard to the discount rates, for 2023, 2022 and 2021, and with regard to the price and production, for 2022 and 2023. In the case of production volumes or gas and oil prices, a considerable decrease for one of these parameters may be associated with a potential risk of impairment of the allocated goodwill in 2021 – the recoverable amounts of Germany and Norway exceed their carrying amounts by $476 million and $919 million, respectively. The recoverable amounts would correspond to the carrying amounts of the business units if the gas and oil price forecasts were approximately 15 per cent. lower in Germany and 13 per cent. lower in Norway or if production volumes were 13 per cent. lower in Germany and 11 per cent. lower in Norway.

12. OTHER INTANGIBLE ASSETS

	Total
	$m
Cost:	
At 1 January 2021	516
Additions during the year	128
Disposals during the year	(18)
Transfers to property, plant and equipment	(245)
Transfers to assets held for sale	(7)
Currency translation adjustment	(4)
At 31 December 2021	**370**
Additions during the year	125
Disposals during the year	(47)
Currency translation adjustment	(3)
At 31 December 2022	**445**
Additions during the year	136
Disposals during the year	(43)
Transfers to property, plant and equipment	(3)
Currency translation adjustment	2
At 31 December 2023	**537**
Amortisation:	
At 1 January 2021	(118)
Charge for the year	(2)
Impairments	(47)
Disposals	1
Currency translation adjustment	2
At 31 December 2021	**(164)**
Charge for the year	(2)
Disposals	2
Currency translation adjustment	4
At 31 December 2022	**(160)**
Charge for the year	(2)
Disposals	1
Currency translation adjustment	(2)
At 31 December 2023	**(163)**
Net book value:	
At 31 December 2021	**206**
At 31 December 2022	**285**
At 31 December 2023	**374**

Impairments recorded have been explained as part of note 7. Included above are E&E assets of $245m (2022: $182m; 2021: $123m).

13. PROPERTY, PLANT AND EQUIPMENT

	Oil & Gas	Other	Total
	$m	*$m*	*$m*
Cost:			
At 1 January 2021	**20,605**	**4,471**	**25,076**
Additions during the year	1,221	12	1,233
Disposals during the year	(795)	(124)	(919)
Transfers from other intangible assets	236	9	245
Transfers to assets held for sale	—	(221)	(221)
Currency translation adjustment	(355)	(74)	(429)
At 31 December 2021	**20,912**	**4,073**	**24,985**
Additions during the year	879	17	896
Disposals during the year	(2,511)	(33)	(2,544)
Currency translation adjustment	(312)	(65)	(377)
At 31 December 2022	**18,968**	**3,992**	**22,960**
Additions during the year	1,371	73	1,444
Disposals during the year	(183)	(9)	(192)
Transfers from other intangible assets	(3)	6	3
Currency translation adjustment	179	35	214
At 31 December 2023	**20,332**	**4,097**	**24,429**
Accumulated depreciation:			
At 1 January 2021	**(10,869)**	**(1,152)**	**(12,021)**
Charge for the year	(1,391)	(232)	(1,623)
Impairment	(243)	(209)	(452)
Reversal of impairment	308	101	409
Disposals	411	53	464
Transfers to assets held for sale	112	44	156
Currency translation adjustment	212	48	260
At 31 December 2021	**(11,460)**	**(1,347)**	**(12,807)**
Charge for the year	(1,236)	(212)	(1,448)
Impairment	(3)	(308)	(311)
Reversal of impairment	135	—	135
Disposals	1,627	27	1,654
Currency translation adjustment	196	43	239
At 31 December 2022	**(10,741)**	**(1,797)**	**(12,538)**
Charge for the year	(1,154)	(222)	(1,376)
Impairment	(66)	(32)	(98)
Reversal of impairment	12	197	209
Disposals	7	8	15
Currency translation adjustment	(125)	(27)	(150)
At 31 December 2023	**(12,067)**	**(1,873)**	**(13,938)**
Net book value:			
At 31 December 2021	**9,452**	**2,726**	**12,178**
At 31 December 2022	**8,227**	**2,195**	**10,422**
At 31 December 2023	**8,267**	**2,224**	**10,491**

In connection with the acquisition and production of qualified assets, borrowing costs of $3m (2022: $23m; 2021: $21m) were capitalised as part of acquisition and production costs in the reporting period. The financing cost rate applied in this context was between 1.2 per cent. and 1.4 per cent. (2022: 1.2 per cent.; 2021: between 1.1 per cent. and 1.2 per cent.). Assets under construction is included within the above table, and is $2bn for 2023, $2bn for 2022 and $3bn for 2021, respectively. Impairment recorded in each of the HFI years have been explained as part of note 7.

In conjunction with the impairment test for our producing and development assets in 2023, 2022 and 2021, we performed sensitivity analyses for commodity prices as well as for discount rates, where negative balances indicate a further impairment, and positive balances an impairment reduction. Any impairment reversal would not exceed historical impairment.

	31 December 2023		31 December 2022		31 December 2021	
$m	Pre-tax net impairment	Post-tax net impairment	Pre-tax net impairment	Post-tax net impairment	Pre-tax net impairment	Post-tax net impairment
Oil and gas prices						
10% increase	236	175	218	168	58	57
10% decrease	(281)	(211)	(243)	(189)	(193)	(151)
Discount rates						
1% decrease	177	126	133	99	10	11
1% increase	(160)	(114)	(120)	(89)	(83)	(62)

14. **LEASES**

The lease agreements of the Target Portfolio essentially related to office buildings, transport and production vessels and drilling rigs. The capitalised right-of-use-assets are allocated to the following asset classes:

	Year ended 31 December		
	2023	2022	2021
		$m	
Right-of-use assets			
Land & buildings and others	65	55	62
Gas and oil assets	66	38	18
Total	**131**	**93**	**80**

	Year ended 31 December		
	2023	2022	2021
		$m	
Lease creditors			
Current	(29)	(19)	(25)
Non-current	(107)	(78)	(75)
Total	**(136)**	**(97)**	**(100)**

The following amounts are recognised in the combined statement of income:

	Year ended 31 December		
	2023	2022	2021
		$m	
Lease expenses			
Depreciation right-of-use assets	(22)	(14)	(45)
Interest expenses on lease liabilities	(5)	(4)	(4)
Total	**(27)**	**(18)**	**(49)**

The depreciation of right-of-use assets are allocated to the following asset classes for the reporting periods:

	Year ended 31 December		
	2023	2022	2021
		$m	
Depreciation right-of-use assets			
Land & buildings and others	(10)	(7)	(10)
Gas and oil assets	(12)	(7)	(35)
Total	**(22)**	**(14)**	**(45)**

Some of the lease contracts contain price-adjustment clauses as well as extension and termination options. Such options are taken into account in the determination of the lease term only if extension or non-termination options can be assumed with reasonable certainty.

The statement of cash flows comprises cash outflows for leases amounting to $28m (2022: $35m; 2021: $69m). In addition to the cash payments for the interest and principal portions of recognised lease liabilities, the amounts reported include payments for unrecognised short-term leases and leases for low-value assets.

15. INVENTORIES

	Year ended 31 December		
	2023	2022	2021
		$m	
Hydrocarbons	44	94	32
Consumables and subsea supplies	151	145	175
Total inventories	**195**	**239**	**207**

Inventories of consumables and subsea supplies include a provision at the year ended 31 December 2023 of $41m (2022: $43m and 2021: $48m) where it is considered that the net realisable value is lower than the original cost.

16. TRADE AND OTHER RECEIVABLES

	Year ended 31 December		
Current	2023	2022	2021
		$m	
Trade receivables	879	985	889
Underlift position	192	140	122
Other debtors	182	128	141
Related party financial receivables	776	6,827	4,336
Prepayments and accrued income	41	22	5
Corporation tax receivable	10	23	3
Financial receivables	2	—	—
Total trade and other receivables	**2,082**	**8,125**	**5,496**

The carrying value of the trade and other receivables are equal to their fair value as at the balance sheet date.

	Year ended 31 December		
Non-Current	2023	2022	2021
		$m	
Other debtors	15	12	10
Prepayments and accrued income	5	4	1
Related party financial receivables and assets	—	3,646	4,610
Other financial receivables and assets	13	13	3
Total other receivables and assets	**33**	**3,675**	**4,624**

Trade receivables comprises of related party trade receivables of $270m (2022: $502m; 2021: $289m).

The current related party financial receivables mainly comprise cash pooling receivables. In 2021 and 2022, cash generated by perimeter assets are pooled by Wintershall Dea AG, an entity outside of the transaction perimeter, and therefore included within related party financial receivables. Current receivables are assumed to be recoverable in one year, with interest at an arm's length basis based on Euro Short Term rate ("**Euro-STR**"), Sterling Overnight Index Average, ("**SONIA**"), Secure Overnight Financing Rates ("**SOFR**") and Norwegian Overnight Weighted Average ("**NOWA**").

In 2021 and 2022 non-current financial receivables mainly related to related party finance receivables (loans). The loans are contractual, with interest at an arm's length basis (with maturities ranging up to 2031).

In the context of a (net) debt push down, as explained in note 24, cash pooling liabilities and intercompany loans (liabilities) were transferred from Wintershall Dea AG into the Target Portfolio in 2023, resulting in the related party balances and transactions turning into intercompany balances and therefore eliminated in 2023, which led to a reduction in current and non-current financial receivables.

17. FINANCIAL ASSETS AND LIABILITIES

The Target Portfolio held the following derivative assets and liabilities measured at fair value as at:

	Year ended 31 December		
	2023	2022	2021
		$m	
Long-term derivative assets			
Financial derivative assets	—	—	1
Commodity derivative assets	134	7	2
Total long-term derivative assets	**134**	**7**	**3**
Short-term derivative assets			
Financial derivative assets	96	45	10
Commodity derivative assets	138	52	6
Total short-term derivative assets	**234**	**97**	**16**
Long-term derivative liabilities			
Financial derivative liabilities	(38)	(110)	(25)
Commodity derivative liabilities	(4)	(1,183)	(1,047)
Total long-term derivative liabilities	**(42)**	**(1,293)**	**(1,072)**
Short-term derivative liabilities			
Financial derivative liabilities	(1)	(78)	(62)
Commodity derivative liabilities	(257)	(2,343)	(1,862)
Total short-term derivative liabilities	**(258)**	**(2,421)**	**(1,924)**

The commodity derivatives have fluctuated significantly over the last three years, since the Target Portfolio's all-in-one gas hedges commenced in 2020 while prices were still relatively low, upon which the high gas prices during 2021 and 2022 impacted the fair value of the commodity derivative liabilities. Following the price downturn in 2023 again, the Target Portfolio hedged at much higher price levels, where the fair values decreased significantly.

Fair value measurements of all financial assets and liabilities

All financial instruments that are initially recognised and subsequently remeasured at fair value have been classified in accordance with the hierarchy described in IFRS 13 Fair Value Measurement. The hierarchy groups fair value measurements into the following levels based on the degree to which the fair value is observable.

- Level 1: fair value measurements are derived from unadjusted quoted prices for identical assets or liabilities.
- Level 2: fair value measurements include inputs, other than quoted prices included within level 1, which are observable directly or indirectly.
- Level 3: fair value measurements are derived from valuation techniques that include significant inputs not based on observable data.

Year ended 31 December 2023	Level 1	Level 2	Level 3
		$m	
Other financial assets	—	—	13
Other receivables and assets	—	—	1
Derivative financial assets	**—**	**368**	**—**
Thereof commodity derivatives (assets)	—	272	—
Thereof financial derivatives (assets)	—	96	—
Other payables and liabilities	—	—	(10)
Derivative financial liabilities	**—**	**(300)**	**—**
Thereof commodity derivatives (liabilities)	—	(261)	—
Thereof financial derivatives (liabilities)	—	(39)	—

Year ended 31 December 2022	Level 1	Level 2	Level 3
		$m	
Other financial assets	—	—	13
Trade accounts receivable	—	—	54
Other receivables and assets	—	—	3
Derivative financial assets	**—**	**104**	**—**
Thereof commodity derivatives	—	59	—
Thereof financial derivatives	—	45	—
Derivative financial liabilities	**—**	**(3,714)**	**—**
Thereof commodity derivatives	—	(3,526)	—
Thereof financial derivatives	—	(188)	—

Year ended 31 December 2021	Level 1	Level 2	Level 3
		$m	
Other receivables and assets	—	—	3
Derivative financial assets	**—**	**19**	**—**
Thereof commodity derivatives	—	8	—
Thereof financial derivatives	—	11	—
Derivative financial liabilities	**—**	**(2,996)**	**—**
Thereof commodity derivatives	—	(2,909)	—
Thereof financial derivatives	—	(87)	—

There were no transfers between fair value levels in the three years.

Commodity prices and foreign currencies are hedged using derivative instruments as necessary in accordance with a centrally defined strategy. Hedging is only employed for underlying items in the operating business, cash investments, financing and planned capital measures. The risks associated with the hedged items and the derivatives are constantly monitored. Where derivatives have a positive market value, the Target Portfolio is exposed to credit risks from derivative transactions in the event of the non-performance of the counterparty. To minimise the default risk of derivatives with positive market values, transactions are conducted exclusively with creditworthy banks and partners and subject to predefined credit limits, with no collateral.

The contracting and execution of derivative financial instruments for hedging purposes are conducted according to internal guidelines and are subject to strict control mechanisms.

$m	2023	2022	2021
Commodity derivatives	**11**	**(3,468)**	**(2,901)**
of which designated hedging instruments as defined by IFRS 9 (hedge accounting)	6	(3,465)	(2,894)
Foreign currency derivatives	**56**	**(142)**	**(77)**
of which designated hedging instruments as defined by IFRS 9 (hedge accounting)	(8)	(182)	(24)
Total	**67**	**(3,610)**	**(2,978)**

Fair value movements recognised in the income statement are disclosed in note 9 as realisations of fixed price gas sales and oils swaps are included in revenues. The following table summarises the impact of fair value movements recognised in other comprehensive profit/(loss):

	2023			2022			2021		
	Fixed price gas sales	Oil swaps	Foreign currency	Fixed price gas sales	Oil swaps	Foreign currency	Fixed price gas sales	Oil swaps	Foreign currency
Change in fair value of hedging instrument recognised in OCI, pre-tax. $m	2,796	22	36	(4,375)	(279)	(156)	(4,063)	(404)	(180)
Reclassified from OCI to profit or loss, pre-tax. $m	550	113	(24)	3,560	329	173	1,532	160	220

The following table summarises the hedge ineffectiveness as at 31 December, for each year:

$m	2023	2022	2021
Commodity derivatives			
Change in fair value of the hedging instrument	136	28	(254)
Change in fair value of the hedged item	(136)	(30)	262
Hedge ineffectiveness	**—**	**(2)**	**8**
Foreign currency derivatives			
Change in fair value of the hedging instrument	92	(88)	(177)
Change in fair value of the hedged item	(40)	90	181
Hedge ineffectiveness	**52**	**2**	**4**

17.1 **Commodity derivatives**

The Target Portfolio has designated oil swaps, zero cost collars and certain fixed-price gas sales agreements as hedging instruments within the scope of cash flow hedges. Cash flow hedges are used to hedge the risk of variability in cash flows related to highly probable forecast transactions.

The effective portion of changes in the fair value of commodity derivatives that are designated as cash flow hedges is recognised as other comprehensive income within equity. The gains or losses relating to the ineffective portion are recognised immediately in profit or loss.

Existing hedges as at 31 December 2023 include forward gas sales and zero cost collars to stabilise portions of gas revenues until 2025 as well as Dated Brent oil swaps and zero cost collars to stabilise portions of the Target Portfolio's oil sales until 2025. For the Dated Brent oil swaps and the zero cost collars, German and Norwegian oil production currently serves as a hedged item. The contracted price is defined via a price formula. Regression analyses show a high correlation between Dated Brent oil prices and contracted prices and provide the basis for determining optimal hedge ratios. In the case of fixed-price gas sales agreements, to which the hedge accounting regulations are applicable, the critical terms match method is applied to assess hedge effectiveness.

Commodity price risks also arise in the ordinary course of business for contracted gas purchase and supply agreements. The specific price risk, which results from the valuation of the gas agreements concluded in the event of an adverse change in market prices, is mitigated by the Target Portfolio by imposing and constantly monitoring the limits on the type and scope of the transactions concluded.

Existing derivatives related to the gas trading business are recognised at FVTPL and disclosed based on net risk exposure in accordance with IFRS 13.48. The following table summarises the nominal amounts, volumes, average hedged price and timings associated with the financial commodity derivatives:

	2023		2022		2021	
Year ended 31 December	Fixed price gas sales	Oil swaps	Fixed price gas sales	Oil swaps	Fixed price gas sales	Oil swaps
Nominal amount, $m	1,167	722	1,944	878	1,862	1,090
Maturity date	01/2024–12/2025		01/2023–12/2025		01/2022–12/2024	
Quantity	104,748 mmscf	10,122 mbbl	217,592 mmscf	12,342 mbbl	293,176 mmscf	15,662 mbbl
Average price or rate	10.29 €/mscf	72.86 $/bbl	8.51 €/mscf	67.83 $/bbl	5.39 €/mscf	59.03 $/bbl

17.2 **Foreign currency derivatives**

In the context of the Target Portfolio's ordinary net foreign currency exposure, derivatives are recognised at FVTPL. In order to hedge the foreign currency risk from future USD repayments of intercompany loans in a EUR functional currency entity, the Target Portfolio entered into cross-currency swaps. Additionally, in order to hedge the foreign currency risk from future EUR repayments of intercompany loans in a USD functional currency entity, the Target Portfolio entered into FX forward contracts. The future cash flows resulting from the repayment of these intercompany loans have been designated as hedged items. The spot elements and the forward elements of these foreign currency derivatives have been separated, whereas only the value changes of the spot elements have been designated as hedging instrument. The forward elements are recognised as cost of hedging in other comprehensive income and are reclassified to profit or loss on a systematic and rational basis. Hedge ineffectiveness is immediately recognised in profit or loss.

Year ended 31 December	**2023**	**2022**	**2021**
Nominal amount, $m	1,835	2,296	2,485
Maturity date	01/2024–09/2028	01/2023–09/2028	01/2022–09/2028
Average price or rate	1.08 $/€	1.11 $/€	1.14 $/€

18. CASH AND CASH EQUIVALENTS

	Year ended 31 December		
	2023	**2023**	**2023**
		$m	
Cash at bank and in hand	244	324	149

Cash at bank consists of both short-term fixed deposits and cash balances that earn interest at floating rates based on daily bank deposit rates. The Target Portfolio only deposits cash with major banks of high-quality credit standing.

Restricted cash and cash equivalents at the year ended 31 December 2023 include amounts in Egypt and Argentina of $183m (2022: $198m; 2021: $53m) that are subject to foreign currency transfer and amounts of $4m (2022: $6m; 2021: $6m) due to legal restrictions.

19. COMMITMENT

Contingent liabilities

Contingent liabilities relate to legal disputes and potential tax risks. The Target Portfolio is regularly involved as a defendant or other party in judicial and arbitration proceedings, as well as in official proceedings. Based on the present knowledge, these proceedings have no significant impact on Target Portfolio's economic situation.

Target Portfolio is also subject to statutory liability related to participations in various joint ownerships. Based on the present knowledge, these proceedings have no significant impact on Target Portfolio's economic situation.

Capital commitments

As at 31 December 2023, the Target Portfolio has obligations based on firm orders for property, plant and equipment, as well as from field development projects, exploration wells and seismic surveys in the amount of $2,017m (2022: $866m and 2021: $490m).

20. TRADE AND OTHER PAYABLES

	Year ended 31 December		
	2023	**2022**	**2021**
		$m	
Current			
Trade payables	610	386	365
Overlift position	46	81	57
Other payables	417	280	252
Deferred income	1	26	55
Related party financial liabilities	568	809	604
Total	**1,642**	**1,582**	**1,333**
Non-current			
Other payables	27	23	27
Related party financial liabilities	—	1,302	1,372
Total	**27**	**1,325**	**1,399**

Trade payables comprises of related party trade payables of $265m (2022: $170m; 2021: $126m).

The current related party financial payables include cash pooling payables and other short term financial liabilities with related parties. Current payables are assumed to be payable in one year, with interest at an arm's length basis based on Euro-STR, SONIA, SOFR and NOWA.

In 2021 and 2022 non-current financial liabilities relate to related party financial liabilities (loans). The loans are contractual, with interest at an arm's length basis (with maturities ranging up to 2051).

In the context of a (net) debt push down, as explained in note 24, intercompany loans (assets) were transferred from Wintershall Dea AG into the Target Portfolio in 2023, resulting in the related party transactions turning into intercompany transactions and therefore eliminated in 2023, which led to a reduction in related party financial liabilities.

21. PENSION PROVISIONS

In addition to state pension plans, most employees are granted company pension benefits from either defined contribution or defined benefit plans. Benefits generally depend on the length of service, compensation and contributions and take into consideration the legal framework of labour, tax and social security laws in the countries where the companies are located. To limit the risks of changes in financial market conditions and demographic developments, for a number of years now, employees have been offered almost exclusively defined contribution plans or equivalent company pension benefits for future years of service.

Description of the defined benefit plans

Germany

Some Target Portfolio companies in Germany have been participating in a capital market oriented defined benefit pension scheme. This scheme applies to all new employees joining the Target Portfolio company since 2020 and is financed by employer and employee contributions and the performance of the investment. The Target Portfolio guarantee at least the sum of all employer and employee contributions paid and generally fully covers these pension obligations with plan assets as part of an additional Contractual Trust Arrangement ("**CTA**"). The option of building up employee-financed retirement provisions through deferred compensation is also available to all employees of Target Portfolio companies in Germany as part of the capital market-oriented defined benefit pension scheme. All other pension plans (including deferred compensation plans) have been closed to new employees.

Furthermore, pension plans previously provided by BASF Pensionskasse VVaG for Target Portfolio company employees in Germany were replaced from April 2023 by new plans for future periods of service. The defined benefit plan of BASF Pensionskasse VVaG, which was closed to new employees in 2004, is continued as a defined benefit plan via a direct commitment by the Target Portfolio. The contribution-based plan of BASF Pensionskasse VVaG was replaced by the capital market-oriented pension scheme that is also granted to all new entrants.

Since the changeover in April 2023, some Target Portfolio companies in Germany only participate in the BASF group's pension plans for periods of service already rendered (past service). Some of the past service benefits financed via BASF Pensionskasse VVaG are subject to adjustments that must be borne by its member companies to the extent that these cannot be borne by BASF Pensionskasse VVaG due to the regulations imposed by the German supervisory authority. In addition to the former basic level of BASF Pensionskasse VVaG benefits, there are still defined pension schemes, which are financed via pension provisions at the German entities within the Target Portfolio. The benefits are largely based on modular plans. Only employees who already participated in various existing deferred compensation plans before 2022 can continue to participate in these plans.

BASF SE is not providing the required plan information from BASF Pensionskasse regarding the allocation of assets to the Target Portfolio for year-end closing. As a result, the former participation in BASF Pensionskasse for periods of service before April 2023 is accounted for as a multi-employer defined benefit plan with no access to sufficient information about the asset allocation and, therefore, as a defined contribution plan in accordance with IAS 19.36.

For further existing pension plans in Germany that are self-managed by the Target Portfolio, assets were transferred to Willis Towers Watson Treuhand GmbH within the framework of CTAs and to Willis Towers Watson Pensionsfonds AG as insolvency insurance. Willis Towers Watson Pensionsfonds AG falls within the scope of the Act on Supervision of Insurance Undertakings and Oversight by the German Federal Financial Supervisory Authority ("**BaFin**"). Insofar as a regulatory deficit occurs in the pension fund, supplementary payments are requested from the employer. Irrespective of the aforementioned rules, the liability of the employer remains in place. The bodies of Willis Towers Watson Treuhand GmbH and Willis Towers Watson Pensionsfonds AG are responsible for ensuring that the funds under management are used in compliance with the contract and thus fulfil the requirements for their recognition as plan assets.

The defined benefit plans that are recognised as pension provisions mainly include pension promises and are hence subject to longevity risk.

Norway

The Target Portfolio Norway defined benefit plans have been closed to new employees since 1 January 2016. For Norwegian employees whose remaining length of service until retirement on 1 January 2016 was 15 years or less, a final salary commitment continues to apply after the closure of the plan.

The plans are partly funded via Nordea Liv AS. Employees who still had a remaining length of service of more than 15 years on the date of 1 January 2016 and employees who joined the company after this date are entitled to benefits under a defined contribution pension plan. Defined contribution plans are either secured with Nordea Liv AS or unfunded and administered by Storebrand Pensjonstjenester on behalf of the Target Portfolio.

Moreover, closed defined benefit plans are in place for former DEA Norge employees. These are secured with DNB ASA. Employees who on 1 January 2021 still had 15 years or less until retirement remained in the existing plans. All others were transferred to existing defined contribution plans.

Actuarial assumptions

The amount of the provision for defined benefit pension schemes was determined by actuarial methods on the basis of the following key assumptions:

	2023		2022		2021	
Key assumptions (%)	**Germany**	**Norway**	**Germany**	**Norway**	**Germany**	**Norway**
Discount rate	3.2%	3.7%	3.7%	3.2%	1.2%	1.5%
Pension growth	2.3%	2.4%	2.3%	1.7%	1.7%	0.0%

The valuation of the defined benefit obligation is performed using the most recent actuarial mortality tables as at each year-end:

Germany	Heubeck Richttafeln 2018 G
Norway	K2013

The present value of the defined benefit obligations less plan assets measured at fair value results in the net defined benefit obligation arising from funded and unfunded plans and is recognised as pension provision on the balance sheet. Of the present value of defined benefit obligations, \$458m (2022: \$421m and 2021: \$590m) relate to benefit obligations in Germany and \$64m (2022: \$68m and 2021: \$90m) to benefit obligations in Norway.

German entities within the Target Portfolio's pensions are subject to an obligation to review for adjustments every three years pursuant to Section 16 of the German Occupational Pension Act ("**BetrAVG**"). Additionally, some commitments grant annual pension adjustments, which may exceed the legally mandated adjustment obligation.

The weighted average duration of the pension obligations is 12 years in Germany (2022: 12 years and 2021: 15 years) and 19 years in Norway (2022: 15 years and 2021: 19 years).

	Year ended 31 December		
	Defined benefit Obligations	Plan assets	Total
		$m	
As at 1 January 2021	**(765)**	**520**	**(245)**
Current service costs	(13)	—	(13)
Interest expense/(income)	(6)	4	(2)
	(19)	**4**	**(15)**
Remeasurements			
Return on plan assets, excluding amounts already recognized in Interest income	—	32	32
Actuarial gains/(losses)			
Of which effect of changes in financial assumptions	36	—	36
Of which effect of experience adjustments	(16)	—	(16)
Pre-tax other OCI impact of remeasurements	**20**	**32**	**52**
Currency effect	46	(32)	14
Employer contribution to the funded plans	—	8	8
Employee contribution to the funded plans	—	—	—
Benefit payments	36	(29)	7
Other	(1)	—	(1)
Change in scope	—	—	—
As at 31 December 2021	**(683)**	**503**	**(180)**
Current service costs	(8)	—	(8)
Interest expense/(income)	(8)	6	(2)
	(16)	**6**	**(10)**
Remeasurements			
Return on plan assets, excluding amounts already recognized in Interest income	—	(49)	(49)
Actuarial gains/(losses):			
Of which effect of changes in financial assumptions	153	—	153
Of which effect of experience adjustments	(37)	—	(37)
Pre-tax OCI impact of remeasurements	**116**	**(49)**	**67**
Currency effect	50	(36)	14
Employer contribution to the funded plans	—	2	2
Benefit payments	34	(22)	12
Other	6	(6)	—
As at 31 December 2022	**(493)**	**398**	**(95)**
Current service costs	(5)	—	(5)
Interest expense/(income)	(17)	14	(3)
	(22)	**14**	**(8)**
Remeasurements			
Return on plan assets, excluding amounts already recognized in Interest income	—	13	13
Actuarial gains/losses			
Of which effect of changes in financial assumptions	(35)	—	(35)
Of which effect of experience adjustments	(2)	—	(2)
Pre-tax OCI impact of remeasurements	**(37)**	**13**	**(24)**
Currency effect	(16)	15	(1)
Employer contribution to the funded plans	—	39	39
Benefit payments	33	(24)	9
Other	8	(7)	1
As at 31 December 2023	**(527)**	**448**	**(79)**

Sensitivity analysis of defined benefit obligations

An increase or decrease in the discount rate and pension growth would have the following impact on the present value of the defined benefit obligations:

	2023	2022	2021
		$m	
Discount rate			
Increase of 0.5 percentage points	(31)	(27)	(35)
Reduction of 0.5 percentage points	34	31	40
Pension growth			
Increase of 0.5 percentage points	23	22	30
Reduction of 0.5 percentage points	(21)	(19)	(25)

Plan assets

The investment policy in Germany is based on detailed asset liability management ("**ALM**") studies. Portfolios are identified that can achieve the best target return within a given risk budget. From these efficient portfolios, one is selected, and the strategic asset allocation is determined. The strategic asset allocation consists of two main elements. The first one is used to hedge fluctuations. This involves the use of capital market instruments that hedge the financial risks arising from the valuation of pension obligations. The second part of the allocation is used to generate income and for diversification purposes. The broadly diversified portfolio includes investments in bonds, equities, real estate and other asset classes. The assets are continuously monitored and managed from a risk and return perspective.

Contributions to the CTA are usually processed to the extent that at least an overall constant or increasing level of funding is achieved.

	Year ended 31 December		
	2023	2022	2021
		$m	
Assets held by insurance company	31	37	43
Specialised funds	413	358	457
Total	**444**	**395**	**500**

Defined contribution plans

For defined contribution plans, expenses of $8m were incurred (2022: $8m and 2021: $7m). As the Target Portfolio does not have the required information on the asset allocation of BASF Pensionskasse, it accounts for the multi-employer defined benefit plan for the past service before April 2023 as if it were a defined contribution plan. The pension provision covers the obligation for future pension adjustments with the amount of $9m (2022: $7m and 2021: $10m), in Germany. Other future supplementary payment obligations may occur due to unexpected funding requirements. Since these obligations are neither predictable nor probable, they are not included in the Target Portfolio's pension provisions. The Target Portfolio's contributions to the multi-employer plan made until April 2023 represent a certain percentage of the employee contributions. This percentage is the same for all participating employers. It takes into account the differences between the actuarial estimates and the actual values for the factors used to determine liabilities and contributions. Since April 2023, no ongoing contributions have been paid into the plan.

22. PROVISIONS

	Decommissioning provision	Other	Total
		$m	
At 1 January 2021	**3,370**	**318**	**3,688**
Additions	4	174	178
Changes in estimates: (decrease)/increase to assets*	(90)	—	(90)
Changes in estimates: debit/(credit) to the income statement*	(8)	—	(8)
Disposals	(171)	(13)	(184)
Amounts used	(38)	(90)	(128)
Unwinding of discount	23	—	23
Currency translation adjustment	(92)	(14)	(106)
At 31 December 2021	**2,998**	**375**	**3,373**
Additions	36	70	106
Changes in estimates: (decrease)/increase to assets*	(623)	—	(623)
Changes in estimates: debit/(credit) to the income statement*	3	—	3
Disposals	(89)	(18)	(107)
Amounts used	(68)	(86)	(154)
Unwinding of discount	30	—	30
Currency translation adjustment	(68)	(21)	(89)
At 31 December 2022	**2,219**	**320**	**2,539**
Additions	10	200	210
Additions from business combinations	38	—	38
Changes in estimates: (decrease)/increase to assets*	(113)	—	(113)
Changes in estimates: debit/(credit) to the income statement*	(9)	—	(9)
Disposals	(10)	(14)	(24)
Amounts used	(41)	(104)	(145)
Unwinding of discount	74	2	76
Currency translation adjustment	32	8	40
At 31 December 2023	**2,200**	**412**	**2,612**

Decommissioning provision

*The changes in estimates includes the effect of the discount rates changes for the three main jurisdictions of $134m (decrease in provision) in 2023, $790m (decrease in provision) in 2022 and $123m (decrease in provision) in 2021.

Decommissioning obligations pertain mainly to anticipated costs for filling wells and removing production equipment after production activities have come to an end. The costs of decommissioning and removal activities require revisions due to changes in current regulations and technology while considering relevant risks and uncertainties. Most of the removal activities are many years into the future, and the removal technology and costs are constantly changing. The speed of the transition to renewable energy sources may also influence the production period, hence the timing of the removal activities. The estimates include assumptions of norms, rates and time required which can vary considerably depending on the assumed removal complexity. The cost estimation differs based on the different categories of assets to be decommissioned. In regard to the estimation approach, it has to be differentiated between operated and non-operated assets. The estimation of costs for non-operated assets is either performed by the respective operator, while the responsible Target Portfolio company is reviewing the estimation provided, based on its own expertise, and the market as well as regulatory environment, or performed by the responsible Target Portfolio company and challenged by the data provided from the operator. For own operated assets the estimation of costs is based on own calculations, which are partially based on country-specific, industry-wide agreed upon standard cost estimates, while prices for specific activities in the area of field clearance are externally reviewed whenever possible. Furthermore, decommissioning cost estimates are continuously benchmarked against completed decommissioning activities and adjusted if needed.

In order to determine the present value, discount rates between 2.55 per cent. and 7.18 per cent. were applied in the reporting period (2022: 2.05 per cent. to 6.94 per cent., 2021: 0.00 per cent. to 8.69 per cent.). For Germany, the discount rates between 2.55 per cent. and 2.97 per cent. were applied in the reporting period (2022: 2.13 per cent. to 2.41 per cent., 2021: 0.00 per cent.) and were determined based on local government bond yield return, with an identical maturity of the expected cash flows to fulfil the decommissioning obligation. For Norway and Argentina, the discount rates between 4.69 per cent. and 5.37 per cent. were applied in the reporting period (2022: 4.18 per cent. to 4.76 per cent., 2021: 0.14 per cent. to 1.96 per cent.), and were determined based on US Treasury bond yield return, with an identical maturity of the expected cash flows.

The following table summarises the aggregated sensitivity analysis performed on the discount rates for the material business units, where negative balances indicate a decrease in the provision, and positive balances an increase in the provision:

	31 December 2023		31 December 2022		31 December 2021	
$m	0.5% rate decrease	0.5% rate increase	0.5% rate decrease	0.5% rate increase	0.5% rate decrease	0.5% rate increase
Total decommissioning provision sensitivity	(121)	111	(136)	125	(186)	170

The expected settlement of the provisions depends on the ratio of produced reserves to expected reserves and generally varies within a range of less than one year up to approximately 30 years, the majority of which are anticipated to be incurred between the next 10 to 20 years. Any reasonable changes in the in the year of abandonment assumption within the next 12 months will not result in material revision in the decommissioning provision.

Other – Employee obligations provision

Provisions for employee obligations include, in particular, obligations to pay long-service bonuses, anniversary bonuses, and variable remuneration, including the associated social security contributions and provisions due to restructuring measures or early retirement as well as phased-in early retirement models.

Pension provisions

Please refer to note 21 for pension provisions. The balances are non-current liabilities, and 2023: $79m, 2022: $95m, 2021: $180m respectively.

Total provisions* classified within:

$m	Non-current liabilities	Current liabilities
At 31 December 2021	3,082	471
At 31 December 2022	2,259	375
At 31 December 2023	2,238	453

**This includes the pension provision balances, as per note 21.*

23. BORROWINGS AND FACILITIES

	Year ended 31 December		
	2023	2022	2021
		$m	
Bonds	3,323	4,149	4,561
Transaction costs on bonds	(8)	(10)	(15)
Subordinated notes	1,690	1,624	1,742
Transaction costs on subordinated notes	4	3	2
Total borrowings	**5,009**	**5,766**	**6,290**
Classified within:			
Non-current liabilities	4,963	4,766	6,241
Current liabilities	46	1,000	49
Total borrowings	**5,009**	**5,766**	**6,290**

Bonds

	%	Maturity	Currency	Nominal Value €m	Fair Value 31 Dec-23 €m	Carrying Value 31 Dec-23 €m
Bond ISIN: XS2054209833	0.8%	2025	EUR	1,000	955	999
Bond ISIN: XS2054210252	1.3%	2028	EUR	1,000	907	997
Bond ISIN: XS2055079904	1.8%	2031	EUR	1,000	867	997
Total				**3,000**	**2,729**	**2,993**

In September 2019, Wintershall Dea Finance B.V., an entity within the Target Portfolio, issued senior bonds in the amount of €4,000 million. The transaction comprised four tranches.

Transaction costs were capitalised as a reduction in the bond amount and are being amortised over the expected life applying the EIR method.

In Q2 2022, Wintershall Dea Finance B.V. repurchased €99 million in aggregate principal amount of its senior bonds due in 2023. The redemption was executed between 12 May 2022 and 20 June 2022 pursuant to an open market repurchase programme. The bonds were cancelled by the issuer. The remaining amount of the Tranche (€901 million plus €42m worth of accrued interest) was repaid in September 2023, as at the due date.

As at 31 December 2023, the fair value of the bonds, which is determined using quoted market prices in an active market, amounts to €2,729 million. The repayment obligation remains at €3,000 million.

Subordinated notes

In January 2021, Wintershall Dea AG (outside the Target Portfolio) issued two series of subordinated resettable fixed rate notes (subordinated notes) in the aggregate principal amount of €1,500 million through subsidiary Wintershall Dea Finance 2 B.V. The subordinated notes are callable three months prior to the first reset date for the NC2026 series and six months prior to the first reset date for the NC2029 series, and have no maturity:

	%	Maturity	Currency	Nominal Value €m
Bond ISIN: XS2286041517	2.5%	2026	EUR	650
Bond ISIN: XS2286041947	3.0%	2029	EUR	850
Total				**1,500**

In the consolidated group financial statements of Wintershall Dea AG the subordinated notes, as included in the Target Portfolio, are classified as equity. For purposes of the HFI, the subordinated notes have been classified as liabilities in line with IAS 32 Financial Instruments on the basis that the guarantor, who has the ability to control the deferral of interest on the subordinated notes, is Wintershall Dea AG (which is outside the Target Portfolio), and therefore the cash flows are outside the control of the entities within the perimeter.

Going forward, it is probable that the subordinated notes will be treated as equity within the consolidated group financial statements of Harbour Energy plc because on 22 February 2024 the bondholders approved a change in guarantor from Wintershall Dea AG to Harbour Energy plc which will be effective upon completion of the transaction.

Changes in liabilities arising from financing activities under IAS 7

	1 Jan 2021	Cash flows from (repayments)/ proceeds	Currency effect	Other changes	31 Dec 2021
Bonds	4,881	—	(338)	3	4,546
Subordinated notes	—	1,758	(14)	—	1,744
Term loan	804	(800)	—	(4)	—
Financial liabilities to related parties	2,198	130	106	(457)	1,977
Lease liabilities	162	(69)	(2)	9	100
Total	**8,045**	**1,019**	**(248)**	**(449)**	**8,367**

	1 Jan 2022	Cash flows from (repayments)/ proceeds	Currency effect	Other changes	31 Dec 2022
Bonds	4,546	(106)	(307)	6	4,139
Subordinated notes	1,744	—	(117)	—	1,627
Financial liabilities to related parties	1,977	—	71	62	2,110
Lease liabilities	100	(35)	(2)	34	97
Total	**8,367**	**(141)**	**(355)**	**102**	**7,973**

	1 Jan 2023	Cash flows from (repayments)/ proceeds	Currency effect	Other changes	31 Dec 2023
Bonds	4,139	(979)	149	6	3,315
Subordinated notes	1,627	—	67	—	1,694
Financial liabilities to related parties	2,110	(17)	(106)	(1,419)	568
Lease liabilities	97	(28)	2	65	136
Total	**7,973**	**(1,024)**	**112**	**(1,348)**	**5,713**

The table details the change in the carrying amount of the Target Portfolio's borrowings arising from financing cash flow.

24. INVESTED CAPITAL

The key balance movements within invested capital are:

- Total comprehensive income directly from the Combined statement of other comprehensive income; and

- Capital contributions and reduction consist of transactions with the owner of the target portfolio and comprise of:

Capital Contributions	Amount ($'m)	Narrative
2021		
Capital contribution	131	Allocation of Wintershall Dea AG head office costs in line with SIR2000
PLTA	(156)	Profit and loss transfer agreements ("**PLTA**") in relation to target portfolio entities who transfer profits to the contractual partner (Wintershall Dea AG) resulting in a receivable (loss) or liability (profit) against that company and an equity distribution. The settlement, including interest, will take place in the following year via non cash settlement to/from the cash pooling receivables/liabilities
Total Capital Reductions 2021	**(25)**	
2022		
Capital contribution	132	Allocation of Wintershall Dea AG head office costs in line with SIR2000
PLTA	(760)	Changes from Profit and loss transfer agreements
Other	25	Other capital contributions from Wintershall Dea AG to entities within the Perimeter
Total Capital Reductions 2022	**(603)**	
2023		
Capital contribution	11	Allocation of Wintershall Dea AG head office costs in line with SIR2000
Capital reduction	(6,494)	Capital reduction as a result of the group restructure, as set out in debt pushdown of interests in the Target Portfolio below.
PLTA	(553)	Changes from Profit and loss transfer agreements
Dividends	(339)	Dividends were declared to Wintershall Dea AG and settled in the year via non cash settlement from the cash pooling receivables / liabilities
Total Capital Reductions 2023	**(7,375)**	

Hive down of interests in the Target Portfolio

On 15 August 2023, WDGH was incorporated and inserted at the top of the entities in the Target Portfolio. During the hive down, Wintershall Dea AG transferred its interest in the Target Portfolio into WDGH.

This transfer of interests into WDGH resulted in the recognition of an investment in WDGH's balance sheet and an opposite entry within invested capital of $6.8bn (€6.3bn), which was initially recorded at the previous carrying value of the investments in Wintershall Dea AG.

As all entities are within the Target Portfolio the investment balances are eliminated upon combination reversing the impact on invested capital.

Debt pushdown

On 31 October 2023, certain balances Wintershall Dea AG held with entities within the Target Portfolio were transferred from Wintershall Dea AG to WDGH. These balances comprised of:

	Amount ($'bn)
Cash pooling balances (liability)	(4.4)
Intercompany loans (asset)	1.3
Intercompany loans (liability)	(3.7)
Net liability transferred	**(6.8)**

In exchange, WDGH released $6.5bn or (€6.0bn) of capital reserves (from the €6.3bn created during the hive down) and recorded a cash pooling receivable against Wintershall Dea AG of $0.5bn (€0.5bn).

As a result of the debt pushdown, the counterparty of the intergroup financial payable and receivable balances in the perimeter balance sheet changed from Wintershall Dea AG to WDGH, resulting in a $6.5bn reduction in capital reserves, in reflection of the elimination of net receivable the Target Portfolio was owed by Wintershall Dea AG immediately before the debt pushdown occurred.

25. FINANCIAL RISK FACTORS AND RISK MANAGEMENT

By operating in an international environment, the Target Portfolio is exposed to market (price and foreign currency risks) and interest rate risks as well as to credit and liquidity risks in the ordinary course of its business. The Target Portfolio are subject to a strict risk management regime. The operational framework, as well as responsibilities and controls, are regulated by binding internal corporate guidelines. Financial derivatives are used exclusively to hedge the risk related to underlying transactions, and not for speculative purposes.

25.1 Foreign currency risk

Changes in exchange rates could lead to losses in the value of financial instruments and adverse changes in future cash flows. Foreign currency risks from financial instruments arise from the translation of financial receivables, cash and cash equivalents and financial liabilities into the functional currency of the respective Target Portfolio company at the closing rates. The Target Portfolio's foreign currency exposures are monitored and managed with the aim to eliminate the effect of currency fluctuations on the statement of income.

Exposure and sensitivity per currency:

	31 December 2023			31 December 2022			31 December 2021		
$m	**Exposure**	**+10%**	**-10%**	**Exposure**	**+10%**	**-10%**	**Exposure**	**+10%**	**-10%**
EGP	10	(1)	1	71	(6)	6	—	—	—
GBP	—	—	—	148	(13)	13	206	(19)	19
USD	(2,295)	209	(209)	(150)	13	(13)	81	(7)	7
ARS	176	(16)	16	208	(19)	19	20	(2)	2
NOK	49	(4)	4	(337)	31	(31)	(186)	17	(17)
MXN	(128)	11	(11)	(99)	9	(9)	29	(3)	3
Total	**(2,188)**	**199**	**(199)**	**(159)**	**15**	**(15)**	**150**	**(14)**	**14**

25.2 Interest rate risks

Interest rate risks arise due to potential changes in prevailing market interest rates, which can lead to changes in the fair value of fixed-rate instruments and interest payment fluctuations for variable-rate instruments. Even though the interest rates for the subordinated bonds are currently fixed, this will change over time, in line with the respective first option for the issuer to call one of the bonds for redemption in the year 2026, and the other in the year 2029. Following these dates, the interest rate for the respective subordinated bond will be reset to become a variable interest rate, based on a benchmark rate and a spread. These risks are not of material significance for the Target Portfolio's operating activities.

25.3 Commodity price risks

The Target Portfolio's revenue, cash flows and profitability depend to a large extent on prevailing international and local commodity prices. Any resulting adverse changes in market prices could have a negative impact on the Target Portfolio's net result and equity.

Commodity price risks related to production are assessed and mitigated regularly using systematic risk management. The principles of this approach are defined in the commodity hedging policy.

All hedging transactions are entered into for the sole purpose of reducing risks from planned transactions exposed to commodity price risks that have a high probability of occurrence. Part of the oil and gas price risks are hedged. The volumes to be hedged depend on the economic exposure and the current level of oil and gas prices.

The target hedge volumes are 50 per cent. and 25 per cent. of economic exposure after tax, capped by 75 per cent. and 37.5 per cent. of effectively hedgeable volumes, for a one-year and two-year horizon, respectively.

Existing hedges as at 31 December 2023 include forward gas sales and zero cost collars to stabilise portions of gas revenues until 2025 as well as Dated Brent oil swaps and zero cost collars to stabilise portions of oil sales until 2025.

For the Dated Brent oil swaps and the zero cost collars, German and Norwegian oil production currently serves as a hedged item. The contracted price is defined via a price formula. Regression analyses show a high correlation between Dated Brent oil prices and contracted prices and provide the basis for determining optimal hedge ratios. In the case of fixed-price gas sales agreements, to which the hedge accounting regulations are applicable, the critical terms match method is applied to assess hedge effectiveness.

Commodity price risks also arise in the ordinary course of business for contracted gas purchase and supply agreements. The specific price risk, which results from the valuation of the gas agreements concluded in the event of an adverse change in market prices, is mitigated by imposing and constantly monitoring the limits on the type and scope of the transactions concluded.

The following table summarises the impact on the Target Portfolio's pre-tax profit and other comprehensive income from a reasonably foreseeable movement in commodity prices on the fair value of commodity based derivative instruments held:

	31 December 2023		31 December 2022		31 December 2021	
$m	Effect on profit before tax	Effect on OCI	Effect on profit before tax	Effect on OCI	Effect on profit before tax	Effect on OCI
Brent crude oil						
$10/bbl increase	—	(96)	—	(123)	—	(157)
$10/bbl decrease	—	96	—	123	—	157
Natural gas						
$1.5/MMBtu increase	(11)	(155)	(64)	(514)	(47)	(644)
$1.5/MMBtu decrease	11	155	64	514	47	644

25.4 Credit risk

Default and credit risks arise when contractual partners do not fulfil their obligations. The Target Portfolio is exposed to credit risks from its operating activities (primarily trade accounts receivable) and its financing activities, including deposits with banks and financial institutions, favourable derivative financial instruments (positive fair value) and other financial receivables.

If customers are independently rated, these ratings are used for assessment. If there is no independent rating, the risk management function assesses customers' credit quality based on their financial position or bases the assessment on past experience and other factors. Individual risk limits are set based on internal or external ratings in accordance with set limits. There are no significant concentrations of credit risks through the exposure to individual customers or regions. Country-specific payment risks are within the limits stipulated by the management and closely monitored.

A default event occurs if management has good reason to believe that a customer will not repay its liability to the Target Portfolio usually due to the customer's financial difficulty. A payment delay in the course of regular business practice does not alone indicate a customer default. An assessment of the overall situation is required on a case-by-case basis.

The maximum risk of default corresponds to the carrying amounts of the financial assets.

Financial assets are written off when there is no reasonable expectation of recovery of the contractual cash flows. Losses from financial assets that have been written off were not material in 2023, 2022 and 2021.

25.5 Liquidity risks

The liquidity risk management ensures that the required liquidity to meet financial obligations is available at all times and that the liquidity position of the Target Portfolio is optimised. Centralised financial planning is the basis for liquidity risk management. Financial planning is performed for the following twelve months on a monthly basis and for the following month on a daily basis.

Wintershall Dea AG has a revolving credit facility ("**RCF**") that was available to the Target Portfolio in the total amount of €900 million, with an initial tenor of five years and additional extension options of up to two years, was agreed with a bank consortium and can be utilised if necessary. The first and second one-year extensions were confirmed for the full amount. This facility is available until March 2026 and remains undrawn, however it will no longer be available on completion of the transaction.

The Target Portfolio's cash flow requirements are monitored on a regular basis, taking into consideration the funding sources, existing bank facilities and cash flow generation from the producing asset base. Specifically, it is ensured that there is sufficient liquidity to meet operational funding requirements and debt servicing.

Maturity Analysis:

	≤1 year	1–5 years	>5 years	Total Payment Amount
	$m	$m	$m	$m
As at 31 December 2023				
Non-derivative financial liabilities				
Bond	12	2,207	1,104	3,323
Subordinated notes	34	—	1,656	1,690
Trade and other payables (excluding related party financial liabilities)	949	7	—	956
Lease obligations	34	81	41	156
Related party financial liabilities	568	—	—	568
Total non-derivative financial liabilities	**1,597**	**2,295**	**2,801**	**6,693**
Derivative financial liabilities				
Foreign currency derivatives	585	—	—	585
Commodity derivatives (settled in cash)	44	3	—	47
Total	**2,226**	**2,298**	**2,801**	**7,325**
As at 31 December 2022				
Non-derivative financial liabilities				
Bond	967	1,061	2,121	4,149
Subordinated notes	33	—	1,591	1,624
Trade and other payables (excluding related party financial liabilities)	603	12	—	615
Lease obligations	21	52	37	110
Related party financial liabilities	809	—	1,302	2,111
Total non-derivative financial liabilities	**2,433**	**1,125**	**5,051**	**8,609**
Derivative financial liabilities				
Foreign currency derivatives	1,112	—	—	1,112
Commodity derivatives (settled in cash)	119	42	—	161
Total	**3,664**	**1,167**	**5,051**	**9,882**
As at 31 December 2021				
Non-derivative financial liabilities				
Bond	13	2,274	2,274	4,561
Subordinated notes	36	—	1,706	1,742
Trade and other payables (excluding related party financial liabilities)	559	11	—	570
Lease obligations	27	45	41	113
Related party financial liabilities	604	—	1,372	1,976
Total non-derivative financial liabilities	**1,238**	**2,330**	**5,393**	**8,962**
Derivative financial liabilities				
Foreign currency derivatives	749	—	—	749
Commodity derivatives (settled in cash)	132	78	—	210
Total	**2,119**	**2,408**	**5,393**	**9,921**

25.6 **Impairment on financial assets**

In order to determine the impairment of financial assets, the Target Portfolio uses either a general three-stage approach or the simplified approach, according to IFRS 9, as applicable. In the case of financial assets for which the simplified approach does not apply, their assessment takes place as at each reporting date to determine whether the credit risk on a financial instrument has increased significantly since its initial recognition.

Trade accounts receivable, other receivables, financial receivables and deposits with banks are subject to the expected credit loss model. This is generally based on either externally provided or internal ratings for each debtor which, in certain cases, are updated based on recently available information.

To measure the expected credit losses on trade accounts receivable, the Target Portfolio applies the simplified approach according to IFRS 9. Accordingly, the loss allowance is measured at an amount equal to the lifetime expected credit losses. For trade accounts receivable, the contractual payment term is usually 30 days. In deviation to this general rule, terms of up to one year are considered for the calculation of expected credit losses due to different regional payment practices, especially in Egypt and Mexico.

The loss allowance for other receivables, financial receivables and deposits with banks is measured at an amount equal to the twelve-month expected credit loss. If the term of the financial instrument is shorter than 12 months, the lifetime expected credit loss is applied.

The valuation loss allowances are determined as follows for the 3 HFI years:

$m	As at 1 Jan 2023	Additions	Reversals	Currency translation adjustments	As at 31 Dec 2023
Trade accounts receivable					
of which Stage 2	(2)	(49)	3	(1)	(49)
of which Stage 3	(9)	—	5	—	(4)
	(11)	**(49)**	**8**	**(1)**	**(53)**
Other receivables					
of which Stage 3	(6)	(5)	—	—	(11)
	(6)	**(5)**	**—**	**—**	**(11)**
Financial receivables					
of which Stage 1	—	(8)	8	—	—
Total	**(17)**	**(62)**	**16**	**(1)**	**(64)**

$m	As at 1 Jan 2022	Additions	Reversals	Disposals	Transfer	Currency translation adjustments	As at 31 Dec 2022
Trade accounts receivable							
of which Stage 2	(3)	(4)	4	—	—	—	(3)
of which Stage 3	(14)	—	5	—	—	—	(9)
	(17)	**(4)**	**9**	**—**	**—**	**—**	**(12)**
Other receivables							
of which Stage 2	(4)	—	—	—	4	—	—
of which Stage 3	—	(3)	—	—	(3)	—	(6)
	(4)	**(3)**	**—**	**—**	**1**	**—**	**(6)**
Financial receivables							
of which Stage 3	—	—	—	—	—	—	—
Total	**(21)**	**(7)**	**9**	**—**	**1**	**—**	**(18)**

$m	As at 1 Jan 2021	Additions	Reversals	Disposals	Currency translation adjustments	As at 31 Dec 2021
Trade accounts receivable						
of which Stage 2	(3)	(6)	6	—	1	(2)
of which Stage 3	(16)	(1)	3	—	—	(14)
	(19)	**(7)**	**9**	**—**	**1**	**(16)**
Other receivables						
of which Stage 3	—	(3)	—	—	(1)	(4)
	—	**(3)**	**—**	**—**	**(1)**	**(4)**
Financial receivables						
of which Stage 3	(27)	—	—	24	1	(2)
Total	**(46)**	**(10)**	**9**	**24**	**1**	**(22)**

26. NOTES TO THE STATEMENT OF CASH FLOWS

Net cash flows from operating activities consist of:

$m	Year ended 31 December 2023	2022	2021
Profit before tax for the year	2,575	4,115	1,302
Adjustments to reconcile profit before tax to net cash flows:			
Finance income	(497)	(198)	(224)
Finance expense	281	192	182
Depreciation and amortisation	1,400	1,464	1,670
Impairment (reversal)/expense of property, plant and equipment	(111)	176	(23)
Impairment goodwill	—	12	17
Net loss/(gain) on disposal	10	128	(25)
SIR 2000 adjustment	11	132	131
Exploration costs written-off	72	28	193
Decommissioning costs paid	(41)	(68)	(38)
Fair value movement of derivatives not yet settled	(41)	15	29
Unrealised foreign currency movement	367	(309)	(231)
Decrease /(Increase) in inventories	43	(32)	(23)
(Increase) in trade and other receivables	(68)	(133)	(276)
Increase in trade and other payables	228	111	151
Increase / (decrease) in provisions	(26)	66	176
Other operating cash flows	(91)	(34)	(123)
Tax paid	(2,515)	(2,010)	220
Net cash inflow from operating activities	**1,597**	**3,655**	**3,108**

Exclude financial receivables and liabilities.

Reconciliation of net cash flow to movement in net borrowings

$m	Year ended 31 December 2023	2022	2021
Repayment of bond	979	106	—
Proceeds from subordinated notes	—	—	(1,758)
Repayment of debt to banks	—	12	862
Proceeds from debt to banks	—	(12)	(62)
Repayment of lease liabilities	28	35	69
Currency translation adjustment	(218)	426	354
Other charges	(71)	(40)	(8)
Movement in total borrowings	**718**	**527**	**(543)**
Net increase in cash and cash equivalents	221	203	39
Net foreign exchange difference	(301)	(28)	(6)
Movement in cash and cash equivalents	**(80)**	**175**	**33**
(Increase)/decrease in net borrowings in the year	**638**	**702**	**(510)**
Opening net borrowings	**(5,539)**	**(6,241)**	**(5,731)**
Closing net borrowings	**(4,901)**	**(5,539)**	**(6,241)**

Analysis of net borrowings

$m	Year ended 31 December 2023	2022	2021
Cash and cash equivalents	244	324	149
Bonds	(3,315)	(4,139)	(4,546)
Subordinated notes	(1,694)	(1,627)	(1,744)
Lease liabilities	(136)	(97)	(100)
Closing net borrowings	**(4,901)**	**(5,539)**	**(6,241)**

27. ASSETS HELD FOR SALE

Following the agreed divestment of the 50 per cent. interest in the unconventional Aguada Federal and Bandurria Norte blocks in Argentina (Segment Latin America) in January 2022, the respective fixed assets were written down to fair value less costs to sell.

The concerned assets and associated liabilities are shown as held for sale as at 31 December 2021:

$m	Year ended 31 December 2021
Assets held for sale	
Oil and gas assets	73
Other receivables (non-current)	36
Other receivables (current)	37
	146
Liabilities directly associated with assets held for sale	
Decommissioning provision	(6)
	(6)

28. RELATED PARTY DISCLOSURES

A related party is a natural person or legal entity that can exert influence on the Target Portfolio or over which the Target Portfolio exercises control, joint control or a significant influence. The Target Portfolio is subject to significant influence from Wintershall Dea AG's shareholders BASF and LetterOne—therefore, BASF and LetterOne and their subsidiaries are considered related parties, in addition related parties also comprise of Wintershall Dea AG and its affiliates that are not in the transaction perimeter.

Revenues with related parties

$m	Year ended 31 December 2023	2022	2021
Ultimate shareholders and their affiliates	304	—	—
Wintershall Dea AG and their affiliates	2,553	3,312	1,140
Total	**2,857**	**3,312**	**1,140**

Financial income/(expenses) with related parties

$m	Year ended 31 December 2023	2022	2021
Ultimate shareholders and their affiliates	—	—	—
Wintershall Dea AG and their affiliates	(194)	(113)	(153)
Total	**(194)**	**(113)**	**(153)**

Revenues, trade accounts receivable and trade accounts payable from related parties comprise transactions mainly in the Target Portfolio's own products, as well as other typical business transactions.

Gas purchases to related parties amounted to $399m for 2023 (2022: $140m; 2021: $66m).

Balance sheet receivables from / payables to related parties

	Year ended 31 December					
	Balance sheet receivables			Balance sheet payables		
$m	2023	2022	2021	2023	2022	2021
Ultimate shareholders and their affiliates	16	—	—	—	—	—
Wintershall Dea AG and their affiliates	259	4,774	4,980	(835)	(2,276)	(1,723)
Cash pooling with Wintershall Dea AG	771	6,201	4,255	—	(1)	(379)
Total	**1,046**	**10,975**	**9,235**	**(835)**	**(2,277)**	**(2,102)**

Please refer to note 16 and note 20 for an understanding of the cash pooling arrangement.

Costs related to key management are incurred in Wintershall Dea AG with part of these costs recharged across the Wintershall Dea AG group (including the Target Portfolio) in the HFI period through an arm's length transfer pricing mechanism. We are unable to quantify the amount of these costs recharged to the Target Portfolio. The additional costs were allocated to the Target Portfolio to meet the requirements of SIR 2000. Refer to note 7.

Certain Wintershall Dea AG head-office costs were recharged across the Wintershall Dea AG group (including the Target Portfolio) in the HFI period though an arm's length transfer pricing mechanism. In this context, costs of $375m, $218m, $242m for 2023, 2022 and 2021, respectively, have been recharged to the Target Portfolio. Some of the costs were capitalized or charged out to the partners. In addition, certain central related party costs were allocated to the Target Portfolio in line with SIR2000. Refer to note 7.

29. THE TARGET PORTFOLIO

See note 2.1 for a complete list of concession producing entities, held at 100 per cent. equity interest. In addition, the Target Portfolio includes a 100 per cent. equity interest in the following entities which do not contain upstream assets:

- Wintershall Dea Global Holding GmbH
- E & A Internationale Explorations- und Produktions -GmbH
- Wintershall Dea Vermögensverwaltungsgesellschaft mbH
- Wintershall Dea Insurance Limited
- Wintershall Dea Nederland B.V.
- Wintershall Global Support B.V.

- Wintershall Dea Carbon Management Solutions B.V.
- DEA E & P GmbH
- DEA Trinidad & Tobago GmbH
- WD México-Alemania S. de R.L. de C.V.
- DEM Mexico Erdoel, S.A.P.I. de C.V.
- Wintershall Dea Mexico Holding B.V.
- Sierra Oil & Gas Holdings, L.P.
- Sierra Oil & Gas, S. de R.L. de C.V.
- Sierra Perote E&P, S. de R.L. de C.V.
- Izta Energia, S. de R.L. de C.V.
- Wintershall Dea Immobilien GmbH & Co. KG
- Wintershall Dea Finance B.V.
- Wintershall Dea TSC GmbH & Co. KG
- Wintershall Dea Technology Ventures GmbH
- Wintershall Dea Finance 2 B.V.
- Wintershall Dea TSC Management GmbH
- Nordkaspische Explorations- und Produktions GmbH
- Wintershall Dea Marketing Services GmbH
- DEA Ukraine LLC i.L.
- Wintershall Dea South East Asia GmbH
- Wintershall DEA Mexico Holdings GP Ltd.

30. **EVENTS AFTER THE REPORTING PERIOD**

There were no material events post the balance sheet date ending 31 December 2023 which impacts the Combined HFI.

PART X
UNAUDITED PRO FORMA FINANCIAL INFORMATION

SECTION A:
ACCOUNTANTS' REPORT IN RESPECT OF THE UNAUDITED PRO FORMA INFORMATION RELATING TO THE ENLARGED GROUP

The Board of Directors
Harbour Energy plc
23 Lower Belgrave Street
SW1W 0NR

12 June 2024

Dear Sirs/Madams

Harbour Energy plc (the "Company")

We report on the pro forma financial information set out in Section B of Part X of the prospectus dated 12 June 2024 of the Company (the "**Prospectus**") (the "**Pro Forma Financial Information**").

This report is required by Section 3 of Annex 20 of the UK version of Commission Delegated Regulation (EU) 2019/980 and is given for the purpose of complying with that item and for no other purpose.

Save for any responsibility arising under Prospectus Regulation Rule 5.3.2R(2)(f) to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with item 1.3 of Annex 1 to the UK version of Commission Delegated Regulation (EU) 2019/980, consenting to its inclusion in the Prospectus.

Opinion

In our opinion:

- the Pro Forma Financial Information has been properly compiled on the basis stated; and
- such basis is consistent with the accounting policies of the Company.

Responsibilities

It is the responsibility of the directors of the Company to prepare the Pro Forma Financial Information in accordance with Sections 1 and 2 of Annex 20 of the UK version of Commission Delegated Regulation (EU) 2019/980.

It is our responsibility to form an opinion, as required by Section 3 of Annex 20 of the UK version of Commission Delegated Regulation (EU) 2019/980, as to the proper compilation of the Pro Forma Financial Information and to report that opinion to you.

No reports or opinions have been made by us on any financial information of the Target Portfolio (defined as Wintershall Dea's upstream assets, including those in Norway, Germany, Denmark (excluding the Ravn field), Argentina, Mexico, Egypt, Libya (excluding Wintershall Aktiengesellschaft) and Algeria as well as Wintershall Dea's CO2 CCS licences in Europe) used in the compilation of the Pro Forma Financial Information. In providing this opinion we are not providing any assurance on any source financial information on which the Pro Forma Financial Information is based beyond the above opinion.

In providing this opinion we are not updating or refreshing any reports or opinions previously made by us on any financial information of the Company used in the compilation of the Pro Forma Financial Information, nor do we accept responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed by us at the dates of their issue.

Basis of Preparation

The Pro Forma Financial Information has been prepared on the basis described in the notes to the Pro Forma Financial Information, for illustrative purposes only, to provide information about how the acquisition of the Target Portfolio and associated financing arrangements might have affected the financial information presented on the basis of the accounting policies adopted by the Company in preparing the financial statements for the period ended 31 December 2023.

Basis of opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Financial Reporting Council in the United Kingdom. We are independent in accordance with the FRC's Ethical Standard as applied to Investment Circular Reporting Engagements, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

The work that we performed for the purpose of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments and discussing the Pro Forma Financial Information with the directors of the Company.

We planned and performed our work so as to obtain the information and explanations we considered necessary in order to provide us with reasonable assurance that the Pro Forma Financial Information has been properly compiled on the basis stated and that such basis is consistent with the accounting policies of the Company.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in other jurisdictions and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Declaration

For the purposes of Prospectus Regulation Rule 5.3.2R(2)(f) we are responsible for this report as part of the Prospectus and declare that, to the best of our knowledge, the information contained in this report is in accordance with the facts and that the report makes no omission likely to affect its import. This declaration is included in the Prospectus in compliance with item 1.2 of Annex 1 of the UK version of Commission Delegated Regulation (EU) 2019/980.

Yours faithfully

Ernst & Young LLP

SECTION B:
UNAUDITED PRO FORMA FINANCIAL INFORMATION RELATING TO THE ENLARGED GROUP

The following unaudited pro forma statement of net assets and pro forma income statement (the "**unaudited pro forma financial information**") have been prepared to show the effect (1) on the consolidated net assets of Harbour Energy as if the Acquisition, and associated financing arrangements, had occurred on 31 December 2023, and (2) on the consolidated income statement of Harbour Energy as if the Acquisition, and associated financing arrangements, had occurred on 1 January 2023.

The unaudited pro forma financial information has been prepared for illustrative purposes only and, due to its nature, addresses a hypothetical situation and, therefore, the financial position and results included in the unaudited pro forma financial information may differ from Harbour Energy's or the Enlarged Group's actual financial position or results.

The unaudited pro forma financial information has been prepared in accordance with Annex 20 of the UK Prospectus Delegated Regulation, on the basis of the notes to the unaudited pro forma financial information and in a manner consistent with the accounting policies and presentation adopted by Harbour Energy in the audited consolidated financial statements for the year ended 31 December 2023, incorporated by reference into this document, as set out in Part VIII (*Historical Financial Information relating to Harbour Energy*).

The adjustments in the unaudited pro forma income statement are expected to have a continuing impact on the Enlarged Group, unless stated otherwise.

The unaudited pro forma financial information does not constitute financial statements within the meaning of section 434 of the Act. Shareholders should read the whole of the Prospectus and not rely solely on the unaudited financial information in this Section B (*Unaudited Pro Forma Financial Information Relating to the Enlarged Group*) of this Part X (*Unaudited Pro Forma Financial Information*).

Ernst and Young LLP's report on the unaudited pro forma financial information is set out in Section A (*Accountants' report in respect of the unaudited pro forma information relating to the Enlarged Group)* of this Part X (*Unaudited Pro Forma Financial Information*).

Unaudited Pro Forma Income Statement for the financial year ended 31 December 2023

		Adjustments				
	Harbour Energy for the year ended 31 December 2023	**The Target Portfolio for the year ended 31 December 2023**	**Transaction costs**	**Financing adjustments**	**Subordinated Notes**	**Pro forma income statement of the Enlarged Group**
	Note 1	**Note 2**	**Note 3**	**Note 5**	**Note 6**	
			$ million			
Revenue	3,715	6,337	—	—	—	10,052
Other income	36	43	—	—	—	79
Revenue and other income	**3,751**	**6,380**	**—**	**—**	**—**	**10,131**
Cost of operations	(2,357)	(3,128)	—	—	—	(5,485)
(Impairment)/impairment reversal of property, plant and equipment	(214)	111	—	—	—	(103)
Impairment of goodwill	(25)	—	—	—	—	(25)
Exploration and evaluation expenses and new ventures	(36)	(78)	—	—	—	(114)
Exploration costs written-off	(57)	(72)	—	—	—	(129)
Gain on disposal	—	(10)	—	—	—	(10)
General and administrative expenses	(149)	(412)	(61)	—	—	(622)
Operating profit/(loss)	**913**	**2,791**	**(61)**	**—**	**—**	**3,643**
Finance income	104	497	—	—	—	601
Finance expenses	(420)	(713)	—	(85)	59	(1,159)
Profit/(loss) before taxation	**597**	**2,575**	**(61)**	**(85)**	**59**	**3,085**
Income tax (expense)/credit	(565)	(2,028)	—	53	—	(2,540)
Profit/(loss) for the year attributable to: equity owners of the company	**32**	**547**	**(61)**	**(32)**	**59**	**545**

Unaudited Pro Forma Statement of Net Assets as at 31 December 2023

			Adjustments				
	Harbour Energy as at 31 December 2023	The Target Portfolio as at 31 December 2023	Transaction costs	Combination accounting adjustments	Financing adjustments	Subordinated Notes	Pro forma statement of net assets of the Enlarged Group
	Note 1	Note 2	Note 3	Note 4	Note 5	Note 6	
				$ million			
Assets							
Non-current assets							
Goodwill	1,302	2,304	—	3,236	—	(213)	6,629
Other intangible assets	1,172	374	—	—	—	—	1,546
Property, plant and equipment	4,717	10,491	—	—	—	—	15,208
Right-of-use assets	587	131	—	—	—	—	718
Deferred tax assets	7	312	—	—	—	—	319
Other receivables	184	33	—	—	(42)	—	175
Other financial assets	112	134	—	—	—	—	246
Total non-current assets	**8,081**	**13,779**	**—**	**3,236**	**(42)**	(213)	**24,841**
Current assets							
Inventories	200	195	—	—	—	—	395
Trade and other receivables	832	2,082	—	—	(37)	—	2,877
Other financial assets	170	234	—	—	—	—	404
Cash and cash equivalents	280	244	(71)	(2,150)	1,697	—	—
	1,482	2,755	(71)	(2,150)	1,660	—	3,676
Assets held for sale	334	—	—	—	—	—	334
Total current assets	**1,816**	**2,755**	**(71)**	**(2,150)**	**1,660**	—	**4,010**
Total assets	**9,897**	**16,534**	**(71)**	**1,086**	**1,618**	(213)	**28,851**
Liabilities							
Non-current liabilities							
Borrowings	493	4,963	—	—	(6)	(1,694)	3,756
Provisions	3,818	2,238	—	39	—	—	6,095
Deferred tax	1,260	4,641	—	—	—	—	5,901
Trade and other payables	13	27	—	—	—	—	40
Lease creditor	474	107	—	—	—	—	581
Other financial liabilities	87	42	—	—	—	—	129
Total non-current liabilities	**6,145**	**12,018**	**—**	**39**	**(6)**	**(1,694)**	**16,502**
Current liabilities							
Trade and other payables	886	1,642	(10)	—	—	—	2,518
Borrowings	16	46	—		1,693	—	1,755
Lease creditor	199	29	—	—	—	—	228
Provisions	230	453	—	—	—	—	683
Current tax liabilities	442	1,296	—	—	—	—	1,738
Other financial liabilities	197	258	—	—	—	—	455
	1,970	3,724	(10)	—	1,693	—	7,377
Liabilities directly associated with the assets held for sale	242	—	—	—	—	—	242
Total current liabilities	**2,212**	**3,724**	**(10)**	—	**1,693**	—	**7,619**
Total liabilities	**8,357**	**15,742**	**(10)**	**39**	**1,687**	**(1,694)**	**24,121**
Net assets	**1,540**	**792**	**(61)**	**1,047**	**(69)**	**1,481**	**4,730**

Notes:

(1) The consolidated income statement and consolidated net assets of Harbour Energy have been extracted, without material adjustment, from the audited consolidated financial statements of Harbour Energy for the year ended 31 December 2023, incorporated by reference into this document, as set out in Part VIII (*Historical Financial Information relating to Harbour Energy*).

(2) The consolidated income statement and consolidated net assets of the Target Portfolio have been extracted, without material adjustment, from the historical financial information relating to the Target Portfolio for the year ended 31 December 2023, as set out in Part IX (*Historical Financial Information relating to the Target Portfolio*).

(3) Total transaction costs are estimated to be $150 million. Of this, $71 million are related to refinancing and have been capitalised as described in note 5. Of the remaining $79 million, $18 million was charged to Harbour Energy income statement in the year ended 31 December 2023, of which $10 million was accrued and $8 million had been paid in cash. The remaining $61 million has been charged to the pro forma income statement within the line item "General and administrative expenses". The transaction costs are assumed to be satisfied in cash. All such costs have been treated as non-deductible for tax purposes. No transaction costs have been allocated against equity for the purposes of this unaudited pro forma financial information as any such allocation would be immaterial. This adjustment will not have a continuing impact.

(4) The adjustments arising as a result of the Acquisition are set out below:

While the Acquisition constitutes a reverse takeover for the purpose of the Listing Rules, the unaudited pro forma financial information has been prepared on the basis that, under IFRS 3 "Business Combinations" guidance, Harbour Energy will be the legal and accounting acquirer and the Target Portfolio will be the legal and accounting acquiree. This is on the basis that Harbour Energy will obtain control over the Target Portfolio through the business combination; as a result of the fact that: it is the entity issuing equity and paying cash to effect the business combination; at Completion existing Harbour Energy shareholders will hold a majority of Ordinary Shares; and day-to-day management of the Enlarged Group will be led by existing Harbour Energy personnel, with no change to the executive directorship.

The unaudited pro forma financial information does not reflect any fair value adjustments to the acquired assets and liabilities that may be recognised as part of the purchase price allocation. As such, the fair value measurement of these assets and liabilities will only be performed subsequent to Completion. The fair value adjustments, when finalised, may be material. Were the fair value adjustments to have been reflected in the unaudited pro forma financial information, additional depreciation of property, plant and equipment or amortisation of intangible assets, amongst other things, may have been required.

The excess of consideration over the net assets of the Target Portfolio has, for the purposes of the unaudited pro forma financial information, been allocated entirely to goodwill.

The consideration payable and the calculation of the adjustment to goodwill is set out below:

	Note	$ million
Equity consideration	(i)	3,533
Cash consideration	(ii)	2,150
Contingent consideration	(iii)	39
Less: net assets acquired of the Target Portfolio		(792)
Less: adjustment to net assets relating to Subordinated Notes	(6)	(1,694)
Pro forma adjustment		**3,236**

The consideration is due to be settled as follows:

(i) The equity consideration to be settled in Ordinary Shares of $2,569 million has been calculated based on 669,714,027 BASF Consideration Shares being issued by the Company at a price of £3.03 per share, being the Closing Price of Ordinary Shares as at the Latest Practicable Date and translated at the spot USD/GBP rate on that date of 0.790.

The equity consideration to be settled in Non-Voting Shares of $965 million has been calculated based on 251,488,211 Non-Voting Shares being issued at their fair value, measured in accordance with IFRS 13 "Fair Value Measurement". A binomial lattice valuation methodology has been utilised to determine the fair value of the Non-Voting Shares based on the value of Ordinary Shares with inputs that reflect the different features of these shares. Key assumptions input into the fair value model include: timing and quantum of future dividend payments; estimates of the timing of lifting of relevant sanctions on the minority ultimate beneficial owners of LetterOne; estimated date of conversion to Ordinary Shares under certain conditions; expected volatility of Ordinary Shares; appropriate discount rate; and discount for lack of marketability. The resultant fair value of a Non-Voting Share has been determined to closely approximate that of an Ordinary Share, £3.03 per share, being the Closing Price of Ordinary Shares as at the Latest Practicable Date and translated at the spot USD/GBP rate on that date of 0.790. The fair value of Non-Voting Shares will only be determined at Completion for the purposes of the Enlarged Group's financial statements for the year ended 31 December 2024 and as a result the value calculated at that point may be materially different to that reflected in the pro forma financial information.

(ii) The cash consideration is $2,150 million.

(iii) Contingent consideration of up to a maximum of $300 million may be paid by the Company to BASF and LetterOne over the four years following Completion, conditional upon the average price of Brent oil in certain agreed test periods. Under the terms of the Business Combination Agreement, payments will either be $nil, $30 million or $50 million at each of the six contingent payment test dates, depending on the average price of Brent oil during the relevant test periods. Harbour Energy has estimated the fair value of the contingent consideration at the date of this unaudited pro forma financial information, to be $39 million; however the fair value at the point of Completion, and subsequent balance sheet dates, will be assessed at such dates based on future expectations of the Brent oil price at that time. A corresponding provision for the contingent liability has been recognised within non-current liabilities.

(5) Related to the Acquisition, Harbour Energy has secured an underwritten, unsecured bridge facility of $1,500 million (the "**BFA**") and an underwritten, unsecured revolving credit facility of $3,000 million (the "**RCF**"). See paragraph 15.10 (Bridge Facility Agreement) and paragraph 15.11 (Revolving Credit Facility) of Part XIV (*Additional Information*).

The adjustment to current borrowings in the pro forma statement of net assets in connection with these new facilities is $1,693 million, assuming the BFA is drawn down in full on Completion (for the purpose of cash consideration) and $250 million is drawn under the RCF on Completion (in order to maintain a positive cash position). Note that, at the point of Completion, Harbour Energy does not expect to have to draw on the RCF due to expected generation of cash within the Target Portfolio between 31 December 2023 and the date of Completion. The drawings of $1,750 million are offset by $57 million of capitalised transaction costs. These new facilities replace Harbour Energy's existing reserve base lending facility (the "**RBL Facility**"). See paragraph 15.9 (Reserve Base Lending Facility) of Part XIV (*Additional Information*). There is no adjustment to current borrowings or non-current borrowings in the pro forma statement of net assets in respect of this as the RBL Facility was undrawn at 31 December 2023.

Of the total $71 million transaction costs relating to financing, $18 million was paid in 2023 and is already included in the net assets of Harbour Energy as at 31 December 2023 (within the line item trade and other receivables).

Adjustments to non-current other receivables of $42 million and trade and other receivables of $37 million in the pro forma statement of net assets reflect the derecognition of $61 million of capitalised transaction costs recognised in relation to the RBL Facility and reallocation of the $18 million of transaction costs related to financing which was paid during 2023 from trade and other receivables to current borrowings, offsetting drawings on the BFA and RCF.

The adjustment of $6 million to non-current borrowings in the pro forma statement of net assets represents $14 million of new capitalised transaction costs in respect of the Wintershall Dea Bonds, offset by derecognition of $8 million of capitalised transaction costs included in the net assets of the Target Portfolio as at 31 December 2023.

The adjustment to finance expenses of $85 million in the pro forma income statement represents:

(i) the expensing of existing capitalised transaction costs of $73 million;

(ii) reversal of finance costs (including amortisation of capitalised transaction costs) in respect of the RBL Facility of $113 million, being interest paid on the RBL Facility of $15 million, amortisation of capitalised transaction costs of $46 million and other fees payable in respect of the RBL Facility of $52 million, primarily relating to letters of credit; and

(iii) finance costs in respect of the BFA, RCF and the Wintershall Dea Bonds of $125 million, being amortisation of new capitalised transaction costs of $28 million, interest payable on the drawn BFA of $71 million and other fees in respect of the RCF, primarily relating to letters of credit, of $26 million.

The tax effect of the adjustment to finance expenses has been calculated based on Harbour Energy's accounting policies for taxation and the applicable statutory rates of taxation.

No other adjustments have been recognised in respect of the Wintershall Dea Bonds as the liabilities and finance costs are included in the consolidated net assets and consolidated income statement of the Target Portfolio.

(6) In the consolidated group financial statements of Wintershall Dea for the year ended 31 December 2023, the Subordinated Notes, as included in the Target Portfolio, were classified as a separate component of equity. For the purposes of the Historical Financial Information relating to the Target Portfolio, the Subordinated Notes have been classified as liabilities in line with IAS 32 "Financial Instruments: Presentation" on the basis that the guarantor of the Subordinated Notes, Wintershall Dea, an entity outside the Target Portfolio, controls the actions that may trigger payment of interest and/or principal amounts on the Subordinated Notes, and therefore the cash flows are outside the control of the entities within the perimeter.

On 22 February 2024 the holders of the Subordinated Notes approved a change in guarantor from Wintershall Dea to the Company, which will be effective upon Completion. As a result, Harbour Energy will recognise the Subordinated Notes as a separate component of equity upon Completion as all cash flows relating to the Subordinated Notes will be within the control of Harbour Energy. For more information on the Subordinated Notes, see paragraph 16.2 (Wintershall Dea Subordinated Notes) of Part XIV (*Additional Information*). The following adjustments have been made to reflect how these instruments will be presented in the Enlarged Group's financial statements from Completion:

(i) the adjustment to non-current borrowings of $1,694 million is to derecognise the Subordinated Notes liability, as presented in the Historical Financial Information relating to the Target Portfolio, with an equivalent amount recognised as a separate component of equity (not shown in the pro forma statement of net assets). The $1,694 million comprises proceeds of $1,758 million less $64 million of accumulated currency effect;

(ii) an associated adjustment to goodwill, representing the difference between the value of the Subordinated Notes as presented in the Historical Financial Information relating to the Target Portfolio (at amortised cost) and the fair value of the notes, which is how they will be valued on acquisition under Harbour Energy's accounting policies, as at the Latest Practicable Date, of $1,481 million. The fair value as of the date of this unaudited pro forma financial information could be materially different to the fair value at Completion; and

(iii) an associated adjustment of $59 million made to finance expenses to reverse the finance costs recognised in the Historical Financial Information relating to the Target Portfolio in respect of the Subordinated Notes. In the Enlarged Group's financial statements from Completion, such amounts will be shown within other comprehensive income (not shown in the pro forma income statement).

(7) In preparing the unaudited pro forma financial information, no account has been taken of the trading activity of Harbour Energy or the Target Portfolio since 31 December 2023.

PART XI

COMPETENT PERSON'S REPORT ON THE TARGET COMPANY'S PORTFOLIO

In view of its size relative to that of Harbour Energy, the Acquisition constitutes a reverse takeover and class 1 transaction under the Listing Rules. Consequently, the Company is required by Listing Rule 13.4.6R to include an independent mineral expert's report in the Circular, along with a glossary of the technical terms used in such report. DeGolyer and MacNaughton ("**D&M**") has been commissioned to prepare the independent mineral expert's report in relation to the Target Portfolio (the "**Target Company CPR**"). The Target Company CPR was prepared on the basis of the reporting date of 31 December 2023.

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

This is a digital representation of a DeGolyer and MacNaughton report.

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

June 10, 2024

The Directors of
Harbour Energy PLC
23 Lower Belgrave Street
London SW1W ONR
United Kingdom

Barclays Bank PLC
One Churchill Place
London E14 5HP
United Kingdom

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2023, of the extent of the proved, probable, and possible oil, condensate, liquefied petroleum gas (LPG), and sales gas reserves, of the value of the proved (1P), proved-plus-probable (2P), and proved-plus-probable-plus-possible (3P) reserves, and of the extent of the 1C, 2C, and 3C contingent resources of certain properties in eight countries in which Wintershall Dea GmbH (Wintershall Dea) has represented it holds an interest: Algeria, Argentina, Denmark, Egypt, Germany, Libya, Mexico, and Norway. For the purposes of this report, the properties located in Algeria, Egypt, and Libya evaluated herein are grouped together as “North Africa” in certain instances.

Estimates of reserves and contingent resources presented in this report have been prepared in accordance with the Petroleum Resources Management System (PRMS) approved in March 2007 and revised in June 2018 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. PRMS is a referenced standard in published guidance for listing companies in the United Kingdom. The reserves definitions are discussed in detail under the Definition of Reserves heading of this report. The contingent resources definitions are discussed in detail under the Definition of Contingent Resources heading of this report.

This report is compliant with the Competent Person's Report requirements as published in the United Kingdom Financial Conduct Authority Primary Market Technical Note TN/619.1 "Guidelines on disclosure requirements under the Prospectus Regulation and Guidance on specialist issuers" (FCA Technical Note TN/619.1).

In addition, this report has been prepared in accordance with the requirements of the Prospectus Regulation Rules of the FCA as set forth under Section 73A of the Financial Services and Markets Act 2000 (FSMA), as amended, and the Listing Rules of the FCA as set forth under Part VI of the FSMA. For the purposes of Prospectus Regulation Rule 5.3.2 R(2)(f), we accept responsibility for the information contained in this report and declare that, to the best of our knowledge, the information contained in this report is in accordance with the facts and that this report makes no omission likely to affect its import.

Reserves estimated in this report are expressed as gross reserves, working interest reserves, and net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2023. Working interest reserves are defined as the product of the working interest and the gross reserves. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Wintershall Dea after deducting all interests held by others.

Some fields within certain countries evaluated in this report are subject to production sharing agreements (PSA) in various forms. The terms of a PSA allow for working interest participants to be reimbursed for portions of capital costs and operating expenses and to share in the profits. In addition, the income tax paid on behalf of Wintershall Dea may also be credited to Wintershall Dea in some instances. The reimbursements, credits, and profit proceeds net to Wintershall Dea, based on its working interest share, are converted to a barrel of oil equivalent or standard cubic foot of gas equivalent by dividing by product prices to estimate the Wintershall Dea "entitlement quantities." These entitlement quantities are equivalent, in principle, to net reserves and are termed "net Wintershall Dea quantities" herein. The ratio of the net Wintershall Dea quantities to the gross quantities is termed an "entitlement interest." In this report, Wintershall Dea net reserves for certain properties subject to these agreements is the entitlement based on Wintershall Dea working interest.

Detailed explanations of the terms of the applicable PSA are included under the Valuation of Reserves heading of this report.

This report presents values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves that were estimated using initial prices, expenses, and costs provided by or on behalf of Wintershall Dea and forecast prices, expenses, and costs as described herein. Prices, expenses, and costs provided were expressed in European Union euros (€), Danish kroner (DKK), Norwegian kroner (NOK), and United States dollars (U.S.$). All monetary values in this report are expressed in U.S.$ unless noted otherwise. The currency exchange rates used herein are included under the Valuation of Reserves heading of this report, along with a detailed explanation of the forecast price, expense, and cost assumptions.

Values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting operating expenses, capital costs, abandonment costs, royalty, and taxes from future gross revenue. Operating expenses include field operating expenses, the estimated expenses of direct supervision, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and certain field maintenance costs. Abandonment costs are represented by Wintershall Dea to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. Consideration of German corporate income taxes were not included in this report; however, field-level taxes for fields in Germany are included in the evaluation herein. Present worth is defined as the future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold. In this report, present worth values using a discount rate of 10 percent are reported in detail and values using discount rates of 6, 8, and 12 percent are reported as totals.

The contingent resources estimated in this report are expressed as gross contingent resources, working interest contingent resources, and net contingent resources. Gross contingent resources are defined as the total estimated petroleum that is potentially recoverable from known accumulations after December 31, 2023. Working interest contingent resources are defined as the product of the working interest and the gross contingent resources. For the purposes of this report, net contingent resources are defined as being equivalent to the working interest contingent resources.

The contingent resources estimated herein are those quantities of petroleum that are potentially recoverable from known accumulations but which are not currently considered to be commercially recoverable. Because of the uncertainty of commerciality, the contingent resources estimated herein cannot be classified as reserves. The contingent resources estimates in this report are provided as a means of comparison to other contingent resources and do not provide a means of direct comparison to reserves. A detailed explanation of the contingent resources estimated herein is included under the Estimation of Contingent Resources heading of this report.

Contingent resources quantities should not be confused with those quantities that are associated with reserves due to the additional risks involved. The quantities that might actually be recovered, should they be developed, may differ significantly from the estimates presented herein. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.

Estimates of reserves and revenue and contingent resources should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

In this report, key information was provided by Wintershall Dea on the fields evaluated herein. As far as we are aware, there are no special factors that would affect the interests held by Wintershall Dea that would require additional information for the proper evaluation of these fields. All evaluations herein are considered in the context of current agreements and regulations and do not consider uncertainties that might be associated with political conditions.

Information used in the preparation of this report was obtained from Wintershall Dea. In the preparation of this report, we have relied upon information furnished by or directed to be furnished by Wintershall Dea with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, concession area expiration dates, and various other information and data that were accepted as represented.

Although we have not had independent verification, the information used in this report appears reasonable. The technical staff of Wintershall Dea involved with the assessment and implementation of development of Wintershall Dea's petroleum assets are represented as adherent to the generally accepted practices of the petroleum industry. The staff members appear to be experienced and technically competent in their fields of expertise. No site visit to the fields was made by us. However, existing production data, reports from third parties, and photographic evidence of the fields were considered adequate because the fields are in established producing venues.

Executive Summary

Wintershall Dea has represented that it holds certain interests in 140 fields and discoveries in 8 countries: Algeria, Argentina, Denmark, Egypt, Germany, Libya, Mexico, and Norway. These interests are evaluated herein.

For this report, technical and commercial uncertainties have been considered in each case exclusive of ongoing political events in a given venue. All contracts, regulations, and agreements in place on December 31, 2023, have been considered to be valid for their stated terms, as represented by Wintershall Dea.

The estimated reserves, revenue, and contingent resources are summarized herein. The barrels of oil equivalent are based on the summation of oil, condensate, LPG, and sales gas, where sales gas is converted to oil equivalent volumes using a factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent (boe).

Estimation of Reserves

The estimated gross proved, probable, and possible reserves, as of December 31, 2023, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Gross Reserves			
	Oil and Condensate (10^3bbl)	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina				
Proved	26,414	19,186	2,987,893	579,152
Probable	7,374	5,270	1,000,454	191,297
Proved plus Probable	33,788	24,456	3,988,347	770,449
Possible	6,424	2,437	1,072,002	200,290
Proved plus Probable plus Possible	40,212	26,893	5,060,349	970,739
Denmark				
Proved	0	0	0	0
Probable	0	0	0	0
Proved plus Probable	0	0	0	0
Possible	0	0	0	0
Proved plus Probable plus Possible	0	0	0	0
Germany				
Proved	67,866	0	326,648	126,196
Probable	34,849	0	159,894	63,402
Proved plus Probable	102,715	0	486,542	189,598
Possible	20,850	0	119,816	42,245
Proved plus Probable plus Possible	123,565	0	606,358	231,843
Mexico				
Proved	91,518	0	50,299	100,500
Probable	24,681	0	27,095	29,519
Proved plus Probable	116,199	0	77,394	130,019
Possible	16,562	0	19,577	20,058
Proved plus Probable plus Possible	132,761	0	96,971	150,077
North Africa				
Proved	67,471	111	975,118	241,710
Probable	13,438	209	514,002	105,433
Proved plus Probable	80,909	320	1,489,120	347,143
Possible	14,431	200	483,582	100,985
Proved plus Probable plus Possible	95,340	520	1,972,702	448,128
Norway				
Proved	843,535	160,286	7,591,809	2,359,501
Probable	217,812	61,795	2,231,688	678,123
Proved plus Probable	1,061,347	222,081	9,823,497	3,037,624
Possible	224,067	54,642	2,596,081	742,295
Proved plus Probable plus Possible	1,285,414	276,723	12,419,578	3,779,919
Total Proved	**1,096,804**	**179,583**	**11,931,767**	**3,407,059**
Total Probable	**298,154**	**67,274**	**3,933,133**	**1,067,774**
Total Proved plus Probable	**1,394,958**	**246,857**	**15,864,900**	**4,474,833**
Total Possible	**282,334**	**57,279**	**4,291,058**	**1,105,873**
Total Proved plus Probable plus Possible	**1,677,292**	**304,136**	**20,155,958**	**5,580,706**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas reserves estimated herein were converted to oil equivalent using a factor of 5,600 cubic feet of gas per 1 boe.
3. The oil equivalent reserves reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

The estimated working interest proved, probable, and possible reserves, as of December 31, 2023, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Working Interest Reserves			
	Oil and Condensate (10^3bbl)	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina				
Proved	9,336	7,194	1,000,626	195,213
Probable	2,572	1,979	330,652	63,596
Proved plus Probable	11,908	9,173	1,331,278	258,809
Possible	2,210	912	352,981	66,155
Proved plus Probable plus Possible	14,118	10,085	1,684,259	324,964
Denmark				
Proved	0	0	0	0
Probable	0	0	0	0
Proved plus Probable	0	0	0	0
Possible	0	0	0	0
Proved plus Probable plus Possible	0	0	0	0
Germany				
Proved	66,949	0	135,026	91,061
Probable	34,642	0	82,605	49,393
Proved plus Probable	101,591	0	217,631	140,454
Possible	20,598	0	64,384	32,095
Proved plus Probable plus Possible	122,189	0	282,015	172,549
Mexico				
Proved	35,712	0	22,896	39,801
Probable	10,223	0	12,678	12,487
Proved plus Probable	45,935	0	35,574	52,288
Possible	6,919	0	9,168	8,556
Proved plus Probable plus Possible	52,854	0	44,742	60,844
North Africa				
Proved	9,204	111	249,044	53,787
Probable	2,804	209	138,481	27,742
Proved plus Probable	12,008	320	387,525	81,529
Possible	2,919	200	123,211	25,121
Proved plus Probable plus Possible	14,927	520	510,736	106,650
Norway				
Proved	121,861	39,988	1,321,364	397,807
Probable	44,440	21,264	676,819	186,564
Proved plus Probable	166,301	61,252	1,998,183	584,371
Possible	44,626	15,555	696,282	184,517
Proved plus Probable plus Possible	210,927	76,807	2,694,465	768,888
Total Proved	**243,062**	**47,293**	**2,728,956**	**777,669**
Total Probable	**94,681**	**23,452**	**1,241,235**	**339,782**
Total Proved plus Probable	**337,743**	**70,745**	**3,970,191**	**1,117,451**
Total Possible	**77,272**	**16,667**	**1,246,026**	**316,444**
Total Proved plus Probable plus Possible	**415,015**	**87,412**	**5,216,217**	**1,433,895**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas reserves estimated herein were converted to oil equivalent using a factor of 5,600 cubic feet of gas per 1 boe.
3. The oil equivalent reserves reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

The estimated net interest proved, probable, and possible reserves, as of December 31, 2023, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Net Reserves			
	Oil and Condensate (10^3bbl)	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina				
Proved	9,336	7,194	1,000,626	195,213
Probable	2,572	1,979	330,652	63,596
Proved plus Probable	11,908	9,173	1,331,278	258,809
Possible	2,210	912	352,981	66,155
Proved plus Probable plus Possible	14,118	10,085	1,684,259	324,964
Denmark				
Proved	0	0	0	0
Probable	0	0	0	0
Proved plus Probable	0	0	0	0
Possible	0	0	0	0
Proved plus Probable plus Possible	0	0	0	0
Germany				
Proved	66,949	0	135,026	91,061
Probable	34,642	0	82,605	49,393
Proved plus Probable	101,591	0	217,631	140,454
Possible	20,598	0	64,384	32,095
Proved plus Probable plus Possible	122,189	0	282,015	172,549
Mexico				
Proved	22,549	0	20,018	26,124
Probable	6,317	0	11,291	8,333
Proved plus Probable	28,866	0	31,309	34,457
Possible	4,410	0	8,138	5,863
Proved plus Probable plus Possible	33,276	0	39,447	40,320
North Africa				
Proved	5,517	61	133,124	29,350
Probable	1,933	113	82,195	16,724
Proved plus Probable	7,450	174	215,319	46,074
Possible	2,089	108	79,360	16,368
Proved plus Probable plus Possible	9,539	282	294,679	62,442
Norway				
Proved	121,861	39,988	1,321,364	397,807
Probable	44,440	21,264	676,819	186,564
Proved plus Probable	166,301	61,252	1,998,183	584,371
Possible	44,626	15,555	696,282	184,517
Proved plus Probable plus Possible	210,927	76,807	2,694,465	768,888
Total Proved	**226,212**	**47,243**	**2,610,158**	**739,555**
Total Probable	**89,904**	**23,356**	**1,183,562**	**324,610**
Total Proved plus Probable	**316,116**	**70,599**	**3,793,720**	**1,064,165**
Total Possible	**73,933**	**16,575**	**1,201,145**	**304,998**
Total Proved plus Probable plus Possible	**390,049**	**87,174**	**4,994,865**	**1,369,163**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas reserves estimated herein were converted to oil equivalent using a factor of 5,600 cubic feet of gas per 1 boe.
3. The oil equivalent reserves reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

Valuation of Reserves

Revenue values in this report were estimated using initial prices, expenses, and costs provided by or on behalf of Wintershall Dea. Forecast price, expense, and cost assumptions used for this report are detailed herein. Estimates of future net revenue and present worth of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves estimated in this report were prepared using a Base Case Prices scenario and two price sensitivities.

The two price sensitivities are labeled as Low Case Prices and High Case Prices, which represent price scenarios that are 10-percent lower and 10-percent higher than the Base Case Prices scenario, respectively. Further explanation of the Base Case Prices and two price sensitivity assumptions are included under the Valuation of Reserves heading of this report.

The estimated future net revenue and present worth of the future net revenue discounted at 6, 8, 10, and 12 percent to be derived from the production and sale of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves, as of December 31, 2023, of the properties evaluated under the three economic scenarios described herein are summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

	Valuation Summary				
	Future Net Revenue (10^3U.S.$)	Present Worth at 6 Percent (10^3U.S.$)	Present Worth at 8 Percent (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)	Present Worth at 12 Percent (10^3U.S.$)
Proved					
Base Case Prices	10,414,162	8,508,852	7,983,892	7,371,082	7,087,189
Low Case Prices	8,804,685	7,289,099	6,854,990	6,336,988	6,102,659
High Case Prices	12,024,458	9,719,797	9,102,196	8,393,520	8,058,669
Proved plus Probable					
Base Case Prices	16,474,084	12,568,051	11,593,251	10,528,176	10,001,149
Low Case Prices	14,143,898	10,876,591	10,047,673	9,130,797	8,684,333
High Case Prices	18,799,670	14,243,953	13,122,214	11,908,822	11,301,044
Proved plus Probable plus Possible					
Base Case Prices	22,106,234	16,196,493	14,779,665	13,282,049	12,515,256
Low Case Prices	19,107,183	14,088,821	12,871,823	11,573,915	10,916,575
High Case Prices	25,101,048	18,289,707	16,672,921	14,976,320	14,100,595

Note: Values for probable and possible reserves and quantities have not been risk adjusted to make them comparable to values for proved reserves and quantities.

Reserves estimates herein were based on the Base Case Prices scenario projected to an economic limit, and quantities in the sensitivity cases are those included to the limit of projected Base Case Prices production or when an annual economic limit is reached, whichever occurs first. Details of the annual price, expense, and cost assumptions are presented under the Valuation of Reserves heading of this report.

Estimation of Contingent Resources

Contingent resources were estimated for oil, condensate, LPG, and sales gas in certain fields evaluated herein. Tables summarizing the gross, working interest, and net contingent resources by country and region are presented in Tables A-6, A-7, and A-8, respectively.

The estimated gross, working interest, and net 1C, 2C, and 3C contingent resources, as of December 31, 2023, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Gross Contingent Resources			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
1C	819,246	47,135	8,649,610	2,410,954
2C	1,725,147	96,091	17,832,473	5,005,607
3C	2,961,243	149,985	33,140,193	9,029,120

	Working Interest Contingent Resources			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
1C	193,193	19,163	2,009,819	571,252
2C	448,473	39,654	4,196,852	1,237,565
3C	787,226	62,684	7,727,263	2,229,778

	Net Contingent Resources			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
1C	193,193	19,163	2,009,819	571,252
2C	448,473	39,654	4,196,852	1,237,565
3C	787,226	62,684	7,727,263	2,229,778

Notes:
1. For the purposes of this report, net contingent resources are set equal to working interest contingent resources.
2. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
3. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
4. The contingent resources reported herein have an economic status of undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the associated cash flows.
5. Sales gas contingent resources estimated herein were converted to oil equivalent using a factor of 5,600 cubic feet per 1 boe.
6. The oil equivalent contingent resources reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

Ownership

Wintershall Dea has represented that it holds interests in certain licenses for production and development in eight countries: Algeria, Argentina, Denmark, Egypt, Germany, Libya, Mexico, and Norway. The properties evaluated herein are listed by country in the following table:

Country	Field/Discovery	Working Interest (percent)	License Expiration
Algeria	Azrafil Southeast	24.00	November 1, 2041
	Kahlouche	24.00	November 1, 2041
	Kahlouche South	24.00	November 1, 2041
	Reggane	24.00	November 1, 2041
	Sali	24.00	November 1, 2041
	Tiouliline	24.00	November 1, 2041
Argentina	Aguada Pichana East Residual	27.27	July 17, 2052
	Aguada Pichana East Vaca Muerta	22.50	July 17, 2052
	Aguada San Roque	24.71	November 14, 2027
	Ara South	37.50	April 30, 2031
	Aries	37.50	April 30, 2041
	Cañadón Alfa	37.50	April 30, 2031
	Carina	37.50	April 30, 2041
	Fenix	37.50	April 30, 2041
	Hidra	37.50	April 30, 2031
	Kaus	37.50	April 30, 2031

Country	Field/Discovery	Working Interest (percent)	License Expiration
Argentina – *(Continued)*	Leo	37.50	October 23, 2038
	Loma Las Yeguas	24.71	November 14, 2027
	Rincon Chico	24.71	November 14, 2027
	San Roque Vaca Muerta	24.71	November 14, 2027
	Tauro-Unicornio-Sirius	35.00	October 23, 2038
	Vega-Pleyade	37.50	April 30, 2041
Denmark	Cecilie	43.59	June 18, 2032
	Nini	42.857	June 18, 2032
Egypt	Disouq 1-3	100.00	August 11, 2034
	Disouq 1-5	100.00	August 11, 2034
	Disouq 2	100.00	August 11, 2034
	East Damanhour	40.00	September 26, 2043
	El Arish P00 Seg 1	17.25	February 5, 2039
	Fayoum	17.25	February 5, 2039
	Giza	17.25	February 5, 2039
	Hodoa Aquitan (M15 Top sand)	17.25	August 8, 2026
	Libra	17.25	March 24, 2037
	Libra DA	9.4875	March 24, 2037
	Libra P80 Seg 1a	17.25	March 24, 2037
	Maadi P80 Seg 1 (includes Seg 2 and Levee)	17.25	August 8, 2026
	Maadi Segment 3	17.25	August 8, 2026
	North Sidi Ghazy-1	100.00	August 11, 2034
	North Sidi Ghazy-2-1	100.00	August 11, 2034
	North Sidi Ghazy-2-3	100.00	August 11, 2034
	North Sidi Ghazy-4	100.00	August 11, 2034
	Northwest Khilala	100.00	September 2, 2033
	Northwest Sidi Ghazy-1	100.00	August 11, 2034
	Northwest Sidi Ghazy-7	100.00	August 11, 2034
	Polaris Pliocene P78 Ch	17.25	August 8, 2026
	Polaris Pliocene P78 Ch Splay	17.25	August 8, 2026
	Raven	17.25	February 5, 2039
	Raven West M15	17.25	February 5, 2039
	Raven West M20	17.25	February 5, 2039
	Raven West M40D2	17.25	February 5, 2039
	Raven West M40E	17.25	February 5, 2039
	Raven West Serravallian 2	17.25	February 5, 2039
	Raven West Serravallian 4	17.25	February 5, 2039
	Ruby P78 R1 Seg 1	17.25	February 5, 2039
	Sidi Salam Southeast-1	100.00	August 11, 2034
	Sidi Salam Southeast-2	100.00	August 11, 2034
	Sidi Salam Southeast-3	100.00	August 11, 2034
	Sidi Salam Southeast-6	100.00	August 11, 2034
	South Sidi Ghazy-1-1	100.00	August 11, 2034
	South Sidi Ghazy-1-2	100.00	August 11, 2034
	Taurus	17.25	March 24, 2037
	Taurus Deep Serravallian SV7	17.25	March 24, 2037
	Taurus Deep Serravallian SV8	17.25	March 24, 2037
	Taurus P80 Seg 1	17.25	March 24, 2037
	Taurus P86 Seg 2	17.25	March 24, 2037
	Viper P83 Viper Channel and Aband	17.25	August 8, 2026

Country	Field/Discovery	Working Interest (percent)	License Expiration
Germany	Aldorf	100.00	June 30, 2030
	Barrien	50.00	September 13, 2040
	Bockstedt	100.00	January 31, 2030
	Boetersen	20.8120	September 30, 2045
	Boetersen South	0.85	August 31, 2033
	Boestlingen	50.00	October 31, 2027
	Dueste Valendis	100.00	June 30, 2030
	Emlichheim	90.00	May 31, 2043
	Fehndorf	70.00	December 31, 2035
	Hemsbuende	36.279	September 30, 2045
	Mittelplate	100.00	December 31, 2041
	Preyersmuehle South	8.273	December 31, 2045
	Rehden	100.00	December 31, 2040
	Ruetenbrock	100.00	September 30, 2034
	Soehlingen	27.48	December 31, 2045
	Staffhorst HD	50.00	August 7, 2030
	Staffhorst North	50.00	April 17, 2024
	Taaken	14.28	December 5, 2040
	Voelkersen	100.00	December 31, 2028
	Weissenmoor	40.00	January 27, 2028
Libya	Al-Jurf	12.50	April 10, 2035
Mexico	Chinwol	25.00	May 7, 2053
	Hokchi	37.00	December 31, 2040
	Kan	40.00	March 31, 2024
	Naajal	50.00	March 7, 2052
	Ogarrio	50.00	March 6, 2043
	Polok	25.00	May 7, 2053
	Zama	19.83	September 4, 2045
Norway	Aasta Hansteen	24.00	February 2, 2041
	Adriana	40.00	February 2, 2032
	Ærfugl North (Snadd Outer PL212E)	25.00	February 2, 2033
	Alta	30.00	May 14, 2051
	Alve North	20.00	December 31, 2036
	Balderbrå	30.00	February 10, 2027
	Bauge	27.50	December 17, 2029
	Beaujolais	40.00	June 4, 2035
	Bergknapp	40.00	February 5, 2026
	Bergknapp Åre	40.00	February 5, 2026
	Busta	20.00	February 6, 2025
	Dvalin	55.00	October 3, 2041
	Dvalin North	55.00	October 3, 2041
	Edvard Grieg	15.00	December 17, 2029
	Gjøa	28.00	July 8, 2028
	Hamlet (Gjøa North)	28.00	July 8, 2028
	Hyme	27.50	December 17, 2029
	Idun North	40.00	December 31, 2036
	Irpa	19.00	June 18, 2041
	Iving	6.50	February 5, 2026
	Maria	50.00	February 28, 2036
	Neiden	30.00	May 14, 2051
	Newt	10.00	June 2, 2027

Country	Field/Discovery	Working Interest (percent)	License Expiration
Norway – *(Continued)*	Nidhogg	20.00	March 1, 2028
	Njord Unit	50.00	April 10, 2034
	Noatun	45.00	April 10, 2034
	Nova	39.00	February 16, 2041
	Obelix	10.00	February 19, 2027
	Ofelia	20.00	September 2, 2026
	Ofelia Kyrre	20.00	September 2, 2026
	Orion	40.00	June 4, 2035
	Oswig	20.00	February 19, 2027
	Sabina	40.00	February 2, 2032
	Skarv Unit	28.0825	March 3, 2029
	Snøhvit Unit	2.81	October 1, 2035
	Snorre Unit	8.5711	December 31, 2040
	Solveig	15.00	January 6, 2036
	Statfjord East Unit	1.40	August 10, 2026
	Storjo	30.00	May 12, 2036
	Storjo Cretaceous	30.00	May 12, 2036
	Sygna Unit	1.26	August 10, 2026
	Syrah	40.00	June 4, 2035
	Tordis	2.80	December 31, 2040
	Tornerose	2.80	December 17, 2035
	Vega Unit	56.70	June 4, 2035
	Vigdis	2.80	December 31, 2040

Note: In certain cases, the working interests shown are not representative of Wintershall Dea net reserves entitlement due to certain fields being subject to the terms of PSAs.

Wintershall Dea's interests in Denmark, Germany, and Norway are held through licenses that are routinely extended to the economic limit; therefore, reserves reported herein were not limited by license dates and were projected to the economic limit, unless business decisions by the operator or working interest holders define an earlier point of time for abandonment. In Algeria, reserves reported herein were projected to the economic limit or to the license date of November 1, 2041, whichever occurred first. In Egypt, reserves reported herein were limited to those to be recovered by the license dates with no consideration given to license extensions. In Libya, reserves reported for the Al-Jurf field include a 5-year extension to the license date of April 10, 2035, to April 10, 2040. In Argentina and Mexico, the reserves reported herein were limited to those to be recovered by the license dates with no consideration given to license extensions.

These interests are held through contractual instruments that are common in the petroleum industry. We had an opportunity to review certain segments of pertinent agreements; however, we, as engineers, cannot express an opinion as to the accounting or legal aspects of those agreements.

Infrastructure

The infrastructure in the eight countries evaluated is well established. Both the onshore and offshore petroleum production provinces evaluated herein have access to a composite of pipelines, service structures, established platforms, and flow stations. There is an extensive established network of service companies to allow developments of all types, including complex mechanical and operational elements. Power options, including electrical, natural gas, and diesel sources, are readily available to operators in the evaluated venues.

Environmental Considerations

There are certain environmental considerations in any venue of petroleum production. We are not aware of any extraordinary environmental elements associated with the properties evaluated herein. As such, we have included abandonment costs, as appropriate, to accomplish routine and safe removal of subsurface and surface equipment, plugging any outstanding wells, and reclamation costs, if any.

Definition of Reserves

Estimates of proved, probable, and possible reserves presented in this report have been prepared in accordance with the PRMS approved in March 2007 and revised in June 2018 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. The petroleum reserves are defined as follows:

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

> *Proved Reserves* are those quantities of petroleum that, 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. 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 (P90) that the quantities actually recovered will equal or exceed the estimate.

Probable Reserves are 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 plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability (P50) that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves are those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate.

Once projects satisfy commercial maturity, the associated quantities are classified as Reserves. These quantities may be allocated to the following subdivisions based on the funding and operational status of wells and associated facilities within the reservoir development plan:

Developed Reserves are quantities expected to be recovered from existing wells and facilities. Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves include shut-in and behind-pipe reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Undeveloped Reserves are quantities expected to be recovered through future significant investments. Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

The extent to which probable and possible reserves ultimately may be recategorized as proved reserves is dependent upon future drilling, testing, and well performance. The degree of risk to be applied in evaluating probable and possible reserves is influenced by economic and technological factors as well as the time element. Estimates of probable and possible reserves in this report have not been adjusted in consideration of these additional risks to make them comparable to estimates of proved reserves.

Estimation of Reserves

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry, which are presented in the PRMS and Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Wintershall Dea, and analyses of areas offsetting existing wells with test or production data, reserves were categorized as proved, probable, or possible.

The undeveloped reserves estimates were based on opportunities identified in the plans of development provided by Wintershall Dea. Developed reserves consist of those quantities associated with producing wells and non-producing components that require minor remaining capital expenditure as compared to the cost of a new well, such as behind-pipe zones.

Wintershall Dea has represented that its senior management is committed to the development plans provided by Wintershall Dea and that Wintershall Dea has the financial capability to execute the development plans, including the drilling and completion of wells and the installation of equipment and facilities.

Where applicable, the volumetric method was used to estimate the original oil in place (OOIP) and original gas in place (OGIP). Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and water saturation (S_w). When adequate data were available and when circumstances justified, material-balance methods were used to estimate OOIP or OGIP.

Where applicable, estimates of ultimate recovery were obtained after applying recovery factors to OOIP and OGIP. These recovery factors were based on consideration of the type of energy inherent in the reservoirs, analyses of the petroleum, the structural positions of the properties, and the production histories. When applicable, material balance and other engineering methods were used to estimate recovery factors based on an analysis of reservoir performance, including production rate, reservoir pressure, and reservoir fluid properties.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production as defined under the Definition of Reserves heading of this report or the license limit (where applicable), whichever occurs first.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

In certain cases, reserves were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

Except where noted, reserves estimates presented herein were generally based on data available through December 31, 2023, and were supported by drilling results, analyses of available geological data, well-test results, pressures, available core data, and production history. The reserves estimates presented herein were based on consideration of daily or monthly production data through December 2023. Cumulative production, as of December 31, 2023, was deducted from the gross ultimate recovery to estimate gross reserves. This report takes into account all relevant information provided by Wintershall Dea.

Oil and condensate reserves estimated herein are to be recovered by normal field separation. LPG reserves estimated herein consist primarily of propane and butane fractions and are the result of low-temperature plant processing. Oil, condensate, and LPG reserves included in this report are expressed in thousands of barrels (10^3bbl). In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate reserves have been estimated separately and are presented herein as a summed quantity in certain instances.

Gas quantities estimated herein are expressed as sales gas. Separator gas is defined as the total gas produced from the reservoir after field separation but before reduction for field use (including fuel usage), flare, and gas injection. Sales gas is defined as the quantities of separator gas available to be sold at the point of delivery after field use (including fuel usage), flare, and gas injection. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.7 pounds per square inch absolute (psia). Gas quantities included in this report are expressed in millions of cubic feet (10^6ft^3).

In this report, gas quantities are identified by the type of reservoir from which the gas is or will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Solution gas and gas-cap gas are sometimes produced together and, as a whole, referred to as associated gas. Gas quantities estimated herein include both associated and nonassociated gas.

For the purposes of this report, sales gas reserves estimated herein were converted to oil equivalent volumes using a factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent. This conversion factor was provided by Wintershall Dea.

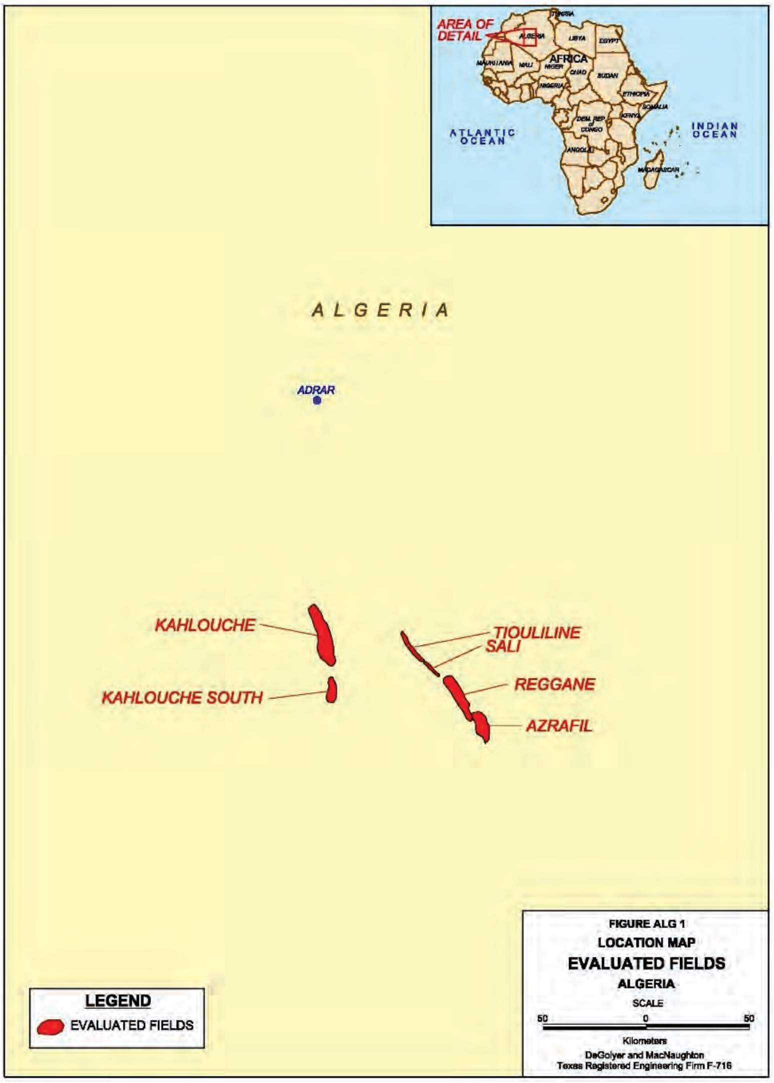
Procedure and Methodology

Wintershall Dea has represented that it holds interests in certain licenses for production and development in eight countries: Algeria, Argentina, Denmark, Egypt, Germany, Libya, Mexico, and Norway. The procedures associated with the evaluation of reserves in these countries are as follows.

Generally, developed producing reserves were estimated based on performance trends of existing wells and completions where such trends exist. If performance trends did not exist, reserves were based on performance analogies for similar types of reservoirs and expected performance or based on analysis of modeling methods. Developed non-producing reserves were estimated for recompletions using a combination of analogous performance and volumetric analysis. Undeveloped reserves were estimated for scheduled drilling, improved recovery, and sidetracks based on analogy with produced reservoirs, as well as volumetric analysis where sufficient data were available. Proved reserves were estimated based on projections premised on reasonable certainty, while probable and possible reserves were based on better well performance than projected for proved reserves plus incremental volumetric recovery where appropriate.

Algeria

There are six fields located within Algeria evaluated herein (Figure ALG 1), which collectively are referred to as "Reggane Nord." The larger fields, Azarafil Southeast and Reggane, are discussed below. Reserves associated with the fields in Algeria were projected to the economic limit or to the license date of November 1, 2041, whichever occurred first. A stratigraphic column of the main producing reservoirs in the Reggane Basin is shown on Figure ALG 2.



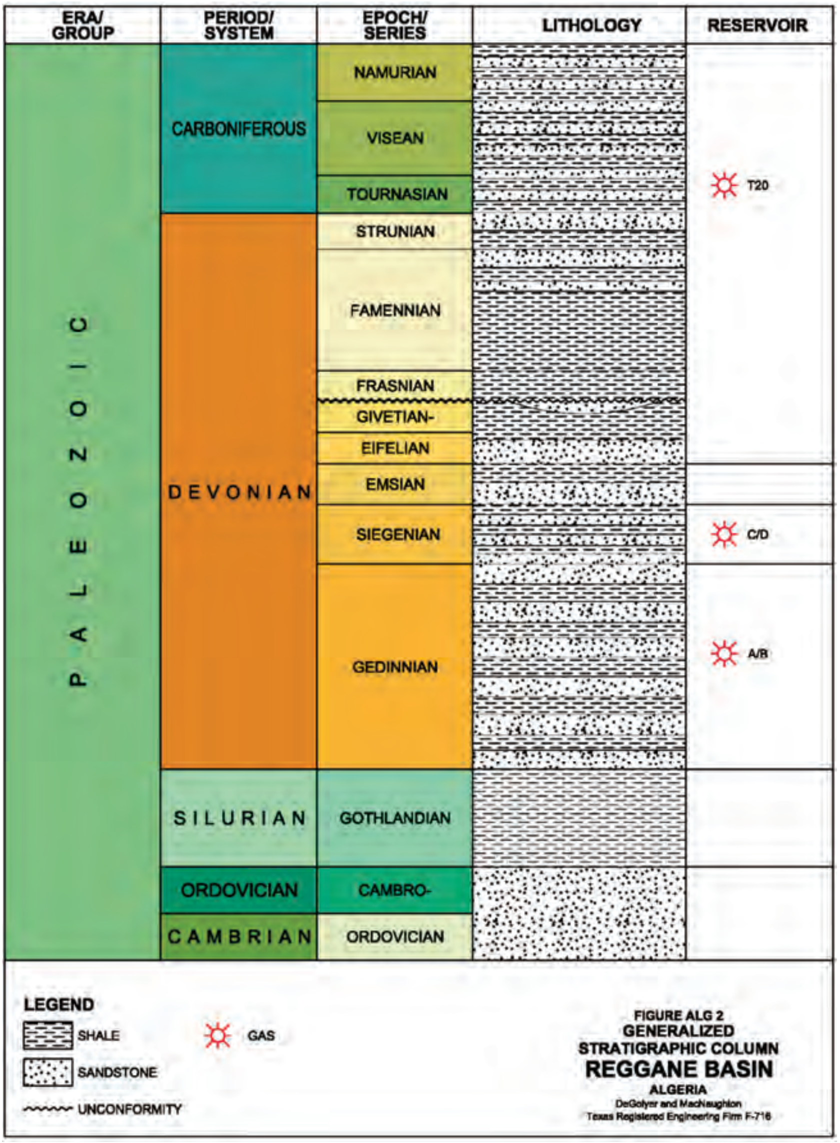


FIGURE ALG 2
GENERALIZED
STRATIGRAPHIC COLUMN
REGGANE BASIN
ALGERIA
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

Azarafil Southeast Field

The Azrafil Southeast field commenced production in 2017. Developed reserves estimated herein were based on nine drilled wells, and the field currently produces on plateau at a rate of 140 million cubic feet per day of gas. Undeveloped reserves were estimated for four additional planned producers. Estimated total reserves were based on volumetric analysis.

Reggane Field

The Reggane field started producing in 2017. Developed reserves estimated herein were based on 11 drilled wells, and the field currently produces on plateau at 140 million cubic feet per day of gas . Undeveloped reserves were estimated for five additional planned producers. Estimated total reserves were based on volumetric analysis.

Argentina

There are 16 fields within Argentina evaluated herein (Figure ARG 1). Reserves associated with the fields in Argentina were limited to those to be recovered by the license dates with no consideration given to license extensions. Selected fields are discussed in detail as follows.

Aguada Pichana East Block

The Aguada Pichana East Block is located in the central portion of the Neuquén Basin, 50 kilometers from the city of Añelo in the Neuquén Province, Argentina. The field was discovered in 1972 and produces mainly dry gas and some condensate. The Aguada Pichana East Block was initially part of a bigger block that was divided in 2017 into the Aguada Pichana East Block, operated by Total, and the Aguada Pichana West Block, operated by Pan American Energy.

Production from the Aguada Pichana East Block is split into Aguada Pichana East Residual and Aguada Pichana East Vaca Muerta. The Aguada Pichana East Residual portion includes the production from the conventional and tight sand reservoirs of the Mulichinco Formation and the production from the wells drilled before December 31, 2016, targeting the Vaca Muerta Formation. The Aguada Pichana East Vaca Muerta includes all production and development of the Vaca Muerta Formation after December 31, 2016. A stratigraphic column of the main producing reservoirs in the Neuquén Basin is shown on Figure ARG 2.

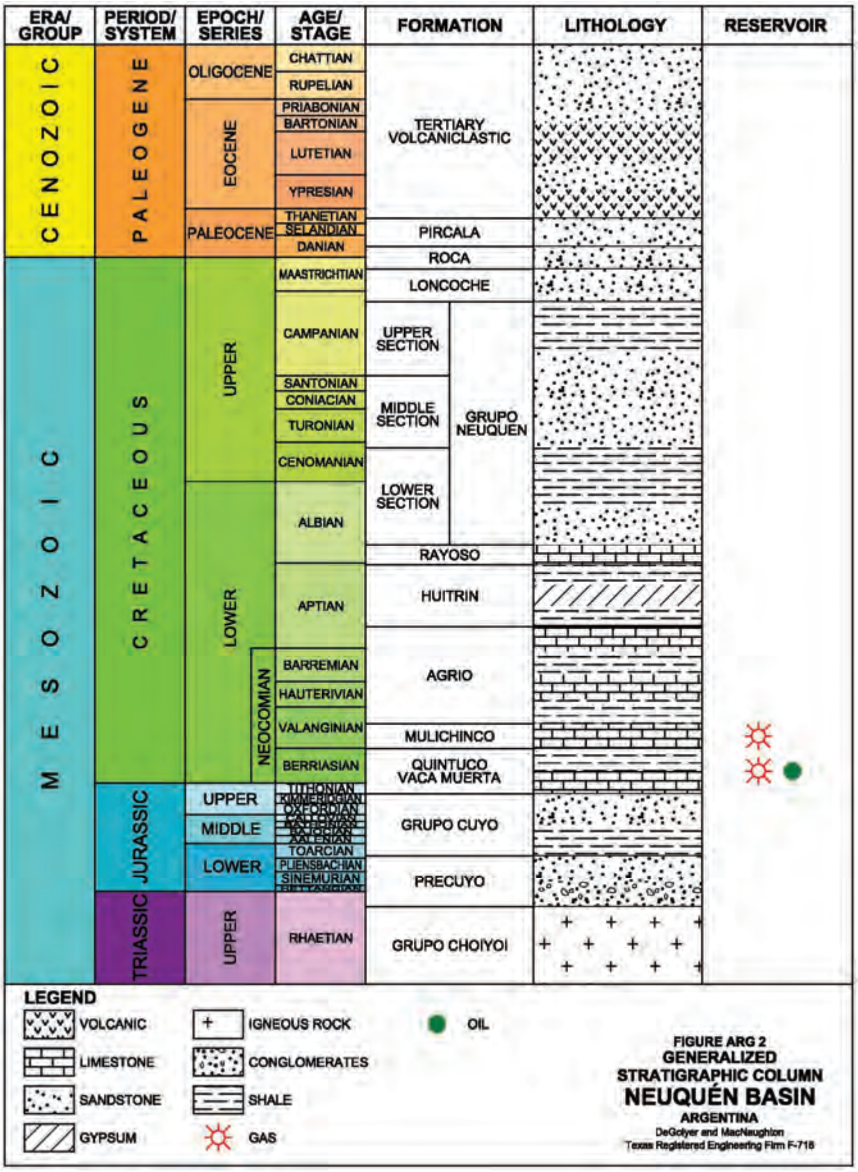
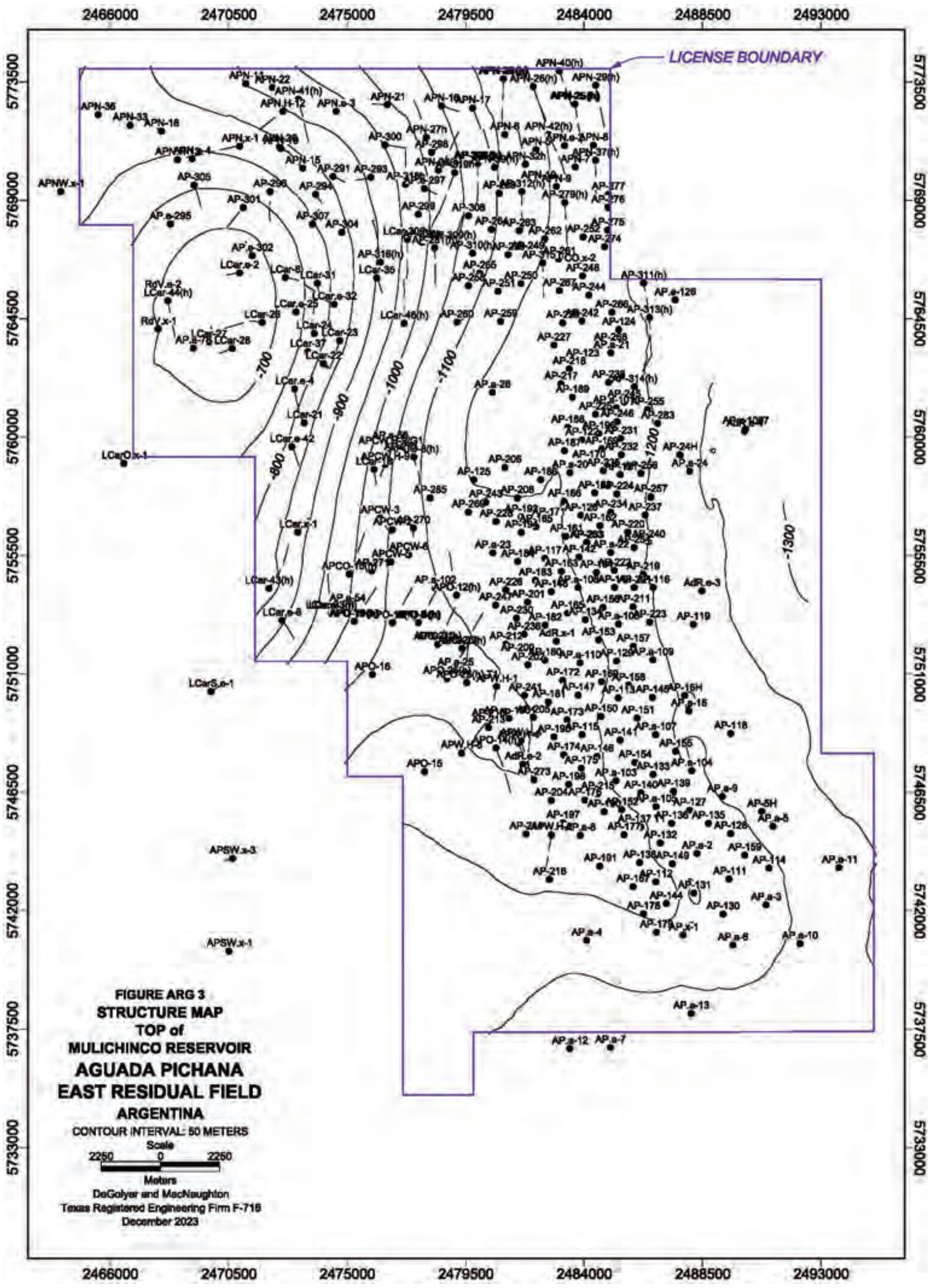


FIGURE ARG 2
GENERALIZED
STRATIGRAPHIC COLUMN
NEUQUÉN BASIN
ARGENTINA
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

Aguada Pichana East Residual

The development of the Aguada Pichana East Residual is subdivided into three areas: Aguada Pichana Main, Aguada Pichana Norte, and Las Cárceles. The main reservoir of the Aguada Pichana Main area is the Middle Mulichinco; gross thickness ranges between 30 and 77 meters, net-to-gross ratio (NGR) ranges from 60 to 95 percent, porosity was estimated to range between 8 and 14 percent, and permeability was estimated to range from 0.1 to 19 millidarcys. The main reservoir of the Aguada Pichana Norte is the Upper Mulichinco; gross thickness ranges between 22 and 37 meters, NGR ranges from 40 to 60 percent, porosity was estimated to range between 10 and 17 percent, and permeability was estimated to range from 10 to 70 millidarcys. The Aguada Pichana East Residual is in a tighter area of the Middle Mulichinco reservoir; gross thickness ranges between 35 and 60 meters, NGR ranges from 40 to 75 percent, porosity was estimated to range between 5 and 10 percent, and permeability was estimated to be less than 0.01 millidarcys.

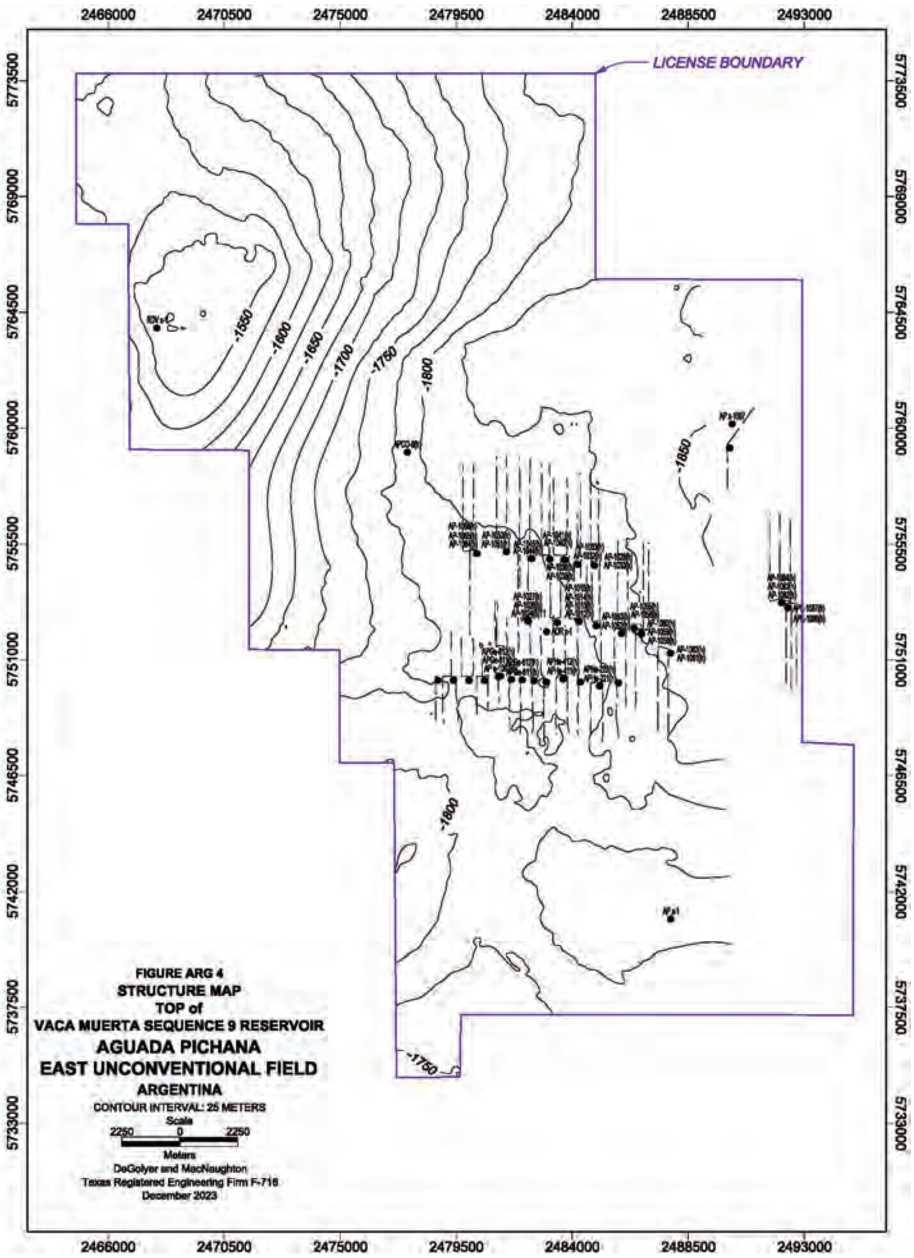
The Aguada Pichana East Block was initially developed with the Aguada Pichana Main Development Project in the east portion of the block, and production started in 1996. The objective was the Cretaceous sandstones of the Mulichinco Formation, which comprises fluvial, tidal to shallow marine deposits and represents a low-frequency lowstand wedge developed during the Early Cretaceous (Valanginian). The Mulichinco Formation was divided vertically into three zones: Lower, Middle, and Upper. The main reservoirs are the Middle and Upper Mulichinco. Toward the west, the petrophysical characteristics of the Mulichinco Formation are poor; low permeability values define it as a tight sand reservoir. From 2007 to 2009, the northern part of the block was developed by drilling vertical wells with high carbon dioxide content as part of the Aguada Pichana Norte Phase I and Aguada Pichana Norte Phase II Development Projects. In 2010, the development was focused to the south of Aguada Pichana Norte by drilling vertical wells with lower carbon dioxide content as part of the Cañadón de la Zorra Development. In 2011, Las Cárceles was developed with vertical wells of low productivity. In the following years, the Aguada Pichana Oeste and Aguada Pichana Norte tight developments were performed by drilling horizontal multi-fracture wells. A structure map on the top of the Mulichinco reservoir in the Aguada Pichana East Residual field is shown on Figure ARG 3.



All reserves estimated herein are associated with the established development. Proved developed producing reserves were estimated by decline-curve analysis. Probable and possible developed incremental reserves were also estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

Aguada Pichana East Vaca Muerta

The Aguada Pichana East Vaca Muerta produces gas and condensate from the unconventional reservoir of the Vaca Muerta Formation. The Vaca Muerta Formation is composed of Tithonian to Valanginian cycles developed in a prograding marine system. The Vaca Muerta Formation is an interbedded reservoir of mudstones and marls. The average gross thickness of the reservoir is 230 meters and the average net thickness is 150 meters; porosity was estimated to range between 8 and 12 percent, average permeability was estimated to be 0.000265 millidarcys, and average total organic carbon is 7 percent. A structural map on the top of the Vaca Muerta Sequence 9 reservoir is shown on Figure ARG 4.



The AP.xp-1001 well discovered gas in the Vaca Muerta Formation in 2011, and production started in 2012. During the Technology Phase, an additional vertical well was drilled in 2012. From 2013 to 2015, 12 horizontal wells were drilled for a pilot project. The first development project, Development 1A, consisted of approximately 20 horizontal wells that were drilled between 2016 and 2018. The Development 1B Project consisted of approximately 36 horizontal wells. The Development 2A Project is underway, and as of December 31, 2023, a total of five of these wells have been drilled.

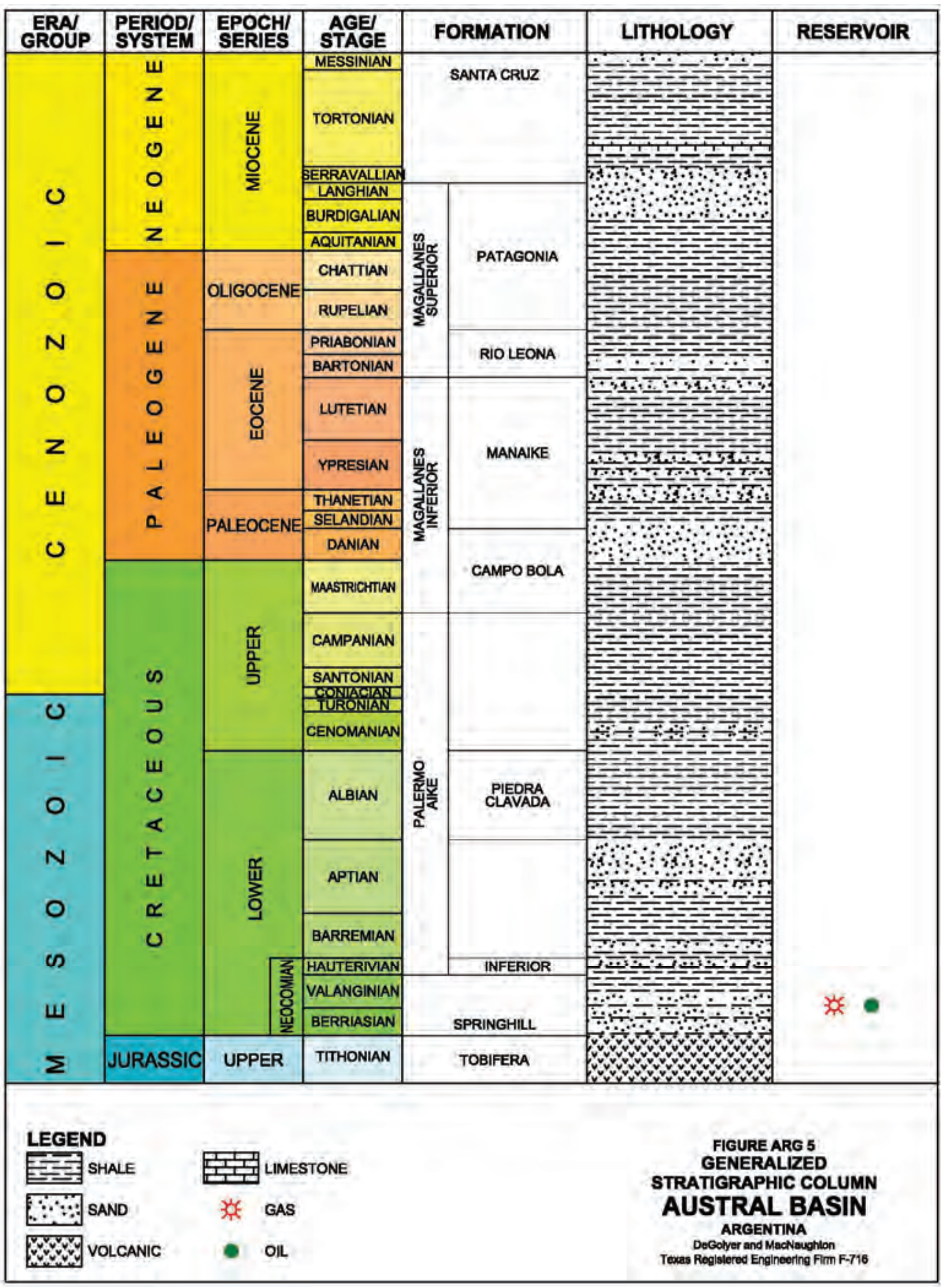
A performance-based methodology was used for estimated reserves associated with unconventional reservoirs. Performance-based methodology primarily includes production diagnostics and decline-curve analysis. Production diagnostics include data quality control, identification of flow regimes and characteristic flow behavior. Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Proved developed producing reserves were estimated by decline-curve analysis. Probable and possible developed incremental reserves were also estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous wells in the Vaca Muerta reservoir for which more complete historical performance data were available. Proved undeveloped reserves were estimated for the remaining horizontal wells of the Development 2A project. Probable and possible undeveloped incremental reserves were also estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

Ara South Field

The Ara South field is located in the Austral Basin, 7 to 12 kilometers offshore Tierra del Fuego in water depths ranging from 20 to 40 meters. The field was discovered in 1982 and started production in 1996. The field has one oil well on production as of December 31, 2023.

The reservoir in the Ara South field is the Hidra sequence of the Springhill Formation (Figure ARG 5). The Springhill Formation is a lithostratigraphic unit that presents a second-order transgressive pattern. The Springhill Formation was deposited during the Cretaceous above the volcaniclastic deposits of the Serie Tobífera Formation and filled the paleotopography. The first deposits of the Springhill Formation were fluvial, evolving to coastal, deltaic estuarine, and proximal marine deposits. The marine deposits evolved to offshore shales, represented by the Inoceramus Inferior Formation, which act as the seal and source rock of the Springhill Formation reservoirs. The different sequences that comprise the Springhill Formation have a retrogradational stacking pattern that backsteps from the west of the basin to the west, toward the Rio Chico High. The Springhill Formation was divided into several depositional sequences: Hidra, Argo, Paloma, and Carina. The RH-5 sands are the main reservoir and have a net thickness of 9.2 meters; porosity was estimated to be 24 percent and permeability was estimated to range from 500 to 1,000 millidarcys.



Proved developed reserves for the Ara South field are associated with its one active well producing as of December 31, 2023, and were estimated by decline-curve analysis. Probable and possible developed incremental reserves were also estimated by decline-curve analysis and are associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves were estimated for the Ara South field.

Aries Field

The Aries field is located in the Austral Basin, 25 to 35 kilometers offshore Tierra del Fuego in water depths ranging from 55 to 80 meters. The field was discovered in 1982 and started production in 2006. The Aries field consists of a gas cap with an associated oil rim of 11 meters in thickness; however, the field produces from only the gas cap. The trap is structural (four-way dip closure). There are currently one deviated and two horizontal production wells.

The reservoirs in the Aries field are the Argo sequence and the Hidra sequence of the Springhill Formation. The Argo sequence has a gross thickness ranging from 8 to 12 meters; net sand porosity was estimated to range from 20 to 30 percent and permeability was estimated to range from 80 to 1,000 millidarcys. The Hidra sequence has a gross thickness ranging from 4 to 14 meters; net sand porosity was estimated to range from 20 to 25 percent and permeability was estimated to range from 1 to 550 millidarcys.

Proved developed reserves for the Aries field are associated with its three active wells on production as of December 31, 2023, and were estimated using a material-balance model in the integrated production system model for the CMA-1 complex. Probable and possible developed incremental reserves were also estimated with the integrated production system model associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves or contingent resources were estimated for the Aries field.

Cañadon Alfa Complex

The Cañadon Alfa complex (consisting of the Antares and Ara-Cañadon Alfa fields) is located both onshore and offshore in the Austral Basin. The offshore part of the field extends up to 17 kilometers from the shore of Tierra del Fuego in water depth up to 50 meters. The field was discovered in 1972 and started production the same year. The field has 29 gas and 7 oil wells on production as of December 31, 2023.

The reservoirs in the Cañadon Alfa complex are the Argo sequence and the Hidra sequence of the Springhill Formation. The main reservoirs are the marine sandstones of the Argo sequence with an average gross thickness of 25 meters and an average net sand thickness of 18 meters; average porosity was estimated to be 22 percent and average permeability was estimated to be 500 millidarcys.

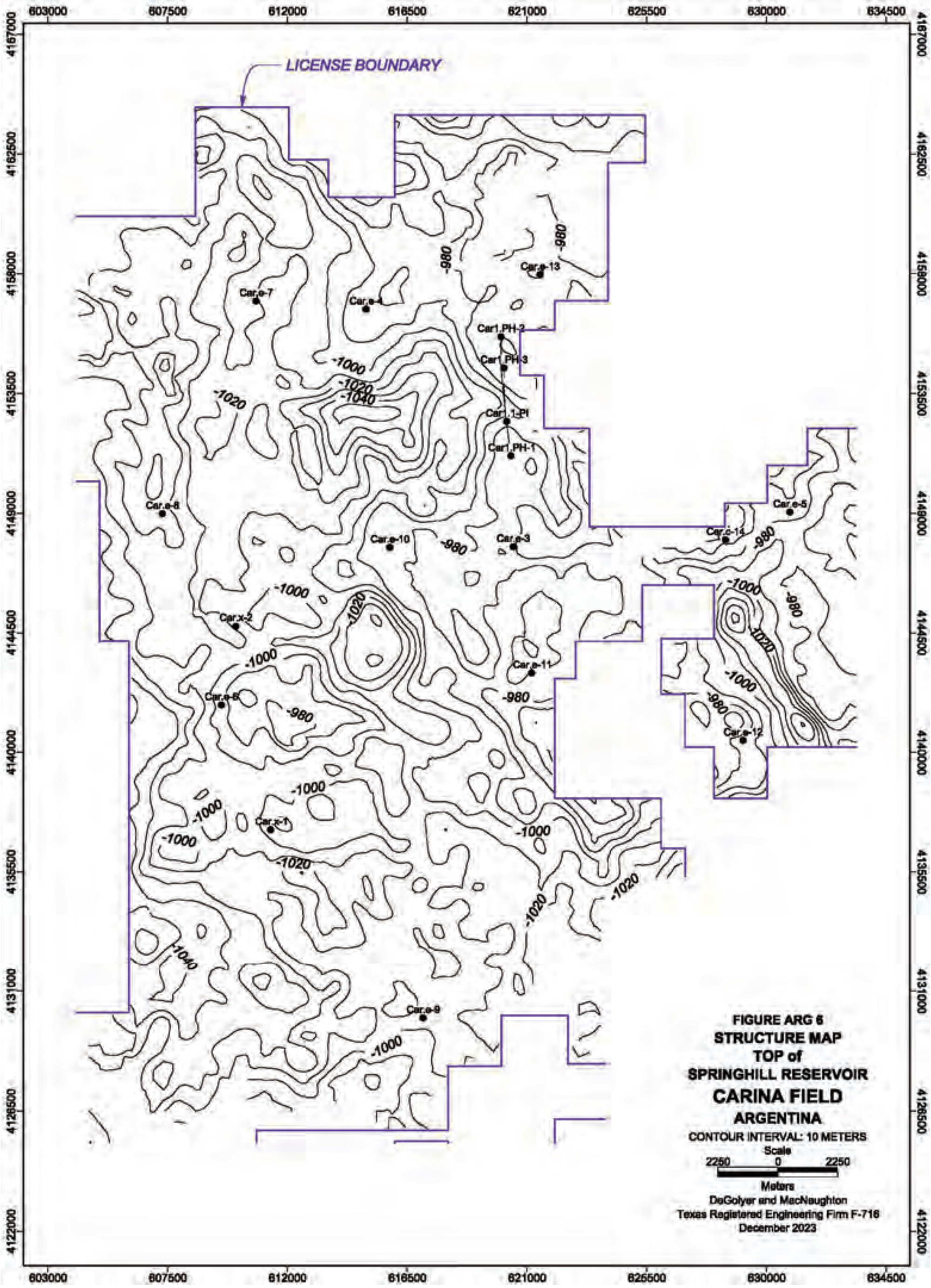
Proved developed reserves for the Cañadon Alfa complex are associated with the active wells on production as of December 31, 2023, and were estimated by decline-curve analysis. Probable and possible developed incremental reserves were also estimated by decline-curve analysis and are associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves were estimated for the Cañadon Alfa complex.

Carina Field

The Carina field is located in the Austral Basin, 65 kilometers offshore Tierra del Fuego in an average water depth of 80 meters. The field was discovered in 1983 and started production in 2005.

The Carina field consists of a gas cap with an associated oil rim and produces gas from the Springhill Formation. The Springhill Formation is a lithostratigraphic unit that presents a second-order transgressive pattern. The Springhill Formation was deposited during the Cretaceous above the volcaniclastic deposits of the Serie Tobífera Formation and filled the paleotopography. The first deposits of the Spinghill Formation were fluvial, evolving to coastal, deltaic estuarine, and proximal marine deposits. The marine deposits evolved to offshore shales represented by the Inoceramus Inferior Formation, which act as the seal and source rock of the Springhill Formation reservoirs. The different sequences that comprise the Springhill Formation have a retrogradational stacking pattern that backsteps from the west of the basin to the west, toward the Rio Chico High. The Springhill Formation was divided into several depositional sequences: Hidra, Argo, Paloma, and Carina.

The producing sequences within the Springhill reservoir in the Carina field are the Paloma and Carina sequences. The Paloma sequence has a gross thickness of up to 60 meters and an average NGR of 60 percent. The Carina field sequence has a gross thickness of up to 35 meters and an average NGR of 90 percent. The Springhill Formation net sand porosity was estimated to range from 15 to 35 percent, average permeability was estimated to range between 100 and 300 millidarcys, with values of up to 5,000 millidarcys, and average S_w was estimated to be 33 percent. The trap is structural (four-way dip closure) and stratigraphic (pinchout at the basement highs) (Figure ARG 6).



Proved developed reserves for the Carina field are associated with its four active producing wells as of December 31, 2023, and were estimated using a three-dimensional (3–D) integrated reservoir simulation model. Probable and possible developed incremental reserves were also estimated with the simulation model associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves were estimated for the Carina field.

Fenix Field

The Fenix field is located in the Austral Basin, to the south of the Carina field, 80 kilometers offshore Tierra del Fuego in water depths ranging from 70 to 90 meters over an area of 425 square kilometers. The field was discovered in 1983 with the drilling of the Fenix-1 exploration well that proved oil in the Springhill Formation. The field was subsequently appraised by three additional wells between 1987 and 2015. In 1987, the Fenix.e-2 delineation well tested gas in the Springhill Formation. The field has one vertical exploratory well and four vertical delineation wells.

The reservoirs in the Fenix field are the Carina sequence and the Paloma sequence of the Springhill Formation. The fluvial and marine reservoirs have an average net sand thickness of 15 meters and a NGR of nearly 100 percent; net sand porosity was estimated to range from 15 to 35 percent with an average of 24 percent. Permeability was estimated to range between 100 and 1,000 millidarcys.

The Fenix field will be developed as a gas field. Undeveloped reserves estimated for the Fenix Phase 1 project are associated with the drilling of three development wells from a new platform, which will be connected via pipeline to the existing CMA-1 complex.

Hidra Field

The Hidra field is located in the Austral Basin, 11 to 14 kilometers offshore Tierra del Fuego in water depths ranging from 25 to 40 meters. The field was discovered in 1982 and started production in 1989. The field has five active oil wells on production as of December 31, 2023.

The reservoir in the Hidra field is the Hidra sequence of the Springhill Formation. The Hidra sequence has an average gross thickness of 70 meters and an average NGR of 45 percent; porosity was estimated to range from 13 to 25 percent and permeability was estimated to range from 50 to 5,000 millidarcys.

Proved developed reserves for the Hidra field are associated with the five active wells producing as of December 31, 2023, and were estimated by decline-curve analysis. Probable and possible developed incremental reserves were also estimated by decline-curve analysis and are associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves were estimated for the Hidra field.

Kaus Field

The Kaus field is located in the Austral Basin, 3 to 8 kilometers offshore Tierra del Fuego in a water depth of over 20 meters. The field was discovered in 1982 and started production in 1998. The field has one active oil well on production as of December 31, 2023.

The reservoir in the Kaus field is within the Hidra sequence of the Springhill Formation. The Hidra sequence has a gross thickness of 25 meters and an average net sand thickness of 11.2 meters; average porosity was estimated to be 21 percent and average permeability was estimated to be 500 millidarcys.

Proved developed reserves for the Kaus field are associated with one active well on production as of August 31, 2023, and were estimated by decline-curve analysis. Probable and possible developed incremental reserves were also estimated by decline-curve analysis and are associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves were estimated for the Kaus field.

San Roque Vaca Muerta

The San Roque Vaca Muerta field is located in the center of the Neuquén Province to the northeast of the Aguada Pichana Block, 130 kilometers from the city of Neuquén, Argentina. The San Roque Vaca Muerta field covers an area of 1,040 square kilometers, and the main source rock is the Vaca Muerta Formation. The Vaca Muerta Formation, which is composed of marls and bituminous claystones with type II kerogen of marine origin, extends throughout the field with an average thickness of 200 meters and total organic content (TOC) of 4.5 percent. The field is located in a transitional fluid-type region, from volatile oil in the west to black oil in the east.

A performance-based methodology was used for estimating reserves associated with unconventional reservoirs in this field. Proved developed reserves were estimated for three wells by decline-curve analysis. Probable and possible developed reserves were estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

Vega Pleyade Field

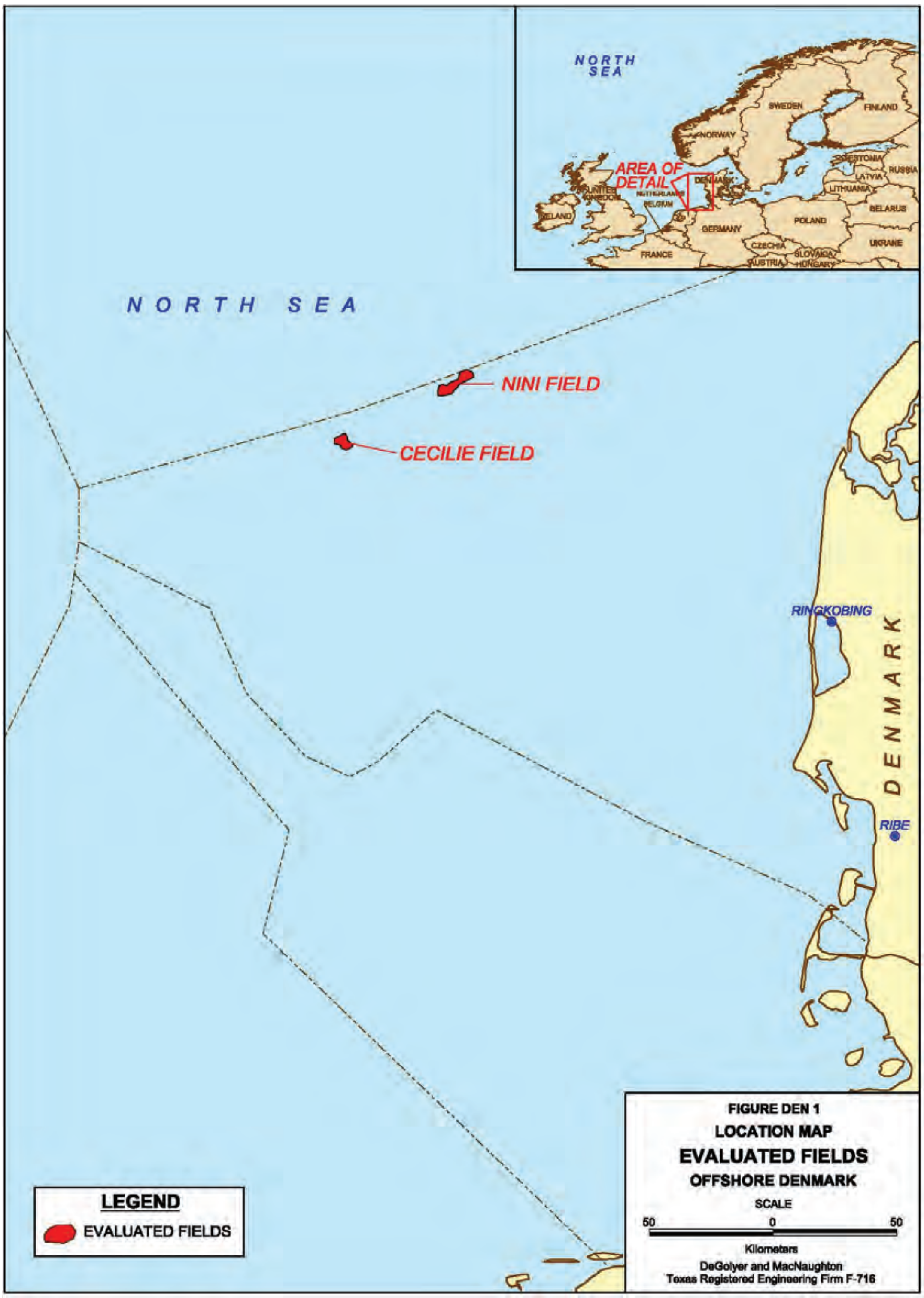
The Vega Pleyade field is located 20 kilometers offshore Tierra del Fuego, in water depths ranging from 40 to 60 meters. The field was discovered in 1981 and started production in 2016. The Vega Pleyade field consists of a gas cap with an associated oil rim and produces gas from the Springhill Formation. There are two horizontal production wells. The trap is structural (four-way dip closure) and stratigraphic (pinchout at the basement highs).

The reservoirs in the Vega Pleyade field are the Hidra sequence, Argo sequence, and Paloma sequence of the Springhill Formation. The Paloma sequence is the main reservoir. The gross thickness of the Springhill Formation ranges from 40 to 75 meters. The sandstones of the Paloma sequence have an average NGR of 69 percent, porosity was estimated to be 19 percent, permeability was estimated to be 200 millidarcys, and S_w was estimated to be 45 percent.

Proved developed reserves for the Vega Pleyade field are associated with two active wells on production as of December 31, 2023, and were estimated using a 3–D integrated reservoir simulation model. Probable and possible developed incremental reserves were also estimated with the simulation model associated with incremental recovery above quantities estimated for proved and probable reserves, respectively. No undeveloped reserves were estimated for the Vega Pleyade field.

Denmark

There are two fields located in Denmark evaluated herein: Cecilie and Nini (Figure DEN 1). The reserves in these fields were estimated to be zero, as any further production or development is not economically viable.



Egypt

There are 42 fields located within Egypt evaluated herein (Figure EGY 1). Reserves associated with the fields in Egypt were limited to those expected to be recovered prior to the license dates with no consideration given to license extensions.

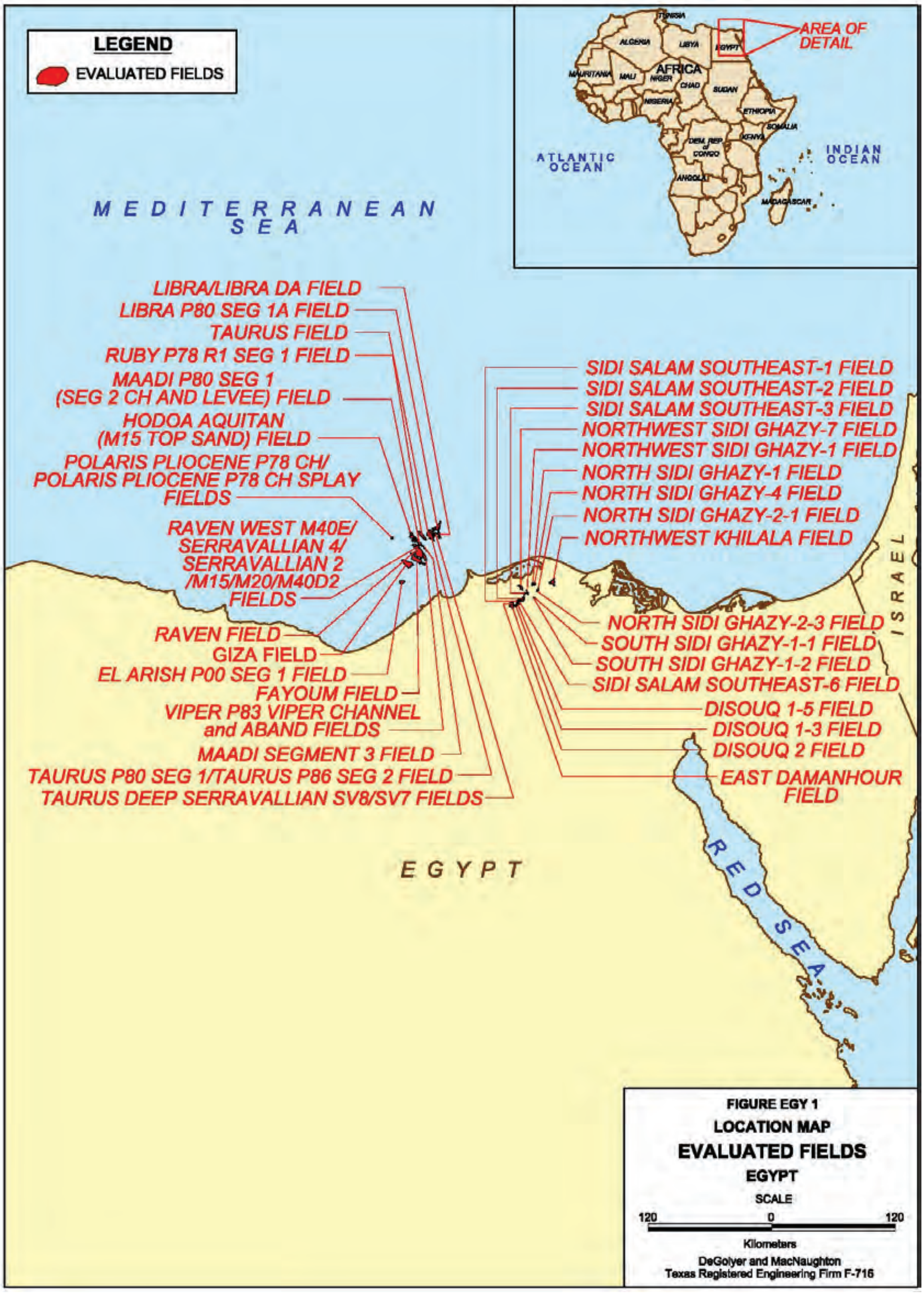
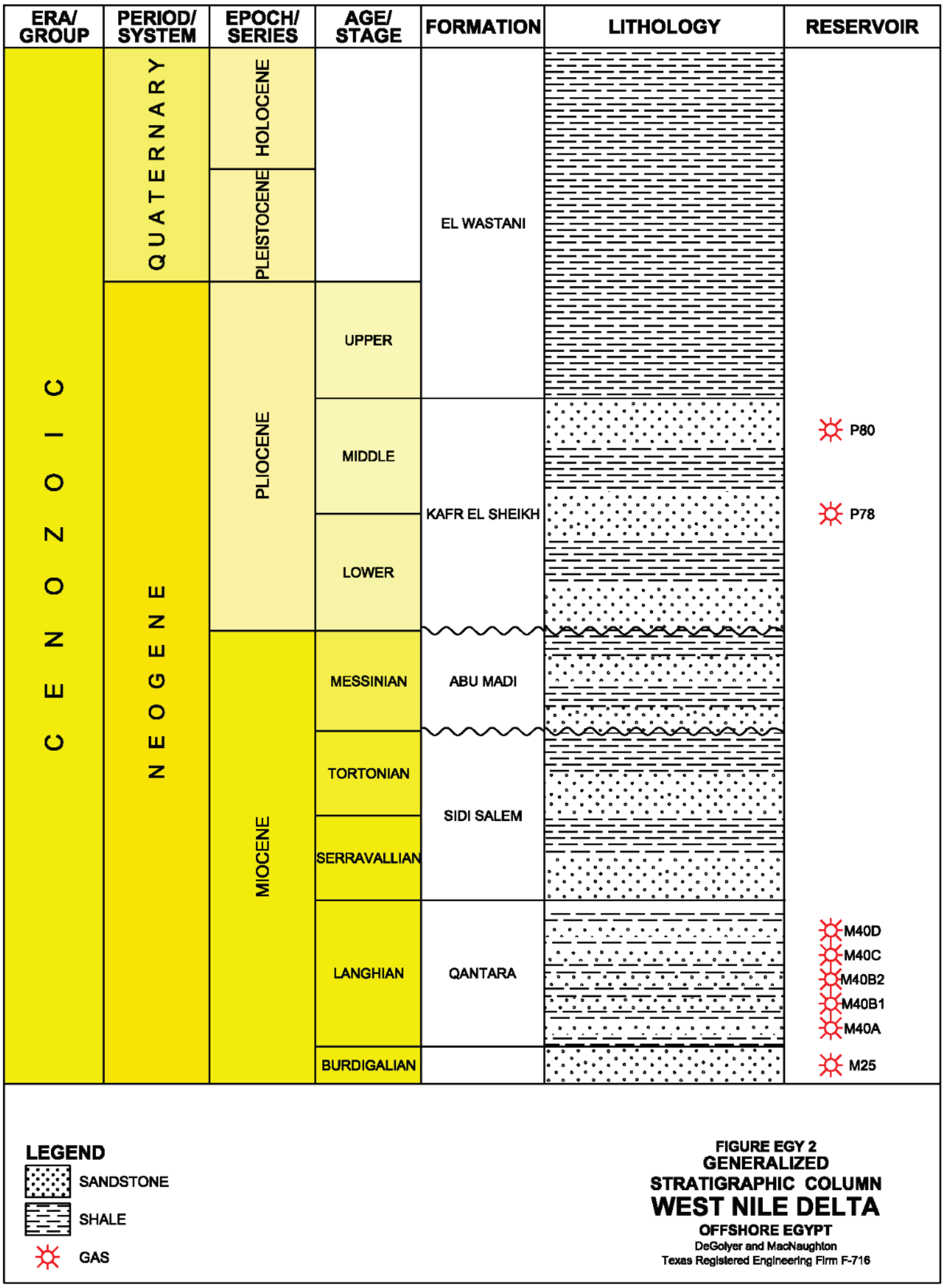


FIGURE EGY 1
LOCATION MAP
EVALUATED FIELDS
EGYPT

The Fayoum, Giza, Libra, Raven, and Taurus fields in the West Nile Delta area and the onshore Disouq area are discussed in detail herein. A stratigraphic column of the main producing reservoirs in the West Nile Delta area is shown on Figure EGY 2.



Disouq Area

The Disouq area consists of 16 fields, including the Disouq fields, North Sidi Ghazy fields, Northwest Khilala field, Northwest Sidi Ghazy fields, Sidi Salam Southeast fields, and South Sidi Ghazy fields. There are a total of 31 wells in the Disouq area, and most of the fields have 1 or 2 wells. The area produces gas with low condensate yields. Reserves were estimated based on performance analysis of the wells.

Fayoum Field

The Fayoum field is a gas field located in the Mediterranean Sea approximately 10 kilometers south-southeast of the Giza field, approximately 55 kilometers northwest of the city of Alexandria, Egypt. The field was discovered by the FN-1 well in 2001 and is part of the West Nile Delta Concession area.

The geologic structure of the Fayoum field consists of a faulted anticline. A 3--D seismic survey shot over the Fayoum field in 2005 helped define the stratigraphic limits of the reservoirs.

There are two main sandstone reservoir intervals in the field, the P79 and P78, which are of Pliocene age. The reservoirs were deposited in a mid-slope setting as a turbidite channel and splay system composed of thinly bedded sandstones. Figure EGY 3 presents a structure map on the top of the P79 reservoir in the Fayoum field. Average net thickness is less than 15 meters. Porosity was estimated to range from 24 to 31 percent, initial S_w was estimated to range from 30 to 33 percent, and permeability was estimated up to 2.5 darcys in the P79 reservoir and up to 2.9 darcys in the P78 reservoir.

Production from the field began in 2019. The field produces lean gas from four wells with a low condensate-gas ratio (CGR) of less than 1 barrel per million cubic feet ($bbl/10^6ft^3$). The P79 and P78 reservoirs are normally pressured, and the drive mechanism is a combination of gas expansion and aquifer drive. The produced gas is transported via pipeline to the existing Rosetta and Burullus onshore facilities and is then transferred to the Egyptian national grid via the Gasco export system. Condensate is metered at the Rosetta facility and then exported via the Burullus condensate export system into the Petroleum Pipelines Company (PPC) pipeline.

Proved, probable, and possible developed reserves were estimated based on volumetric analysis and performance of existing wells. No additional drilling is currently planned for the field. Reserves estimated herein are expected to be produced prior to the license expiration on February 5, 2039.

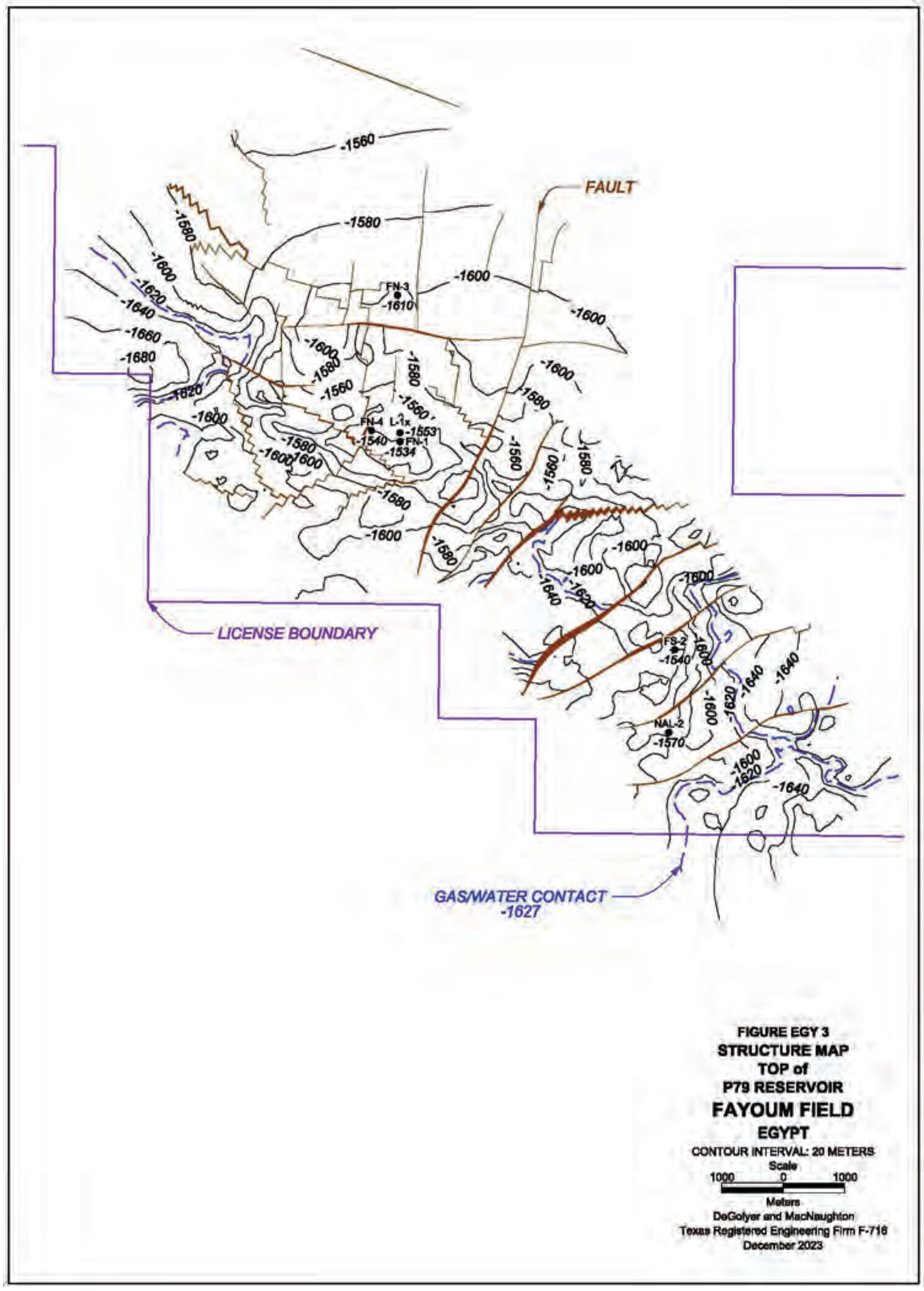
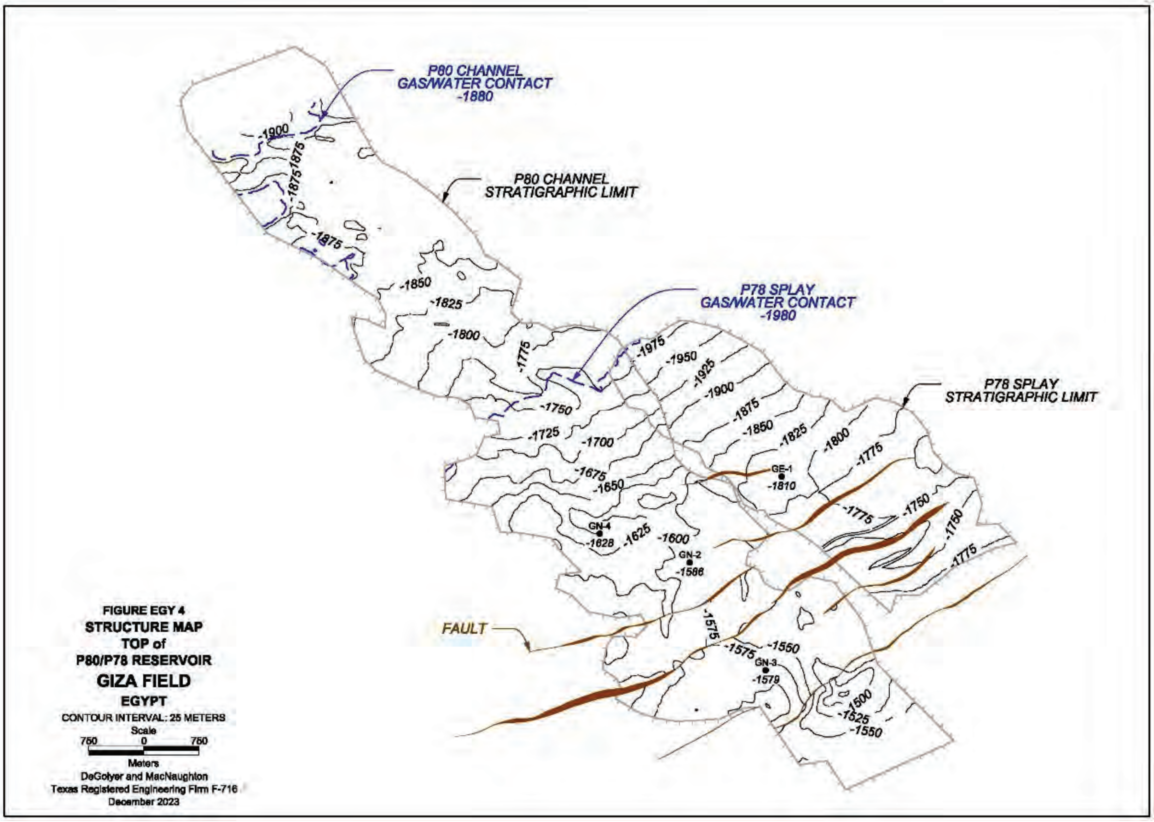


FIGURE EGY 3
STRUCTURE MAP
TOP of
P79 RESERVOIR
FAYOUM FIELD
EGYPT

<u>Giza Field</u>

The Giza field is a gas field located in the Mediterranean Sea approximately 65 kilometers northwest of Alexandria, Egypt. The field was discovered by the Giza North-1 well in 2007 and is part of the West Nile Delta Concession area. The structure consists of a faulted anticline; however, a stratigraphic pinchout is the hydrocarbon trapping mechanism (Figure EGY 4). A 3–D seismic survey shot over the Giza field in 2005 was crucial in defining the stratigraphic limits of the reservoirs.



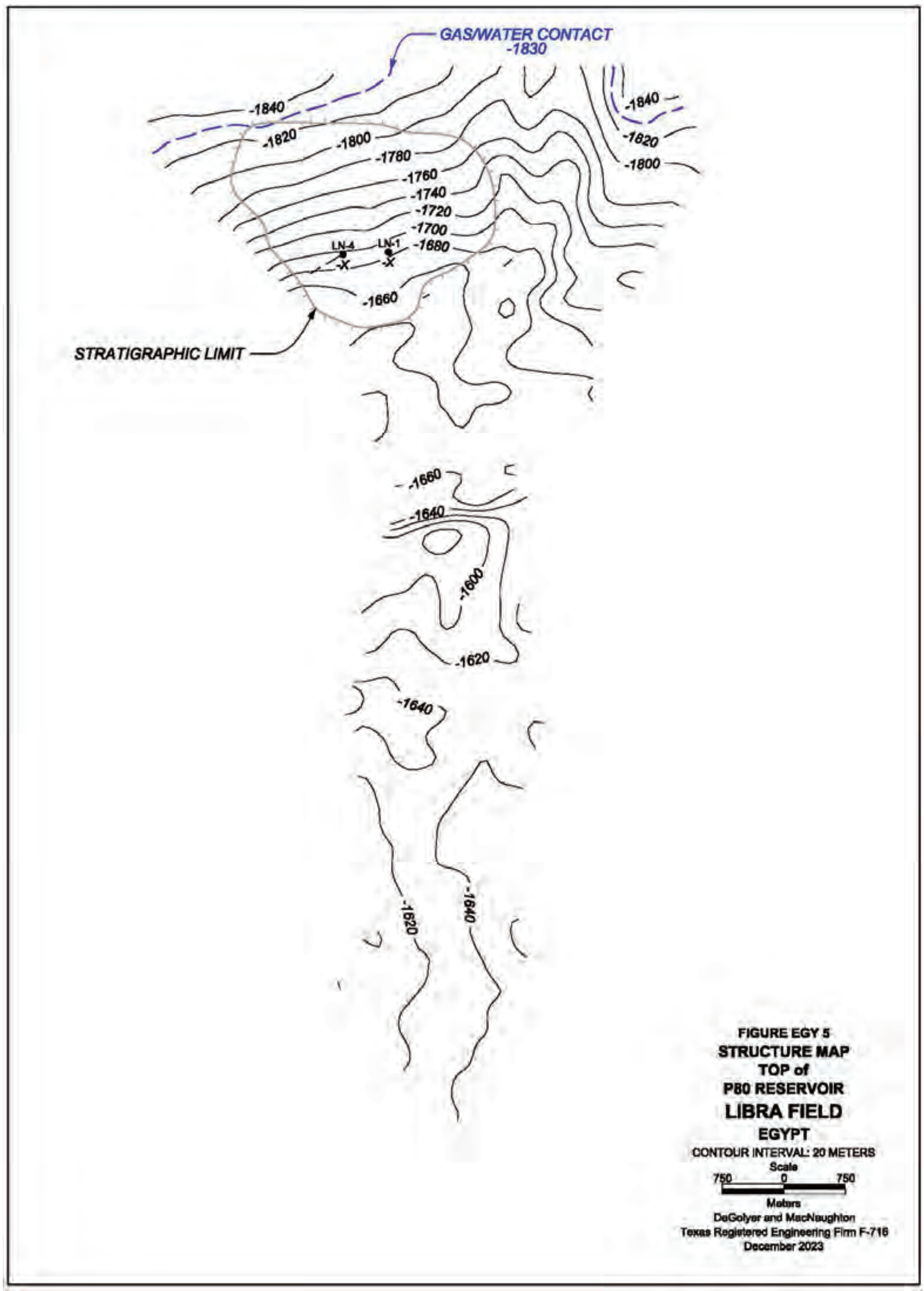
There are two main sandstone reservoir intervals in the field, the P80 and P78, which are of Pliocene age. The reservoirs were deposited as marine channels, channel-levees, and crevasse splays in a slope channel complex. The reservoir sections are highly heterogeneous, ranging from aggradational massive sands to heteroliths and thin beds. Average net thickness is less than 25 meters. Porosity was estimated to be greater than 27 percent, initial S_w was estimated to be less than 41 percent, and permeability was estimated to be up to 90 millidarcys in the splays and levees and greater than 400 millidarcys in the channel facies.

Production from the field began in 2019. The field currently produces lean gas from four wells with a low CGR of less than 1 bbl/10^6ft^3. The produced gas is transported via pipeline to the existing Rosetta and Burullus onshore facilities and is then transferred to the Egyptian national grid via the Gasco export system. Condensate is metered at the Rosetta facility and then exported via the Burullus condensate export system into the PPC pipeline.

Proved, probable, and possible developed reserves were estimated based on volumetric analysis and performance of existing wells. No additional drilling is currently planned for the field. Reserves estimated herein are expected to be produced prior to the license expiration of February 5, 2039.

Libra Field

The Libra field is a gas field located in the Mediterranean Sea approximately 5 kilometers northeast of the Taurus field and approximately 85 kilometers north-northwest of Alexandria, Egypt. The field was discovered by the K-1X exploration well in 2003 and is part of the West Nile Delta Concession area.



Additional appraisal wells were drilled in the field and confirmed the presence of gas-saturated channel levee sandstone reservoirs consisting of the P78 Channel, P78 Splay, P80 Splay, and P76 Levee reservoirs. The field is dominated by the P80 Channel complex, which trends southeast to northwest. The reservoirs range in depth from approximately 1,100 to 2,500 meters TVDSS. Figure EGY 5 presents a structure map on the top of the P76/P80 reservoir in the Libra field.

Production from the field began in March 2017 from two wells and consists of lean gas with low CGR of less than 1 bbl/10^6ft^3. The P76 and P80 reservoirs are the primary reservoirs contributing to the production. The produced gas is transported via pipeline to the existing Burullus onshore facilities and is then transferred to the Egyptian national grid via the Gasco export system. Condensate is metered at the Burullus facility and then exported via the Burullus condensate export system into the PPC pipeline.

Proved, probable, and possible developed reserves were estimated based on performance analysis of existing wells. No additional drilling is currently planned for the field. Reserves estimated herein are expected to be produced prior to the license expiration of March 24, 2037.

Raven Field

The Raven field is a gas field located in the Mediterranean Sea approximately 60 kilometers northwest of Alexandria, Egypt. The field was discovered by the Raven--1 well in 2004 and is part of the West Nile Delta Concession area. The field was further appraised by the Raven-2, Raven-3, and Raven-4 wells. The water depth over the field ranges from 500 to 700 meters.

The main reservoir in the field is the Miocene (Langhian) M40 reservoir, which consists of an amalgamated channel complex within a large deeply incised northwest/southeast-trending confined system that drapes over the northeast-plunging Raven anticline. Reservoir depths range from approximately 4,100 meters TVDSS near the crest to approximately 4,520 meters TVDSS at the north flank gas/water contact (GWC). Figure EGY 6 presents a structure map on the top of the M40D member of the M40 reservoir. Although reservoir net thickness varies across the M40 channel complex, the average reservoir thickness is less than 25 meters. Reservoir properties are generally good; average porosity and S_w for the individual channels within the M40 reservoir were estimated to be greater than 15 percent and less than 46 percent, respectively. Permeability was estimated to range from 0.1 to over 1,000 millidarcys with an average of several hundred millidarcys.

Production from the Raven field began in the first quarter of 2021 through eight development wells. The production license expires on February 5, 2039. The produced gas is routed to the Rosetta East facilities for processing with no substantial LPG production. The gas is rich with an estimated condensate yield of greater than 30 bbl/10^6ft^3.

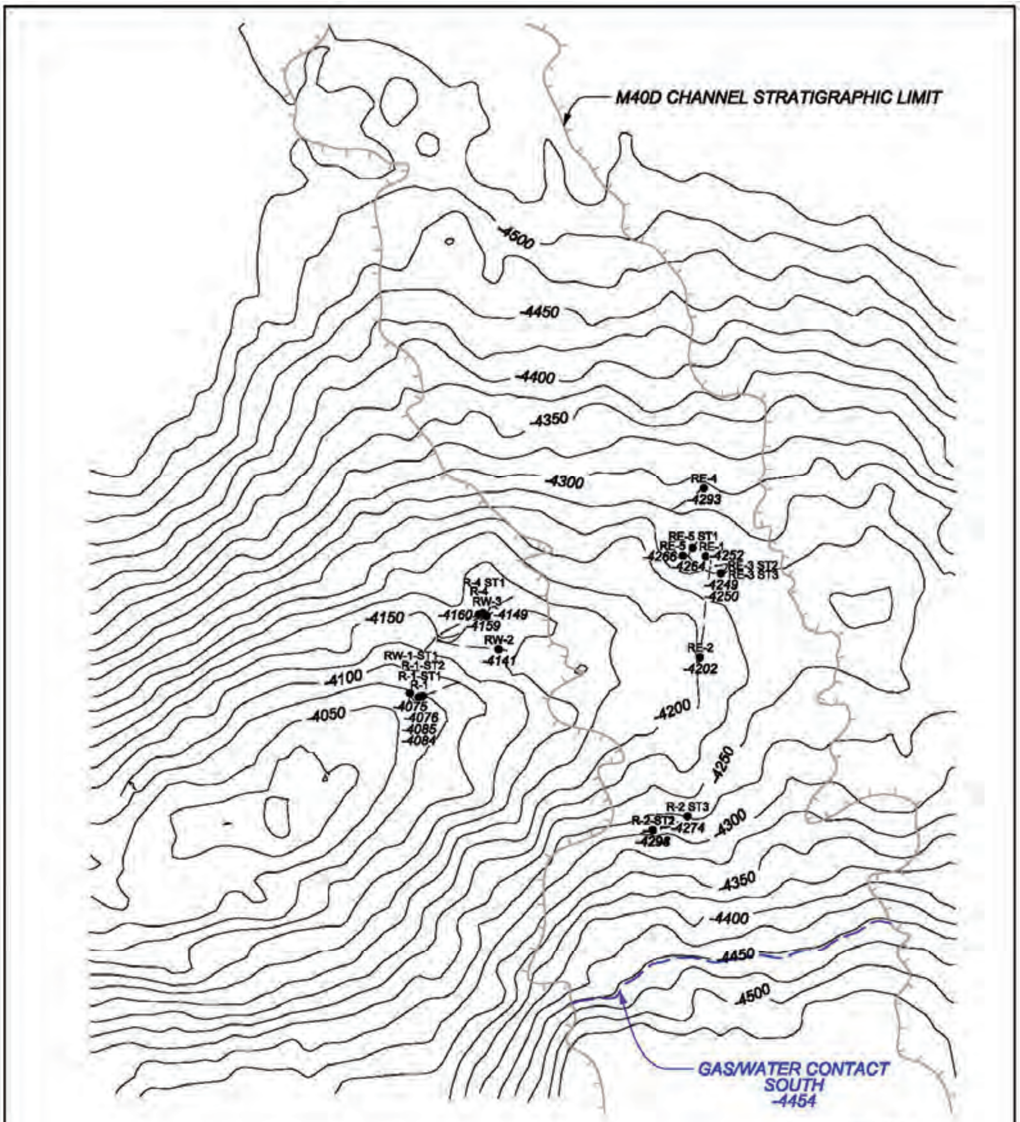


FIGURE EGY 6
STRUCTURE MAP
TOP of
M40D RESERVOIR
RAVEN FIELD
EGYPT
CONTOUR INTERVAL: 25 METERS
Scale
1000 0 1000
Meters
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716
December 2023

Reserves for the Raven field were estimated volumetrically. The recovery factors for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves in this area were estimated to be 60, 70, and 80 percent, respectively. The recovery and well performance estimates were based on well-test information acquired from the Raven field as well as analogy to other comparable fields in the region.

Raven West M40E Field

The Raven West M40E field is a gas field located several kilometers to the west of the main Raven field in the Mediterranean Sea approximately 65 kilometers northwest of Alexandria, Egypt. The field was discovered by the Raven West-3 ST1 well and is part of the North Alexandria Concession area. The water depth over the field ranges from 500 to 700 meters.

The main reservoir in the field is the Miocene (Langhian) M40E reservoir located at a depth of approximately 4,437 meters TVDSS. Although reservoir net thickness varies across the M40E channel complex, the average reservoir thickness is less than 20 meters. Reservoir properties are generally good; average porosity and S_w for the M40E reservoir were estimated to be greater than 18 percent and less than 29 percent, respectively.

The Raven West M40E field is scheduled to commence producing gas and condensate, under normal depletion, in 2025 through the Raven West-5 development well, which is currently being drilled. The production license expires on February 5, 2039. The produced gas will be routed to the existing Rosetta East facilities for processing with no substantial LPG production. The gas is anticipated to be rich with an estimated condensate yield of 30 bbl/10^6ft^3 based on analogy to the main Raven field.

Reserves for the Raven West M40E field were estimated volumetrically and take into consideration the expected deliverability of the Raven West-5 development well, which produces at a maximum rate of 50 million cubic feet per day. The recovery factors for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves in this area were estimated to be 60, 70, and 80 percent, respectively. The proved reserves were estimated to be zero based on economic considerations. The probable and possible reserves estimated for the field are classified as undeveloped because a significant amount of capital expenditures remain for drilling and completing the Raven West-5 development well. The recovery and well performance estimates were based on analogy to well-test information acquired from the Raven field as well as other comparable fields in the region. Reserves estimated herein are expected to be produced prior to the license expiration on February 5, 2039.

Raven West Serravallian 4 Field

The Raven West Serravallian 4 field is a gas field located several kilometers to the west of the main Raven field in the Mediterranean Sea approximately 65 kilometers northwest of Alexandria, Egypt. The field was discovered by the Raven West-3 ST1 well and is part of the North Alexandria Concession area. The water depth over the field ranges from 500 to 700 meters.

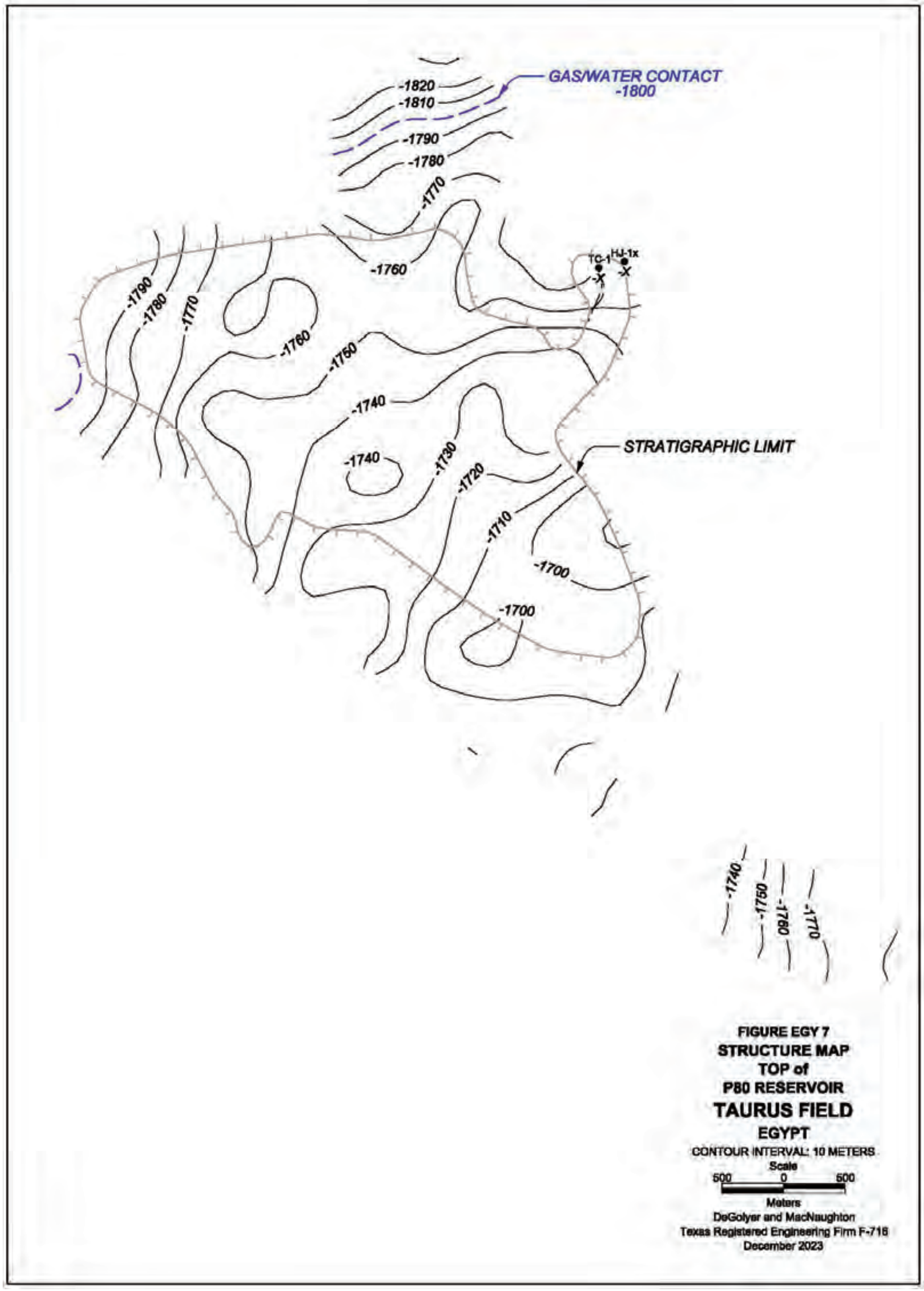
The main reservoir in the field is the Miocene Serravallian 4 reservoir located at a depth of approximately 3,592 meters TVDSS. Although reservoir net thickness varies across the Serravallian 4 channel complex, the average reservoir thickness is less than 15 meters. Reservoir properties are generally good; average porosity and S_w for the Serravallian 4 reservoir were estimated to be than 19 percent and less than 36 percent, respectively.

The Raven West Serravallian 4 field is scheduled to commence producing gas and condensate, under normal depletion, following drainage of the Raven West M40E reservoir through an uphole recompletion of the Raven West-5 development well, which is currently being drilled. The production license expires on February 5, 2039. The produced gas will be routed to the existing Rosetta East facilities for processing with no substantial LPG production. The gas is anticipated to be rich with an estimated condensate yield of 30 bbl/10^6ft^3 based on analogy to the main Raven field.

Reserves for the Raven West Serravallian 4 field were estimated volumetrically and take into consideration the expected deliverability of the Raven West-5 development well producing at a maximum rate of 50 10^6ft^3/d. The recovery factors for proved, proved-plus-probable, and proved-plus-probable-plus- possible reserves in this area were estimated to be 60, 70, and 80 percent, respectively. The proved reserves were estimated to be zero based on economic considerations. The probable and possible reserves estimated for the field are classified as undeveloped because a significant amount of capital expenditures remain for drilling and completing the Raven West-5 development well. The recovery and well performance estimates were based on analogy to well-test information acquired from the Raven field as well other comparable fields in the region. Reserves estimated herein are expected to be produced prior to the license expiration on February 5, 2039.

Taurus Field

The Taurus field is a gas field located in the Mediterranean Sea approximately 80 kilometers north-northwest of Alexandria, Egypt and is part of the West Nile Delta Concession area. The field was discovered by the HJ-1X exploration well in 2000 while testing gas in Pliocene channel sandstone reservoirs.



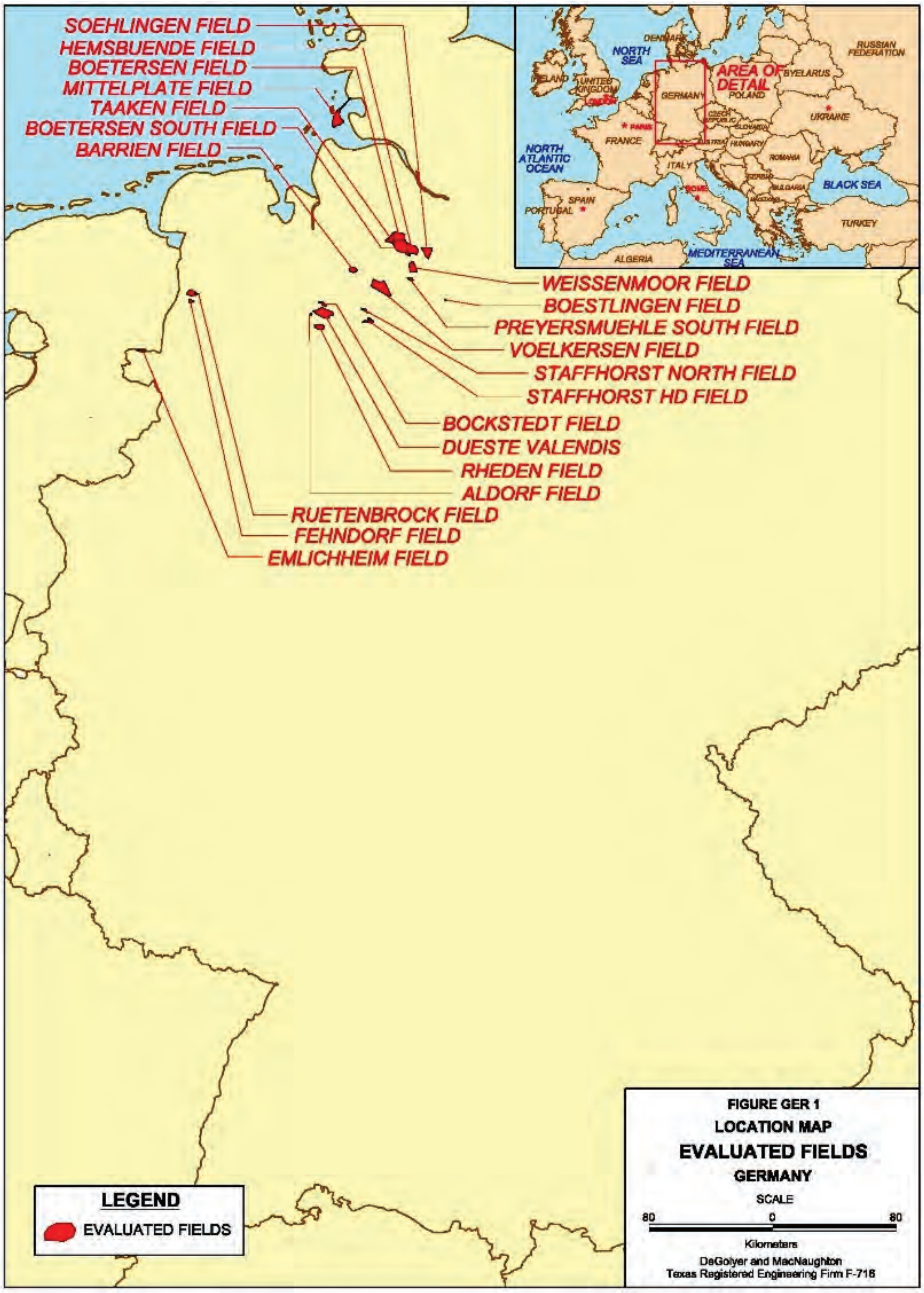
Additional appraisal wells were drilled in the field and confirmed the presence of gas-saturated channel sandstone reservoirs consisting of the P78 Channel, P78 Splay, P80 Splay, and P76 Levee reservoirs. The field is dominated by the P78 Channel complex, which trends southeast to northwest. The reservoirs range in depth from approximately 1,100 to 2,500 meters TVDSS. Figure EGY 7 presents a structure map on the top of the P80 reservoir in the Taurus field.

Production from the Taurus field began in March 2017. The field produces lean gas from six wells with a low CGR of less than 1 bbl/10^6ft^3. The P78 reservoir is the primary reservoir contributing to production. The produced gas is transported via pipeline to the existing Burullus onshore facilities and is then transferred to the Egyptian national grid via the Gasco export system. Condensate is metered at the Burullus facility and then exported via the Burullus condensate export system into the PPC pipeline.

Proved, probable, and possible developed reserves were estimated based on performance analysis of existing wells. No additional drilling is currently planned for the field. Reserves estimated herein are expected to be produced prior to the license expiration of March 24, 2037.

Germany

There are 20 fields located in Germany evaluated herein (Figure GER 1). Other than the Mittleplate field, reserves associated with the fields in Germany were projected to the economic limit and were not limited by license dates, as licenses are routinely extended to the economic limit in Germany. The Mittleplate field is expected to cease production at the license expiration date of December 31, 2041. The Emlichheim, Mittelplate, and Voelkersen fields are discussed in detail herein.



Emlichheim Field

The Emlichheim field is operated by Wintershall Dea and is located in the western Emsland region on the German-Dutch border. Production began in 1944. The field currently contains 69 producing wells and 9 injection wells, 5 of which are steam injection wells.

The Emlichheim field consists of a structural trap in the form of an anticline situated on the western part of an inversion axis that formed during Upper Cretaceous time. The Lower Cretaceous-age Bentheimer and Gildehaus sandstone reservoirs were deposited in a shallow marine environment and rest conformably atop the Wealden Formation. Overlying shelf mudstones, deposited during a global sea level rise, represent the seal for the two reservoirs. Porosity was estimated to range from 23 to 30 percent, initial S_w was estimated to range from 20 to 37 percent, and permeability was estimated to range from 300 to 15,000 millidarcys.

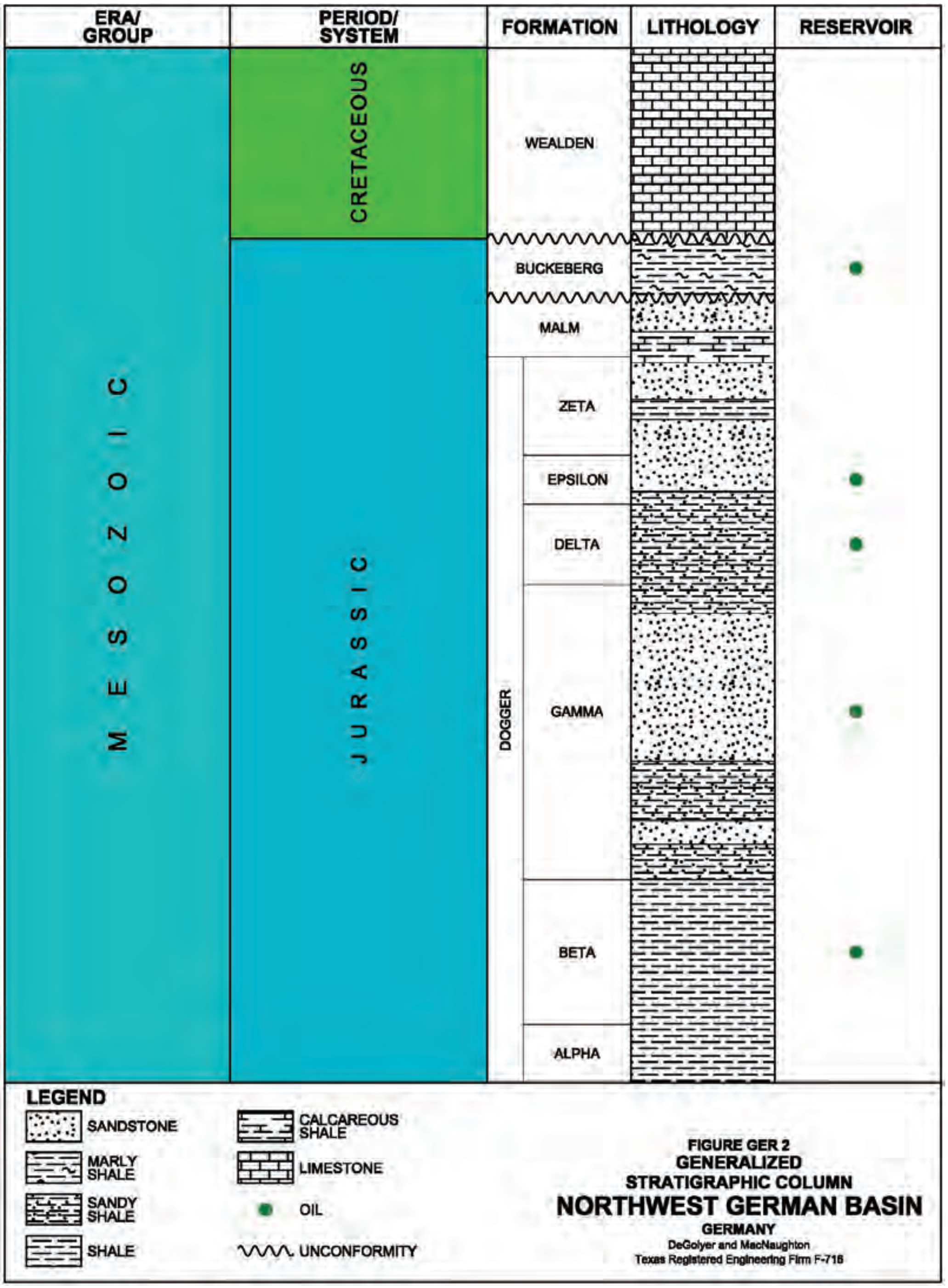
Production from the Bentheimer and Gildehaus reservoirs consists of 245 centipoise, 25 degrees API heavy oil. The initial reservoir pressure was 1,233 pounds per square inch (psi) in both reservoirs, with no aquifer pressure support, and an initial gas/oil ratio (GOR) of 73 cubic feet per barrel. The field was put under steam flooding in 1981, which will be converted to hot water injection after 2025.

Proved developed reserves were estimated by decline-curve analysis. Proved undeveloped reserves were estimated by applying a recovery factor to the estimated OOIP and limiting future development well counts and production rates to those provided in the development plans provided by Wintershall Dea. Probable and possible incremental reserves were also estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

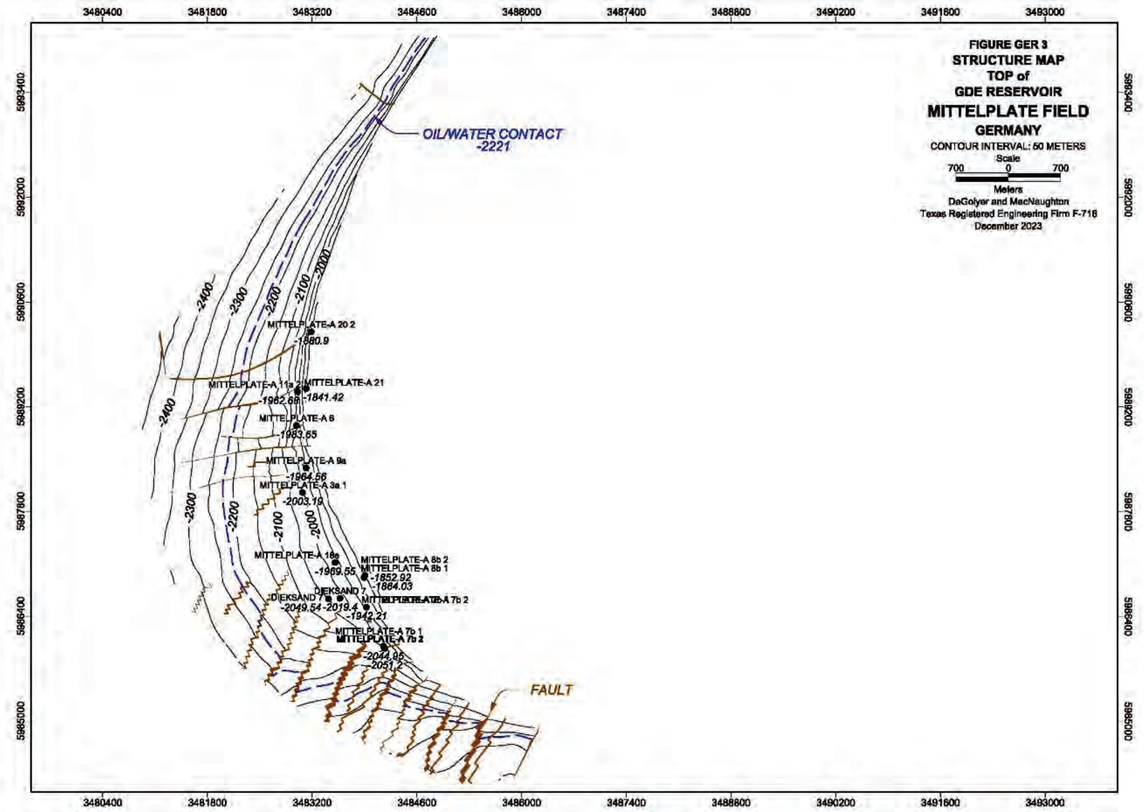
Mittelplate Field

The Mittelplate field is operated by Wintershall Dea and is located 7 kilometers off the German North Sea coast on the southern edge of the Wadden Sea national park in the State of Schleswig-Holstein, Germany.

The field was discovered in 1981 through the Mittelplate 1 well, where oil was discovered in the Jurassic-age Dogger sandstone (Figure GER 2). The field began production in 1987 and currently has 27 producing wells and 10 injection wells. Offshore operations are conducted from the Mittelplate artificial island, a drilling and production facility built in 1985, and onshore operations began in 2000 from the Dieksand production facility.



The Mittelplate structure consists of a three-way closure against a salt dome that flanks the field to the east (Figure GER 3). The field is productive from the Jurassic-age Dogger Beta, Dogger Gamma/Delta/Epsilon, and Lower Cretaceous-age Buckeberg sandstone reservoir (not currently on production). These reservoirs were deposited in a shallow marine setting and represent tide-dominated deltaic facies.



Porosity was estimated to range from 19 to 23 percent, initial S_w was estimated to range from 17 to 27 percent, and average permeability was estimated to range from 800 millidarcys in the Beta reservoir to up to 7 darcys in the Delta reservoir.

Oil quality varies from 19 degrees API in the Beta reservoir to 26 degrees API in the Gamma/Delta/Epsilon reservoirs. Initial reservoir pressure was 4,365 psi in the Beta reservoir with a weak aquifer drive mechanism and 3,394 psi in the Gamma/Delta/Epsilon reservoirs with a strong aquifer drive. Water injection provides pressure support in all reservoirs.

Proved developed producing reserves were estimated by decline-curve analysis and undeveloped reserves were estimated using type wells. Probable and possible incremental reserves were also estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

Voelkersen field

The Voelkersen field was discovered in 1992 and began producing in 1994. The field produces from 14 wells. Production has occurred from four reservoirs: Havel, Niendorf, Wustrow, and Heidburg. The Havel reservoir is the largest contributor. Reserves were estimated based on performance analysis of the field.

Libya

The Al-Jurf field in Libya was evaluated herein, and reserves projections include a 5-year extension to the license date of April 10, 2035, to April 10, 2040. The location of the Al-Jurf field is shown on Figure LIB 1.

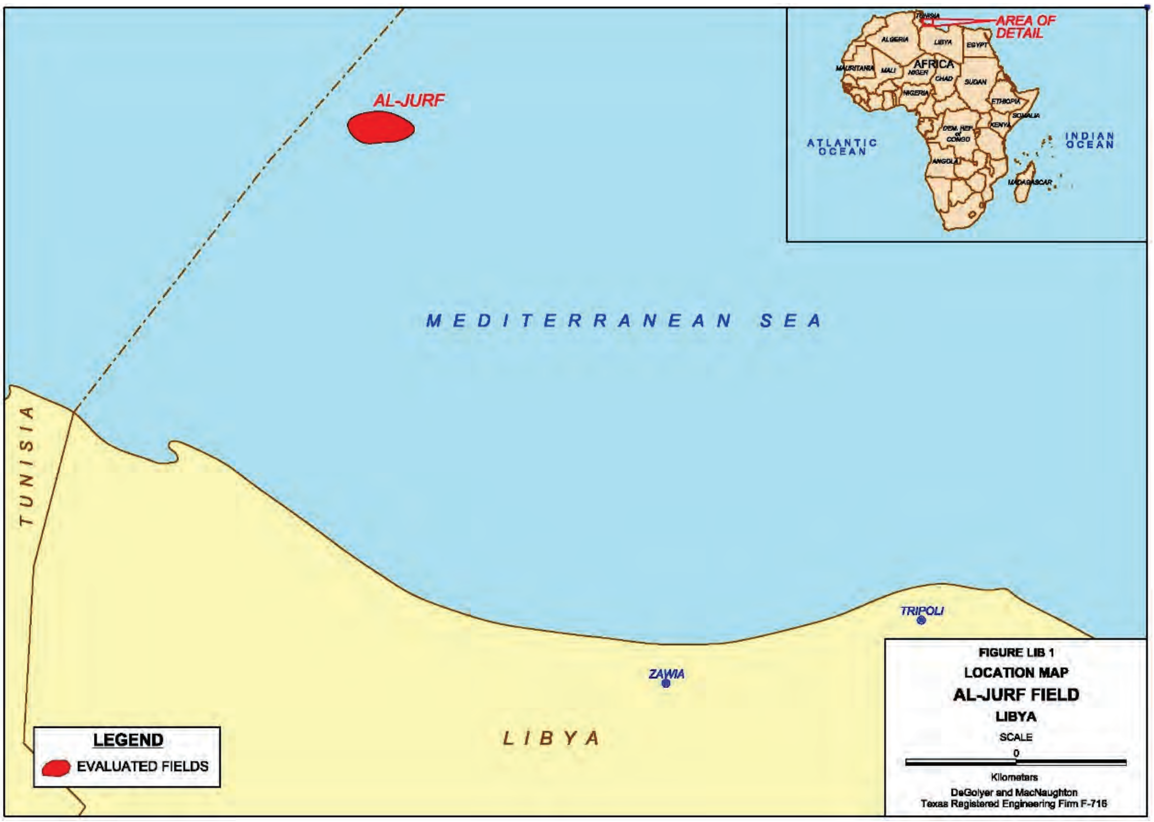


FIGURE LIB 1
LOCATION MAP
AL-JURF FIELD
LIBYA

Al-Jurf Field

The Al-Jurf field commenced production in 2003 and 13 wells have been drilled to date. Developed reserves estimates were based on performance analysis of the producing wells, and no future development is planned. Probable and possible reserves estimates were based on better well performance than projected for proved reserves.

Mexico

There are seven fields within Mexico evaluated herein: Chinwol, Hokchi, Kan, Naajal, Ogarrio, Polok, and Zama (Figure MEX 1). Reserves associated with the fields in Mexico were limited to those to be recovered by the license dates with no consideration given to license extensions. The Hokchi and Ogarrio fields are discussed in detail herein.

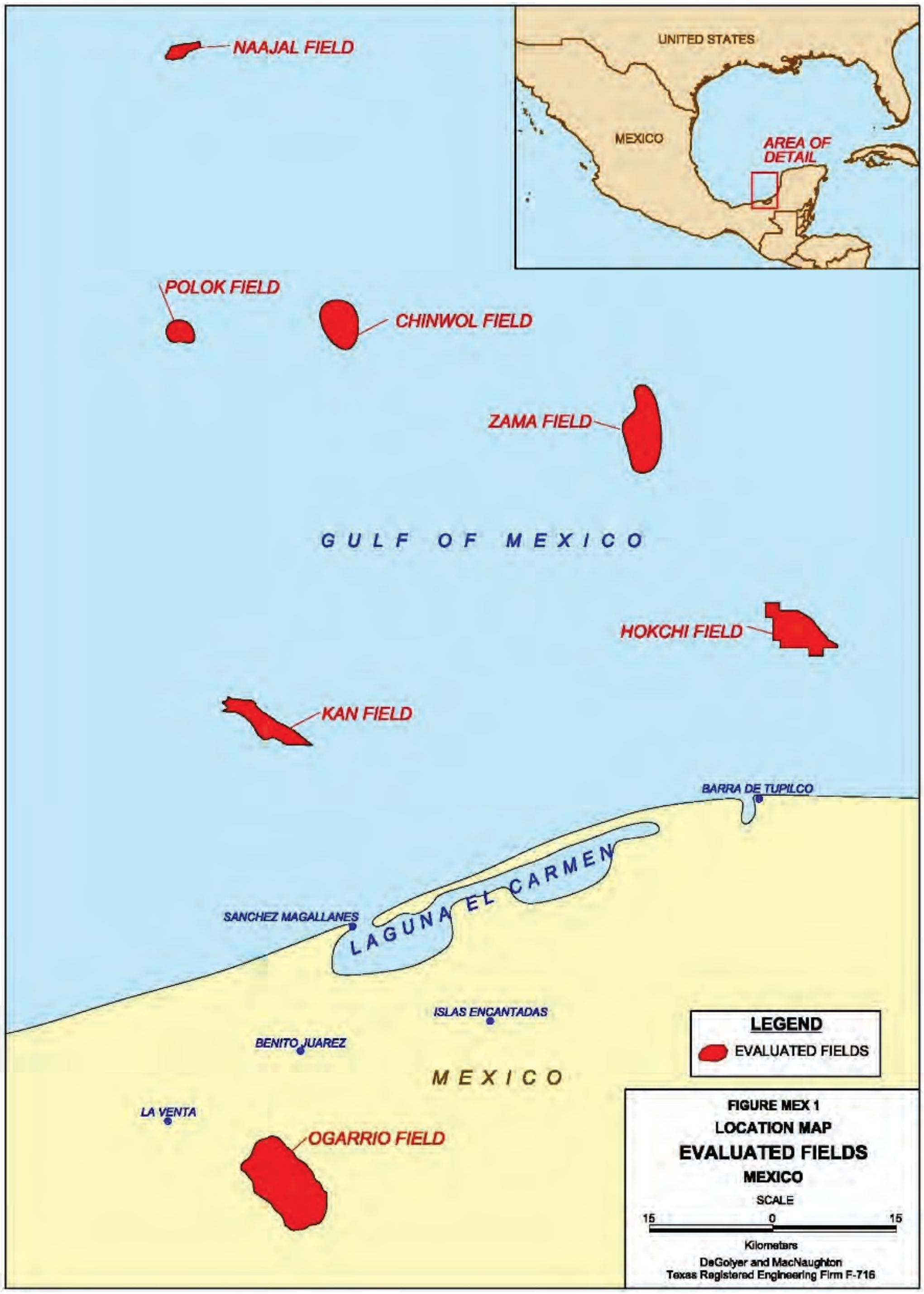


FIGURE MEX 1
LOCATION MAP
EVALUATED FIELDS
MEXICO

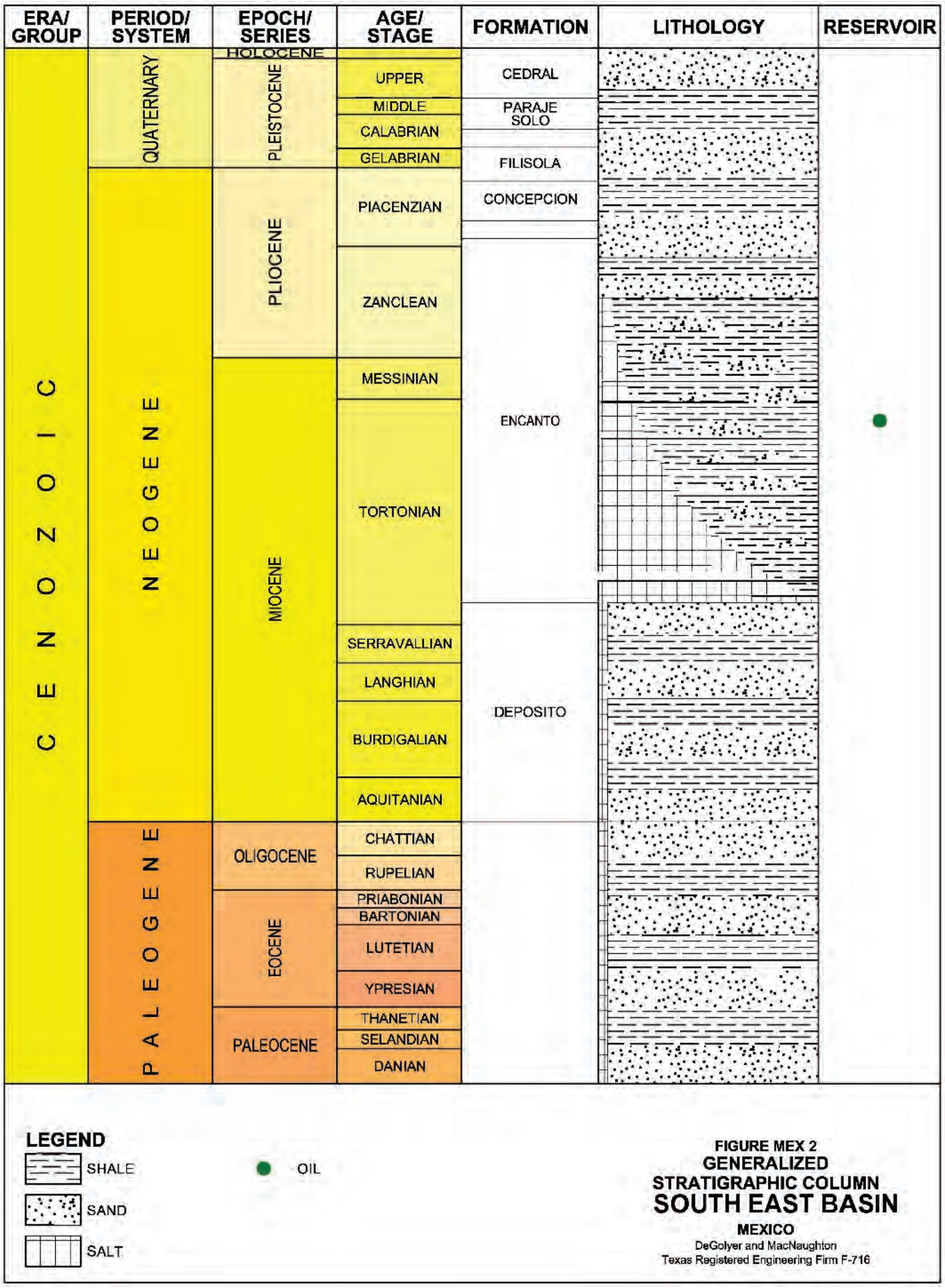


FIGURE MEX 2
GENERALIZED
STRATIGRAPHIC COLUMN
SOUTH EAST BASIN
MEXICO
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

<u>Hokchi Field</u>

The Hokchi field is located offshore, approximately 27 kilometers northwest of the city of Dos Bocas, in a transitional position between the Salina del Este and Comalcalco Sub-Basins. The average water depth is around 30 meters.

Pemex's exploratory activity in the area, leading to the discovery of the Hokchi field, was aimed primarily at investigating the petroleum potential of the middle Miocene and Pliocene interval, as represented by the turbiditic-origin clastic deposits, that constitute the reservoir rock of the field.

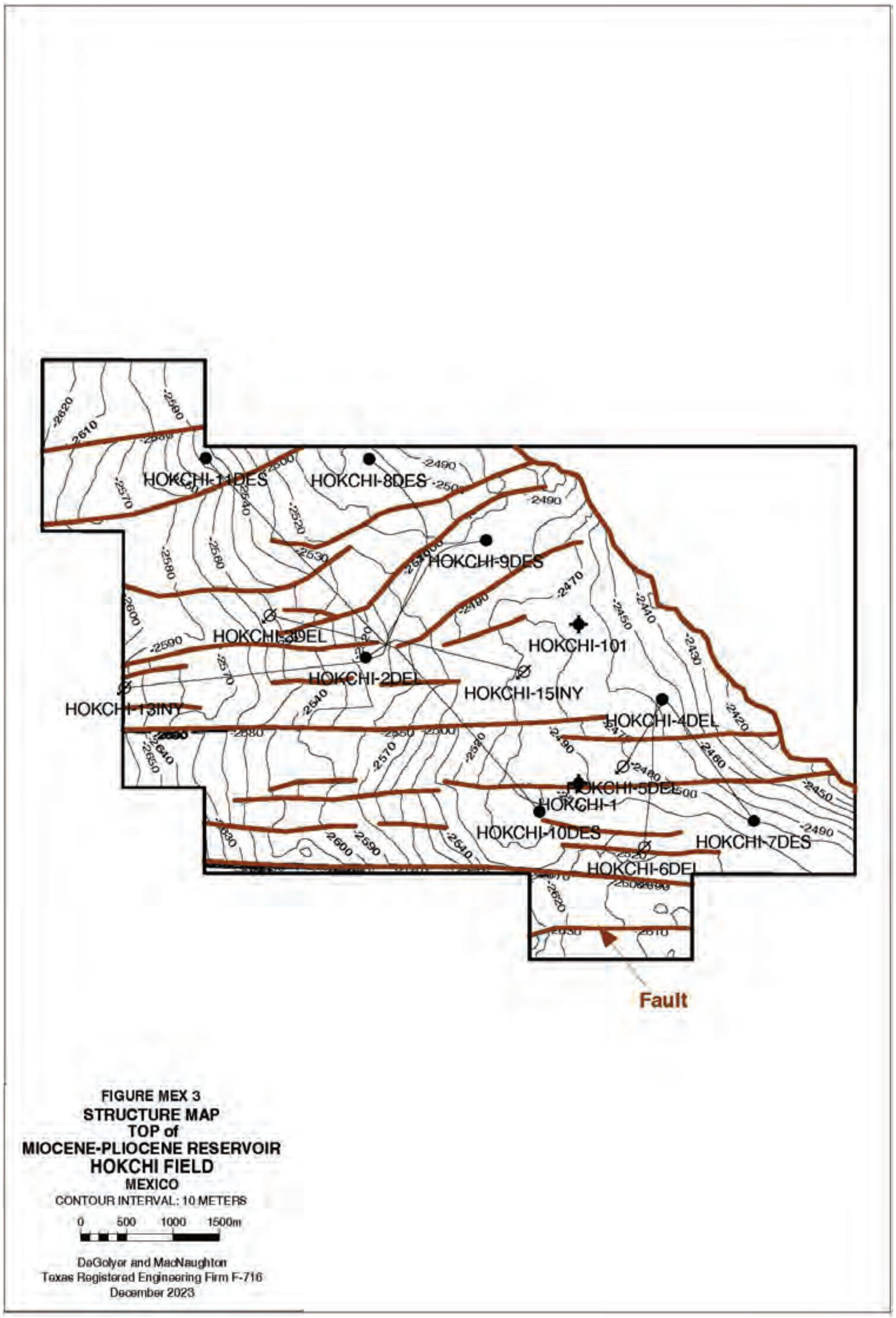
Seven wells were drilled in the Hokchi area during exploration and appraisal phases. Two of those wells were drilled by Pemex during the exploratory phase between 2009 and 2011 (Hokchi-1 and 101). Both were permanently abandoned. The remaining five wells (Hokchi-2DEL, 3-DEL, 4-DEL, 5-DEL, and 6-DEL) were drilled by Hokchi Energy between 2016 and 2017, during the evaluation phase, and all were temporarily abandoned in all cases.

The reservoir rock consists of a section of fine-grained sandstones (Figure MEX 2) with a thickness of up to 40 meters with around 10-percent clay matrix and carbonate cement, moderate to good sorting, angular to subangular clasts, and predominantly intergranular porosity. It includes intercalations of gray sandy shales in beds that are 1 to 3 meters thick. Overall, the interval does not show a clearly defined vertical granulometric trend. From a petrophysical perspective, the average porosity of the reservoir, based on laboratory measurements and petrophysical log analysis, was estimated to be about 25 percent, and permeability was estimated to range between 100 and 700 millidarcys with an average of 250 millidarcys. Sampled oil gravity varies from 22 to 29 degrees API.

The trapping mechanism is both structural and stratigraphic and is the result of salt tectonics. To the north, the accumulation is defined by a normal fault with inclination in the same direction, while the southern limit is associated with another fault, in this case, inclined to the south (Figure MEX 3). The eastern limit of the field is stratigraphic, a result of wedging of the different sandy intervals that make up the reservoir rock eastward, where a salt diapir is located. Finally, the western limit of the field is determined by the end of the accumulation and the contact with the corresponding aquifer for each sandy interval.

The geological structure of Hokchi corresponds to the axial zone of an anticline (Figure MEX-3). Such a structure is the result of the inversion of the inclination direction of synclinal limbs due to the collapse and evacuation of salt diapirs that previously limited the depocenter.

The Hokchi field started production in May 2020. By the end of 2023, the field was producing at rates of 23,000 barrels per day of oil and approximately 9 million cubic feet per day of gas. Water injection started in April 2023. Wells were drilled from two wellhead platforms in water depths of around 30 meters. No further wells are envisioned in the current development plan. The artificial-lift system consists of electric submersible pumps (ESP). Multiphase production is processed at an onshore plant that also provides the platforms with injection water and electrical power services.



Proved reserves were estimated by applying a recovery factor to the estimated OOIP considering future production rates. Probable and possible incremental reserves were also estimated associated with incremental recovery greater than quantities estimated for proved and probable reserves, respectively. The field is considered to be fully developed.

Ogarrio Field

The Ogarrio field is operated by Wintershall Dea and is located in the Ogarrio Contract Area in the central-eastern region of the Salina del Istmo Basin, southeast Mexico. The field is divided into two blocks, Block A to the southwest and Block BC to the northeast, due to a salt intrusion that structured the area into two independent accumulations (Figure MEX 4). The discovery and development of this field began in 1957 with the drilling of the Ogarrio-1 well in the Block BC area.

The producing reservoirs in this field are Tertiary sandstones of upper Miocene age of the Encanto Formation (Figure MEX 2). These clastic reservoirs were originally associated with a variety of sub-environments, deepwater turbidities, and submarine fans deposited in the Miocene slope basin. This formation was affected by salt tectonics, which contributed to the generation of normal faults and, together with the top of the salt dome, work as seals for this field.

In the Encanto Formation in the Ogarrio field, average S_w values for Block A and Block BC were estimated to be 28 and 30 percent, respectively. The average effective porosity in both blocks was estimated to be approximately 22 percent, and the average permeability was estimated to range from 60 to 136 millidarcys in both blocks. The average gross thickness is 805 and 975 meters for Block A and Block BC, respectively. The average net thickness is 29 and 71 meters for Block A and Block BC, respectively.

The reservoir fluid is black oil and has a density varying from 36 to 39 degrees API. The viscosity ranges from 0.3 to 0.5 centipoise, and the initial GOR is approximately 1,180 cubic feet per barrel. The initial pressure is approximately 4,150 psi and the bubblepoint pressure is 2,830 psi.

By the end of 2023, a total of 234 million barrels of oil had been recovered from the field, corresponding to a recovery factor of 18 percent. In December 2023, the field was producing at average rates of 4,900 barrels per day of oil and 8 million cubic feet per day of gas from 91 wells. Production forecasts are in accordance with the expected activity levels as stated in the Ogarrio field development plan, performance review of individual active wells, 101 well interventions carried out in 2022 and 2023, and the results of new wells.

Proved developed producing reserves were estimated using performance-based methods, primarily decline-curve analysis of oil rate versus time of individual wells and oil rate versus cumulative oil production. Developed non-producing and undeveloped reserves were estimated by analogy (type-well analysis) with nearby wells producing from the targeted reservoirs. Probable and possible incremental reserves were also estimated associated with incremental recovery above quantities estimated for proved and probable reserves, respectively.

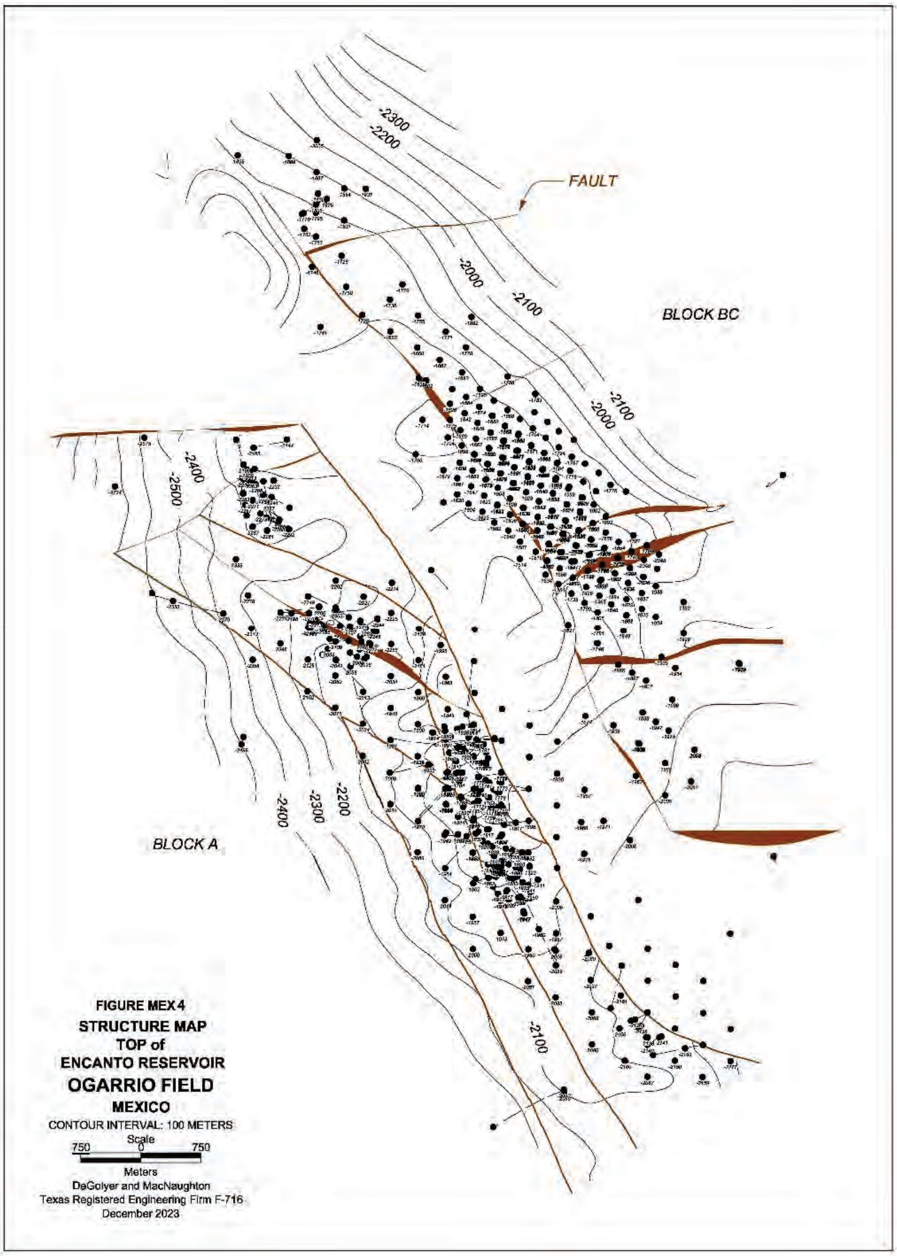
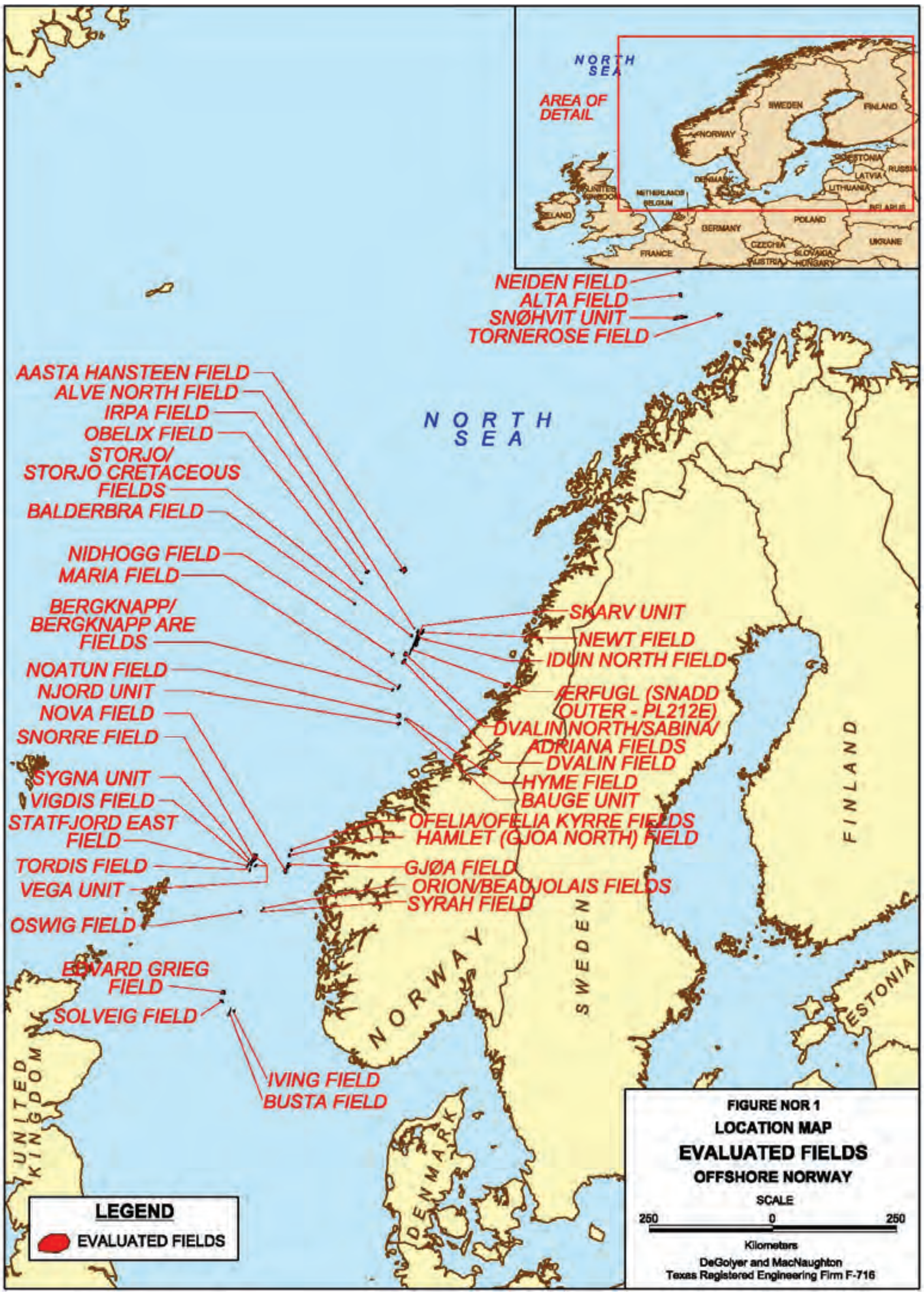


FIGURE MEX 4
STRUCTURE MAP
TOP of
ENCANTO RESERVOIR
OGARRIO FIELD
MEXICO
CONTOUR INTERVAL: 100 METERS

Norway

There are 46 fields located within Norway evaluated herein (Figure NOR 1). Reserves associated with the fields in Norway were projected to the economic limit and were not limited by license dates, as licenses are routinely extended to the economic limit in Norway. Production occurs mainly from Jurassic and Cretaceous reservoirs as noted in the stratigraphic column below (Figure NOR 2). Selected fields are discussed in detail herein.



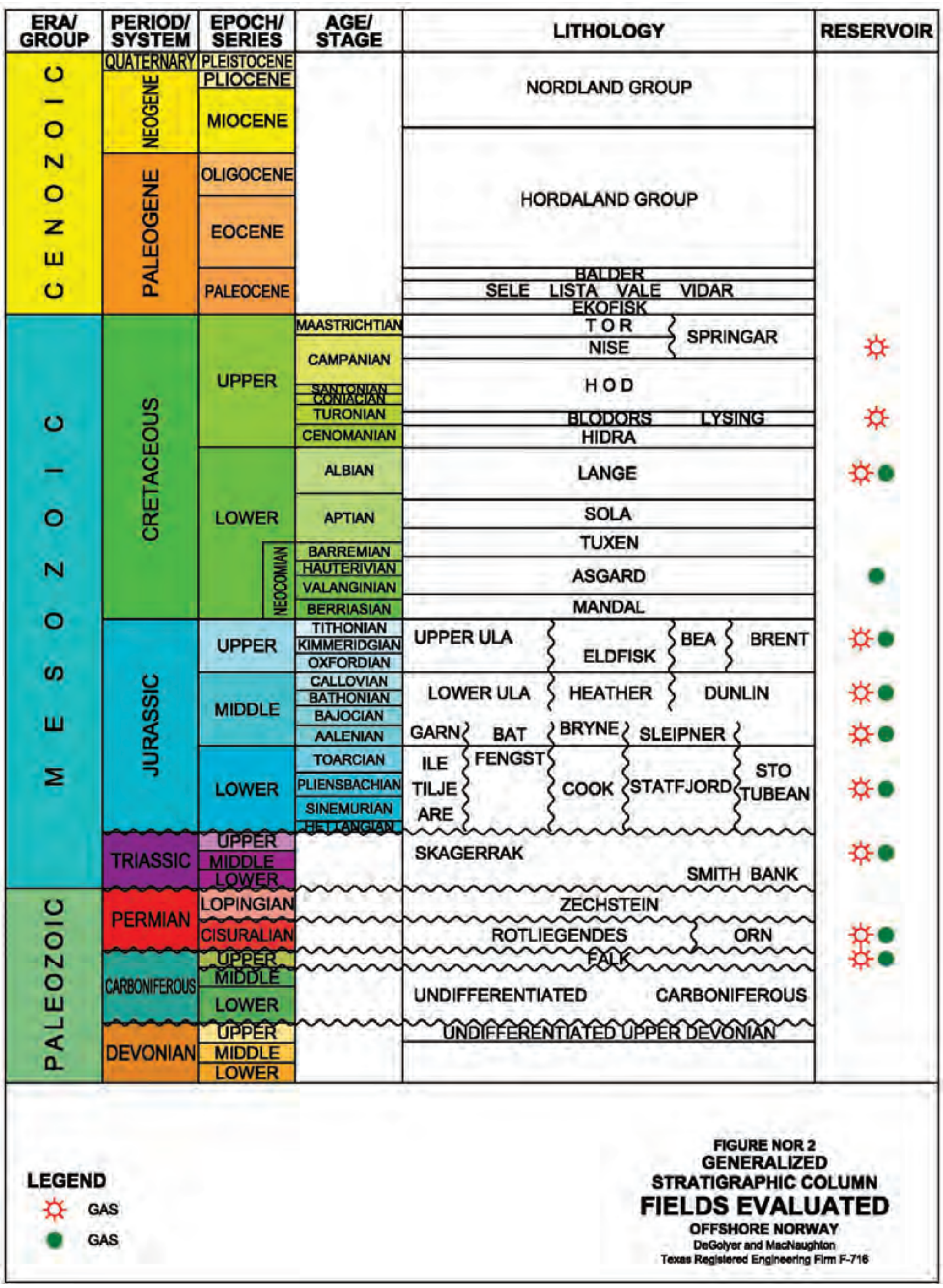


FIGURE NOR 2
GENERALIZED
STRATIGRAPHIC COLUMN
FIELDS EVALUATED
OFFSHORE NORWAY
DeGolyer and MacNaughton
Texas Registered Engineering Firm F-716

Aasta Hansteen Field

The Aasta Hansteen field is located in PL218 and PL218B of the Norwegian North Sea, approximately 300 kilometers offshore in 1,260 meters of water. The field was discovered in 1997 when well 6707/10-1 was drilled into the Upper Cretaceous-age, gas-charged Nise Formation. The structure is composed of four tilted fault blocks: Haklang, Luva, Snefrid North, and Snefrid South. The primary trapping mechanism within the field is composed of three-way or four-way closures associated with these tilted fault blocks (Figure NOR 3).

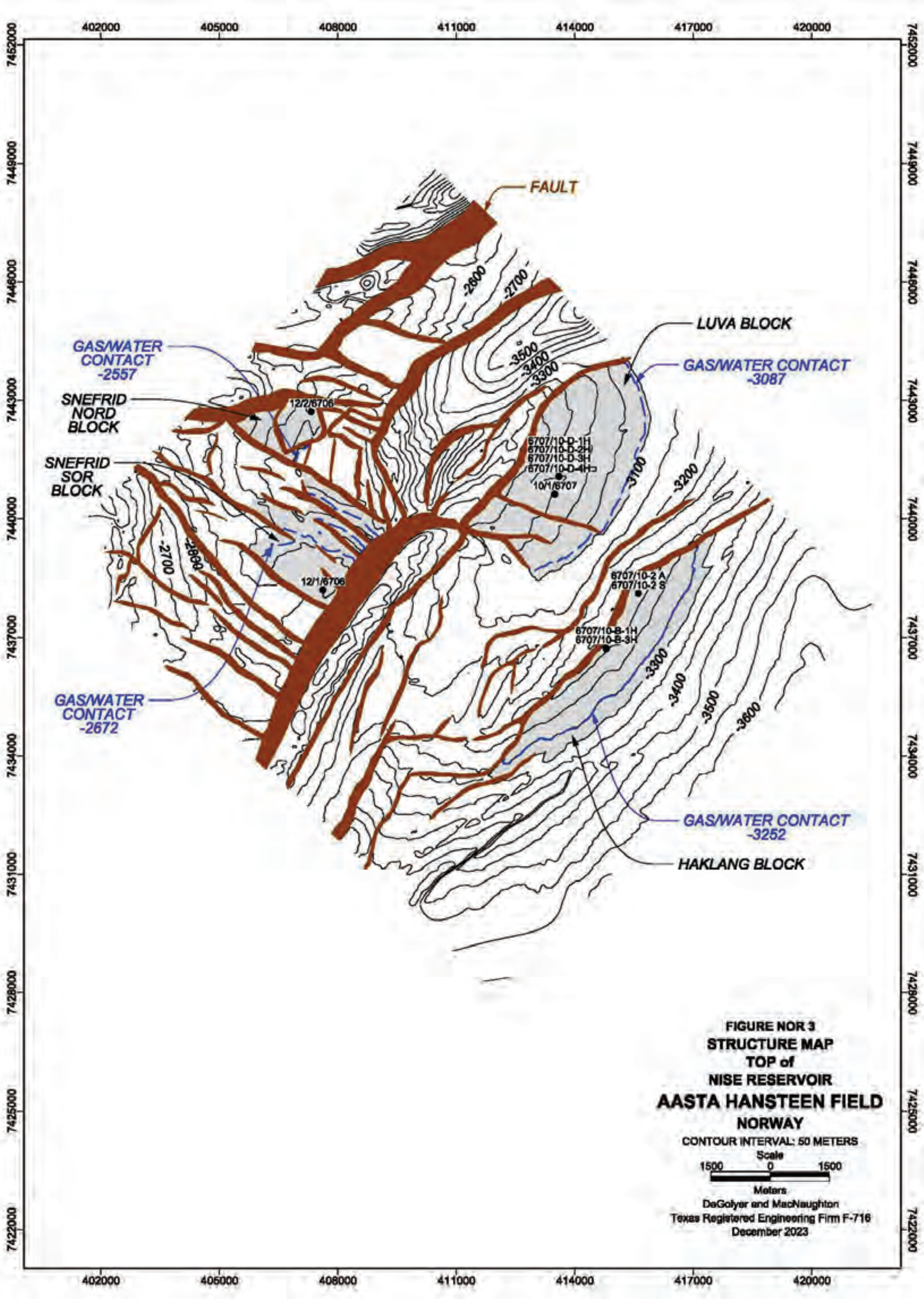


FIGURE NOR 3
STRUCTURE MAP
TOP of
NISE RESERVOIR
AASTA HANSTEEN FIELD
NORWAY

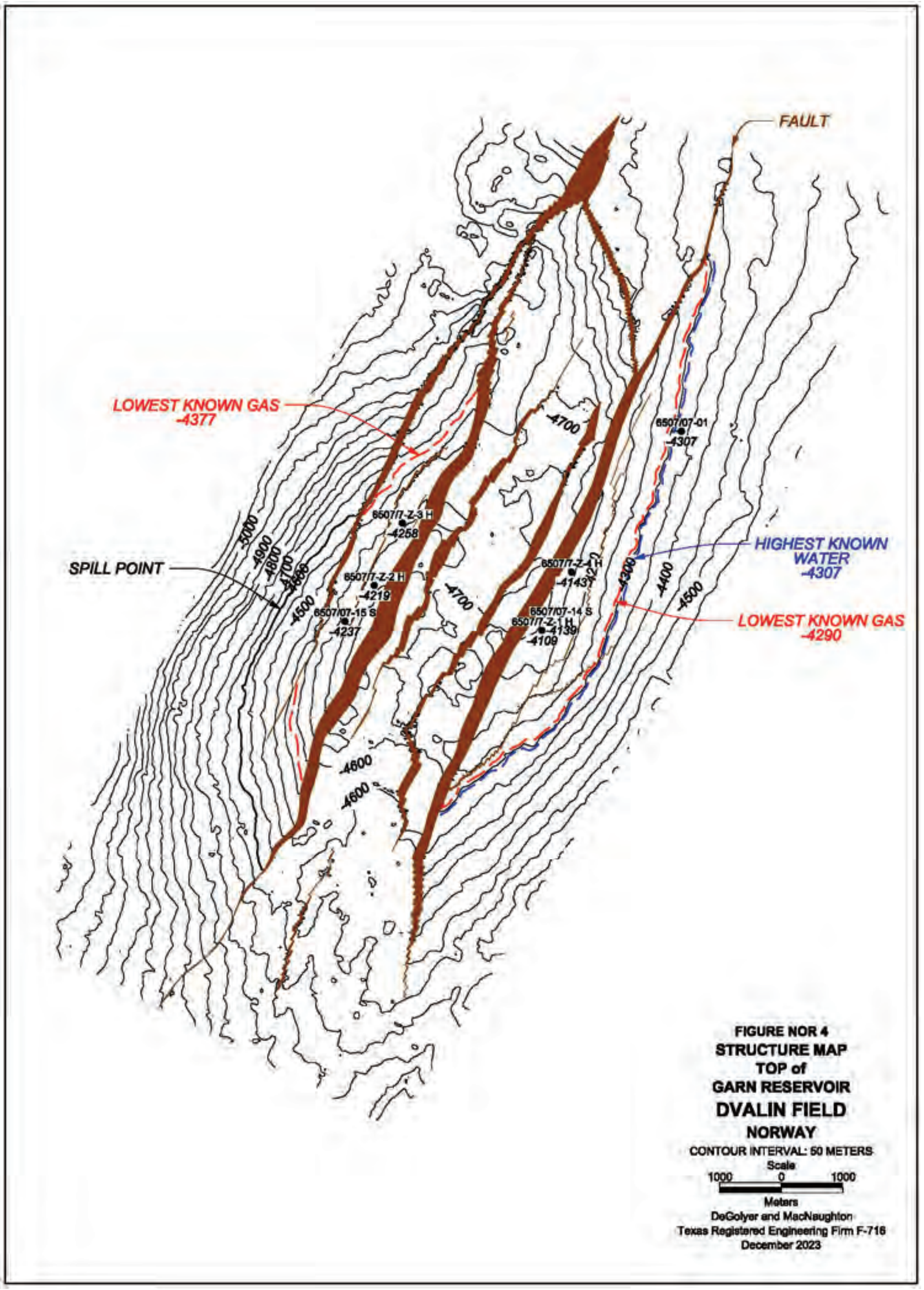
The Nise Formation is composed of unconsolidated turbidite sands sourced from the Western Greenland Margin. The sands were deposited in a deep, bathyal paleoenvironment. At the Aasta Hansteen field, reservoir porosity was estimated to range from 24 percent in the Snefrid North Block to 30 percent in the Snefrid South Block. The GWCs differ between the four fault blocks: 3,087 meters true vertical depth subsea (TVDSS) in the Luva Block; 3,252 meters TVDSS in the Haklang Block; 2,672 meters TVDSS in the Snefrid South Block; and 2,557 meters TVDSS in the Snefrid North Block.

The last development well, E-1 HT2, was completed in the main portion of the field in November 2018, and production started in December 2018. The field produces gas and a small amount of condensate; gas is transported via the Polarled pipeline to the Nyhamna gas processing facility and condensate is stored on the SPAR platform and offloaded to shuttle tankers.

Proved, probable, and possible reserves were estimated volumetrically with recovery factor estimates ranging from 69 to 82 percent based on depletion drive. A total of eight wells were drilled in the development of the Haklang, Luva, Snefrid South, and Snefrid Nord structures. Estimates of future performance from the wells took into account sales capacity constraints and expectations of future production efficiency.

<u>Dvalin Field</u>

The Dvalin field, formerly known as the Zidane field, is located northwest of the Heidrun field in the Norwegian North Sea and is operated by Wintershall Dea. The field is a faulted anticline that is separated into western and eastern accumulations (Figure NOR 4). The eastern accumulation was discovered in 2010 and the western accumulation was discovered in 2012. The development targets in the field are the Jurassic-age Garn and Ile sandstones, which produce gas and condensate. The Garn is the larger of the two reservoirs and has more favorable reservoir characteristics. The average NGR in the Garn reservoir is approximately 90 percent, and the Ile reservoir has an average NGR of approximately 50 percent. Permeability of the Garn Formation was estimated to range from 0.1 to 1,000 millidarcys with an average of approximately 100 millidarcys. Permeability of the Ile reservoir permeability was estimated to range from 0.01 to 1 millidarcy. Average porosity in the Garn and Ile reservoirs was estimated to be approximately 10 percent and S_w was estimated to range from 17 to 40 percent.



The Dvalin field began producing to the Heidrun facilities in 2020. Proved, probable, and possible reserves were estimated using volumetrics. The OGIP associated with proved reserves in this accumulation considers a vertical limit at the lowest known gas seen in the discovery well. The proved-plus-probable-plus-possible scenario considers the structure to be gas saturated to the structural spillpoint. The proved-plus-probable scenario considers a vertical limit at a depth halfway between the lowest known gas and the spillpoint of the structure. Recovery factors were estimated to range from 74 to 76 percent based on estimated abandonment pressures.

Dvalin North

The Dvalin North field is located approximately 10 kilometers north of the Dvalin field in the Norwegian North Sea and is operated by Wintershall Dea. The field is a faulted closure with three blocks: East, Graben, and West. The 6507/4-2S discovery well was drilled in the East block in 2021. The development target in the field is the Jurassic-age Garn Sandstone, which contains gas and condensate.

The average NGR in the Garn reservoir was estimated to be approximately 90 percent. Permeability in the Garn Formation was estimated to range from 0.01 to 2,000 millidarcys with an average of approximately 10 millidarcys. Average porosity in the Garn reservoir was estimated to range from approximately 12 to 15 percent and average S_w was estimated to range from approximately 20 to 25 percent.

The Dvalin North development will consist of three slanted producing wells tied back to the Dvalin field, which will be produced to the Heidrun facility. Dvalin North production will be combined with production from the Dvalin field to maintain a production plateau rate based on facility capacity.

Proved, probable, and possible reserves were estimated using volumetrics, and each fault block was considered separately for recovery. Successive fault blocks farther away from the drilled discovery well are less certain to contribute to recovery based on current data. Recovery factors may range up to 76 percent based on estimated abandonment pressure.

Irpa Field

The Irpa field is a single-well discovery located in the Voring Basin approximately 70 kilometers west of the Aasta Hansteen field. The field was discovered in 2009 by well 6705/10-1, which encountered gas in the turbidite sands of the Late Cretaceous-age Springar Formation. The Irpa structure is defined by a northeast-trending, double-plunging anticline with stratigraphic pinchouts to the northwest and southeast. A GWC was observed at 3,276 meters TVDSS. Due to the depositional environment and lack of well control, uncertainties in lateral reservoir continuity were the primary consideration for estimating recovery.

Reserves associated with the Irpa field were estimated by applying a recovery factor to the estimated OGIP and limiting future development well counts and production rates to those provided in the development plans provided by Wintershall Dea. The Irpa field is currently being developed as a tie-in to Aasta Hansteen.

<u>Maria Field</u>

The Maria field is located in the Norwegian North Sea and is operated by Wintershall Dea. The field is a one-accumulation stratigraphic trap with two structural highs to the north and south separated by a structural low. The Maria field was discovered in 2010 and has been producing since 2017. The development target in the field is the Jurassic-age, oil-bearing Garn Formation. The sandstones of the Garn Formation were deposited in a shallow marine progradational depositional setting.

The NGR in the Garn ranges from 55 to 85 percent with an average of 70 percent. Permeability was estimated to range from 1 to 1,000 millidarcys with an average of 150 millidarcys, porosity was estimated to range from 11 to 18 percent with an average of 14 percent, and S_w was estimated to range from 15 to 60 percent with an average of 40 percent.

Nine wells have been drilled to develop the Maria field, plus three exploration wells. Water used for water injection is supplied from the Heidrun platform and gas used for gas lift is supplied from the Åsgard B platform. Oil is transported through the Kristin platform to the Åsgard C offloading and export facility.

Reserves for the Maria field were estimated based on volumetric analysis. The recovery factors for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were estimated to range from 28 to 43 percent.

<u>Njord Field</u>

The Njord field is located in the Norwegian Sea, 30 kilometers west of the Draugen field in a water depth of 330 meters, and is operated by Equinor ASA. The Njord field was discovered in 1986 through the 6407/7-1 S well, where oil was discovered in the Jurassic-age Tilje, Ile, and Åre Formations. The field consists of a highly faulted anticlinal structure with fluid contacts that vary by fault block. The Tilje Formation was deposited in a fluvial-tidal environment with some shallow marine influence, while the Ile Formation was deposited in a shallow tidal marine environment. The Åre Formation was deposited in a fluvial setting.

For the Tilje Formation, porosity was estimated to range from 16 to 19 percent with an average of 17 percent and S_w was estimated to range from 36 to 37 percent with an average of 37 percent.

For the Ile Formation, porosity was estimated to range from 16 to 19 percent with an average of 18 percent, permeability was estimated to range from 7 to 287 millidarcys with an average of 101 millidarcys, and S_w was estimated to range from 36 to 37 percent with an average of 37 percent.

For the Åre Formation, porosity was estimated to range from 14 to 16 percent with an average of 15 percent, permeability was estimated to range from 1 to 35 millidarcys with an average of 24 millidarcys, and S_w was estimated to range from 53 to 55 percent with an average of 54 percent.

The Njord field began production in 1997 and currently consists of nine producing wells and two injection wells. The field produces through the Njord A production platform and exports through the Njord Bravo storage and offloading facility. The field was temporarily shut in for new drilling, upgrades, and repairs in 2016. Production was re-established in December 2022.

Reserves for the Njord field were estimated based on volumetric analysis. The recovery factors for the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were estimated to range from 20 to 25 percent for the oil-producing formations and from 50 to 60 percent for the gas-producing formations.

Nova Field

The Nova field is an oil and gas field located in the northeastern North Sea, 17 kilometers from the Gjøa platform, and is operated by Wintershall Dea. The field is a faulted, angular unconformity trap consisting of several fault blocks. The Nova field was discovered in 2012 and appraised in 2013 and 2014. Production began in 2022. The development targets in the field are the Middle Oxfordian- and Bathonian-age deepwater turbidite Heather sandstone reservoirs.

The NGR in the Intra Heather sandstone reservoirs ranges from 55 to 80 percent with an average of 70 percent. Porosity was estimated to range from 1 to 24 percent with an average of 14 percent, permeability was estimated to range from 0.01 to 1,000 millidarcys with an average of 200 millidarcys, and S_w was estimated to range from 10 to 60 percent with an average of 30 percent.

The Nova field is tied back to the Gjøa platform for processing and export. The Gjøa platform also provides lift gas to the field and water injection for pressure support.

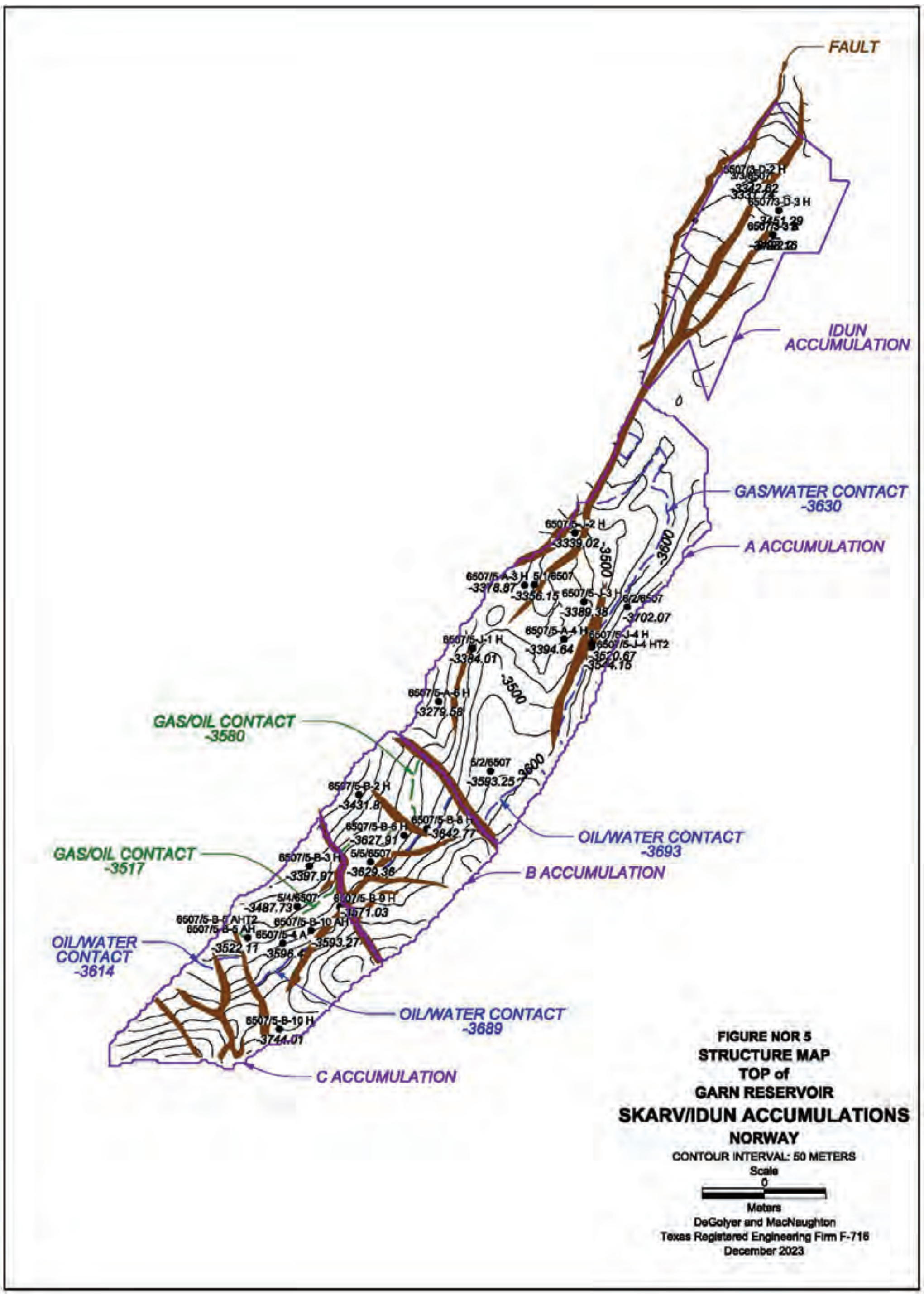
Reserves estimates for the Nova field were based on volumetric analysis and performance to date. The recovery factors for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were estimated to range from 29 to 45 percent.

Skarv Unit

The Skarv Unit in inclusive of three Skarv accumulations (A, B, and C) as well as the Ærfugl, Gråsel, and Idun accumulations, but does not include the Idun North or Ærfugl North discoveries, which are separate accumulations north of the Skarv and Idun structures on a separate license.

The Skarv field, inclusive of Idun, (Figure NOR 5) was discovered in 1998 and the plan for development and operation was approved in June 2007. Production began in 2013 to a floating production, storage, and offloading vessel (FPSO) which services the subsea templates of the Skarv Unit, as well as tie-backs off license. Similar to a number of fields in this area, the field produces a combination of gas, LPG, condensate, and oil. The produced oil and condensate are comingled on the FPSO for storage and export, and the LPG is extracted from the rich gas export stream at the Karsto plant onshore.

The Skarv field contains four producing wells and two injection wells in Accumulation A, two producing wells and one converted gas producer well in Accumulation B, and two producing wells and one injection well in Accumulation C. The Idun accumulation was historically produced from two gas wells, both of which are shut-in. Gas was historically injected into all three of the Skarv accumulations, but now only Accumulation A has active injection for pressure support; however, injection is expected to end in the near future. Undeveloped reserves were estimated for the planned gas blowdown to start subsequent to the end of injection. Fuel gas and costs were allocated among the fields (including Ærfugl) contributing to the FPSO.



The main reservoirs in the Skarv accumulations and Idun accumulation are the Lower and Middle Jurassic-age sandstones of the Garn, Tilje, and Ile Formations. These reservoirs were deposited in varied environments of deposition ranging from progradational shallow marine for the Garn reservoir, to shallow tidal marine for the Ile reservoir, to fluvial-tidal, lagoonal, and shelfal environments for the Tilje reservoir. The average reservoir depth is 3,500 meters below mean sea level. The Skarv field is broken into three main fault blocks, each with different fluid contacts and each with different hydrocarbon compositions. There is additional minor faulting in all three fault blocks that may serve as baffles to flow within each fault block.

The porosity in the Garn Formation was estimated to range from 14 to 19 percent with an average of 15.5 percent and S_w was estimated to range from 8 to 18 percent with an average of 12 percent. The average permeability was estimated to be 1,500 millidarcys and average net hydrocarbon thickness was estimated to be 80 meters.

The porosity in the Ile Formation was estimated to range from 13 to 16 percent with an average of 14 percent and S_w was estimated to range from 30 to 55 percent with an average of 32 percent. The average permeability was estimated to be 10 millidarcys and the average net hydrocarbon thicknesses was estimated to be 37 meters.

The porosity in the Tilje Formation was estimated to range from 12 to 17 percent with an average of 15 percent and S_w was estimated to range from 31 to 52 percent with an average of 35 percent. The average permeability was estimated to be 40 millidarcys and the average net hydrocarbon thickness was estimated to be 65 meters.

Produced liquids from the Garn, Ile, and Tilje reservoirs in the Skarv field consist primarily of oil with a gravity of 33 degrees API. There are some deeper gas-condensate reservoirs not currently producing. The producing GOR of the Skarv field has risen steadily over the past several years of gas injection and is currently approximately 88,000 cubic feet per barrel.

The Idun accumulation is split by a central fault into the East and West fault blocks. It is interpreted that there is limited pressure communication between the two fault blocks. The produced fluid is gas-condensate.

Developed reserves estimates for the Skarv field and Idun accumulation were based on performance analysis of existing individual wells and the declines they manifested and were supported by volumetric calculations. As oil production ceases in parts of the Skarv Unit, gas injectors are converted to gas producers. The gas recovery associated with the gas blowdown is included in estimates of reserves. Gas rate projections are constrained to accommodate FPSO limits, inter-field connection limits, and operator annual rate maximums.

Snorre Field

The Snorre field began producing in 1992. It produces from 24 wells with pressure support from water injection, gas injection, and water-alternating-gas (WAG) injection wells. Developed reserves estimates reflect performance analysis of the existing active wells. Undeveloped reserves estimates were based on projected performance from an ongoing infill drilling program. Reserves were estimated up to the technical lifetime of the platform, ending in 2050.

Vega Field

The Vega field, located in the North Sea 30 kilometers west of the Gjøa field in 370 meters of water, was discovered by well 35/8-1 in 1981. The field is operated by Wintershall Dea and is located in licenses PL090C and PL248. The production of gas-condensate commenced in 2010.

The Vega field consists of three separate structures, Vega North, Vega Central, and Vega South, which are separated by north-trending extensional faults crossed by secondary northeast-trending faults that formed during Late Jurassic time. The Middle Jurassic-age Brent Group sandstones were deposited in a shallow marine, delta-dominated environment. The overlying shelf mudstones of the Viking group, deposited during a global sea level rise, represent the seal for the reservoir. Porosity was estimated to range from 11 to 22 percent and initial S_w was estimated to range from 16 to 52 percent.

The field is currently producing, and hydrocarbons are transported via pipeline and processed at the Gjøa facilities. The field was evaluated based on performance analysis using decline-curve analysis.

Reserves Summary

The estimated gross proved, probable, and possible reserves, as of December 31, 2023, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Gross Reserves			
	Oil and Condensate (10^3bbl)	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina				
Proved	26,414	19,186	2,987,893	579,152
Probable	7,374	5,270	1,000,454	191,297
Proved plus Probable	33,788	24,456	3,988,347	770,449
Possible	6,424	2,437	1,072,002	200,290
Proved plus Probable plus Possible	40,212	26,893	5,060,349	970,739
Denmark				
Proved	0	0	0	0
Probable	0	0	0	0
Proved plus Probable	0	0	0	0
Possible	0	0	0	0
Proved plus Probable plus Possible	0	0	0	0
Germany				
Proved	67,866	0	326,648	126,196
Probable	34,849	0	159,894	63,402
Proved plus Probable	102,715	0	486,542	189,598
Possible	20,850	0	119,816	42,245
Proved plus Probable plus Possible	123,565	0	606,358	231,843
Mexico				
Proved	91,518	0	50,299	100,500
Probable	24,681	0	27,095	29,519
Proved plus Probable	116,199	0	77,394	130,019
Possible	16,562	0	19,577	20,058
Proved plus Probable plus Possible	132,761	0	96,971	150,077
North Africa				
Proved	67,471	111	975,118	241,710
Probable	13,438	209	514,002	105,433
Proved plus Probable	80,909	320	1,489,120	347,143
Possible	14,431	200	483,582	100,985
Proved plus Probable plus Possible	95,340	520	1,972,702	448,128
Norway				
Proved	843,535	160,286	7,591,809	2,359,501
Probable	217,812	61,795	2,231,688	678,123
Proved plus Probable	1,061,347	222,081	9,823,497	3,037,624
Possible	224,067	54,642	2,596,081	742,295
Proved plus Probable plus Possible	1,285,414	276,723	12,419,578	3,779,919
Total Proved	**1,096,804**	**179,583**	**11,931,767**	**3,407,059**
Total Probable	**298,154**	**67,274**	**3,933,133**	**1,067,774**
Total Proved plus Probable	**1,394,958**	**246,857**	**15,864,900**	**4,474,833**
Total Possible	**282,334**	**57,279**	**4,291,058**	**1,105,873**
Total Proved plus Probable plus Possible	**1,677,292**	**304,136**	**20,155,958**	**5,580,706**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas reserves estimated herein were converted to oil equivalent using a factor of 5,600 cubic feet of gas per 1 boe.
3. The oil equivalent reserves reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

The estimated working interest proved, probable, and possible reserves, as of December 31, 2023, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Working Interest Reserves			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
Argentina				
Proved	9,336	7,194	1,000,626	195,213
Probable	2,572	1,979	330,652	63,596
Proved plus Probable	11,908	9,173	1,331,278	258,809
Possible	2,210	912	352,981	66,155
Proved plus Probable plus Possible	14,118	10,085	1,684,259	324,964
Denmark				
Proved	0	0	0	0
Probable	0	0	0	0
Proved plus Probable	0	0	0	0
Possible	0	0	0	0
Proved plus Probable plus Possible	0	0	0	0
Germany				
Proved	66,949	0	135,026	91,061
Probable	34,642	0	82,605	49,393
Proved plus Probable	101,591	0	217,631	140,454
Possible	20,598	0	64,384	32,095
Proved plus Probable plus Possible	122,189	0	282,015	172,549
Mexico				
Proved	35,712	0	22,896	39,801
Probable	10,223	0	12,678	12,487
Proved plus Probable	45,935	0	35,574	52,288
Possible	6,919	0	9,168	8,556
Proved plus Probable plus Possible	52,854	0	44,742	60,844
North Africa				
Proved	9,204	111	249,044	53,787
Probable	2,804	209	138,481	27,742
Proved plus Probable	12,008	320	387,525	81,529
Possible	2,919	200	123,211	25,121
Proved plus Probable plus Possible	14,927	520	510,736	106,650
Norway				
Proved	121,861	39,988	1,321,364	397,807
Probable	44,440	21,264	676,819	186,564
Proved plus Probable	166,301	61,252	1,998,183	584,371
Possible	44,626	15,555	696,282	184,517
Proved plus Probable plus Possible	210,927	76,807	2,694,465	768,888
Total Proved	**243,062**	**47,293**	**2,728,956**	**777,669**
Total Probable	**94,681**	**23,452**	**1,241,235**	**339,782**
Total Proved plus Probable	**337,743**	**70,745**	**3,970,191**	**1,117,451**
Total Possible	**77,272**	**16,667**	**1,246,026**	**316,444**
Total Proved plus Probable plus Possible	**415,015**	**87,412**	**5,216,217**	**1,433,895**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas reserves estimated herein were converted to oil equivalent using a factor of 5,600 cubic feet of gas per 1 boe.
3. The oil equivalent reserves reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

The estimated net interest proved, probable, and possible reserves, as of December 31, 2023, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Net Reserves			
	Oil and Condensate (10^3bbl)	**LPG (10^3bbl)**	**Sales Gas (10^6ft^3)**	**Combined Oil Equivalent (10^3boe)**
Argentina				
Proved	9,336	7,194	1,000,626	195,213
Probable	2,572	1,979	330,652	63,596
Proved plus Probable	11,908	9,173	1,331,278	258,809
Possible	2,210	912	352,981	66,155
Proved plus Probable plus Possible	14,118	10,085	1,684,259	324,964
Denmark				
Proved	0	0	0	0
Probable	0	0	0	0
Proved plus Probable	0	0	0	0
Possible	0	0	0	0
Proved plus Probable plus Possible	0	0	0	0
Germany				
Proved	66,949	0	135,026	91,061
Probable	34,642	0	82,605	49,393
Proved plus Probable	101,591	0	217,631	140,454
Possible	20,598	0	64,384	32,095
Proved plus Probable plus Possible	122,189	0	282,015	172,549
Mexico				
Proved	22,549	0	20,018	26,124
Probable	6,317	0	11,291	8,333
Proved plus Probable	28,866	0	31,309	34,457
Possible	4,410	0	8,138	5,863
Proved plus Probable plus Possible	33,276	0	39,447	40,320
North Africa				
Proved	5,517	61	133,124	29,350
Probable	1,933	113	82,195	16,724
Proved plus Probable	7,450	174	215,319	46,074
Possible	2,089	108	79,360	16,368
Proved plus Probable plus Possible	9,539	282	294,679	62,442
Norway				
Proved	121,861	39,988	1,321,364	397,807
Probable	44,440	21,264	676,819	186,564
Proved plus Probable	166,301	61,252	1,998,183	584,371
Possible	44,626	15,555	696,282	184,517
Proved plus Probable plus Possible	210,927	76,807	2,694,465	768,888
Total Proved	**226,212**	**47,243**	**2,610,158**	**739,555**
Total Probable	**89,904**	**23,356**	**1,183,562**	**324,610**
Total Proved plus Probable	**316,116**	**70,599**	**3,793,720**	**1,064,165**
Total Possible	**73,933**	**16,575**	**1,201,145**	**304,998**
Total Proved plus Probable plus Possible	**390,049**	**87,174**	**4,994,865**	**1,369,163**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas reserves estimated herein were converted to oil equivalent using a factor of 5,600 cubic feet of gas per 1 boe.
3. The oil equivalent reserves reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

The reserves in fields that were evaluated according to the terms of a PSA, as summarized under the Valuation of Reserves heading of this report, can vary. Net reserves in such fields are estimated from the future net revenue attributable to Wintershall Dea under the terms of the respective PSA. The components of that future net revenue are cost revenue, profit revenue, and tax revenue (where applicable). Cost revenue is the revenue entitlement attributable to the PSA contractor for its share of operating expenses and capital costs. Profit revenue is the portion of the sales revenue that remains after cost revenue is contractually apportioned to the contractor based on the PSA terms. Tax revenue, where applicable, is the estimated income tax to be paid by the host on behalf of the contractor. The revenues are converted to entitlement quantities by dividing the revenues by a prevailing product price or prices. The entitlement quantities (net reserves or resources) are based on Wintershall Dea's working interest in the respective PSA. Net reserves or resources under each PSA can vary according to the schedule of production, expended costs, and product prices. Therefore, net reserves or resources can vary by category and under different economic scenario assumptions. Further, a different projection of any component of the estimate could result in a varying net entitlement interest.

Valuation of Reserves

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Wintershall Dea and certain forecast price, expense, and cost assumptions as described below. Three economic scenario cases (Base Case Prices, Low Case Prices, and High Case Prices) were evaluated. Gross, working interest, and net reserves estimated herein were based on the Base Case price, expense, and cost estimations. The Low Case Prices and High Case Prices sensitivity cases were forecast to the Base Case Prices projected limit or the economic limit, whichever occurred first. The economic assumptions for the sensitivity cases differ from the Base Case Prices only in the forecast product prices.

In this report, values for proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were based on projections of estimated future production and revenue prepared for these properties with no risk adjustment applied to the probable or possible reserves. Probable and possible reserves involve substantially higher risks than proved reserves. Revenue values associated with proved-plus-probable and proved-plus-probable-plus-possible reserves have not been adjusted to account for such risks; this adjustment would be necessary in order to make values associated with probable and possible reserves comparable to values associated with proved reserves.

Revenue associated with the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were estimated utilizing methods generally accepted by the petroleum industry. Production forecasts of the proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves were based on the development plan for the fields. The future net revenue and present worth of the fields' reserves were estimated using the price and cost assumptions, monetary conversion values, and the appropriate fiscal terms described herein.

The following economic assumptions were used for estimating the revenue values reported herein:

Oil, Condensate, LPG, and Gas Prices

Base Case Price Assumptions

The products and locations vary considerably in the portfolio evaluated herein. Historical pricing was provided for properties across the portfolio by Wintershall Dea, including prices as of December 31, 2023. Forecast pricing for this report was based on projections of a marker price for oil (Brent), gas prices (title transfer facility virtual trading point (TTF)), and Henry Hub Gas prices reflective of conditions on December 31, 2023. The initial marker prices used in this evaluation were U.S.$76.84 per barrel for oil and U.S.$12.41 per thousand cubic feet (10^3ft^3) for gas. In December 2023, the Brent oil price was U.S.$76.64 per barrel, the TTF gas price was U.S.$10.70 per 10^3ft^3, and the Henry Hub gas price was U.S.$3.96 per 10^3ft^3. The prices received at the field level vary from the marker prices due to location, quality, heating value content, and contractual sales agreements. The field-level prices, including differentials where appropriate, were applied to the analysis herein. Marker prices used to estimate reserves and future net revenue herein under the Base Case Prices assumptions are shown below, expressed in United States dollars per barrel (U.S.$/bbl) and United States dollars per thousand cubic feet (U.S.$/$10^3ft^3$):

	Base Case Prices				
Year	**Brent Oil (U.S.$/bbl)**	**Condensate (U.S.$/bbl)**	**LPG (U.S.$/bbl)**	**TTF Gas (U.S.$/$10^3ft^3$)**	**Henry Hub Gas (U.S.$/$10^3ft^3$)**
2024	76.84	74.53	61.44	12.41	2.92
2025	73.70	71.49	55.80	12.13	3.86
2026	71.40	69.26	48.77	10.67	4.06

	Base Case Prices – *(Continued)*				
Year	Brent Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	LPG (U.S.$/bbl)	TTF Gas (U.S.$/$10^3$ft^3)	Henry Hub Gas (U.S.$/$10^3$ft^3)
2027	69.48	67.40	42.19	9.18	4.50
2028	70.98	68.85	46.48	9.36	4.60
2029	72.52	70.34	50.80	9.55	4.69
2030	74.09	71.86	57.26	9.74	4.79
2031	75.69	73.42	58.14	9.93	4.88
2032	77.32	75.00	59.07	10.13	4.97
2033	79.00	76.63	60.06	10.33	5.08
2034	81.54	79.09	61.73	10.54	5.18
2035	84.15	81.63	63.71	10.75	5.28
2036	86.84	84.23	65.74	10.97	5.39
2037	89.60	86.91	67.83	11.19	5.49
2038	92.43	89.66	69.98	11.41	5.61
2039	95.34	92.48	72.18	11.64	5.71
2040	98.33	95.38	74.44	11.87	5.82
2041	101.41	98.36	76.77	12.11	5.95
2042	104.56	101.43	79.16	12.35	6.06
2043	107.80	104.57	81.61	12.60	6.19
2044	109.96	106.66	83.25	12.85	6.31
2045	112.16	108.79	84.91	13.11	6.44
2046	114.40	110.97	86.61	13.37	6.56
2047	116.69	113.19	88.34	13.63	6.70
2048	119.02	115.45	90.11	13.91	6.83
2049	121.40	117.76	91.91	14.19	6.96
2050	123.83	120.12	93.75	14.47	7.10
2051	126.31	122.52	95.62	14.76	7.25
2052	128.84	124.97	97.54	15.05	7.39
2053	131.41	127.47	99.49	15.36	7.54
2054	134.04	130.02	101.48	15.66	7.69
2055	136.72	132.62	103.51	15.98	7.85
2056	139.46	135.27	105.58	16.12	8.00
2057	141.91	137.65	107.44	16.45	8.16

Notes:
1. Prices were held constant from 2057 forward.
2. TTF gas prices were utilized for properties located in Algeria, Argentina, Denmark, Egypt, Germany, Libya, and Norway.
3. Henry Hub gas prices were utilized for properties located in Mexico.

Low Case Price Assumptions

Oil, condensate, gas, and LPG prices for the Low Case Prices scenario are 10 percent lower than those used in the Base Case Prices scenario. Reserves estimates herein were based on the Base Case Prices scenario, and quantities in the sensitivity cases are those estimated prior to the Base Case Prices scenario limit of projected production or when an annual economic limit is reached, whichever occurs first. All other components of the evaluation, including costs, for the sensitivity cases are the same as those stated for the Base Case Prices scenario herein. Marker prices used to estimate reserves and future net revenue herein under the Low Case Prices scenario assumptions are shown below, expressed in United States dollars per barrel (U.S.$/bbl) and United States dollars per thousand cubic feet (U.S.$/$10^3$ft^3):

	Low Case Prices				
Year	Brent Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	LPG (U.S.$/bbl)	TTF Gas (U.S.$/$10^3$ft^3)	Henry Hub Gas (U.S.$/$10^3$ft^3)
2024	69.16	67.08	55.30	11.17	2.63
2025	66.33	64.34	50.22	10.92	3.48
2026	64.26	62.33	43.90	9.60	3.65
2027	62.53	60.66	37.97	8.26	4.05
2028	63.88	61.97	41.84	8.42	4.14
2029	65.27	63.31	45.72	8.59	4.22
2030	66.68	64.68	51.53	8.76	4.31
2031	68.12	66.08	52.32	8.94	4.39
2032	69.59	67.50	53.16	9.12	4.47
2033	71.10	68.96	54.05	9.30	4.57
2034	73.38	71.18	55.56	9.49	4.66
2035	75.74	73.46	57.34	9.68	4.76
2036	78.15	75.81	59.17	9.87	4.85
2037	80.64	78.22	61.05	10.07	4.94
2038	83.19	80.69	62.98	10.27	5.04
2039	85.81	83.23	64.96	10.47	5.14
2040	88.50	85.84	67.00	10.68	5.24
2041	91.26	88.53	69.09	10.90	5.35
2042	94.11	91.28	71.24	11.11	5.46
2043	97.02	94.11	73.45	11.34	5.57
2044	98.96	96.00	74.92	11.56	5.68
2045	100.94	97.92	76.42	11.79	5.79
2046	102.96	99.87	77.95	12.03	5.90
2047	105.02	101.87	79.51	12.27	6.03
2048	107.12	103.91	81.10	12.52	6.15
2049	109.26	105.99	82.72	12.77	6.27
2050	111.45	108.11	84.37	13.02	6.39
2051	113.68	110.27	86.06	13.28	6.52
2052	115.95	112.47	87.78	13.55	6.65
2053	118.27	114.72	89.54	13.82	6.78
2054	120.64	117.02	91.33	14.10	6.92
2055	123.05	119.36	93.16	14.38	7.06
2056	125.51	121.75	95.02	14.51	7.20
2057	127.72	123.89	96.69	14.80	7.34

Notes:
1. Prices were held constant from 2057 forward.
2. TTF gas prices were utilized for properties located in Algeria, Argentina, Denmark, Egypt, Germany, Libya, and Norway.
3. Henry Hub gas prices were utilized for properties located in Mexico.

High Case Price Assumptions

Oil, condensate, gas, and LPG prices for the High Case Prices scenario are 10 percent higher than those used in the Base Case Prices scenario. Reserves estimates herein were based on the Base Case Prices scenario, and quantities in the sensitivity cases are those estimated prior to the Base Case Prices scenario limit of projected production or when an annual economic limit is reached, whichever occurs first. All other components of the evaluation, including costs, for the sensitivity cases are the same as those stated for the Base Case Prices scenario herein. Marker prices used to estimate reserves and future net revenue herein under the High Case Prices scenario assumptions are shown below, expressed in United States dollars per barrel (U.S.$/bbl) and United States dollars per thousand cubic feet (U.S.$/$10^3$ft^3):

	High Case Prices				
Year	Brent Oil (U.S.$/bbl)	Condensate (U.S.$/bbl)	LPG (U.S.$/bbl)	TTF Gas (U.S.$/$10^3$ft^3)	Henry Hub Gas (U.S.$/$10^3$ft^3)
2024	84.52	81.99	67.59	13.66	3.21
2025	81.07	78.64	61.38	13.35	4.25
2026	78.54	76.18	53.65	11.74	4.46
2027	76.43	74.14	46.40	10.09	4.96
2028	78.08	75.74	51.13	10.30	5.06
2029	79.77	77.38	55.88	10.50	5.16
2030	81.49	79.08	62.98	10.71	5.26
2031	83.26	80.76	63.95	10.93	5.37
2032	85.06	82.50	64.98	11.14	5.47
2033	86.90	84.29	66.06	11.37	5.58
2034	89.69	87.00	67.90	11.59	5.70
2035	92.57	89.79	70.08	11.83	5.81
2036	95.52	92.65	72.32	12.06	5.93
2037	98.55	95.60	74.61	12.30	6.04
2038	101.67	98.62	76.97	12.55	6.17
2039	104.88	101.73	79.40	12.80	6.28
2040	108.17	104.92	81.89	13.06	6.41
2041	111.55	108.20	84.45	13.32	6.54
2042	115.02	111.57	87.08	13.58	6.67
2043	118.58	115.03	89.78	13.86	6.81
2044	120.96	117.33	91.57	14.13	6.94
2045	123.38	119.67	93.40	14.42	7.08
2046	125.84	122.07	95.27	14.70	7.22
2047	128.36	124.51	97.18	15.00	7.36
2048	130.93	127.00	99.12	15.30	7.51
2049	133.55	129.54	101.10	15.60	7.66
2050	136.22	132.13	103.12	15.92	7.81
2051	138.94	134.77	105.19	16.23	7.97
2052	141.72	137.47	107.29	16.56	8.13
2053	144.55	140.22	109.44	16.89	8.29
2054	147.44	143.05	111.63	17.23	8.46

	High Case Prices – *(Continued)*				
Year	**Brent Oil (U.S.$/bbl)**	**Condensate (U.S.$/bbl)**	**LPG (U.S.$/bbl)**	**TTF Gas (U.S.$/$10^3$ft^3)**	**Henry Hub Gas (U.S.$/$10^3$ft^3)**
2055	150.39	145.88	113.86	17.57	8.63
2056	153.40	148.80	116.14	17.73	8.80
2057	156.10	151.42	118.18	18.09	8.97

Notes:
1. Prices were held constant from 2057 forward.
2. TTF gas prices were utilized for properties located in Algeria, Argentina, Denmark, Egypt, Germany, Libya, and Norway.
3. Henry Hub gas prices were utilized for properties located in Mexico.

Operating Expenses, Capital Costs, and Abandonment Costs

Current operating expenses and operating expense forecasts provided by Wintershall Dea were used in estimating future expenses required to operate the fields for all three economic scenarios. In certain cases, future expenses, either higher or lower than current expenses, may have been used because of anticipated changed operating conditions. Pipeline and processing tariffs are paid for access to markets. Future capital expenditures and abandonment costs were estimated using current forecasts provided by Wintershall Dea. A 2-percent cost escalation per year was applied for fixed operating expenses, capital costs, and abandonment costs for 2024 and beyond. Generally, abandonment costs, which can be substantial in mature fields, are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were assigned the year after cessation of production, except where other anticipated abandonment dates were represented by Wintershall Dea. Economic limits for each field were estimated based on annual operating expenses with no consideration of German corporate income taxes.

Exchange Rates

Certain information on costs was provided in currencies other than U.S.$. Where applicable, an exchange rate of €0.93 per U.S.$1.00 was used for this report. Other exchange rates used herein include DKK6.95 per U.S.$1.00, and NOK10.61 per U.S.$1.00. These currency exchange rates were held constant for this report.

Fiscal Regime

Fields in all countries are governed by concessionary (working interest) regimes, except for certain fields located in Algeria, Libya, and Egypt, as well as the Hokchi and Ogarrio fields in Mexico, which are governed by PSAs. Selected key parameters of fiscal regimes evaluated herein are summarized as follows:

	Parameters					
	Cash Royalty (percent)	Royalty in Kind (percent)	Cost Recovery Limit (percent)	Profit Sharing (percent)	Production Taxes (percent)	Host-Country Taxes (percent)
Algeria	NA	NA	NA	50 to 60	NA	NA
Argentina	12 to 18	NA	NA	NA	2.4 to 3.0	35.00
Denmark	NA	NA	NA	NA	52	25.00
Egypt	NA	NA	40	27 to 32	NA	40.55
Egypt: Disouq	NA	NA	35	17 to 30	NA	40.55
Libya	NA	NA	25 to 50	80 to 90	NA	65.00
Germany	4 to 10	NA	NA	NA	NA	30.10
Mexico: Hokchi	NA	1.2 to 12.0	60	31	NA	30.00
Mexico: Ogarrio	20.5 to 25.0	NA	NA	NA	NA	30.00
Norway	NA	NA	NA	NA	56	22.00

Notes:
1. Production bonuses are paid in the Egyptian concessions, calculated on the basis of total cumulative production in the concession. None of the fields evaluated reach the required production to pay a production bonus.
2. Production is shared with the Algerian government based on a formula referred to as the K*A-B formula, resulting in an entitlement share between 50 and 60 percent.
3. Production tax in Algeria consists of the excess profits tax (TPE) and is applied only to liquids.
4. Unless otherwise noted herein, “Royalty in Kind” is a reduction in ownership and not reflected as a negative revenue.
5. “NA” is not applicable.

In certain instances, commercial terms for concessions and PSAs may be subject to strict confidentiality restrictions that prevent stating specific terms. As such, specific terms, as provided by Wintershall Dea, may not be described herein, but were applied as appropriate for each country and property evaluated. Generally, the terms of the concession area licenses and PSAs include royalty in-kind considerations, cost recovery limits, profit sharing percentages, certain production taxes, and the host country income tax. Production bonuses are a consideration in the PSAs.

Income Taxes

For the purposes of this report, German corporate income taxes were not considered in this report; however, field-level estimates of host-country income taxes, where applicable, were included in the evaluation of each individual field located in each respective host country, including Germany. Production taxes were applied as appropriate in each country.

As in any evaluation, there may be a risk of unexpected cost variances and timing delays or accelerations. For this evaluation, consideration was given to these elements to the extent possible. The resulting scheduling of production and costs is represented as a reliable estimate incorporating operational variances and timing delays where reasonable.

The estimated future revenue to be derived from the production and sale of the net proved, proved-plus-probable, and proved-plus-probable-plus-possible reserves, as of December 31, 2023, of the properties evaluated under the Base Case Prices economic assumptions described herein is summarized as follows, expressed in thousands of United States dollars (10^3U.S.\$):

	Valuation of Reserves – Base Case Prices		
	Proved (10^3U.S.\$)	**Proved plus Probable (10^3U.S.\$)**	**Proved plus Probable plus Possible (10^3U.S.\$)**
Future Gross Revenue	45,225,814	64,793,427	83,203,526
Operating Expenses	11,152,380	14,048,407	16,549,209
Capital Costs	2,890,632	3,255,024	3,332,452
Abandonment Cost	3,271,678	3,402,041	3,467,421
Royalty (Cash)	2,510,072	3,649,268	4,533,424
Taxes	14,986,890	23,964,603	33,214,786
Future Net Revenue	10,414,162	16,474,084	22,106,234
Present Worth at 6 Percent	8,508,852	12,568,051	16,196,493
Present Worth at 8 Percent	7,983,892	11,593,251	14,779,665
Present Worth at 10 Percent	7,371,082	10,528,176	13,282,049
Present Worth at 12 Percent	7,087,189	10,001,149	12,515,256

Note: Values for probable and possible reserves have not been risk adjusted to make them comparable to values for proved reserves.

The estimated future revenue to be derived from the production and sale of the net proved, proved-plus-probable, and proved-plus-probable-plus-possible quantities, as of December 31, 2023, of the properties evaluated under the Low Case Prices and High Case Prices economic assumptions described herein is summarized as follows, expressed in thousands of United States dollars (10^3U.S.$):

Valuation of Quantities – Price Sensitivity Cases

	Low Case Prices			**High Case Prices**		
	Proved (10^3U.S.$)	**Proved plus Probable (10^3U.S.$)**	**Proved plus Probable plus Possible (10^3U.S.$)**	**Proved (10^3U.S.$)**	**Proved plus Probable (10^3U.S.$)**	**Proved plus Probable plus Possible (10^3U.S.$)**
Future Gross Revenue	40,473,092	58,058,420	74,657,865	49,790,884	71,339,456	91,620,309
Operating Expenses	10,984,127	13,874,353	16,434,413	11,152,013	14,047,969	16,548,718
Capital Costs	2,885,432	3,255,023	3,332,449	2,890,632	3,255,023	3,332,449
Abandonment Cost	3,263,367	3,391,343	3,456,419	3,271,558	3,401,920	3,467,302
Royalty (Cash)	2,226,405	3,253,747	4,044,621	2,778,325	4,038,898	5,018,407
Taxes	12,309,076	20,140,056	28,282,780	17,673,898	27,795,976	38,152,385
Future Net Revenue	8,804,685	14,143,898	19,107,183	12,024,458	18,799,670	25,101,048
Present Worth at 6 Percent	7,289,099	10,876,591	14,088,821	9,719,797	14,243,953	18,289,707
Present Worth at 8 Percent	6,854,990	10,047,673	12,871,823	9,102,196	13,122,214	16,672,921
Present Worth at 10 Percent	6,336,988	9,130,797	11,573,915	8,393,520	11,908,822	14,976,320
Present Worth at 12 Percent	6,102,659	8,684,333	10,916,575	8,058,669	11,301,044	14,100,595

Note: Values for probable and possible quantities have not been risk adjusted to make them comparable to values for proved quantities.

Definition of Contingent Resources

Estimates of contingent resources presented in this report have been prepared in accordance with the PRMS approved in March 2007 and revised in June 2018 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. Because of the lack of commerciality or sufficient development drilling, the contingent resources estimated herein cannot be classified as reserves. The petroleum contingent resources are classified as follows:

> *Contingent 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 currently considered to be commercially recoverable owing to one or more contingencies.

Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.

> *Economically Viable Contingent Resources* are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecast conditions but are not Reserves because it does not meet the other commercial criteria.

> *Economically Not Viable Contingent Resources* are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions. May also be subject to additional unsatisfied contingencies.

Where evaluations are incomplete and it is premature to clearly define the associated cash flows, it is acceptable to note that the project economic status is "undetermined."

The estimation of petroleum resources is subject to both technical and commercial uncertainties and, in general, may be quoted as a range. The range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities. In all cases, the range of uncertainty is dependent on the amount and quality of both technical and commercial data that are available and may change as more data become available.

> *1C (Low), 2C (Best), and 3C (High) Estimates* – Estimates of contingent resources in this report are expressed using the terms 1C (low) estimate, 2C (best) estimate, and 3C (high) estimate to reflect the range of uncertainty.

<u>Estimation of Contingent Resources</u>

Estimates of contingent resources were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry and in accordance with definitions established by the PRMS. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

When applicable, the volumetric method was used to estimate original quantities of OGIP or OOIP. Structure maps were prepared to delineate each reservoir, and isopach maps were constructed to estimate reservoir volume. Electrical logs, radioactivity logs, core analyses, and other available data were used to prepare these maps as well as to estimate representative values for porosity and S_w.

Estimates of ultimate recovery were obtained after applying recovery factors to original quantities of petroleum in place. These recovery factors were based on consideration of the type of energy inherent in the reservoir, analyses of the fluid and rock properties, and the structural position of the properties.

In certain cases, contingent resources were estimated by incorporating elements of analogy with similar wells or reservoirs for which more complete data were available.

The contingent resources estimates presented herein were generally based on consideration of drilling results, analyses of available geophysical and geological data, well-test results, production data, and pressure and core data available through December 31, 2023. The development and economic status of the properties evaluated was based on the status as of December 31, 2023.

Oil and condensate contingent resources estimated herein are to be recovered by normal field separation. LPG contingent resources estimated herein consist primarily of propane and butane fractions and are the result of low-temperature plant processing. Oil, condensate, and LPG contingent resources included in this report are expressed in 10^3bbl. In these estimates, 1 barrel equals 42 United States gallons. For reporting purposes, oil and condensate contingent resources have been estimated separately and are presented herein as a summed quantity.

Gas quantities associated with contingent resources estimated herein are expressed as separator gas and sales gas contingent resources. Separator gas is defined as the total gas produced from the reservoir after field separation but before reduction for field use (including fuel usage), flare, and gas injection. Sales gas is defined as the quantities of separator gas available to be sold after field use (including fuel usage), flare, and gas injection. Gas contingent resources estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60°F and at a pressure base of 14.7 psia. Gas quantities included in this report are expressed in 10^6ft^3.

For the purposes of this report, sales gas contingent resources estimated herein were converted to oil equivalent volumes using a factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent. This conversion factor was provided by Wintershall Dea.

In this report, gas quantities are identified by the type of reservoir from which the gas is or will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Solution gas and gas-cap gas are sometimes produced together and, as a whole, referred to as associated gas. Gas quantities estimated herein include both associated and nonassociated gas.

The contingent resources estimated for the fields evaluated herein are those quantities of petroleum that are potentially recoverable from discovered accumulations but which are not currently considered to be commercially recoverable because of one or more contingencies, including lack of internal Wintershall Dea approval or partner agreement for commitment to develop and produce, production tails beyond license limits, and uneconomic projects. No contingent resources were estimated for reserves projected beyond the economic limit. Because of the uncertainty of commerciality, the contingent resources estimated herein cannot be classified as reserves. The contingent resources estimates in this report are provided as a means of comparison to other contingent resources and do not provide a means of direct comparison to reserves.

The contingent resources estimated herein are reported as having an economic status of undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the associated cash flows.

The classification of contingent resources estimates presented herein is generally based on a lack of development plans, a lack of sales contracts, and quantities to be recovered after current license expiration.

Procedure and Methodology

Oil, condensate, LPG, and sales gas contingent resources were estimated for certain fields evaluated herein. Tables summarizing the gross, working interest, and net contingent resources are presented by country and by area in Tables A-6, A-7, and A-8, respectively.

For the purposes of this report, net contingent resources for fields evaluated in this report were calculated by multiplying Wintershall Dea's working interest by the gross contingent resources. As such, net contingent resources equals working interest contingent resources.

Selected fields from all countries containing contingent resources estimated herein are discussed in detail as follows.

Algeria

Contingent resources associated with the Reggane Nord fields evaluated herein include a 10-year license extension from the license date of November 1, 2041, to November 1, 2051.

Argentina

Aguada Pichana East Vaca Muerta Field

Contingent resources estimated for the Aguada Pichana East Vaca Muerta field are associated with future development projects, including approximately 760 wells to be drilled. Contingent resources estimates were based on type-well analysis performed using well data from analogous wells in the Vaca Muerta reservoir, for which more complete historical performance data were available.

Ara South Field

Contingent resources estimated for the Ara South field are associated with a 10-year license extension from May 2031 until May 2041. The license extension project consists of the continued operation of the wells active as of December 31, 2023, beyond the current license expiration date of April 30, 2031.

Cañadon Alfa Complex

Contingent resources estimated for the Cañadon Alfa complex are associated with a 10-year license extension from May 2031 until May 2041. The license extension project consists of the continued operation of the wells active as of December 31, 2023, beyond the current license expiration date of April 30, 2031.

Carina Field

Contingent resources estimated for the Carina field are associated with three different projects: a 10-year license extension from May 2041 until May 2051, the Carina Phase 2 project, and the Carina Phase 3 project. The license extension project consists of the continued operation of the active wells beyond May 2041. Contingent resources estimated for the Carina Phase 2 project in the Carina field are associated with the drilling of two additional gas producer wells targeting the Springhill Formation. The Carina Phase 3 project consists of the installation of an offshore facility compression system. Contingent resources were estimated for each project using a 3–D integrated reservoir simulation model.

Contingent resources estimated for the Fenix Phase 2 project are associated with the drilling of three satellite wells. Contingent resources estimated for the Fenix Phase 3 project are associated with offshore compression. The license extension project consists of the continued operation of the wells active as of May 2041 for a period of 10 years, until May 2051. Contingent resources were estimated for each project using a 3–D integrated reservoir simulation model.

Hidra Field

Contingent resources estimated for the Hidra field are associated with a 10-year license extension from May 2031 until May 2041. The license extension project consists of the continued operation of the wells active as of December 31, 2023, beyond the current license expiration date of April 30, 2031.

Kaus Field

Contingent resources estimated for the Kaus field are associated with a 10-year license extension from May 2031 until May 2041. The license extension project consists of the continued operation of the wells active as of December 31, 2023, beyond the current license expiration date of April 30, 2031.

San Roque Vaca Muerta Field

Contingent resources estimated for the San Roque Vaca Muerta field are associated with future development projects, including drilling locations for 636 horizontal wells. Contingent resources estimates were based on type-well analysis performed using well data from analogous wells in the Vaca Muerta Formation for which more complete historical performance data were available.

Vega Pleyade Field

Contingent resources estimated for the Vega Pleyade field are associated with two different projects: a 10-year license extension from May 2041 until April 30, 2051 and the drilling of a third gas production well targeting the Springhill Formation. The license extension project consists of the continued operation of the wells active as of December 31, 2023, beyond the current license expiration date of April 30, 2041. Contingent resources were estimated for both projects using a 3–D integrated reservoir simulation model.

Egypt

Raven West M40E Field

Contingent resources for the Raven West M40E field were estimated volumetrically and include volumes that are potentially recoverable from additional drilling that has not yet been approved. The gas recovery factors were estimated to range from 60 to 80 percent.

Raven West Serravallian 4 Field

Contingent resources for the Raven West Serravallian 4 field were estimated volumetrically and include volumes that are potentially recoverable from additional drilling in the field not yet approved. The gas recovery factors were estimated to range from 60 to 80 percent.

Germany

Emlichheim Field

Contingent resources estimated for the Emlichheim field include volumes associated with continued drilling programs and developing the area of the field that is within 50 meters of the Dutch border.

Mittelplate Field

Contingent resources estimated for the Mittelplate field are associated with two additional production wells to be drilled and a polymer injection pilot, all targeting the Dogger Beta reservoir.

Mexico

Hokchi Field

Contingent resources estimated for the Hokchi field correspond to production volumes to be produced after the contract expiration date of December 31, 2040.

Kan Field

The Kan field was discovered in 2023 and is not on production. Planned development includes a waterflood production scheme with seven producers and three water injectors, but the development plan has not yet been finalized. The first producer is planned to be drilled in 2028. The first water injector is planned to be drilled in 2030.

Polok Field

The Polok field was discovered in 2020 and is not on production. Planned development includes a waterflood production scheme with four producers and two water injectors, but the development plan has not yet been finalized. Drilling may start in 2026 with injectors drilled 2 years later.

Zama Field

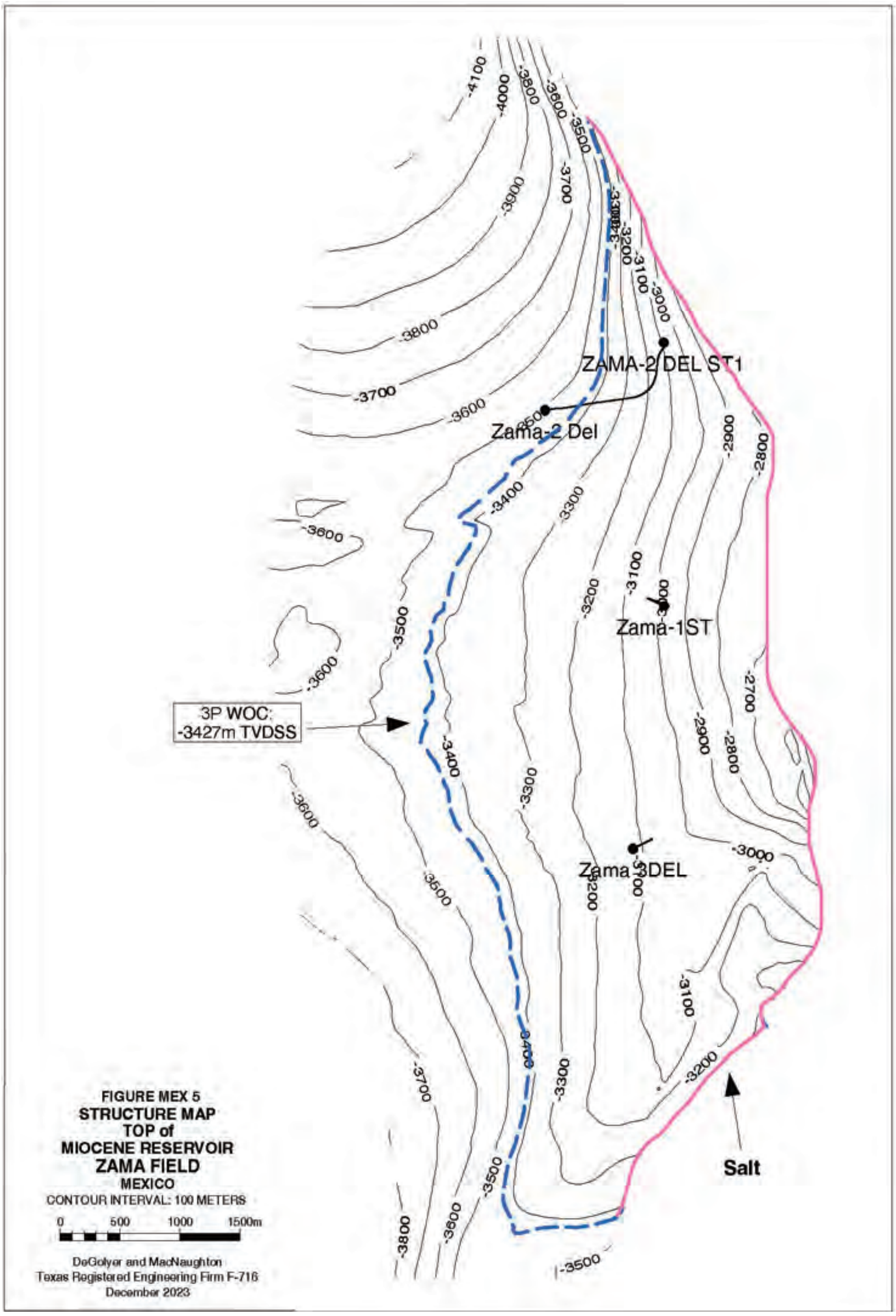
The Zama field is located in the Bay of Campeche, in the South East Basin, 60 kilometers southeast from Dos Bocas, México (Figure MEX 1, page 54).

The Zama-1 discovery well was drilled in 2017 and reached a total depth of 3,360 meters subsea. The well was designed to test a series of stacked Miocene amplitude anomalies that exhibit a “common” downdip amplitude termination (flat spot) with good amplitude versus offset. The Zama-1 well tested the Miocene clastic reservoirs (Figure MEX 2, page 55) that developed as a result of gravity flows from sand sediment in a talus environment. The well encountered more than 500 meters of turbiditic sandstone with a porosity of 25 percent and S_w of 36 percent in the net pay intervals. The structure was identified as a three-way dip structure sealed against a salt diapir (Figure MEX 5, page 91).

In 2019, two appraisal wells (Zama-2 Del and Zama-2 Del ST) were drilled north of the Zama discovery well. A third appraisal well, Zama-3 Del, was drilled to the south in 2021.

In the Miocene sandstone reservoirs of the Zama field, average S_w was estimated to be 33 percent, average effective porosity in all the compartments was estimated to be approximately 25 percent, and average permeability was estimated to range from 95 to 175 millidarcys. The average gross thickness is 160 meters and the average net thickness is 110 meters. Oil gravities vary between 19 and 29 degrees API with an average of 27 degrees API.

The volumetric method was used to estimate the OOIP in the Zama field. Structure maps for the main reservoirs were provided by Wintershall Dea and were prepared using well data and 3–D seismic data. The resulting geological structure maps were reviewed to compare the results to regional geological structural trends.



These comparisons confirmed that the structural interpretations were consistent with structural interpretations in the region. Wireline electrical logs, radioactivity logs, wireline formation pressure tests, wireline fluid sample tests, and other data were acquired in wells drilled in the Zama field. When available, drill cuttings, hole cores, and sidewall cores were analyzed. These combined analyses of the well data were used to establish the petrophysical properties. Petrophysical interpretations of the well-log data were compared to the results of wells in nearby fields; these comparisons confirmed that the local petrophysical interpretations were consistent with geological stratigraphy trends and petrophysical interpretations in the region.

Geocellular models were constructed for the Zama field. Lithological facies and petrophysical properties were propagated in the static models, and vertical fluid limits were defined for the 1C, 2C, and 3C contingent resources scenarios. OOIP was estimated using the volumetric method and net pay isopach maps. These isopach maps were constructed using the 3–D model.

The Zama field is undeveloped. The development plan envisions the drilling of 29 producer wells, a peripheric waterflood scheme with 17 injector wells, the construction of two platforms in water depths between 150 and 180 meters, and an onshore processing facility. Lower completions are to be performed using hydraulic fracturing and gravel packing. Phased implementation of artificial lift using ESP is envisioned.

The 1C, 2C, and 3C ultimate recovery was estimated by applying a recovery factor to the estimated OOIP considering the future development well counts and production rates provided in the development plans. Not all parties have fully committed to the development plan, and the contingent resources estimated herein for the Zama field include quantities to be produced both during and after the license expiration date of September 4, 2045.

Norway

Aasta Hansteen Field

Contingent resources estimated for the Aasta Hansteen field are associated with improved recovery resulting from a reduction in the inlet separator pressure to 40 bars.

Adriana Field

Contingent resources estimated for the Adriana discovery are associated with an undeveloped gas accumulation in the Cretaceous Lysing Reservoir. The results of one well, the 6507/4-2 S, were included in this evaluation.

Alta Field

Contingent resources associated with the Alta field were estimated based on drilling opportunities in the Alta proven area, Alta South and West areas, and gas blowdown.

Bergknapp and Bergknapp Åre Fields

Contingent resources estimated for the Bergknapp and Bergknapp Åre discoveries are associated with undeveloped accumulations in the Jurassic Garn, Tilje, and Åre reservoirs. The results of two wells, the 6406/3-10 and the 6406/3-10 A, were included in this evaluation.

Njord Field

Contingent resources associated with the Njord field were estimated based on additional infill drilling opportunities in the Åre, North Flank, and Northwest Flank reservoirs, improved oil recovery, and low pressure production.

Noatun Field

Contingent resources associated with the Noatun field were estimated based on development with three multi-stage fractured wells in the Ile, Lower Tilje, and Åre reservoirs.

Nova Field

Contingent resources estimated for the Nova field are associated with the development of the gas cap.

Sabina Field

Contingent resources estimated for the Sabina discovery are associated with an undeveloped gas accumulation in the Cretaceous Lange Reservoir. The results of one well, the 6507/4-2 S, were included in this evaluation.

Snøhvit Field

Contingent resources associated with the Snøhvit field were estimated based on development opportunities in Snøhvit Beta and Snøhvit Vest, future projects of electrification, offshore compression, and formation water handling, and production after the current technical limit.

Snorre Field

Contingent resources estimated for the Snorre field consist of multiple projects including a template expansion to allow for additional infill wells, additional development drilling, extended producing lifetime, and gas blowdown.

Storjo Field

Contingent resources estimated for the Storjo discovery are associated with undeveloped gas accumulations in the Cretaceous Lysing and Jurassic Tilje reservoirs. The results of one well, the 6507/2-6 were included in this evaluation.

Contingent Resources Summary

The estimated gross, working interest, and net 1C, 2C, and 3C contingent resources, as of December 31, 2023, of the properties evaluated herein are summarized as follows, expressed in thousands of barrels (10^3bbl), millions of cubic feet (10^6ft^3), and thousands of barrels of oil equivalent (10^3boe):

	Gross Contingent Resources			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
1C	819,246	47,135	8,649,610	2,410,954
2C	1,725,147	96,091	17,832,473	5,005,607
3C	2,961,243	149,985	33,140,193	9,029,120

	Working Interest Contingent Resources			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
1C	193,193	19,163	2,009,819	571,252
2C	448,473	39,654	4,196,852	1,237,565
3C	787,226	62,684	7,727,263	2,229,778

	Net Contingent Resources			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
1C	193,193	19,163	2,009,819	571,252
2C	448,473	39,654	4,196,852	1,237,565
3C	787,226	62,684	7,727,263	2,229,778

Notes:
1. For the purposes of this report, net contingent resources are set equal to working interest contingent resources.
2. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
3. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
4. The contingent resources reported herein have an economic status of undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the associated cash flows.
5. Sales gas contingent resources estimated herein were converted to oil equivalent using a factor of 5,600 cubic feet per 1 boe.
6. The oil equivalent contingent resources reported in this table were based on calculations by country and category as they appear in this table. As such, sum totals may vary immaterially from totals reported in other tables in this report due to accumulated rounding effects from a detailed level.

Tables summarizing the gross, working interest, and net contingent resources are presented by country and by area in Tables A-6, A-7, and A-8, respectively.

Professional Qualifications

DeGolyer and MacNaughton is a Delaware Corporation with offices at 5001 Spring Valley Road, Suite 800 East, Dallas, Texas 75244, U.S.A. The firm has been providing petroleum consulting services throughout the world since 1936. The firm's professional engineers, geologists, geophysicists, petrophysicists, and economists are engaged in the independent evaluation of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, equity studies, and studies of supply and economics related to the energy industry. Except for the provision of professional services on a fee basis, DeGolyer and MacNaughton has no commercial arrangement with any other person or company involved in the interests which are the subject of this report.

The evaluation has been supervised by Mr. Regnald A. Boles, an Executive Vice President and Division Manager with DeGolyer and MacNaughton, a Registered Professional Engineer in the State of Texas, and a member of the Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers, and the European Association of Geoscientists & Engineers. He has over 40 years of oil and gas industry experience.

Submitted,

DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Regnald A. Boles

Regnald A. Boles, P.E.
Executive Vice President
DeGolyer and MacNaughton

TABLE A-1
PROPERTIES EVALUATED
as of
DECEMBER 31, 2023
with interests attributable to
WINTERSHALL DEA

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

Country Field/Discovery	Working Interest (%)	Fiscal Regime	License Expiration
Algeria			
Azrafil Southeast	24.00	PSA	November 1, 2041
Kahlouche	24.00	PSA	November 1, 2041
Kahlouche South	24.00	PSA	November 1, 2041
Reggane	24.00	PSA	November 1, 2041
Sali	24.00	PSA	November 1, 2041
Tiouliline	24.00	PSA	November 1, 2041
Argentina			
Aguada Pichana East Residual	27.27	Concession	July 17, 2052
Aguada Pichana East Vaca Muerta	22.50	Concession	July 17, 2052
Aguada San Roque	24.71	Concession	November 14, 2027
Ara South	37.50	Concession	April 30, 2031
Aries	37.50	Concession	April 30, 2041
Cañadón Alfa	37.50	Concession	April 30, 2031
Carina	37.50	Concession	April 30, 2041
Fenix	37.50	Concession	April 30, 2041
Hidra	37.50	Concession	April 30, 2031
Kaus	37.50	Concession	April 30, 2031
Leo	37.50	Concession	October 23, 2038
Loma Las Yeguas	24.71	Concession	November 14, 2027
Rincon Chico	24.71	Concession	November 14, 2027
San Roque Vaca Muerta	24.71	Concession	November 14, 2027
Tauro-Unicornio-Sirius	35.00	Concession	October 23, 2038
Vega-Pleyade	37.50	Concession	April 30, 2041
Denmark			
Cecilie	43.59	Concession	June 18, 2032
Nini	42.857	Concession	June 18, 2032
Egypt			
Disouq 1-3	100.00	PSA	August 11, 2034
Disouq 1-5	100.00	PSA	August 11, 2034
Disouq 2	100.00	PSA	August 11, 2034
East Damanhour	40.00	PSA	September 26, 2043
El Arish P00 Seg 1	17.25	Concession	February 5, 2039
Fayoum	17.25	Concession	February 5, 2039
Giza	17.25	Concession	February 5, 2039
Hodoa Aquitan (M15 Top sand)	17.25	PSA	August 8, 2026
Libra	17.25	Concession	March 24, 2037
Libra DA	9.4875	Concession	March 24, 2037
Libra P80 Seg 1a	17.25	Concession	March 24, 2037
Maadi P80 Seg 1 (includes Seg 2 and Levee)	17.25	PSA	August 8, 2026
Maadi Segment 3	17.25	PSA	August 8, 2026
North Sidi Ghazy-1	100.00	PSA	August 11, 2034
North Sidi Ghazy-2-1	100.00	PSA	August 11, 2034
North Sidi Ghazy-2-3	100.00	PSA	August 11, 2034
North Sidi Ghazy-4	100.00	PSA	August 11, 2034
Northwest Khilala	100.00	PSA	September 2, 2033
Northwest Sidi Ghazy-1	100.00	PSA	August 11, 2034
Northwest Sidi Ghazy-7	100.00	PSA	August 11, 2034
Polaris Pliocene P78 Ch	17.25	PSA	August 8, 2026
Polaris Pliocene P78 Ch Splay	17.25	PSA	August 8, 2026

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-1 – PROPERTIES EVALUATED – *(Continued)*

Country Field/Discovery	Working Interest (%)	Fiscal Regime	License Expiration
Egypt – *(Continued)*			
Raven	17.25	Concession	February 5, 2039
Raven West M15	17.25	Concession	February 5, 2039
Raven West M20	17.25	Concession	February 5, 2039
Raven West M40D2	17.25	Concession	February 5, 2039
Raven West M40E	17.25	Concession	February 5, 2039
Raven West Serravallian 2	17.25	Concession	February 5, 2039
Raven West Serravallian 4	17.25	Concession	February 5, 2039
Ruby P78 R1 Seg 1	17.25	Concession	February 5, 2039
Sidi Salam Southeast-1	100.00	PSA	August 11, 2034
Sidi Salam Southeast-2	100.00	PSA	August 11, 2034
Sidi Salam Southeast-3	100.00	PSA	August 11, 2034
Sidi Salam Southeast-6	100.00	PSA	August 11, 2034
South Sidi Ghazy-1-1	100.00	PSA	August 11, 2034
South Sidi Ghazy-1-2	100.00	PSA	August 11, 2034
Taurus	17.25	Concession	March 24, 2037
Taurus Deep Serravallian SV7	17.25	Concession	March 24, 2037
Taurus Deep Serravallian SV8	17.25	Concession	March 24, 2037
Taurus P80 Seg 1	17.25	Concession	March 24, 2037
Taurus P86 Seg 2	17.25	Concession	March 24, 2037
Viper P83 Viper Channel and Aband	17.25	PSA	August 8, 2026
Germany			
Aldorf	100.00	Concession	June 30, 2030
Barrien	50.00	Concession	September 13, 2040
Bockstedt	100.00	Concession	January 31, 2030
Boetersen	20.812	Concession	September 30, 2045
Boetersen South	0.85	Concession	August 31, 2033
Boestlingen	50.00	Concession	October 31, 2027
Dueste Valendis	100.00	Concession	June 30, 2030
Emlichheim	90.00	Concession	May 31, 2043
Fehndorf	70.00	Concession	December 31, 2035
Hemsbuende	36.279	Concession	September 30, 2045
Mittelplate	100.00	Concession	December 31, 2041
Preyersmuehle South	8.273	Concession	December 31, 2045
Rehden	100.00	Concession	December 31, 2040
Ruetenbrock	100.00	Concession	September 30, 2034
Soehlingen	27.48	Concession	December 31, 2045
Staffhorst HD	50.00	Concession	August 7, 2030
Staffhorst North	50.00	Concession	April 17, 2024
Taaken	14.28	Concession	December 5, 2040
Voelkersen	100.00	Concession	December 31, 2028
Weissenmoor	40.00	Concession	January 27, 2028
Libya			
Al-Jurf	12.50	PSA	April 10, 2035
Mexico			
Chinwol	25.00	Concession	May 7, 2053
Hokchi	37.00	PSA	December 31, 2040
Kan	40.00	PSA	March 31, 2024
Naajal	50.00	Concession	March 7, 2052
Ogarrio	50.00	Concession	March 6, 2043
Polok	25.00	Concession	May 7, 2053
Zama	19.83	PSA	September 4, 2045

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-1 – PROPERTIES EVALUATED – ***(Continued)***

DEGOLYER AND MACNAUGHTON F-716 TEXAS REGISTERED ENGINEERING FIRM

Country Field/Discovery	Working Interest (%)	Fiscal Regime	License Expiration
Norway			
Aasta Hansteen	24.00	Concession	February 2, 2041
Adriana	40.00	Concession	February 2, 2032
Ærfugl North (Snadd Outer PL212E)	25.00	Concession	February 2, 2033
Alta	30.00	Concession	May 14, 2051
Alve North	20.00	Concession	December 31, 2036
Balderbrå	30.00	Concession	February 10, 2027
Bauge	27.50	Concession	December 17, 2029
Beaujolais	40.00	Concession	June 4, 2035
Bergknapp	40.00	Concession	February 5, 2026
Bergknapp Åre	40.00	Concession	February 5, 2026
Busta	20.00	Concession	February 6, 2025
Dvalin	55.00	Concession	October 3, 2041 / February 2, 2032
Dvalin North	55.00	Concession	October 3, 2041
Edvard Grieg	15.00	Concession	December 17, 2029
Gjøa	28.00	Concession	July 8, 2028
Hamlet (Gjøa North)	28.00	Concession	July 8, 2028
Hyme	27.50	Concession	December 17, 2029
Idun North	40.00	Concession	December 31, 2036
Irpa	19.00	Concession	June 18, 2041
Iving	6.50	Concession	February 5, 2026
Maria	50.00	Concession	February 28, 2036
Neiden	30.00	Concession	May 14, 2051
Newt	10.00	Concession	June 2, 2027
Nidhogg	20.00	Concession	March 1, 2028
Njord Unit	50.00	Concession	April 10, 2034
Noatun	45.00	Concession	April 10, 2034
Nova	39.00	Concession	February 16, 2041
Obelix	10.00	Concession	February 19, 2027
Ofelia	20.00	Concession	September 2, 2026
Ofelia Kyrre	20.00	Concession	September 2, 2026
Orion	40.00	Concession	June 4, 2035
Oswig	20.00	Concession	February 19, 2027
Sabina	40.00	Concession	February 2, 2032
Skarv Unit	28.0825	Concession	March 3, 2029
Snøhvit Unit	2.81	Concession	October 1, 2035
Snorre Unit	8.5711	Concession	December 31, 2040
Solveig	15.00	Concession	January 6, 2036
Statfjord East Unit	1.40	Concession	August 10, 2026
Storjo	30.00	Concession	May 12, 2036
Storjo Cretaceous	30.00	Concession	May 12, 2036
Sygna Unit	1.26	Concession	August 10, 2026
Syrah	40.00	Concession	June 4, 2035
Tordis	2.80	Concession	December 31, 2040
Tornerose	2.80	Concession	December 17, 2035
Vega Unit	56.70	Concession	June 4, 2035
Vigdis	2.80	Concession	December 31, 2040

Note: In certain cases, the working interests shown are not representative of Wintershall Dea net reserves entitlement due to certain fields being subject to the terms of production sharing agreements.

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-2
SUMMARY of NET RESERVES and REVENUE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

Reserves Category	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Future Net Revenue (10^3U.S.$)	Present Worth at 10 Percent (10^3U.S.$)	Present Worth at 6 Percent (10^3U.S.$)	Present Worth at 8 Percent (10^3U.S.$)	Present Worth at 12 Percent (10^3U.S.$)
Total Proved	226,212	47,243	2,610,158	739,555	10,414,162	7,371,082	8,508,852	7,983,892	7,087,189
Proved plus Probable	316,116	70,599	3,793,720	1,064,165	16,474,084	10,528,176	12,568,051	11,593,251	10,001,149
Proved plus Probable plus Possible	390,049	87,174	4,994,865	1,369,163	22,106,234	13,282,049	16,196,493	14,779,665	12,515,256

Notes:
1. Probable and possible reserves and values for probable and possible reserves have not been risk adjusted to make them comparable to proved reserves and values for proved reserves.
2. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-3
SUMMARY of GROSS RESERVES
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
with interests attributable to
WINTERSHALL DEA

Country/Region	Total Proved				Proved plus Probable				Proved plus Probable plus Possible			
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
Argentina	26,414	19,186	2,987,893	579,152	33,788	24,456	3,988,347	770,449	40,212	26,893	5,060,349	970,739
Denmark	0	0	0	0	0	0	0	0	0	0	0	0
Germany	67,866	0	326,648	126,196	102,715	0	486,542	189,598	123,565	0	606,358	231,843
Mexico	91,518	0	50,299	100,500	116,199	0	77,394	130,019	132,761	0	96,971	150,077
North Africa	67,471	111	975,118	241,710	80,909	320	1,489,120	347,143	95,340	520	1,972,702	448,128
Norway	843,535	160,286	7,591,809	2,359,501	1,061,347	222,081	9,823,497	3,037,624	1,285,414	276,723	12,419,578	3,779,919
Total	**1,096,804**	**179,583**	**11,931,767**	**3,407,059**	**1,394,958**	**246,857**	**15,864,900**	**4,474,833**	**1,677,292**	**304,136**	**20,155,958**	**5,580,706**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-4
SUMMARY of WORKING INTEREST RESERVES
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Total Proved				Proved plus Probable				Proved plus Probable plus Possible			
Country/Region	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
Argentina	9,336	7,194	1,000,626	195,213	11,908	9,173	1,331,278	258,809	14,118	10,085	1,684,259	324,964
Denmark	0	0	0	0	0	0	0	0	0	0	0	0
Germany	66,949	0	135,026	91,061	101,591	0	217,631	140,454	122,189	0	282,015	172,549
Mexico	35,712	0	22,896	39,801	45,935	0	35,574	52,288	52,854	0	44,742	60,844
North Africa	9,204	111	249,044	53,787	12,008	320	387,525	81,529	14,927	520	510,736	106,650
Norway	121,861	39,988	1,321,364	397,807	166,301	61,252	1,998,183	584,371	210,927	76,807	2,694,465	768,888
Total	**243,062**	**47,293**	**2,728,956**	**777,669**	**337,743**	**70,745**	**3,970,191**	**1,117,451**	**415,015**	**87,412**	**5,216,217**	**1,433,895**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-5
SUMMARY of NET RESERVES
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

Country/Region	Total Proved: Oil and Condensate (10^3bbl)	Total Proved: LPG (10^3bbl)	Total Proved: Sales Gas (10^6ft^3)	Total Proved: Combined Oil Equivalent (10^3boe)	Proved plus Probable: Oil and Condensate (10^3bbl)	Proved plus Probable: LPG (10^3bbl)	Proved plus Probable: Sales Gas (10^6ft^3)	Proved plus Probable: Combined Oil Equivalent (10^3boe)	Proved plus Probable plus Possible: Oil and Condensate (10^3bbl)	Proved plus Probable plus Possible: LPG (10^3bbl)	Proved plus Probable plus Possible: Sales Gas (10^6ft^3)	Proved plus Probable plus Possible: Combined Oil Equivalent (10^3boe)
Argentina	9,336	7,194	1,000,626	195,213	11,908	9,173	1,331,278	258,809	14,118	10,085	1,684,259	324,964
Denmark	0	0	0	0	0	0	0	0	0	0	0	0
Germany	66,949	0	135,026	91,061	101,591	0	217,631	140,454	122,189	0	282,015	172,549
Mexico	22,549	0	20,018	26,124	28,866	0	31,309	34,457	33,276	0	39,447	40,320
North Africa	5,517	61	133,124	29,350	7,450	174	215,319	46,074	9,539	282	294,679	62,442
Norway	121,861	39,988	1,321,364	397,807	166,301	61,252	1,998,183	584,371	210,927	76,807	2,694,465	768,888
Total	**226,212**	**47,243**	**2,610,158**	**739,555**	**316,116**	**70,599**	**3,793,720**	**1,064,165**	**390,049**	**87,174**	**4,994,865**	**1,369,163**

Notes:
1. Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.
2. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-6
SUMMARY of GROSS CONTINGENT RESOURCES
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
with interests attributable to
WINTERSHALL DEA

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	1C				2C				3C			
Country/Region	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
Argentina	35,900	9,078	5,218,440	976,842	204,569	16,587	11,720,864	2,314,167	633,521	21,379	22,394,691	4,653,952
Denmark	0	0	0	0	0	0	0	0	0	0	0	0
Germany	18,990	0	103,604	37,491	74,216	0	216,943	112,956	108,172	0	342,027	169,248
Mexico	466,532	0	178,438	498,396	926,462	0	303,252	980,614	1,408,490	0	495,763	1,497,019
North Africa	8,753	0	727,889	138,733	25,544	31	1,521,774	297,320	70,458	128	3,613,734	715,896
Norway	289,071	38,057	2,421,239	759,492	494,356	79,473	4,069,640	1,300,550	740,602	128,478	6,293,978	1,993,005
Total	**819,246**	**47,135**	**8,649,610**	**2,410,954**	**1,725,147**	**96,091**	**17,832,473**	**5,005,607**	**2,961,243**	**149,985**	**33,140,193**	**9,029,120**

Notes:
1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
3. All of the contingent resources estimated in this report have an economic status of undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the associated cash flows.
4. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-7
SUMMARY of WORKING INTEREST CONTINGENT RESOURCES
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

	1C				2C				3C			
Country/Region	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
Argentina	10,288	3,394	1,401,194	263,895	52,619	6,207	3,006,006	595,613	159,452	8,002	5,543,828	1,157,423
Denmark	0	0	0	0	0	0	0	0	0	0	0	0
Germany	18,865	0	64,576	30,396	73,971	0	136,169	98,287	107,839	0	212,894	145,856
Mexico	110,231	0	53,673	119,815	226,091	0	95,017	243,058	358,639	0	158,415	386,927
North Africa	1,521	0	129,587	24,662	4,516	31	273,267	53,345	12,568	128	648,613	128,520
Norway	52,288	15,769	360,789	132,484	91,276	33,416	686,393	247,262	148,728	54,554	1,163,513	411,052
Total	**193,193**	**19,163**	**2,009,819**	**571,252**	**448,473**	**39,654**	**4,196,852**	**1,237,565**	**787,226**	**62,684**	**7,727,263**	**2,229,778**

Notes:
1. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
2. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
3. All of the contingent resources estimated in this report have an economic status of undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the associated cash flows.
4. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

DeGolyer and MacNaughton F-716 Texas Registered Engineering Firm

TABLE A-8
SUMMARY of NET CONTINGENT RESOURCES
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

	1C				2C				3C			
Country/Region	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Combined Oil Equivalent (10^3boe)
Argentina	10,288	3,394	1,401,194	263,895	52,619	6,207	3,006,006	595,613	159,452	8,002	5,543,828	1,157,423
Denmark	0	0	0	0	0	0	0	0	0	0	0	0
Germany	18,865	0	64,576	30,396	73,971	0	136,169	98,287	107,839	0	212,894	145,856
Mexico	110,231	0	53,673	119,815	226,091	0	95,017	243,058	358,639	0	158,415	386,927
North Africa	1,521	0	129,587	24,662	4,516	31	273,267	53,345	12,568	128	648,613	128,520
Norway	52,288	15,769	360,789	132,484	91,276	33,416	686,393	247,262	148,728	54,554	1,163,513	411,052
Total	**193,193**	**19,163**	**2,009,819**	**571,252**	**448,473**	**39,654**	**4,196,852**	**1,237,565**	**787,226**	**62,684**	**7,727,263**	**2,229,778**

Notes:
1. For the purposes of this report, net contingent resources are set equal to working interest contingent resources.
2. Application of any risk factor to contingent resources quantities does not equate contingent resources with reserves.
3. There is no certainty that it will be commercially viable to produce any portion of the contingent resources evaluated herein.
4. All of the contingent resources estimated in this report have an economic status of undetermined, since the evaluations of those contingent resources are at a stage such that it is premature to clearly define the associated cash flows.
5. Sales gas volumes were converted to oil equivalent using an energy equivalent factor of 5,600 cubic feet of gas per 1 barrel of oil equivalent.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-9
SUMMARY FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	126,413	16,360	1,450,873	29,982	5,315	403,753	1,090,682	962,737	94,113
2025	111,126	17,551	1,224,793	27,083	5,896	362,278	1,027,208	728,425	14,299
2026	101,513	17,393	1,188,085	25,169	5,981	346,366	1,035,672	380,200	18,491
2027	90,666	16,651	1,048,177	22,608	5,824	299,882	998,693	206,071	26,774
2028	81,547	15,324	920,437	20,437	5,224	263,484	912,960	104,844	174,986
2029	71,262	12,831	785,478	17,374	4,136	208,850	768,533	89,320	137,900
2030	62,726	11,061	674,592	14,885	3,281	165,352	707,086	99,106	29,697
2031	55,130	9,703	559,035	12,741	2,716	122,881	619,990	56,067	86,272
2032	50,185	8,229	494,415	11,201	2,058	99,064	554,705	42,694	92,595
2033	45,177	7,051	451,483	9,649	1,564	84,351	510,983	59,663	80,753
2034	40,323	6,505	417,980	8,565	1,367	73,925	495,437	41,149	6,481
2035	36,789	5,647	390,042	7,670	955	63,325	424,808	14,426	172,887
2036	33,190	4,881	351,186	6,884	735	52,554	368,758	17,391	253,856
2037	30,498	4,711	334,600	6,252	658	47,385	363,365	10,341	5,918
2038	27,922	4,177	293,878	5,755	433	37,523	279,288	22,466	217,161
2039	24,336	4,111	283,877	4,801	386	33,964	244,692	12,026	303,102
2040	20,656	3,843	254,962	3,791	317	28,476	181,155	10,374	216,481
2041	15,517	3,381	210,303	2,727	161	14,132	146,343	3,543	844,174
2042	12,417	2,862	166,326	875	81	5,581	56,972	8,797	0
2043	11,034	2,317	134,341	791	65	4,504	54,332	2,830	12,016
2044	10,200	2,186	126,336	729	61	4,140	53,097	9,152	0
2045	8,792	1,536	88,798	653	43	3,036	50,360	2,944	22,859
2046	7,930	1,272	74,053	597	36	2,415	47,066	3,003	0
2047	5,955	0	1,596	510	0	359	39,726	3,063	30,845
2048	5,552	0	1,504	477	0	338	39,696	0	0
Subtotal	**1,086,856**	**179,583**	**11,927,150**	**242,206**	**47,293**	**2,727,918**	**11,071,607**	**2,890,632**	**2,841,660**
Remaining	9,948	0	4,617	856	0	1,038	80,773	0	430,018
Total	**1,096,804**	**179,583**	**11,931,767**	**243,062**	**47,293**	**2,728,956**	**11,152,380**	**2,890,632**	**3,271,678**

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-10
SUMMARY FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

DeGolyer and MacNaughton F-716 Texas Registered Engineering Firm

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	144,677	18,846	1,609,356	34,762	6,173	441,359	1,130,767	1,104,009	88,742
2025	134,591	23,898	1,458,208	33,853	8,523	430,612	1,116,793	877,751	17,862
2026	125,474	22,236	1,382,713	32,116	7,865	404,843	1,103,424	429,033	17,111
2027	114,017	22,437	1,323,398	29,707	8,064	385,068	1,097,738	218,360	25,341
2028	103,349	21,313	1,208,938	27,470	7,339	346,932	1,056,327	105,109	8,878
2029	93,317	19,259	1,105,934	24,787	6,475	313,750	977,358	91,643	8,856
2030	82,318	16,742	989,262	21,594	5,319	274,485	877,489	100,088	239,133
2031	72,974	14,907	890,022	19,079	4,581	244,532	838,248	56,513	9,465
2032	65,299	12,258	778,269	16,682	3,435	205,375	783,447	42,942	7,133
2033	59,357	10,392	693,351	14,702	2,640	172,744	714,829	59,917	6,949
2034	53,790	9,370	623,893	13,207	2,321	150,099	688,862	41,809	37,851
2035	47,867	8,643	571,795	11,658	2,120	132,364	635,431	14,486	207,779
2036	43,766	7,345	508,566	10,634	1,651	108,723	585,694	18,303	6,483
2037	40,084	6,240	459,634	9,674	1,180	90,917	486,731	10,828	227,784
2038	36,876	5,460	397,559	9,068	966	72,487	434,457	22,886	259,774
2039	33,864	4,854	359,455	8,292	680	60,056	335,320	13,341	273,426
2040	29,926	4,611	326,689	7,384	633	54,171	304,054	11,098	26,874
2041	21,845	3,581	240,287	5,501	315	27,022	253,967	3,959	1,035,897
2042	15,679	2,884	179,142	1,788	139	10,564	128,803	10,229	175,035
2043	13,069	2,534	162,137	960	71	8,832	71,329	3,680	213,422
2044	12,050	2,304	146,939	887	65	7,780	69,020	10,030	5,457
2045	11,009	2,056	130,578	814	58	6,925	66,432	2,944	0
2046	10,063	1,801	116,118	749	50	6,254	65,107	3,003	0
2047	9,174	1,567	101,373	688	44	5,577	63,801	3,063	39,611
2048	8,360	1,319	81,681	632	38	4,043	58,231	0	0
Subtotal	**1,382,795**	**246,857**	**15,845,297**	**336,688**	**70,745**	**3,965,514**	**13,943,659**	**3,255,024**	**2,938,863**
Remaining	12,163	0	19,603	1,055	0	4,677	104,748	0	463,178
Total	**1,394,958**	**246,857**	**15,864,900**	**337,743**	**70,745**	**3,970,191**	**14,048,407**	**3,255,024**	**3,402,041**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-11
SUMMARY FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	155,938	19,582	1,716,532	37,566	6,396	465,687	1,161,553	1,124,231	88,503
2025	149,411	25,063	1,609,630	37,633	8,949	469,481	1,170,109	906,956	17,704
2026	147,259	24,428	1,587,066	37,777	8,699	463,709	1,198,559	449,099	17,016
2027	137,217	26,719	1,614,368	36,321	9,828	475,620	1,256,913	219,576	25,290
2028	124,124	24,932	1,465,296	33,554	8,758	427,583	1,153,847	105,330	8,048
2029	112,612	22,977	1,340,710	30,758	7,840	388,361	1,060,750	89,554	7,801
2030	98,798	20,323	1,198,037	26,896	6,587	342,717	995,291	100,089	163,074
2031	88,168	18,476	1,104,880	23,806	5,797	310,734	950,141	58,687	10,592
2032	80,376	16,029	1,008,706	21,411	4,678	278,912	882,141	42,942	87,196
2033	74,246	14,461	949,123	19,400	3,990	258,962	856,872	59,917	6,995
2034	67,081	13,466	878,840	17,306	3,614	236,727	827,822	41,809	30,444
2035	61,316	11,948	812,338	15,771	3,189	217,063	775,591	14,691	14,330
2036	54,615	10,051	732,393	13,909	2,557	195,255	730,281	18,512	85,157
2037	48,831	8,618	653,702	12,529	2,137	168,694	682,321	11,041	17,107
2038	45,107	6,338	543,811	11,725	1,314	132,543	567,034	23,539	414,818
2039	41,021	5,544	495,278	10,642	909	114,016	485,381	13,563	200,838
2040	36,835	5,434	464,353	9,575	852	102,980	466,287	11,324	5,444
2041	26,588	4,149	326,315	6,982	456	58,582	375,260	4,190	966,099
2042	20,846	3,499	232,986	2,825	223	23,528	229,686	10,465	21,693
2043	17,544	3,287	215,129	1,585	102	13,768	116,862	3,680	331,669
2044	16,133	3,027	200,029	1,497	90	12,591	108,903	10,030	93,486
2045	14,556	2,533	167,600	1,368	75	10,798	103,981	4,089	229,063
2046	12,554	2,336	157,518	933	66	9,954	76,986	3,917	113,453
2047	11,571	2,079	140,886	863	58	9,093	75,573	4,006	39,611
2048	10,603	1,769	115,291	801	50	6,945	68,780	1,215	0
Subtotal	**1,653,350**	**297,068**	**19,730,817**	**413,433**	**87,214**	**5,194,303**	**16,376,924**	**3,332,452**	**2,995,431**
Remaining	23,942	7,068	425,141	1,582	198	21,914	172,285	0	471,990
Total	**1,677,292**	**304,136**	**20,155,958**	**415,015**	**87,412**	**5,216,217**	**16,549,209**	**3,332,452**	**3,467,421**

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-12
FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
ARGENTINA

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	2,986	1,397	345,460	1,001	524	107,464	127,642	178,187	0
2025	2,846	1,464	328,916	976	548	105,646	109,222	100,404	4,294
2026	2,853	1,470	334,473	983	551	109,282	106,960	6,309	8,035
2027	2,522	1,468	285,382	871	549	94,022	92,950	6,436	16,988
2028	2,157	1,424	248,047	777	534	84,489	79,481	1,218	0
2029	1,979	1,415	218,805	714	530	75,155	71,744	1,242	0
2030	1,716	1,407	186,727	622	528	64,262	62,604	0	0
2031	1,396	1,262	155,968	505	474	53,579	53,553	0	0
2032	1,214	1,188	137,518	439	446	47,315	48,284	0	0
2033	1,092	1,080	123,452	395	405	42,578	44,671	0	0
2034	981	966	110,508	356	363	38,165	41,286	0	0
2035	905	903	101,569	330	337	35,178	39,053	0	0
2036	833	831	92,991	301	313	32,264	36,964	0	0
2037	753	751	84,083	274	282	29,195	34,635	0	0
2038	684	709	70,261	254	265	25,431	28,873	0	0
2039	634	658	64,822	232	247	23,498	27,618	0	0
2040	582	602	59,428	215	226	21,565	26,142	0	0
2041	198	191	21,970	72	72	7,600	13,289	0	173,244
2042	10	0	2,249	3	0	506	1,378	0	0
2043	10	0	2,086	2	0	469	1,306	0	0
2044	10	0	1,947	2	0	438	1,246	0	0
2045	8	0	1,814	2	0	408	1,186	0	0
2046	8	0	1,700	2	0	382	1,136	0	0
2047	8	0	1,596	1	0	359	1,090	0	0
2048	7	0	1,504	2	0	338	1,050	0	0
Subtotal	**26,392**	**19,186**	**2,983,276**	**9,331**	**7,194**	**999,588**	**1,053,363**	**293,796**	**202,561**
Remaining	22	0	4,617	5	0	1,038	3,406	0	181,414
Total	**26,414**	**19,186**	**2,987,893**	**9,336**	**7,194**	**1,000,626**	**1,056,769**	**293,796**	**383,975**

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-13
FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
ARGENTINA

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	3,172	1,605	366,036	1,056	603	113,333	133,600	178,187	0
2025	3,176	1,572	367,689	1,080	591	117,848	121,506	100,404	4,294
2026	3,237	1,540	379,454	1,110	578	123,286	121,658	6,309	8,035
2027	2,989	1,548	350,809	1,028	581	115,784	113,138	6,436	16,988
2028	2,521	1,558	302,452	903	583	102,531	95,874	1,218	0
2029	2,377	1,555	276,999	856	584	94,712	90,020	1,242	0
2030	2,092	1,563	241,847	757	586	82,750	79,776	0	0
2031	1,751	1,414	211,276	630	530	72,226	70,816	0	0
2032	1,530	1,325	192,188	551	497	65,812	65,040	0	0
2033	1,446	1,323	177,832	523	495	61,063	61,263	0	0
2034	1,391	1,315	167,569	503	493	57,743	59,049	0	0
2035	1,323	1,312	155,609	480	491	53,709	55,338	0	0
2036	1,291	1,322	149,028	468	496	51,628	54,443	0	0
2037	1,236	1,286	140,208	450	483	48,677	52,365	0	0
2038	1,197	1,312	127,891	439	492	45,555	47,520	0	0
2039	1,159	1,284	122,730	425	481	43,808	46,689	0	0
2040	1,104	1,221	116,594	407	458	41,679	45,241	0	0
2041	399	401	47,627	141	151	15,980	22,431	0	172,350
2042	60	0	13,618	16	0	3,372	10,778	0	0
2043	53	0	12,538	14	0	3,101	10,573	0	0
2044	51	0	11,569	12	0	2,858	10,393	0	0
2045	44	0	10,610	11	0	2,618	10,197	0	0
2046	41	0	9,716	11	0	2,393	10,024	0	0
2047	37	0	8,801	10	0	2,161	9,859	0	0
2048	35	0	8,054	8	0	1,974	9,721	0	0
Subtotal	**33,712**	**24,456**	**3,968,744**	**11,889**	**9,173**	**1,326,601**	**1,407,312**	**293,796**	**201,667**
Remaining	76	0	19,603	19	0	4,677	23,157	0	182,482
Total	**33,788**	**24,456**	**3,988,347**	**11,908**	**9,173**	**1,331,278**	**1,430,469**	**293,796**	**384,149**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-14
FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
ARGENTINA

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	3,335	1,810	384,250	1,102	679	118,327	138,669	178,187	0
2025	3,412	1,645	394,437	1,157	617	125,503	129,289	100,404	4,294
2026	3,588	1,576	430,190	1,223	591	139,356	135,325	6,309	8,035
2027	3,426	1,620	412,056	1,178	608	135,817	129,587	6,436	16,988
2028	2,934	1,689	369,725	1,051	631	125,194	113,419	1,218	0
2029	2,836	1,685	349,956	1,019	633	119,617	109,239	1,242	0
2030	2,642	1,708	325,694	953	640	111,837	104,168	0	0
2031	2,170	1,549	278,819	780	581	95,289	90,444	0	0
2032	1,889	1,431	256,549	677	537	87,772	84,628	0	0
2033	1,802	1,444	240,542	648	541	82,502	81,457	0	0
2034	1,708	1,442	224,576	617	542	77,134	78,114	0	0
2035	1,664	1,479	216,113	600	554	74,500	76,813	0	0
2036	1,614	1,482	206,927	584	556	71,528	75,323	0	0
2037	1,551	1,467	195,301	560	551	67,608	72,869	0	0
2038	1,494	1,479	181,155	545	555	63,881	67,818	0	0
2039	1,454	1,470	173,944	531	550	61,440	66,792	0	0
2040	1,405	1,440	165,658	513	540	58,571	65,119	0	0
2041	528	477	70,826	186	179	23,243	32,063	0	172,350
2042	102	0	24,209	26	0	5,975	15,277	0	0
2043	94	0	22,642	24	0	5,587	15,004	0	0
2044	90	0	21,185	23	0	5,226	14,758	0	0
2045	82	0	19,780	22	0	4,878	14,504	0	0
2046	77	0	18,503	20	0	4,563	14,309	0	0
2047	71	0	17,091	17	0	4,209	14,127	0	0
2048	67	0	15,911	18	0	3,914	13,974	0	0
Subtotal	**40,035**	**26,893**	**5,016,039**	**14,074**	**10,085**	**1,673,471**	**1,753,089**	**293,796**	**201,667**
Remaining	177	0	44,310	44	0	10,788	44,149	0	182,503
Total	**40,212**	**26,893**	**5,060,349**	**14,118**	**10,085**	**1,684,259**	**1,797,238**	**293,796**	**384,170**

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-15
FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
DENMARK

DeGolyer and MacNaughton F-716 TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Remaining	0	0	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DeGolyer and MacNaughton F-716 Texas Registered Engineering Firm

TABLE A-16
FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
DENMARK

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Remaining	0	0	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-17
FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
DENMARK

Year	Gross			Working Interest					
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0
2041	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Remaining	0	0	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-18
FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
GERMANY

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	6,203	0	41,275	6,098	0	20,205	163,684	142,734	83,493
2025	5,990	0	42,011	5,894	0	20,192	158,853	104,696	0
2026	5,781	0	39,578	5,692	0	18,721	156,750	52,186	330
2027	5,403	0	34,906	5,325	0	16,295	158,427	80,239	1,013
2028	5,197	0	30,829	5,119	0	14,201	159,001	36,718	92,718
2029	4,957	0	22,762	4,883	0	7,867	103,900	8,679	0
2030	4,427	0	19,655	4,366	0	6,736	99,862	8,523	22,102
2031	3,936	0	14,722	3,886	0	4,763	93,928	8,290	33,239
2032	3,625	0	12,487	3,578	0	4,053	90,263	6,712	0
2033	3,320	0	11,136	3,276	0	3,594	90,721	6,657	0
2034	3,067	0	9,759	3,027	0	3,127	89,177	6,632	0
2035	2,811	0	8,771	2,775	0	2,803	87,787	8,243	0
2036	2,648	0	7,630	2,614	0	2,421	91,905	5,811	0
2037	2,468	0	6,887	2,440	0	2,178	90,913	4,252	0
2038	2,332	0	6,257	2,302	0	1,979	90,514	4,331	0
2039	2,185	0	5,468	2,158	0	1,709	90,146	17	203,402
2040	1,813	0	5,004	1,812	0	1,558	79,121	12	0
2041	1,702	0	4,261	1,704	0	1,359	78,885	6	647,928
2042	0	0	1,208	0	0	499	3,028	0	0
2043	0	0	876	0	0	343	2,708	0	12,016
2044	1	0	617	0	0	224	2,202	0	0
2045	0	0	549	0	0	199	2,186	0	22,859
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**67,866**	**0**	**326,648**	**66,949**	**0**	**135,026**	**1,983,961**	**484,738**	**1,119,100**
Remaining	0	0	0	0	0	0	0	0	0
Total	**67,866**	**0**	**326,648**	**66,949**	**0**	**135,026**	**1,983,961**	**484,738**	**1,119,100**

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-19
FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
GERMANY

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	7,577	0	46,246	7,467	0	22,752	163,591	143,786	79,257
2025	7,919	0	48,632	7,813	0	23,833	160,430	105,178	4,407
2026	7,783	0	46,950	7,686	0	22,850	158,194	53,506	331
2027	7,297	0	42,785	7,210	0	20,744	160,014	80,500	0
2028	7,385	0	39,499	7,292	0	18,961	160,884	36,983	0
2029	7,276	0	35,824	7,189	0	17,074	146,948	8,913	1,054
2030	6,802	0	31,519	6,730	0	15,082	140,414	9,505	22,102
2031	6,336	0	26,017	6,277	0	12,377	132,472	8,534	0
2032	5,989	0	23,465	5,930	0	10,995	130,774	6,960	0
2033	5,456	0	21,229	5,402	0	9,884	129,462	6,911	0
2034	5,064	0	19,382	5,012	0	8,960	128,668	7,292	0
2035	4,716	0	17,791	4,666	0	8,161	125,829	8,303	106,504
2036	4,457	0	13,024	4,414	0	4,106	95,872	6,503	0
2037	4,201	0	11,871	4,159	0	3,734	94,821	4,739	37,432
2038	3,986	0	9,774	3,946	0	3,113	92,469	4,751	0
2039	3,768	0	8,564	3,731	0	2,689	91,824	383	0
2040	3,452	0	7,707	3,434	0	2,398	91,536	77	0
2041	3,249	0	7,074	3,232	0	2,193	91,302	30	840,349
2042	0	0	6,377	1	0	1,817	6,772	25	0
2043	0	0	5,952	0	0	1,694	6,661	0	12,016
2044	2	0	4,879	0	0	1,256	5,606	0	5,457
2045	0	0	4,266	0	0	1,055	4,464	0	0
2046	0	0	3,986	0	0	984	4,392	0	0
2047	0	0	3,729	0	0	919	4,328	0	39,611
2048	0	0	0	0	0	0	0	0	0
Subtotal	**102,715**	**0**	**486,542**	**101,591**	**0**	**217,631**	**2,327,727**	**492,879**	**1,148,520**
Remaining	0	0	0	0	0	0	0	0	0
Total	**102,715**	**0**	**486,542**	**101,591**	**0**	**217,631**	**2,327,727**	**492,879**	**1,148,520**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-20
FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
GERMANY

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	8,737	0	48,053	8,624	0	23,644	165,166	143,787	79,257
2025	9,141	0	51,507	9,028	0	25,348	161,063	105,178	4,406
2026	9,115	0	50,496	9,012	0	24,747	158,985	53,506	331
2027	8,531	0	46,867	8,436	0	22,945	160,967	80,500	0
2028	8,520	0	44,029	8,418	0	21,400	161,976	36,983	0
2029	8,563	0	40,721	8,466	0	19,690	148,150	8,913	0
2030	8,033	0	36,911	7,953	0	17,837	141,856	9,506	22,104
2031	7,399	0	30,843	7,336	0	14,856	133,614	8,534	1,096
2032	7,094	0	28,131	7,024	0	13,632	131,777	6,960	0
2033	6,607	0	25,905	6,542	0	12,497	130,510	6,911	0
2034	6,233	0	23,888	6,173	0	11,368	129,763	7,292	0
2035	5,870	0	22,289	5,814	0	10,534	126,969	8,508	0
2036	5,559	0	20,882	5,509	0	9,813	130,446	6,712	0
2037	5,206	0	19,429	5,156	0	9,069	129,435	4,952	0
2038	4,942	0	18,163	4,894	0	8,432	129,030	5,404	0
2039	4,654	0	16,760	4,609	0	7,738	128,645	605	0
2040	4,271	0	15,771	4,246	0	7,224	128,631	303	0
2041	3,981	0	14,769	3,957	0	6,718	128,487	261	748,671
2042	292	0	10,763	261	0	3,139	21,667	261	0
2043	243	0	10,167	219	0	2,963	21,571	0	12,015
2044	303	0	9,137	268	0	2,554	20,590	0	42,997
2045	270	0	6,992	243	0	1,924	18,015	0	229,063
2046	0	0	6,205	0	0	1,659	6,568	0	0
2047	0	0	5,898	0	0	1,571	6,524	0	39,611
2048	0	0	639	0	0	256	1,322	0	0
Subtotal	**123,564**	**0**	**605,215**	**122,188**	**0**	**281,558**	**2,621,727**	**495,076**	**1,179,551**
Remaining	1	0	1,143	1	0	457	2,651	0	6,146
Total	**123,565**	**0**	**606,358**	**122,189**	**0**	**282,015**	**2,624,378**	**495,076**	**1,185,697**

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-21
FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
MEXICO

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	9,699	0	6,379	3,801	0	2,854	44,073	21,596	8,441
2025	9,076	0	5,773	3,553	0	2,580	43,523	19,183	7,946
2026	8,624	0	5,325	3,369	0	2,375	43,333	9,294	7,502
2027	7,937	0	4,756	3,098	0	2,122	42,551	2,067	7,104
2028	7,422	0	4,302	2,894	0	1,923	42,143	2,325	6,752
2029	6,852	0	3,840	2,668	0	1,717	41,564	2,299	6,441
2030	6,100	0	3,475	2,379	0	1,574	40,469	2,542	6,167
2031	5,634	0	3,109	2,197	0	1,414	40,062	2,105	5,919
2032	5,199	0	2,754	2,027	0	1,259	39,714	2,235	5,699
2033	4,708	0	2,458	1,836	0	1,135	39,168	2,250	5,508
2034	4,106	0	2,100	1,610	0	990	38,282	2,356	5,338
2035	3,737	0	1,860	1,466	0	890	38,001	1,831	5,183
2036	3,348	0	1,585	1,318	0	773	37,641	1,741	5,044
2037	2,891	0	1,344	1,141	0	672	37,044	1,775	4,923
2038	2,588	0	1,239	1,024	0	618	36,880	970	4,817
2039	1,876	0	0	695	0	0	20,732	0	4,734
2040	1,721	0	0	636	0	0	20,658	0	4,828
2041	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**91,518**	**0**	**50,299**	**35,712**	**0**	**22,896**	**645,838**	**74,569**	**102,346**
Remaining	0	0	0	0	0	0	26	0	0
Total	**91,518**	**0**	**50,299**	**35,712**	**0**	**22,896**	**645,864**	**74,569**	**102,346**

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DeGolyer and MacNaughton F-716 Texas Registered Engineering Firm

TABLE A-22
FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
MEXICO

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	9,892	0	6,706	3,889	0	3,013	44,499	21,596	7,448
2025	9,543	0	6,565	3,763	0	2,966	44,565	19,183	7,215
2026	9,277	0	6,459	3,666	0	2,927	44,815	9,294	6,978
2027	8,970	0	6,147	3,541	0	2,785	44,982	2,067	6,741
2028	8,447	0	5,721	3,336	0	2,602	44,603	2,325	6,521
2029	8,011	0	5,336	3,160	0	2,425	44,408	2,299	6,319
2030	7,667	0	5,154	3,023	0	2,348	44,425	2,542	6,136
2031	7,269	0	4,777	2,863	0	2,180	44,277	2,105	5,965
2032	6,593	0	4,256	2,598	0	1,953	43,375	2,235	5,814
2033	6,165	0	3,943	2,431	0	1,816	43,077	2,250	5,683
2034	5,846	0	3,675	2,304	0	1,697	43,067	2,356	5,567
2035	5,537	0	3,427	2,182	0	1,589	43,054	1,831	5,463
2036	5,204	0	3,131	2,050	0	1,458	42,962	1,741	5,371
2037	4,767	0	2,823	1,879	0	1,324	42,540	1,775	5,293
2038	4,281	0	2,476	1,690	0	1,174	41,936	970	5,229
2039	3,961	0	2,192	1,564	0	1,048	41,799	949	5,178
2040	3,654	0	1,893	1,438	0	912	41,691	659	5,141
2041	592	0	1,439	296	0	720	17,164	392	196
2042	523	0	1,274	262	0	637	17,301	328	88
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**116,199**	**0**	**77,394**	**45,935**	**0**	**35,574**	**774,540**	**76,897**	**102,346**
Remaining	0	0	0	0	0	0	26	0	0
Total	**116,199**	**0**	**77,394**	**45,935**	**0**	**35,574**	**774,566**	**76,897**	**102,346**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-23
FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
MEXICO

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	10,051	0	7,009	3,964	0	3,162	44,844	21,596	7,341
2025	9,935	0	7,291	3,943	0	3,323	45,432	19,183	7,164
2026	9,802	0	7,479	3,911	0	3,427	46,000	9,294	6,962
2027	9,574	0	7,274	3,822	0	3,340	46,373	2,067	6,745
2028	9,323	0	6,995	3,717	0	3,214	46,700	2,325	6,536
2029	8,879	0	6,599	3,539	0	3,030	46,522	2,299	6,340
2030	8,496	0	6,390	3,386	0	2,942	46,485	2,542	6,160
2031	8,158	0	6,024	3,247	0	2,776	46,537	2,105	5,990
2032	7,839	0	5,616	3,111	0	2,582	46,639	2,235	5,836
2033	7,518	0	5,307	2,981	0	2,442	46,713	2,250	5,701
2034	6,974	0	4,892	2,767	0	2,260	46,148	2,356	5,581
2035	6,559	0	4,560	2,605	0	2,114	45,900	1,831	5,474
2036	6,225	0	4,215	2,468	0	1,958	45,868	1,741	5,379
2037	5,938	0	3,921	2,349	0	1,821	45,947	1,775	5,299
2038	5,650	0	3,620	2,231	0	1,681	46,023	970	5,233
2039	5,358	0	3,299	2,112	0	1,534	46,056	949	5,180
2040	5,023	0	2,933	1,971	0	1,362	45,955	659	5,142
2041	775	0	1,886	388	0	943	17,711	392	196
2042	684	0	1,661	342	0	831	17,786	328	87
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**132,761**	**0**	**96,971**	**52,854**	**0**	**44,742**	**819,639**	**76,897**	**102,346**
Remaining	0	0	0	0	0	0	25	0	0
Total	**132,761**	**0**	**96,971**	**52,854**	**0**	**44,742**	**819,664**	**76,897**	**102,346**

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DeGolyer and MacNaughton F-716 Texas Registered Engineering Firm

TABLE A-24
FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
NORTH AFRICA

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	9,637	48	188,018	1,515	48	51,389	72,853	54,438	2,179
2025	7,696	36	132,858	1,164	36	38,823	56,358	62,330	2,059
2026	6,785	27	111,137	997	27	32,564	50,939	13,438	1,848
2027	5,963	0	84,363	781	0	18,866	28,500	560	1,669
2028	5,373	0	89,023	701	0	20,260	25,620	571	1,587
2029	4,819	0	81,214	626	0	18,607	22,928	194	1,503
2030	4,352	0	65,804	565	0	15,087	22,040	198	1,428
2031	3,582	0	45,001	447	0	10,800	17,753	0	1,358
2032	3,276	0	37,518	410	0	9,003	15,919	0	1,296
2033	2,965	0	31,272	370	0	7,506	15,857	0	1,224
2034	2,628	0	26,184	329	0	6,283	17,262	0	1,143
2035	2,377	0	21,962	297	0	5,270	17,223	0	1,089
2036	2,163	0	18,502	270	0	4,441	16,554	0	1,044
2037	1,959	0	15,973	245	0	3,835	16,858	0	995
2038	1,802	0	14,304	225	0	3,433	16,014	0	965
2039	1,659	0	11,985	208	0	2,877	15,790	0	935
2040	435	0	0	54	0	0	(258)	0	21,864
2041	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**67,471**	**111**	**975,118**	**9,204**	**111**	**249,044**	**428,210**	**131,729**	**44,186**
Remaining	0	0	0	0	0	0	0	0	0
Total	**67,471**	**111**	**975,118**	**9,204**	**111**	**249,044**	**428,210**	**131,729**	**44,186**

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-25
FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
NORTH AFRICA

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	11,751	55	254,635	1,903	55	64,733	77,870	81,200	2,037
2025	9,632	56	197,774	1,557	56	53,706	60,465	72,111	1,946
2026	8,050	50	160,197	1,286	50	46,342	53,148	13,438	1,767
2027	7,111	41	134,374	1,109	41	37,573	52,041	777	1,612
2028	6,192	34	121,909	942	34	32,109	46,774	571	1,550
2029	5,896	28	114,882	888	28	29,421	32,679	2,283	1,483
2030	5,480	23	110,619	820	23	26,807	31,586	198	1,424
2031	4,629	18	88,860	673	18	22,069	31,403	202	1,368
2032	3,798	15	63,521	534	15	16,601	22,668	0	1,319
2033	3,300	0	48,150	412	0	11,556	15,816	0	1,266
2034	3,047	0	41,256	382	0	9,901	17,173	0	1,231
2035	2,747	0	35,469	343	0	8,512	17,143	0	1,169
2036	2,477	0	27,779	309	0	6,667	16,488	0	1,112
2037	2,273	0	24,045	284	0	5,772	16,781	0	1,073
2038	2,081	0	21,357	260	0	5,127	15,942	0	1,035
2039	1,934	0	17,825	243	0	4,279	15,710	0	1,013
2040	511	0	14,568	63	0	3,493	9,100	0	282
2041	0	0	11,900	0	0	2,857	8,238	0	0
2042	0	0	0	0	0	0	0	0	21,606
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**80,909**	**320**	**1,489,120**	**12,008**	**320**	**387,525**	**541,025**	**170,780**	**44,293**
Remaining	0	0	0	0	0	0	0	0	0
Total	**80,909**	**320**	**1,489,120**	**12,008**	**320**	**387,525**	**541,025**	**170,780**	**44,293**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-26
FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
NORTH AFRICA

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	13,309	59	308,798	2,186	59	75,851	81,720	81,200	1,905
2025	11,993	60	271,867	1,974	60	68,579	66,221	72,111	1,840
2026	10,541	59	238,466	1,738	59	62,830	58,944	13,438	1,688
2027	8,298	59	177,369	1,363	59	49,266	54,282	776	1,557
2028	7,006	60	149,628	1,159	60	41,693	49,049	792	1,512
2029	6,229	55	122,964	1,017	55	34,545	32,674	194	1,461
2030	5,467	48	109,025	883	48	29,554	31,329	198	1,416
2031	4,984	40	100,996	788	40	27,008	31,375	2,376	1,374
2032	4,596	35	90,813	718	35	24,014	22,929	0	1,337
2033	4,296	29	85,157	662	29	22,162	22,792	0	1,294
2034	3,994	16	75,453	580	16	18,460	24,155	0	1,270
2035	3,613	0	64,040	474	0	14,413	18,013	0	1,247
2036	3,131	0	45,664	400	0	10,570	17,132	0	1,227
2037	2,663	0	35,314	332	0	8,475	16,684	0	1,169
2038	2,413	0	31,264	302	0	7,504	15,861	0	1,116
2039	2,218	0	25,711	278	0	6,173	15,643	0	1,081
2040	589	0	21,777	73	0	5,225	9,080	0	302
2041	0	0	18,396	0	0	4,414	8,238	0	0
2042	0	0	0	0	0	0	0	0	21,606
2043	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0
Subtotal	**95,340**	**520**	**1,972,702**	**14,927**	**520**	**510,736**	**576,121**	**171,085**	**44,402**
Remaining	0	0	0	0	0	0	0	0	0
Total	**95,340**	**520**	**1,972,702**	**14,927**	**520**	**510,736**	**576,121**	**171,085**	**44,402**

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DEGOLYER AND MACNAUGHTON
F-716
TEXAS REGISTERED ENGINEERING FIRM

TABLE A-27
FORECAST of TOTAL PROVED PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
NORWAY

Year	Gross			Working Interest					
	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	97,888	14,915	869,741	17,567	4,743	221,841	682,430	565,782	0
2025	85,518	16,051	715,235	15,496	5,312	195,037	659,252	441,812	0
2026	77,470	15,896	697,572	14,128	5,403	183,424	677,690	298,973	776
2027	68,841	15,183	638,770	12,533	5,275	168,577	676,265	116,769	0
2028	61,398	13,900	548,236	10,946	4,690	142,611	606,715	64,012	73,929
2029	52,655	11,416	458,857	8,483	3,606	105,504	528,397	76,906	129,956
2030	46,131	9,654	398,931	6,953	2,753	77,693	482,111	87,843	0
2031	40,582	8,441	340,235	5,706	2,242	52,325	414,694	45,672	45,756
2032	36,871	7,041	304,138	4,747	1,612	37,434	360,525	33,747	85,600
2033	33,092	5,971	283,165	3,772	1,159	29,538	320,566	50,756	74,021
2034	29,541	5,539	269,429	3,243	1,004	25,360	309,430	32,161	0
2035	26,959	4,744	255,880	2,802	618	19,184	242,744	4,352	166,615
2036	24,198	4,050	230,478	2,381	422	12,655	185,694	9,839	247,768
2037	22,427	3,960	226,313	2,152	376	11,505	183,915	4,314	0
2038	20,516	3,468	201,817	1,950	168	6,062	107,007	17,165	211,379
2039	17,982	3,453	201,602	1,508	139	5,880	90,406	12,009	94,031
2040	16,105	3,241	190,530	1,074	91	5,353	55,492	10,362	189,789
2041	13,617	3,190	184,072	951	89	5,173	54,169	3,537	23,002
2042	12,407	2,862	162,869	872	81	4,576	52,566	8,797	0
2043	11,024	2,317	131,379	789	65	3,692	50,318	2,830	0
2044	10,189	2,186	123,772	727	61	3,478	49,649	9,152	0
2045	8,784	1,536	86,435	651	43	2,429	46,988	2,944	0
2046	7,922	1,272	72,353	595	36	2,033	45,930	3,003	0
2047	5,947	0	0	509	0	0	38,636	3,063	30,845
2048	5,545	0	0	475	0	0	38,646	0	0
Subtotal	**833,609**	**160,286**	**7,591,809**	**121,010**	**39,988**	**1,321,364**	**6,960,235**	**1,905,800**	**1,373,467**
Remaining	9,926	0	0	851	0	0	77,341	0	248,604
Total	**843,535**	**160,286**	**7,591,809**	**121,861**	**39,988**	**1,321,364**	**7,037,576**	**1,905,800**	**1,622,071**

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

DeGolyer and MacNaughton F-716 Texas Registered Engineering Firm

TABLE A-28
FORECAST of TOTAL PROVED-PLUS-PROBABLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
NORWAY

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	112,285	17,186	935,733	20,447	5,515	237,528	711,207	679,240	0
2025	104,321	22,270	837,548	19,640	7,876	232,259	729,827	580,875	0
2026	97,127	20,646	789,653	18,368	7,237	209,438	725,609	346,486	0
2027	87,650	20,848	789,283	16,819	7,442	208,182	727,563	128,580	0
2028	78,804	19,721	739,357	14,997	6,722	190,729	708,192	64,012	807
2029	69,757	17,676	672,893	12,694	5,863	170,118	663,303	76,906	0
2030	60,277	15,156	600,123	10,264	4,710	147,498	581,288	87,843	209,471
2031	52,989	13,475	559,092	8,636	4,033	135,680	559,280	45,672	2,132
2032	47,389	10,918	494,839	7,069	2,923	110,014	521,590	33,747	0
2033	42,990	9,069	442,197	5,934	2,145	88,425	465,211	50,756	0
2034	38,442	8,055	392,011	5,006	1,828	71,798	440,905	32,161	31,053
2035	33,544	7,331	359,499	3,987	1,629	60,393	394,067	4,352	94,643
2036	30,337	6,023	315,604	3,393	1,155	44,864	375,929	10,059	0
2037	27,607	4,954	280,687	2,902	697	31,410	280,224	4,314	183,986
2038	25,331	4,148	236,061	2,733	474	17,518	236,590	17,165	253,510
2039	23,042	3,570	208,144	2,329	199	8,232	139,298	12,009	267,235
2040	21,205	3,390	185,927	2,042	175	5,689	116,486	10,362	21,451
2041	17,605	3,180	172,247	1,832	164	5,272	114,832	3,537	23,002
2042	15,096	2,884	157,873	1,509	139	4,738	93,952	9,876	153,341
2043	13,016	2,534	143,647	946	71	4,037	54,095	3,680	201,406
2044	11,997	2,304	130,491	875	65	3,666	53,021	10,030	0
2045	10,965	2,056	115,702	803	58	3,252	51,771	2,944	0
2046	10,022	1,801	102,416	738	50	2,877	50,691	3,003	0
2047	9,137	1,567	88,843	678	44	2,497	49,614	3,063	0
2048	8,325	1,319	73,627	624	38	2,069	48,510	0	0
Subtotal	**1,049,260**	**222,081**	**9,823,497**	**165,265**	**61,252**	**1,998,183**	**8,893,055**	**2,220,672**	**1,442,037**
Remaining	12,087	0	0	1,036	0	0	81,565	0	280,696
Total	**1,061,347**	**222,081**	**9,823,497**	**166,301**	**61,252**	**1,998,183**	**8,974,620**	**2,220,672**	**1,722,733**

Note: Probable reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

TABLE A-29
FORECAST of TOTAL PROVED-PLUS-PROBABLE-PLUS-POSSIBLE PRODUCTION and EXPENDITURE
as of
DECEMBER 31, 2023
of
CERTAIN PROPERTIES
attributable to
WINTERSHALL DEA
NORWAY

DeGolyer and MacNaughton
F-716
TEXAS REGISTERED ENGINEERING FIRM

	Gross			Working Interest					
Year	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Oil and Condensate (10^3bbl)	LPG (10^3bbl)	Sales Gas (10^6ft^3)	Operating Expenses (10^3U.S.$)	Capital Costs (10^3U.S.$)	Abandonment Cost (10^3U.S.$)
2024	120,506	17,713	968,422	21,690	5,658	244,703	731,154	699,461	0
2025	114,930	23,358	884,528	21,531	8,272	246,728	768,104	610,080	0
2026	114,213	22,793	860,435	21,893	8,049	233,349	799,305	366,552	0
2027	107,388	25,040	970,802	21,522	9,161	264,252	865,704	129,797	0
2028	96,341	23,183	894,919	19,209	8,067	236,082	782,703	64,012	0
2029	86,105	21,237	820,470	16,717	7,152	211,479	724,165	76,906	0
2030	74,160	18,567	720,017	13,721	5,899	180,547	671,453	87,843	133,394
2031	65,457	16,887	688,198	11,655	5,176	170,805	648,171	45,672	2,132
2032	58,958	14,563	627,597	9,881	4,106	150,912	596,168	33,747	80,023
2033	54,023	12,988	592,212	8,567	3,420	139,359	575,400	50,756	0
2034	48,172	12,008	550,031	7,169	3,056	127,505	549,642	32,161	23,593
2035	43,610	10,469	505,336	6,278	2,635	115,502	507,896	4,352	7,609
2036	38,086	8,569	454,705	4,948	2,001	101,386	461,512	10,059	78,551
2037	33,473	7,151	399,737	4,132	1,586	81,721	417,386	4,314	10,639
2038	30,608	4,859	309,609	3,753	759	51,045	308,302	17,165	408,469
2039	27,337	4,074	275,564	3,112	359	37,131	228,245	12,009	194,577
2040	25,547	3,994	258,214	2,772	312	30,598	217,502	10,362	0
2041	21,304	3,672	220,438	2,451	277	23,264	188,761	3,537	44,882
2042	19,768	3,499	196,353	2,196	223	13,583	174,956	9,876	0
2043	17,207	3,287	182,320	1,342	102	5,218	80,287	3,680	319,654
2044	15,740	3,027	169,707	1,206	90	4,811	73,555	10,030	50,489
2045	14,204	2,533	140,828	1,103	75	3,996	71,462	4,089	0
2046	12,477	2,336	132,810	913	66	3,732	56,109	3,917	113,453
2047	11,500	2,079	117,897	846	58	3,313	54,922	4,006	0
2048	10,536	1,769	98,741	783	50	2,775	53,484	1,215	0
Subtotal	**1,261,650**	**269,655**	**12,039,890**	**209,390**	**76,609**	**2,683,796**	**10,606,348**	**2,295,598**	**1,467,465**
Remaining	23,764	7,068	379,688	1,537	198	10,669	125,460	0	283,341
Total	**1,285,414**	**276,723**	**12,419,578**	**210,927**	**76,807**	**2,694,465**	**10,731,808**	**2,295,598**	**1,750,806**

Note: Probable and possible reserves have not been risk adjusted to make them comparable to proved reserves.

These data accompany the report of DeGolyer and MacNaughton and are subject to its specific conditions.

PART XII
UNITED KINGDOM TAXATION

1. GENERAL

A summary of certain UK tax considerations is set out below. It does not constitute tax advice and is intended only as a general guide to the position under current United Kingdom tax law and the published practice of HMRC (which may not be binding on HMRC) as at the date of this document, either of which is subject to change at any time (possibly with retrospective effect). Moreover, the information provided below relates only to certain limited aspects of the United Kingdom taxation treatment of persons who (unless expressly stated otherwise) are resident, and in the case of individuals, domiciled or deemed domiciled, in the UK for UK tax purposes (and not in any other territory) and to whom split-year treatment does not apply and this summary does not purport to be a complete analysis of all potential UK tax consequences of acquiring, holding or disposing of Ordinary Shares. It is assumed that an interest in the Company is held by the absolute beneficial owner of such interest, and some of the statements may not apply to certain classes of persons such as (and without limitation) those who are not the beneficial owners of their interests in the Company (or who will not be the beneficial owners of any Ordinary Shares issued in connection with the Acquisition), dealers in securities and persons who are participating in the Acquisition in connection with their trade, Shareholders who hold any Ordinary Shares through any individual savings account ("**ISA**") or self-invested personal pension, or who are trustees or hold their Ordinary Shares through any form of investment vehicle or Shareholders who hold any Ordinary Shares by reason of their or another person's office or employment.

Investors should note that the tax laws of their own country may affect the tax treatment of acquiring, holding or disposing of Ordinary Shares and that the tax laws of their own country and the country in which the Company is incorporated, and the countries in which Harbour Energy operates, may affect Shareholders' post-tax income from their Ordinary Shares.

Any person who is in any doubt as to their tax position or who may be subject to tax in any jurisdiction other than the UK should consult an appropriate professional tax adviser without delay.

2. TAXATION OF ORDINARY SHARES

2.1 Taxation of Dividends

The Company is not required to withhold tax at source from dividend payments it makes.

(a) Individual Shareholders within the charge to UK income tax

Dividends received from the Company by an individual Shareholder will form part of the Shareholder's total income for income tax purposes and will represent the highest part of that income.

A nil rate of income tax will apply to the first £500 of dividend income (for the tax year 2024/2025) received by an individual Shareholder from all sources in a tax year (the "**Nil Rate Amount**"), regardless of what tax rate would otherwise apply to that dividend income. Any taxable dividend income received by an individual Shareholder in a tax year in excess of the Nil Rate Amount will be subject to income tax at the following dividend rates for the tax year 2024/2025:

(i) at the rate of 8.75 per cent., to the extent that the relevant dividend income falls below the threshold for the higher rate of income tax;

(ii) at the rate of 33.75 per cent., to the extent that the relevant dividend income falls above the threshold for the higher rate of income tax but below the threshold for the additional rate of income tax; and

(iii) at the rate of 39.35 per cent., to the extent that the relevant dividend income falls above the threshold for the additional rate of income tax.

In determining whether and, if so, to what extent the relevant dividend income falls above or below the threshold for the higher rate of income tax or, as the case may be, the additional rate of income tax, the Shareholder's total taxable dividend income for the tax year in question (including the part within the Nil Rate Amount) will, as noted above, be treated as the highest part of the Shareholder's total income for income tax purposes.

(b) **Corporate Shareholders within the charge to UK corporation tax**

Shareholders within the charge to UK corporation tax which are "small companies" (for the purposes of UK taxation of dividends) will not generally be subject to tax on dividends from the Company.

Other Shareholders within the charge to UK corporation tax will not be subject to tax on dividends from the Company so long as the dividends fall within an exempt class and certain conditions are met. Dividends paid on non-redeemable shares that do not carry any present or future preferential rights to dividends or to the relevant company's assets on its winding up, and dividends paid to a person holding less than 10 per cent. of the issued share capital of the payer (or any class of that share capital in respect of which the dividend is paid) and who is entitled to less than 10 per cent. of the profits available for distribution to holders of the same class of shares and would be entitled to less than 10 per cent. of the assets available for distribution to holders of the same class of shares on a winding-up, are examples of dividends that should fall within an exempt class and therefore be exempt from corporation tax, subject to the application of anti-avoidance rules.

2.2 **Taxation of Chargeable Gains**

The following sub-paragraphs do not address the chargeable gains or other tax implications for any persons who, directly or indirectly, hold shares in the Target Company of any disposal of their shares in the Target Company in connection with the Acquisition or the acquisition of BASF Consideration Shares by such Target Company shareholders. The Target Company shareholders should consult their professional advisers regarding such implications.

(a) **UK resident individual Shareholders**

A disposal or deemed disposal of Ordinary Shares may, depending on the circumstances and subject to any available exemption or relief, give rise to a chargeable gain (or an allowable loss) for the purposes of UK capital gains tax.

An individual Shareholder who is resident in the UK for UK tax purposes and whose total taxable gains and income in a given tax year, including any gains made on the disposal or deemed disposal of their Ordinary Shares, are less than or equal to the upper limit of the income tax basic rate band applicable to them in respect of that tax year (the "**Band Limit**") will generally be subject to capital gains tax at the flat rate of 10 per cent. in respect of any gain arising on a disposal or deemed disposal of their Ordinary Shares.

An individual Shareholder who is resident in the UK for UK tax purposes and whose total taxable gains and income in a given tax year, including any gains made on the disposal or deemed disposal of their Ordinary Shares, are more than the Band Limit will generally be subject to capital gains tax at the flat rate of 10 per cent. in respect of any gain arising on a disposal or deemed disposal of their Ordinary Shares (to the extent that, when added to the Shareholder's other taxable gains and income in that tax year, the gain is less than or equal to the Band Limit) and at the flat rate of 20 per cent. in respect of the remainder.

No indexation allowance will be available to an individual Shareholder in respect of any disposal of Ordinary Shares. However, most individuals have an annual exempt amount, such that capital gains tax is chargeable only on gains arising from all sources during the tax year in excess of this figure. The annual exempt amount is £3,000 for the tax year 2024/2025.

Individuals who are temporarily non-resident may, in certain circumstances, be subject to tax in respect of gains realised while they are not resident in the UK.

(b) **UK resident corporate Shareholders**

Where a Shareholder is within the charge to UK corporation tax, a disposal of Ordinary Shares may, depending on the circumstances and subject to any available exemption or relief, give rise to a chargeable gain (or an allowable loss) for the purposes of corporation tax.

Corporation tax is charged on chargeable gains at the same rate as on income. The main rate of corporation tax is 25 per cent. for the tax year 2024/2025. It should be noted for the purposes of calculating any indexation allowance available on a disposal of Ordinary Shares that generally the expenditure incurred in acquiring the Ordinary Shares will be treated as incurred only when the Shareholder made, or became liable to make, payment, and not at the time those shares are otherwise deemed to have been acquired. Regardless of the date of disposal of the Ordinary Shares, indexation allowance will be calculated only up to and including December 2017.

3. **STAMP DUTY AND SDRT**

The following statements are intended as a general guide to the current UK stamp duty and stamp duty reserve tax ("**SDRT**") position for Shareholders. Certain categories of person, including intermediaries, brokers, dealers and persons connected with clearance services and depositary receipt systems, may not be liable to stamp duty or SDRT or may be liable at a higher rate. Furthermore, such persons may, although not primarily liable for the tax, be required to notify and account for it under the Stamp Duty Reserve Tax Regulations 1986.

The comments in this section relating to stamp duty and SDRT apply whether or not a Shareholder is resident in the UK.

(a) **Issue of the Ordinary Shares**

No stamp duty or SDRT will ordinarily be payable on the issue of Ordinary Shares (including BASF Consideration Shares) by the Company. See paragraph 3(d) (Clearance services and depositary receipt system) in this Part XII (*United Kingdom Taxation*) for more detail in relation to the rules applying to issues to clearance services and depositary receipt systems.

(b) Similarly, where Ordinary Shares are first credited in uncertificated form to an account in CREST, no liability to stamp duty or SDRT will generally arise.

(c) **Subsequent transfers**

Except in relation to transfers to clearance services and depositary receipt systems (to which the special rules outlined below apply), any dealings in Ordinary Shares following their issue will be subject to stamp duty or SDRT in the normal way. Such stamp duty or SDRT liabilities will normally be borne by the purchaser but certain other persons who fall within the definition of "accountable persons" in the relevant legislation may have compliance and payment obligations with respect to certain SDRT liabilities.

Accordingly, for subsequent conveyances or transfers to unconnected third parties, stamp duty at the rate of 0.5 per cent. (rounded up to the next multiple of £5) of the amount or value of the consideration given by the purchaser is generally payable on an instrument transferring Ordinary Shares, subject to applicable exemptions and reliefs. An exemption from stamp duty is available on an instrument transferring Ordinary Shares where the amount or value of the consideration is £1,000 or less and it is certified on the instrument that the transaction effected by the instrument does not form part of a larger transaction or series of transactions in respect of which the aggregate amount or value of the consideration exceeds £1,000.

A charge to SDRT will also generally arise on an unconditional agreement (or a conditional agreement which becomes unconditional) to transfer Ordinary Shares (at the rate of 0.5 per cent. of the amount or value of the consideration in money or money's worth given by the purchaser). However, if within six years of the date of the agreement (or, if the agreement is conditional, the date on which it becomes unconditional), an instrument of transfer is executed pursuant to the agreement, and stamp duty is duly paid on that instrument which is then duly stamped, or that instrument is exempt, any SDRT already paid will generally be refunded, **provided that** a claim for payment is made, and any outstanding liability to SDRT will be cancelled.

Paperless transfers of Ordinary Shares within CREST are generally liable to SDRT, rather than stamp duty, at the rate of 0.5 per cent. of the amount or value of the consideration. CREST is obliged to collect SDRT on relevant transactions settled within the CREST system.

In cases where the Ordinary Shares are transferred to a connected company of a Shareholder (or its nominee, as applicable), stamp duty or SDRT may, depending on the circumstances and the agreed terms of the transfer, be chargeable on the higher of: (i) the amount or value of the consideration, or (ii) the market value of the Ordinary Shares.

(d) **Clearance services and depositary receipt systems**

Prior to 1 January 2024, under sections 67, 70, 93 and 96 of the Finance Act 1986, where Ordinary Shares were issued (in the case of SDRT) or transferred (in the case of stamp duty and SDRT): (i) to (or to a nominee or agent for) a person whose business is or includes the provision of clearance services, or (ii) to (or to a nominee or agent for) a person whose business is or includes issuing depositary receipts, stamp duty or SDRT (as applicable) would generally be payable at the higher rate of 1.5 per cent. of the amount or value of the consideration paid for the Ordinary Shares (rounded up to the next multiple of £5 in the case of stamp duty) or in certain circumstances, the value of the Ordinary Shares.

Following the decision of the European Court of Justice in HSBC Holdings plc and Vidacos Nominees Ltd v HMRC (Case C-569/07) and the First-tier Tax Tribunal decision in HSBC Holdings plc and The Bank of New York Mellon Corporation v The Commissioners for HMRC [2012] UKFTT 163 (TC), HMRC confirmed that it would no longer seek to apply the 1.5 per cent. SDRT charge when shares are first issued to a clearance service or depositary receipt system. Following Brexit, the UK Government stated that it did not propose to reintroduce the 1.5 per cent. SDRT charge in respect of an issue of shares to a clearance service or depositary receipt system and passed legislation (the European Union (Withdrawal) Act 2018) to preserve the effect of the decisions mentioned above. However, the introduction of the Retained EU Law (Revocation and Reform) Act 2023 ended the preservation of the HSBC Holdings decisions as of 1 January 2024.

As of 22 February 2024 when the Finance Bill 2023-2024 was granted Royal Assent, the Finance Act 2024 has amended, with effect from 1 January 2024, the main charging provisions at sections 67, 70, 93 and 96 of the Finance Act 1986 to remove from the scope of the 1.5 per cent. charge the issue of chargeable securities to a clearance service or depositary receipt system and certain transfers of securities to a clearance service or depositary receipt system in the course of capital-raising arrangements or qualifying listing arrangements.

Clearance services may opt under section 97A of the Finance Act 1986, provided certain conditions are satisfied, for the normal rate of stamp duty or SDRT (0.5 per cent. of the consideration paid) to apply to transfers of Ordinary Shares into such services that would otherwise be subject to a 1.5 per cent. charge, and to transactions within such services.

Any liability for stamp duty or SDRT in respect of a transfer into a clearance service or depositary receipt system, or in respect of a transfer of Ordinary Shares held within such a service or system, will technically be payable by the operator of the clearance service or depositary receipt system or its nominee, as the case may be, but in practice will generally be reimbursed by participants in the clearance service or depositary receipt system.

PART XIII
DIRECTORS, SENIOR MANAGERS AND CORPORATE GOVERNANCE

1. DIRECTORS

The Directors as at the date of this Prospectus are:

Name	Age	Position	Date appointed to Board
R. Blair Thomas . . .	61	Chair	31 March 2021
Linda Z. Cook	66	Chief Executive Officer	31 March 2021
Alexander Krane . . .	48	Chief Finance Officer	15 April 2021
Simon Henry	62	Senior Independent Non-Executive Director	31 March 2021
Belgacem Chariag . .	61	Independent Non-Executive Director	1 May 2023
Alan Ferguson	66	Independent Non-Executive Director	31 March 2021
Andy Hopwood . . .	66	Independent Non-Executive Director	31 March 2021
Louise Hough	58	Independent Non-Executive Director	1 May 2023
Margareth Øvrum . .	65	Independent Non-Executive Director	1 April 2021
Anne L. Stevens . . .	75	Independent Non-Executive Director	31 March 2021

The business address of each of the Directors is at the head office of the Company at Harbour Energy plc, 23 Lower Belgrave Street, London SW1W 0NR, United Kingdom.

The management expertise and experience of each member of the board of Directors of the Company (the "**Board**") is set out below:

1.1 R. Blair Thomas, *Chair*

Blair was appointed as Non-Executive Chair of the Company in March 2021, pursuant to the EIG Relationship Agreement (as described in paragraph 15.14 (EIG Relationship Agreement of Part XIV (*Additional Information*)). Blair has more than 30 years' experience in the investment management business, with a focus on energy and energy-related infrastructure. Blair's industry experience and knowledge of Harbour Energy is invaluable and his leadership of the Board is of significant benefit to the Company and Shareholders as a whole.

1.2 Linda Z. Cook, *Chief Executive Officer*

Linda was appointed as the Chief Executive Officer of the Company in March 2021. Linda has significant experience in building and managing large-scale, global energy businesses at both Royal Dutch Shell where she worked for almost 30 years and subsequently in private equity at EIG. She has a track record of successful strategic execution and growth, including through M&A, major project delivery and raising capital. Linda's experience in international oil and gas and in disciplined capital allocation within the sector is of great value to Harbour Energy as the Company works to implement its strategy. Linda is currently a non-executive director and chair of the Audit Committee of BNY Mellon.

1.3 Alexander Krane, *Chief Finance Officer*

Alexander was appointed as Chief Finance Officer of the Company in April 2021. Having spent a large portion of his career as CFO of Aker BP, including during the merger of Det Norske Oljeselskap and BP Norge, Alexander has experience leading a large finance function through integration processes. His listed company experience and understanding of debt and equity capital markets are invaluable in ensuring that the Company has the balance sheet strength to be able to deliver its growth and investment plans through the commodity price cycle.

1.4 Simon Henry, *Senior Independent Non-Executive Director*

Simon was appointed as Senior Independent Non-Executive Director of the Company in March 2021. Simon's position as Senior Independent Director ensures that the highest standards of corporate governance are maintained. He plays a pivotal role in managing the relationship with the company's major shareholder, EIG, and ensuring the Company is able to operate independently and in accordance with its obligations as a listed company. In addition, Simon brings significant experience in both the oil and gas sector and public markets having spent his entire career working with large-scale companies, including as

CFO for Royal Dutch Shell plc. Simon is currently a non-executive director and chair of the Audit and Risk Committee of Rio Tinto plc.

1.5 **Belgacem Chariag,** ***Independent Non-Executive Director***

Belgacem was appointed as an Independent Non-Executive Director of the Company in May 2023. Belgacem has extensive experience in the energy, materials and chemicals industries, having held a variety of leadership positions within oil field services companies, including Baker Hughes and Schlumberger. Most recently, Belgacem was Chair and CEO of Ecovyst Inc, a leading global provider of speciality catalysts, materials, chemicals and services. Belgacem brings extensive global industry expertise to Harbour Energy, which enhance the Board's ability to support and oversee the delivery of the strategy. Belgacem is currently a non-executive director of Helmerich & Payne Inc.

1.6 **Alan Ferguson,** ***Independent Non-Executive Director***

Alan was appointed as an Independent Non-Executive Director of the Company in March 2021. Alan is a chartered accountant and brings current and relevant financial experience to the Board and Audit and Risk Committee following his executive career in finance roles including being CFO of three FTSE100/250 companies. Alan has over a decade of experience leading audit committees of listed companies including the Weir Group, Croda International and Johnson Matthey plc. The Audit and Risk Committee benefits from Alan's insight from his position as a Board member of the Audit Committee Chairs' Independent Forum, and his expertise in corporate governance, audit and accounting is of great value to the Board and the Company. Alan is currently a non-executive director and the chair of the audit committee of AngloGold Ashanti plc.

1.7 **Andy Hopwood,** ***Independent Non-Executive Director***

Andy was appointed as an Independent Non-Executive Director of the Company in March 2021. Andy has over 40 years' experience in the global oil and gas industry gained during his long career with BP. He brings a strong understanding of the technical, operational and commercial issues associated with developing and managing large-scale, complex energy assets around the world, from exploration through to decommissioning, including in the areas of safety and the environment. Andy's technical, operational and leadership expertise in the oil and gas sector are invaluable to the Board and its committees in overseeing the existing portfolio and assessing opportunities for investment.

1.8 **Louise Hough,** ***Independent Non-Executive Director***

Louise was appointed as an Independent Non-Executive Director of the Company in May 2023. Louise has a wealth of experience and deep understanding of both financial and energy markets. Following 25 years at UBS, Louise played a lead role in preparing Saudi Aramco for its first public bond issuance and IPO as Head of International Investor Relations. At Saudi Aramco, Louise was also a member of the Sustainability Steering Committee, working extensively on all aspects of ESG reporting. Louise's experience advising investors, boards and executive management teams on capital markets-related activity, sustainability and governance issues is of great value to the Board and its committees.

1.9 **Margareth Øvrum,** ***Independent Non-Executive Director***

Margareth was appointed as an Independent Non-Executive Director of the Company in March 2021. Margareth has extensive experience of international oil and gas operations, having worked for almost 40 years at Equinor and its predecessor companies. At Equinor, Margareth spent almost 17 years on the executive committee with global responsibility for HSES, project development, drilling, procurement, technology and new energy. Margareth's extensive leadership experience of major projects, health and safety, sustainability and the role of digital technology in engineering are valuable to the Board. As Chair of the HSES Committee, Margareth has a passion for safety and the environment which is essential to her role. Margareth also has considerable governance experience through her non-executive director roles at FMC Corporation, Technip FMC plc and Transocean Ltd.

1.10 **Anne L. Stevens,** ***Independent Non-Executive Director***

Anne was appointed as an Independent Non-Executive Director of the Company in March 2021. Anne brings a wealth of experience built up over a long career in engineering and executive roles in large global companies. In recent years, she has served on remuneration committees, including as chair, in a number of large organisations, including Anglo American plc, bringing a high level of expertise to her role as remuneration committee chair. Anne also has significant experience engaging with investors to deliver remuneration outcomes that are of benefit to all stakeholders. Anne is currently a non-executive director and the chair of the remuneration committee and the sustainability committee of Aston Martin Lagonda Global Holdings plc.

2. SENIOR MANAGERS

In addition to the executive management on the Board of the Company, the following senior managers of the Company ("**Senior Managers**") are considered relevant to establishing that the Company has the appropriate expertise and experience for the management of its business.

For the biographies of Linda Z. Cook and Alexander Krane, see paragraph 1.2 and 1.3, respectively, of this Part XIII (*Directors, Senior Managers and Corporate Governance*).

Name	Age	Position
Linda Z. Cook	66	Chief Executive Officer
Alexander Krane	48	Chief Financial Officer
Scott Barr	47	Executive Vice President—North Sea
Philip Whittaker	51	Executive Vice President—Global Services
Howard Landes	48	General Counsel / Legal
Steven Cox	56	Executive Vice President—South East Asia
Gill Riggs	51	Chief Human Resources Officer
Gustavo Baquero	48	Executive Vice President Strategy, Business Development & Energy Transition

2.1 Scott Barr, *Executive Vice President—North Sea*

Scott Barr is Executive Vice President of the North Sea Business Unit at Harbour Energy. Scott has over 25 years of industry experience including 10 years running operations at a senior level. He has both practical and hands on knowledge having started his oil and gas career as a mechanical specialist with Conoco, one of Harbour Energy's legacy companies. He has since progressed and developed his skills with increasing levels of seniority in various operations and maintenance management positions including assignments in the UK, Dubai and Indonesia, working both on and offshore. Scott is a Chartered Engineer, a Fellow of the Institute of Engineering and Technology and a member of the Boards of OEUK and the UK Oil and Gas Chaplaincy Trust.

2.2 Philip Whittaker, *Executive Vice President—Global Services*

Philip Whittaker is Executive Vice President of Global Services at Harbour Energy. Philip has 30 years of experience in exploration and production in both industry and advisory roles. Prior to joining Harbour Energy, Philip was a partner and director at Boston Consulting Group ("**BCG**"), where he co-led the firm's upstream oil and gas activity globally. At BCG he gained extensive experience in strategy, performance improvement and transaction-related activity with leading majors, independents and oilfield service companies. Philip began his career as a drilling engineer at Shell, where he managed front-line operations in the Netherlands, Peru and Oman.

2.3 Howard Landes, *General Counsel*

Howard Landes was appointed General Counsel of Harbour Energy in 2021 and has responsibility for legal, governance and ethics & compliance. Prior to joining Harbour Energy, Howard was General Counsel at Chrysaor, one of Harbour Energy's legacy companies. His previous experience includes more than 10 years at BG Group plc ("**BG**") and, prior to that, at the international law firm, Clifford Chance. Howard graduated from Oxford University and is qualified as a solicitor in England and Wales.

2.4 Steve Cox, *Executive Vice President—South East Asia*

Steve Cox is Executive Vice President of the South East Asia Business Unit at Harbour Energy. Steve has over 25 years' experience in the oil and gas industry. Prior to joining Harbour Energy, Steve was EVP of non-operated ventures at Chrysaor, one of Harbour Energy's legacy companies, where he was responsible for non-operated assets. His industry experience includes stints at BG and Shell, where he gained extensive experience in safety, project and asset management, operational and functional performance, and partner engagement.

2.5 **Gill Riggs,** ***Chief Human Resources Officer***

Gill Riggs is the Chief Human Resources Officer for Harbour Energy. Gill has extensive experience of managing human resources in the energy industry, including many international postings. Prior to joining Harbour Energy, Gill led the Human Resources function, for Chevron's global upstream business head quartered in the US. During her 20-year career with Chevron, Gill took on increasing responsibility in human resources including Regional HR Manager, Africa and Middle East (South Africa), General Manager HR, gas and midstream (US), and General Manager HR, upstream Asia Pacific (Singapore).

2.6 **Gustavo Baquero,** ***Executive Vice President—Strategy, Business Development & Energy Transition***

Gustavo Baquero is Executive Vice President of Strategy, Business Development & Energy Transition at Harbour Energy. Gustavo is an energy professional with 25 years of international experience, having worked in Norway, Brazil, Venezuela, Colombia, Italy, Spain, and the UK. Before joining Harbour Energy, Gustavo was the senior vice president of exploration and production international at Equinor. During his career, Gustavo has also held various senior strategy and business development roles, as well as multiple roles as a process engineer, commodities trader, commercial manager, operations field management and partner operations director at ExxonMobil, Repsol and BP.

3. DIRECTORS' AND SENIOR MANAGERS' CONFIRMATIONS

During the period of five years preceding the date of this Prospectus none of the Directors or the Senior Managers:

(a) has any convictions in relation to fraudulent offences;

(b) has been associated with any bankruptcy, receivership, liquidation or company put into administration when acting in his or her capacity as a member of the administrative, management or supervisory body or senior manager of another company; or

(c) has received any official public incrimination and/or sanction by any statutory or regulatory authorities (including designated professional bodies) or has been disqualified by a court from acting as a director or member of an administrative, management or supervisory body of a company or from acting in the management or conduct of the affairs of a company.

3.1 Potential Conflicts of Interest

By virtue of the nature of the businesses in which the Directors listed below have private interests and/or owe duties, the Company considers the following to be potential conflicts of interest between the duties of the Directors and their private interests and/or other duties. Each conflict has been authorised by the Board.

Name	Potential Conflict(s)
Directors	
R. Blair Thomas	Mr Thomas is the Chief Executive Officer of EIG Global Energy Partners, as well as Chair of its Investment and Executive Committees. Mr Thomas also holds the following positions: ● chair of Prumo Logistica SA, a logistics and infrastructure company that serves activities in Brazil. ● manager of 8 minute Power LLC, a US developer focused on utility-scale solar and battery storage. ● trustee of FS Energy and Power Fund, a business development company investing primarily in debt and equity securities of private US energy and power companies.

Name	Potential Conflict(s)
	• board member of HIF Global LLC, an international e-fuel company in Chile. • board member of Repsol Lux E&P Sarl, an exploration and production company. • chair of MidOcean Energy, LLC, a liquefied natural gas company formed by EIG to build a diversified, resilient, cost and carbon competitive LNG portfolio.
Linda Z. Cook	Ms Cook is a senior advisor at EIG.
Simon Henry	Mr Henry is an adviser to the board of Oxford Flow Ltd., which supplies valves and related technology to the oil and gas industry.
Belgacem Chariag	Mr Chariag is a non-executive director of Helmerich & Payne Inc, a US listed petroleum contract drilling company.
Margareth Øvrum	Ms Øvrum is a non-executive director of Technip FMC plc, a subsea and surface technologies company, and non-executive director of Transocean Ltd., an offshore drilling company providing construction services.
Louise Hough	Ms Hough is a consultant at Tende Energy plc, an Africa-focused oil and gas development, production and exploration company.

Notes

(1) EIG is the Company's largest Shareholder as at the date of this Prospectus. See paragraph 12 (Major Shareholders), in Part XIV (*Additional Information*).

Apart from the potential conflicts disclosed above, there are no actual or potential conflicts of interest between the duties owed by the Directors or the Senior Managers and their private interests and/or other duties that they may also have.

4. CORPORATE GOVERNANCE

The Company is committed to, and recognises the value and importance of, high standards of corporate governance. As at the date of this Prospectus, the Company is in compliance with the provisions of the UK Corporate Governance Code (the "**Code**") except for Provision 9 of the Code, which states that "the chair should be independent on appointment when assessed against the circumstances set out in Provision 10". R. Blair Thomas, the Chair of Harbour Energy, did not meet the independence criteria of Provision 10 of the Code at the time of his appointment by virtue of being appointed pursuant to EIG Global Energy Partners' right to appoint up to two non-executive directors to the Board for so long as it held more than 25 per cent. of the issued share capital of the Company under the relationship agreement entered into with the Company. Notwithstanding this, the Board is comprised of a majority of independent non-executive directors, including a Senior Independent Non-Executive Director to ensure there is sufficient independent challenge and judgement within the Boardroom.

4.1 Roles and Responsibilities of the Board

As at the date of this Prospectus, the Board is comprised of the Chair, two Executive Directors (being the Chief Executive Officer and the Chief Finance Officer), and seven independent Non-Executive Directors. The Board is supported by the Company Secretary.

The Board is responsible to Shareholders and other stakeholders for the management, performance and long-term success of the Company. It sets and oversees the Company's purpose and strategy and ensures that the Company is managed effectively. The Board provides challenge and advice to management, and has established a number of committees with specific remits to assist it in operating effectively. There are certain matters that are reserved for the Board's approval and cannot be delegated.

These include, but are not limited to, the following: determination of the purpose, overall direction, values and strategy of the business; approval of a new country entry, new business activity entry outside of the approved strategy or decision to cease to operate any material part of the business; determination of an appropriate level of risk exposure for the Company; oversight of the Company's operations and performance; approval of the Company's corporate investment guidelines and any further amendments thereto; approval of the annual budgets for Harbour Energy; approval of commitments to expenditures not approved within the annual budget or beyond budget year expenditure; approval of the issue of new debt instruments in excess of $100 million; approval of the Company's annual report and financial statements and dividend policy; approval of significant changes in accounting policies, policies relating to hedging and non-ordinary course financial guarantees and indemnities; oversight of the Company's system of internal controls, risk management processes and the adequacy of both; the appointment and removal of Directors; the approval and recommendation to Shareholders of the remuneration policy for Executive Directors and other members of Senior Management following recommendation of the Remuneration Committee; the approval of, including any amendments to, the Company's corporate policies, procedures and documents, and authorisation of potential conflicts of interest of directors; the setting, instilling and monitoring of the Company's purpose, culture and values; and approval of any major changes to the Company's capital or corporate structures.

The Board held ten meetings during the year ended 31 December 2023 and nine meetings during the year ending 31 December 2022. Currently, the Board consists of ten members and no individual or group of individuals dominates the Board's decision making. In compliance with Provision 12 of the Code, the Board appointed Simon Henry as Senior Independent Director in 2021.

4.2 **Board Committees**

To assist the Board in carrying out its functions and to ensure that there is independent oversight of internal controls and risk management, the Board delegates certain functions to its four principal committees: the Remuneration Committee, the Audit and Risk Committee, the Nomination Committee, and the Health, Safety, Environment & Security (HSES) Committee. Each committee has formal terms of reference approved by the Board, copies of which can be found on the company's website.

The Company Secretary provides advice and support to the Board and its committees. Board committees are authorised to engage the services of external advisers as they deem necessary.

Remuneration Committee

The Remuneration Committee comprises four Independent Non-Executive Directors: Anne L. Stevens (Chair), Alan Ferguson, Louise Hough and Andy Hopwood.

Members of the Remuneration Committee are appointed by the Board, on the recommendation of the Nomination Committee and in consultation with the Chair of the Remuneration Committee. The Remuneration Committee comprises at least three members all of whom are independent Non-Executive Directors. The Chair of the Board may also serve on the Remuneration Committee as an additional member if he or she is considered independent on appointment as Chair. The Board appoints the Chair of the Remuneration Committee who shall be an independent non-executive director. Before appointment as Chair of the Remuneration Committee, the appointee should have served on a remuneration committee for at least 12 months. In the absence of the Remuneration Committee Chair or an appointed Deputy Chair, the remaining members elect one of their number to chair the meeting. The Chair of the Board shall not be Chair of the Remuneration Committee. Appointments to the committee are for a period of up to three years extendable by no more than two additional three-year periods, so long as members still meet the criteria for membership of the Remuneration Committee.

The role of the Remuneration Committee is to assist the Board to fulfil its responsibility to shareholders to ensure that remuneration policy and practices of the Company reward fairly and responsibly, with a clear link to corporate and individual performance, having regard to statutory and regulatory requirements. In particular, in relation to Senior Management, the Remuneration Committee considers remuneration policies, including base pay, long and short term incentives; remuneration practice and its cost to the Company; recruitment, service contracts and severance policies; pension and superannuation arrangements and other benefits; and the engagement and independence of external remuneration advisers.

The Remuneration Committee held 4 formal meetings during the year ended 31 December 2023.

Nomination Committee

The Nomination Committee comprises: R. Blair Thomas (Chair) and three Independent Non-Executive Directors, Belgacem Chariag, Andy Hopwood and Anne L. Stevens.

The Nomination Committee gives due consideration to all relevant laws and regulations, in particular, the Directors' duties contained in the Companies Act 2006, the principles and provisions of the Code and the requirements of the Disclosure Guidance and Transparency Rules in carrying out its duties.

The members of the Nomination Committee are appointed by the Board and comprise a Chair and a minimum of two other members. A majority of members of the Nomination Committee shall be independent non-executive directors. The Board appoints members of the Nomination Committee and the Nomination Committee Chair, who shall be either the Chair of the Board or an independent non-executive director. In the absence of the Nomination Committee Chair and/or an appointed deputy, the remaining Nomination Committee members present shall elect one of their number (who shall be either the Chair of the Board or an independent non-executive director) to chair the meeting. Care should be taken to minimise the risk of any conflict of interest that might be seen to give rise to an unacceptable influence. When the Nomination Committee is assessing the performance of the Chair of the Board or dealing with the matter of succession to the Chairs role of the Board, the discussions will normally be led by the Senior Independent Director.

The Nomination Committee ensures that plans are in place for orderly succession to (a) the Board and (b) Senior Management positions with due regard to the skills, knowledge, experience and diversity required to execute the Company's strategy; oversees the development of a diverse pipeline for succession to Board and senior management positions; ensures that there is a formal, rigorous and transparent procedure for the appointment of new directors to the Board; leads the process for Board appointments; reviews the structure, size and composition of the Board including the balance of skills, knowledge, experience and independence of non-executive directors and make recommendations with regard to any adjustments that are deemed necessary with due regard for the benefits of diversity on the Board.; oversees and reviews the results of any Board performance evaluation; and receives regular reports from the Group Staff Forum.

The Nomination Committee held 5 meetings during the year ended 31 December 2023.

Audit and Risk Committee

The Audit and Risk Committee comprises four non-executive directors: Alan Ferguson (Chair), Simon Henry, Louise Hough and Margareth Øvrum.

The Audit and Risk Committee gives due consideration to all relevant laws and regulations, in particular, the directors' duties contained in the Companies Act 2006, the principles and provisions of the Code and the requirements of the Disclosure Guidance and Transparency Rules in carrying out its duties.

The Audit and Risk Committee comprises not less than three Non-Executive Directors of the Company. The members of the Audit and Risk Committee are appointed by the Board of Directors, on the recommendation of the Nomination Committee in consultation with the Chair of the Committee. All members of the Audit and Risk Committee shall be independent non-executive directors, as determined by the Board. At least one member of the Audit and Risk Committee shall have recent and relevant financial experience and the Committee as a whole shall have competence relevant to the sectors in which the Company operates.

The role of the Audit and Risk Committee is to monitor the integrity of the Company's financial statements and any formal announcements relating to the Company's financial performance, reviewing significant financial reporting judgements contained in them; monitor and review the effectiveness of the Company's risk management and internal control systems; monitor and review the effectiveness and objectivity of the Company's Group Internal Audit and Risk Management function; oversee co-ordination of the internal and external auditors; review the external auditors' independence and objectivity and the effectiveness of the audit process, taking into consideration relevant laws, regulations and ethical codes monitor the enforcement of the Company's Group Code of Conduct and the adequacy and security of its whistleblowing procedures.

The Audit and Risk Committee held 7 formal meetings during the year ended 31 December 2023.

HSES Committee

The Health, Safety, Environment and Security ("**HSES**") Committee comprises three non-executive directors: Margareth Øvrum (Chair), Belgacem Chariag and Simon Henry.

The HSES Committee gives due consideration to all relevant laws and regulations, in particular, the directors' duties contained in the Companies Act 2006, the principles and provisions of the Code and the requirements of the Disclosure Guidance and Transparency Rules in carrying out its duties.

Members of the HSES Committee are appointed by the Board, on the recommendation of the Nomination Committee and in consultation with the Chair of the HSES Committee. The HSES Committee comprises at least two members, all of whom shall be independent Non-Executive Directors. Membership consists solely of Non-Executive Directors and where any such Directors are non-independent, there shall be a majority of independent Non-Executive Directors. At least one member of the HSES Committee shall also be a member of the Audit and Risk Committee. The Chair of the Board may also serve on the HSES Committee as an additional member if he or she was considered independent on appointment as Chair of the Board. The Board shall appoint the Chair of the HSES Committee who shall be an independent non-executive director. In the absence of the HSES Committee Chair or an appointed Deputy Chair, the remaining members shall elect one of their number to chair the meeting. The Chair of the Board shall not be Chair of the HSES Committee.

The role of the HSES Committee is to monitor and review Harbour Energy's HSES strategy; to evaluate the effectiveness of the Group's policies and systems for delivering Harbour Energy's HSES strategy, maintaining regulatory compliance and managing HSES risk; to monitor the quality and integrity of Harbour Energy's internal and external reporting of HSES performance issues; and to assess the policies and systems within Harbour Energy for ensuring compliance with HSES regulatory requirements.

The HSES Committee held 4 formal meetings during the year ended 31 December 2023.

5. RELATIONSHIP AGREEMENTS AND BOARD APPOINTMENT RIGHTS

EIG Relationship Agreement

In connection with the Premier Merger, by virtue of the size of the shareholding of Harbour North Sea Holdings Ltd. ("**Harbour North Sea**") (together with its concert parties), on 31 March 2021 the Company entered into the EIG Relationship Agreement with Harbour North Sea as Harbour North Sea was deemed to be a "controlling shareholder" of the Company for the purposes of the Listing Rules. Pursuant to the EIG Relationship Agreement, if and for so long as Harbour North Sea and its affiliates hold: (i) at least ten per cent. of the Ordinary Shares, it will have the right to nominate one director to the Board; and (ii) at least 25 per cent. of the Ordinary Shares, it will have the right to nominate two directors to the Board. The EIG Relationship Agreement continues in force unless and until Harbour North Sea and its associates cease to own at least ten per cent. or more of the Ordinary Shares or the voting rights attaching to the Ordinary Shares or it otherwise terminates in accordance with its terms. It is anticipated that the EIG Relationship Agreement will terminate upon Completion as a result of Harbour North Sea together with its associates holding less than ten per cent. of the Ordinary Shares (or the voting rights attaching to the Ordinary Shares) following the issue of the BASF Consideration Shares to BASF.

For more information on the EIG Relationship Agreement, see paragraph 15.14 (EIG Relationship Agreement) in Part XIV (*Additional Information*).

BASF Relationship Agreement

Upon Completion, BASF is expected to hold approximately 39.6 per cent. of the enlarged share capital of the Company. Given BASF will hold more than 30 per cent. of the shares of the Enlarged Group, it will be deemed a "controlling shareholder" for the purposes of the Listing Rules. As a result, the Company will enter into the BASF Relationship Agreement at Completion (but conditional on Admission) with BASF.

Pursuant to the BASF Relationship Agreement, following Completion BASF will be entitled to nominate two non-executive directors to the Board for so long as it (together with any of its associates) holds 25 per cent. or more of the Ordinary Shares, and will be able to appoint one non-executive director to the Board for so long as it (together with any of its associates) holds 10 per cent. or more, but less than 25 per cent. of the Ordinary Shares, provided in each case that BASF will be required to take into account certain factors and consult with the Chair and the Nomination Committee before nominating a director.

The BASF Relationship Agreement will remain in full force and effect unless and until BASF and its associates cease to own at least 10 per cent. of the Ordinary Shares. BASF may terminate the BASF Relationship Agreement in certain circumstances, including where the Ordinary Shares cease to be admitted to trading on the London Stock Exchange's main market for listed securities.

For more information on the BASF Relationship Agreement, see paragraph 15.2 (BASF Relationship Agreement) in Part XIV (*Additional Information*).

LetterOne Relationship Agreement

Upon Completion, the Company will also enter into the LetterOne Relationship Agreement (but conditional on Admission) with LetterOne.

Pursuant to the LetterOne Relationship Agreement, LetterOne will have equivalent rights to BASF to nominate non-executive directors to the Board, however any such rights will only apply to the extent that LetterOne has converted Non-Voting Shares into Ordinary Shares (following satisfaction of the relevant Conversion Conditions) and, as a result, holds the requisite percentage of Ordinary Shares.

For more information on the LetterOne Relationship Agreement and the Conversion Conditions, see paragraphs 15.3 (LetterOne Relationship Agreement) and 15.1 (Business Combination Agreement), respectively, in Part XIV (*Additional Information*).

PART XIV
ADDITIONAL INFORMATION

1. RESPONSIBILITY STATEMENT

The Company and the Directors whose names appear in the section entitled "*Directors, Company Secretary, Registered Office and Advisers*", accept responsibility for the information contained in this Prospectus. To the best of the knowledge of the Company and the Directors, the information contained in this Prospectus is in accordance with the facts and this Prospectus makes no omission likely to affect its import.

2. COMPANY DETAILS

The Company was incorporated and registered in Scotland on 31 July 2002 with registered number SC234781 as a private limited company under the Companies Act 1985 with the name Dalgen (No.836) Limited. On 10 March 2003, the Company was re-registered as a public company and changed its name to Premier Oil Group plc. Premier Oil Group plc changed its name to Premier Oil plc on 15 July 2003. Following the completion of the all-share merger of Chrysaor Holdings Ltd and Premier Oil plc, the name of the Company was changed from Premier Oil plc to Harbour Energy plc with effect from 31 March 2021.

The principal legislation under which the Company operates is the Companies Act and regulations made thereunder.

The registered office of the Company is at 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh, EH1 2EN, United Kingdom, and head office of the Company is at Harbour Energy plc, 23 Lower Belgrave Street, London SW1W 0NR, United Kingdom.

The telephone number of the Company is +44 20 7730 1111.

The legal entity identifier of the Company is 213800YPC42DYBKVPF97.

The website of the Company is www.harbourenergy.com. The contents of the Company's website does not form part of this Prospectus.

3. ISSUED SHARE CAPITAL

The issued and fully paid share capital of the Company as at the close of business on the Latest Practicable Date consists of 770,377,712 Ordinary Shares of 0.002 pence each, with an aggregate nominal value of £15,407.5 and 925,532,809 ordinary non-voting deferred shares of 12.4999 pence each, with an aggregate nominal value of £115,690,675.59.

Immediately following Admission it is expected that the Company will have 1,440,091,739 fully paid Ordinary Shares of 0.002 pence each in issue (none of which will be held in treasury) with an aggregate nominal value of £28,801.78.

If Admission occurs, it will result in the allotment and issue of 669,714,027 BASF Consideration Shares and 251,488,211 Non-Voting Shares. Existing Shareholders will suffer an immediate dilution as a result of Admission, following which they will hold approximately 53.5 per cent. of the enlarged ordinary share capital of the Company. If the Non-Voting Shares were to be converted into Ordinary Shares, the Company's current shareholders would own 45.5 per cent. of the Company; BASF and LetterOne would own 39.6 per cent. and 14.9 per cent., respectively.

Other than the Non-Voting Shares, there are no convertible securities, exchangeable securities or securities with warrants in the Company. For further details of the conditions for conversion of the Non-Voting Shares, see paragraph 5.6 (Summary of the Non-Voting Shares) in this Part XIV (*Additional Information*).

There are no acquisition rights or obligations in relation to the issue of Ordinary Shares in the capital of the Company or an undertaking to increase the capital of the Company.

At the Latest Practicable Date, none of the Ordinary Shares were held in treasury and none of the Ordinary Shares have been issued partly paid.

3.1 **History of Share Capital**

As at 1 January 2021, being the first day covered by the Company's financial statements incorporated by reference into this document, the issued and fully paid share capital of the Company comprised 925,532,676 Ordinary Shares.

The following paragraphs provide information on the movements in the issued share capital of the Company between 1 January 2021 and the Latest Practicable Date:

(a) In March 2021, the Company completed a subdivision of each of the existing 12.5 pence Ordinary Shares, subdividing them into (i) one Ordinary Share with a nominal value of 0.0001 pence each; and (ii) one non-voting deferred share with a nominal value of 12.4999 pence each. Following the subdivision of Ordinary Shares, the Company issued 14,253,203,210 Ordinary Shares in consideration for the acquisition of Chrysaor Holdings Limited. In addition to the consideration shares, 3,331,916,120 Ordinary Shares were issued to former creditors of the Company in connection with the restructuring of the Company's debt. On 25 June 2021, the Company undertook a consolidation of its shares whereby 1 new Ordinary Share of 0.002 pence each was issued for every 20 existing Ordinary Shares of 0.0001 pence each previously held. As at 31 December 2021, the Company's issued and fully paid share capital comprised 925,532,639 Ordinary Shares of 0.002 pence each.

(b) Between 1 January 2022 and 31 December 2022, the Company issued 1,024 Ordinary Shares at a nominal value of 0.002 pence per Ordinary Share in relation to the exercise of equity warrants. During the same period, the Company repurchased 78,364,867 Ordinary Shares for a total consideration, including transaction costs of $360.6 million, as part of the share purchase programmes announced on 16 June 2022 and 3 November 2022. All Ordinary Shares purchased were cancelled. As of 15 February 2023, the buyback programme was completed with a further 11,093,925 Ordinary Shares repurchased for cancellation for a cost of $41.1 million. These Ordinary Shares were also cancelled. As at 31 December 2022, the Company's issued and fully paid share capital comprised 847,168,796 Ordinary Shares of 0.002 pence each.

(c) Between 1 January 2023 and 31 December 2023, 5,092 Ordinary Shares were issued. During the same period, the Company repurchased a further 65,709,133 Ordinary shares for a total consideration, including transaction costs of $150 million (exclusive of VAT) as part of a share buyback programme announced on 9 March 2023. All Ordinary Shares were cancelled. As at 31 December 2023, the Company's issued and fully paid share capital comprised 770,377,712 Ordinary Shares of 0.002 pence each.

(d) Between 1 January 2024 and the Latest Practicable Date, 6,882 Ordinary Shares were issued.

Other than the issues of Ordinary Shares referred to above in this paragraph 3.1, there have been no changes to the issued share capital of the Company between 1 January 2021 and the Latest Practicable Date.

Immediately following Admission, it is expected that in excess of 10 per cent. of the Ordinary Shares of the Company will be held in public hands (within the meaning of paragraph 6.14 of the Listing Rules).

4. SHARE CAPITAL AUTHORITIES

On 10 May 2023, at the annual general meeting of the Company, Shareholders resolved to authorise the Directors:

(a) pursuant to section 551 of the Companies Act, to exercise all the powers of the Company to allot shares in the Company and to grant rights to subscribe for, or to convert any security into, shares in the Company up to an aggregate nominal amount of £5,562 (representing 278,100,000 Ordinary Shares of 0.002 pence each). This amount represents approximately one-third of the issued ordinary share capital (excluding treasury shares) of the Company;

(b) pursuant to section 570 and section 573 of the Companies Act, to allot equity securities (as defined in section 560 of the Companies Act) in connection with any pre-emptive offer to existing holders of Ordinary Shares in proportion to their existing shareholdings and to holders of other equity securities if required by the rights of those securities up to an aggregate nominal amount equal to £11,124 or 556,200,000 Ordinary Shares of 0.002 pence each, less the nominal amount of any shares issued under the authority summarised in paragraph (a) above. This amount represents approximately two-thirds of the issued ordinary share capital (excluding treasury shares) of the Company. Such authorities shall expire at the conclusion of the next annual general meeting of the Company or on 10 August 2024, whichever is the earlier unless previously renewed, varied or revoked by the Company in general meeting;

(c) pursuant to the authority given in paragraph (a) above, to allot new equity securities or to sell treasury shares for cash, in each case on a non-pre-emptive basis: (i) by way of rights issue, open offer or other pre-emptive offer of securities to existing shareholders in proportion to their existing shareholdings and to holders of other equity securities if required by the rights of those securities (subject to certain exclusions); (ii) up to a nominal amount of £1,668 equivalent to approximately 10 per cent. of the total issued ordinary share capital (excluding treasury shares) or 83,400,000 Ordinary Shares of 0.002 pence each as at 24 March 2023 for general corporate purposes; or (iii) otherwise up to a nominal amount of £332, equivalent to approximately 2 per cent. of the total issued ordinary share capital (excluding treasury shares) or 16,600,000 Ordinary Shares of 0.002 pence each as at 24 March 2023 for the purposes only of a follow-on offer as described in the Company's pre-emption group's statement of principles (the "**Pre-Emption Group Principles**"); and

(d) to allot new equity securities (or sell treasury shares) for cash, on a non-pre-emptive basis, in connection with the financing (or refinancing, if the authority is to be used within 12 months after the original transaction) of an acquisition or specified capital investment which is announced contemporaneously with the allotment or which has taken place in the preceding 12-month period and is disclosed in the announcement of the allotment. The authority is limited to: (i) up to an additional nominal amount of £1,668 equivalent to approximately 10 per cent. of the total issued ordinary share capital (excluding treasury shares) or 83,400,000 Ordinary Shares of 0.002 pence each as at 24 March 2023 for the purposes of an acquisition or a specified capital investment as described in the Pre-Emption Group Principles; and (ii) up to a nominal amount of £332, equivalent to approximately 2 per cent. of the total issued ordinary share capital (excluding treasury shares) or 16,600,000 Ordinary Shares of 0.002 pence each as at 24 March 2023 for the purposes only of a follow-on offer as described in the Pre-Emption Group Principles.

The Company remains subject to the continuing obligations of the Listing Rules with regard to the issue of securities for cash, and the provisions of section 561 of the Companies Act (which confers on Shareholders rights of pre-emption in respect of the allotment of equity securities which are, or are to be, paid up in cash) apply to any further issuances of share capital of the Company.

Pursuant to the Acquisition, 669,714,027 BASF Consideration Shares and 251,488,211 Non-Voting Shares will be issued. Details of the resolutions, authorisations and approvals by virtue of which the BASF Consideration Shares and the Non-Voting Shares will be issued are set out in the Notice of General Meeting set out at the end of the Circular, which is incorporated by reference into, and forms part of, this Prospectus.

5. INFORMATION ON THE NEW HARBOUR ENERGY SHARES

5.1 Description of the type and class of securities admitted

The BASF Consideration Shares will be Ordinary Shares with a nominal value of 0.002 pence each. The ISIN of the BASF Consideration Shares will be GB00BMBVGQ36. The BASF Consideration Shares will be created under the Companies Act 2006 and the Articles of Association. Following Admission, the Company will have one class of Ordinary Shares.

The BASF Consideration Shares will be credited as fully paid and free from all liens, equities, charges, encumbrances and other interests, and will rank in full for all dividends and distributions on the Ordinary Share capital of the Company declared, made or paid with reference to a record date falling on or after the date of Completion.

5.2 Listing

Applications will be made to the FCA for the Ordinary Shares to be readmitted to the premium listing segment of the Official List (or the segment of the Official List for ESCCs, if applicable at the time of application) and to the London Stock Exchange for the Ordinary Shares to be readmitted to trading on the London Stock Exchange's main market for listed securities. Applications will also be made to the FCA for the BASF Consideration Shares to be admitted to the premium listing segment of the Official

List of the FCA (or the segment of the Official List for ESCCs, if applicable at the time of application) and to the London Stock Exchange for the BASF Consideration Shares to be admitted to trading on the main market for listed securities of the London Stock Exchange. It is expected that Readmission and Admission will become effective, and that dealings in the Ordinary Shares and the BASF Consideration Shares will commence, as soon as reasonably practicable once all the Conditions to Completion (as defined below) have been satisfied, which is currently expected to be in Q4 2024. Admission to trading of the Ordinary Shares and the BASF Consideration Shares is not being sought on any stock exchange other than the London Stock Exchange.

5.3 **Form and currency of the BASF Consideration Shares**

The BASF Consideration Shares will be issued in registered form and will be capable of being held in certificated and uncertificated form.

Title to the certificated BASF Consideration Shares will be evidenced by entry in the register of members of the Company and title to uncertificated BASF Consideration Shares will be evidenced by entry in the operator register maintained by Euroclear (which forms part of the register of members of the Company). The Registrar of the Company is Equiniti Limited.

No share certificates will be issued in respect of the BASF Consideration Shares in uncertificated form. If any such shares are converted to be held in certificated form, share certificates will be issued in respect of those BASF Consideration Shares in accordance with the Articles of Association and applicable legislation.

The BASF Consideration Shares will be denominated in pounds sterling.

5.4 **Dates of issue and settlement**

The BASF Consideration Shares are expected to be issued on the date of Completion, which is expected to occur in Q4 2024, and those entitled to the BASF Consideration Shares are expected to be entered on the Company's register of members on that day.

5.5 **Description of restrictions on free transferability**

Save as set out below, the BASF Consideration Shares will be freely transferable.

The Company may, under the Articles of Association and the Companies Acts, send out statutory notices to those it knows or has reasonable cause to believe have an interest in its shares, asking for details of those who have an interest and the extent of their interest in a particular holding of shares. When a person receives a statutory notice and fails to provide any information required by the notice within the time specified in it, the Company can apply to the Court for an order directing, amongst other things, that any transfer of the shares which are the subject of the statutory notice is void.

The Directors may also, without giving any reason, refuse to register the transfer of any Ordinary Shares which are not fully paid as described more fully in paragraph 6.7 (Transfer of Shares) in this Part XIV (*Additional Information*).

5.6 **Summary of the Non-Voting Shares**

Overview

A summary of the rights attaching to the Non-Voting Shares is set out below. The rights and restrictions attaching to the Non-Voting Shares are set out in full in the Annex to the Notice of General Meeting set out in Part X (*Notice of General Meeting*) of the Circular.

Income

Each Non-Voting Share will be entitled to receive an amount equal to a 13 per cent. premium to the amount of any distribution per Ordinary Share made by the Company, whether by cash dividend, dividend *in specie*, scrip dividend, capitalisation issue or otherwise. Any amount due in relation to Non-Voting Shares that are held by a sanctioned person will be, subject to applicable law, held on trust for any such holder until such time as they are no longer subject to relevant sanctions restrictions.

Voting

Non-Voting Shareholders will not be entitled to receive notice of any general meeting of the Company nor to attend, speak or vote at any such general meeting, unless the business of the meeting includes the consideration of a resolution to: (i) wind up the Company; or (ii) re-register the Company as a private company.

In circumstances where a Non-Voting Shareholder can vote, such Non-Voting Shareholder will be entitled to: (i) on a poll, one vote for each Ordinary Share that would be held by the Non-Voting Shareholder following conversion of the Non-Voting Shares in accordance with their terms; and (ii) on a show of hands one vote per resolution proposed.

Class Rights

Any variation of the rights attaching to the Non-Voting Shares will require the sanction of a special resolution of the Non-Voting Shareholders. All the provisions of the Articles as to general meetings of the Company will apply to a general meeting where any such special resolution is proposed, except that the necessary quorum will be the holders of the Non-Voting Shares (representing more than 50 per cent. of the Non-Voting Shares) present in person or by proxy or (being a corporation) by a duly authorised representative. For these purposes, one holder present in person or by proxy or (being a corporation) by a duly authorised representative may constitute a meeting.

Conversion

A Non-Voting Shareholder will be entitled to require the Company, by delivery of a conversion notice, to convert at least 25,000,000 Non-Voting Shares (and if less than 25,000,000 Non-Voting Shares remain in issue, then all the remaining Non-Voting Shares) either: (i) in conjunction with the sale of Non-Voting Shares to market sale placees ("**Market Sale Placees**") which upon completion of such sale will be redesignated as Ordinary Shares; or (ii) following the satisfaction of the Conversion Conditions.

The Non-Voting Shares will be convertible to Ordinary Shares on a one for one basis except that following any allotment or issue of Ordinary Shares by way of capitalisation of profits or reserves or any sub-division or consolidation of Ordinary Shares by the Company (an "**Adjustment Event**"), the Non-Voting Shares will convert into such number of Ordinary Shares and the Non-Voting Shareholder will receive the same proportion of voting rights and entitlement to participate in distributions of the Company, as nearly as practicable, as would have been the case had no Adjustment Event occurred (the "**Conversion Ratio**").

If the conversion of the Non-Voting Shares can be implemented without publication of a prospectus by the Company, the relevant Non-Voting Shares will automatically convert into Ordinary Shares on the date falling three business days after the receipt by the Company of a conversion notice from the Non-Voting Shareholder except that in the case of a market sale, the conversion will take place at the same time as the transfer to the relevant Market Sale Placee. The Company will then be required to procure that such Ordinary Shares are admitted to the premium listing segment of the Official List (or the segment of the Official List of ESCCs if such new listing category as contemplated in FCA Consultation Paper CP23/31 has been implemented by the FCA and taken effect at the relevant time) and to trading on the London Stock Exchange's main market for listed securities.

If the conversion of the Non-Voting Shares requires the publication of a prospectus by the Company, the Company will be required to prepare a prospectus and obtain approval of the prospectus by the FCA as soon as reasonably practicable (and, in any event, by no later than eight weeks) following receipt by the Company of a conversion notice. The Non-Voting Shares will automatically convert into Ordinary Shares on the date of publication of the prospectus except that in the case of a market sale, the conversion will take place at the same time as transfer to the relevant Market Sale Placee. The Company will then be required to procure promptly (and in any event within 10 business days) following receipt of approval of the prospectus from the FCA that such Ordinary Shares are admitted to the premium listing segment of the Official List (or the segment of the Official List of ESCCs if such new listing category as contemplated in FCA Consultation Paper CP23/31 has been implemented by the FCA and taken effect at the relevant time) and to trading on the London Stock Exchange's main market for listed securities.

The Company will also be required to procure that the Non-Voting Shares automatically convert into Ordinary Shares, following:

(a) the cancellation of listing of the Ordinary Shares on the Official List and the trading of the Ordinary Shares on the main market for listed securities of the London Stock Exchange; and

(b) subject to certain exceptions, the acquisition of more than 50 per cent. of the voting rights exercisable by members of the Company on a poll in a general meeting by any person (other than the Non-Voting Shareholder and any person acting in concert with it), **provided that** the holders of Ordinary Shares resulting from the conversion of the Non-Voting Shares will be entitled to the same rights and receive the same consideration as other holders of Ordinary Shares,

except that if the Non-Voting Shareholder is subject to certain sanctions restrictions the Company will be required to procure, subject to applicable law, that any distribution that otherwise would have been due to the sanctioned Non-Voting Shareholder is held on trust until such time as it is no longer subject to such sanctions restrictions. In any other circumstances, the Non-Voting Shareholder will be entitled to receive an instrument of equivalent value and with equivalent economic, governance and other rights (including rights on a liquidation or winding up) as each Non-Voting Share.

Liquidation

On any liquidation or winding up, each Non-Voting Share will be entitled to a preference amount, such that if the assets of the Company remaining after payments of its liabilities (the "**Distribution Amount**") is less than the total outstanding preference amount with respect to the Non-Voting Shares, then the Distribution Amount will be applied in priority to any holders of other shares in the Company to paying an amount to Non-Voting Shareholders.

If the Distribution Amount is greater than the total outstanding preference amount for the Non-Voting Shares, each Non-Voting Share will be entitled to an amount equal to the higher of: (i) the preference amount; and (ii) an amount equal to the Distribution Amount divided by the fully diluted share capital of the Company and multiplied by the Conversion Ratio **provided that** no payment will be made in respect of any share that is not a Non-Voting Share until the amount due to the Non-Voting Shareholders has been paid in full.

Transfer/Listing

The Non-Voting Shares will not be admitted to listing or trading and will only be capable of being held in certificated form. At the appropriate time, an application will be made for any Ordinary Shares arising on conversion of the Non-Voting Shares to be admitted to the premium listing segment of the Official List (or the segment of the Official List for ESCCs if such new listing segment as contemplated in FCA Consultation Paper CP23/31 has been implemented by the FCA and taken effect at the relevant time) and to trading on the London Stock Exchange's main market for listed Securities on or shortly after conversion.

The Non-Voting Shares may be transferred by LetterOne to certain permitted transferees, in certain cases only with the consent of the Company and in accordance with the terms of the Non-Voting Shares.

6. ARTICLES OF ASSOCIATION

The Articles of Association, which were adopted by a resolution of the Company passed at the annual general meeting held on 23 June 2021, include provisions to the following effect:

6.1 Objects/Purposes

The objects of the Company, in accordance with section 31(1) of the Companies Act, are unrestricted.

6.2 Share rights

Subject to the Companies Act 2006 and other Shareholders' rights, shares may be issued with such rights and restrictions as the Company may by ordinary resolution decide, or (if there is no such resolution or so far as it does not make specific provision) as the Board may decide. Redeemable shares may be issued. Subject to the Articles, the Companies Act 2006 and other Shareholders' rights, unissued shares are at the disposal of the Board.

6.3 Voting rights

Subject to any rights or restrictions attaching to any class of shares, every member present in person at a general meeting has, upon a show of hands, one vote, and every member present in person or by proxy has, upon a poll, one vote for every share held by him. Resolutions put to the meeting will generally be decided on a poll. No member shall be entitled to vote at any general meeting in respect of any share held by him if he has not paid any amount relating to that share which is due at the time of the meeting or if a member has been served with a restriction notice (as defined in the Articles) after failure to provide the Company with information concerning interests in those shares required to be provided under the Companies Act 2006.

6.4 Dividends and other distributions

Subject to the Companies Act 2006, the Shareholders can declare dividends by passing an ordinary resolution. No such dividend can exceed the amount recommended by the Board. Subject to the Companies Act 2006, the Directors may pay interim dividends, and also any fixed rate dividend, if they consider that the financial position of the Company justifies such payments. If the Board acts in good faith, it is not liable for any loss that Shareholders may suffer because a lawful dividend has been paid on other shares which rank equally with or behind their shares.

The Board may withhold payment of all or any part of any dividends (including scrip dividends) or other money which would otherwise be payable in respect of the Company's shares from a person with a 0.25 per cent. interest (as described in the Articles) if such a person has been served with a restriction notice after failure to provide the Company with information concerning interests in those shares required to be provided under the Companies Act 2006.

Except insofar as the rights attaching to, or the terms of issue of, any share otherwise provide, all dividends will be divided and paid in proportions based on the amounts which have been paid up on the shares during any period for which the dividend is paid. Dividends may be declared or paid in any currency.

The Board may, if authorised by an ordinary resolution of the Company, offer Shareholders the right to choose to receive extra Ordinary Shares which are credited as fully paid up, instead of some or all of their cash dividend.

If a dividend has not been claimed for 6 years after being declared or becoming due for payment, it will be forfeited and go back to the Company.

The Company may stop sending dividend payments through the post, or cease using any other method of payment (including payment through CREST), for any dividend if, either (i) at least two consecutive payments have remained uncashed or are returned undelivered or that means of payment has failed or (ii) one payment remains uncashed or is returned undelivered or that means of payment has failed and reasonable enquiries have failed to establish any new address or account of the registered holder. The Company will resume sending dividend payments if requested in writing by the Shareholder.

Each Ordinary Share entitles the holder to an equal share of any surplus assets of the Company after creditors have been paid in the event of a winding-up of the Company.

6.5 Variation of rights

Subject to the Companies Act 2006, rights attached to any class of shares may be varied with the written consent of the holders of not less than three-quarters in nominal value of the issued shares of that class, or by an extraordinary resolution passed at a separate general meeting of the holders of those shares. At every such separate general meeting (except an adjourned meeting) the quorum shall be two persons holding or representing by proxy not less than one-third in nominal value of the issued shares of the class.

Rights attached to any class of share can be altered using the mechanism set out in the rights attached to that share, or if no such mechanism is provided for, by approval of the shareholders of that class.

The purchase or redemption by the Company of any of its own shares will not constitute a variation of the rights of other shares unless otherwise expressly provided in the rights attached to those shares.

6.6 Lien, forfeiture and untraced Shareholders

The Company has a lien (enforceable by sale) on all partly-paid shares for any money owed to the Company for the shares. The Directors are entitled to exercise their right of sale where the money owed by the Shareholder is payable immediately, the Directors have given notice to the Shareholder of the amount owed (stating the amount due, demanding payment and setting out the Directors' right to enforce the lien through sale), the notice has been served on the Shareholder and the Directors have waited 14 days for the Shareholder to pay the sum due.

The Board can also call on Shareholders to pay any money which has not yet been paid to the Company for their shares as well as any interest which may accrue from the date of the call until the date it is satisfied and any expenses incurred as a result of the non-payment of the call. The Directors can send the Shareholder a notice requiring payment of the unpaid amount; the notice must demand payment of the sum due plus interest and expenses, give the date by which the total is due (which must be at least 14 days after the date of the notice), specify where payment is to be made and state the Company's right of forfeiture in respect of outstanding calls. Where this call remains unsatisfied the shares can be forfeited; the shares become the property of the Company and the Directors can dispose of them in any way they decide.

As regards certificated shares, if during a 12 year period at least three cash dividends have gone unclaimed and at least three letters from the Company have not been responded to, the Company is required to use 'reasonable efforts' to trace a shareholder which may include, if considered appropriate, the Company engaging a professional asset reunification company or other tracing agent to search for a shareholder who has not kept their shareholder details up to date. If the untraced Shareholder does not claim the proceeds of the sale of his/her shares within two years of such sale (i.e. it has been at least 14 years since the Shareholder last claimed a dividend or communicated with the Company) then the proceeds of the sale are forfeited and belong to the Company absolutely. The Company may also sell any additional shares issued during and after the 12 year period during which a shareholder has not been traced even if the 12 year waiting period is not fulfilled with regard to the additional shares.

6.7 Transfer of shares

Any member may transfer all or any of his certificated shares by an instrument of transfer in any usual form or in any other form which the Board may approve. The instrument of transfer must be executed by or on behalf of the transferor and (in the case of a partly-paid share) the transferee and the transferor will continue to be treated as the holder until the transferee's name is entered in the register.

The Board may, without giving any reason, refuse to register the transfer of any shares which are not fully paid. The Board may also decline to register a transfer of certificated shares if the instrument of transfer:

(a) is not properly stamped to show the payment of any applicable stamp duty and accompanied by the relevant share certificate and such other evidence of the right to transfer as the Board may reasonably require;

(b) is in respect of more than one class of share; and

(c) is to joint transferees and is in favour of more than four such transferees.

Furthermore, where a Shareholder holds over 0.25 per cent. of the existing shares in a particular class and has been served with a restriction notice the Board can refuse to register a transfer of any shares which are certificated shares unless they are satisfied that they have been transferred to an independent third party.

Any shares in the Company may be held in uncertificated form and these shares must be transferred through CREST. (Provisions of the Articles do not apply to any uncertificated shares to the extent that such provisions are inconsistent with the holding of shares in uncertificated form with the transfer of shares through CREST or with any provision of the Uncertificated Securities Regulations.) If according to the Articles or any relevant legislation the Company has the right to sell, transfer or otherwise deal with the CREST shares the Directors may require the holder of that share to change the CREST share to a certificated share.

The Board may decline to register a transfer of CREST shares in the circumstances set out in the Uncertificated Securities Regulations and where, in the case of a transfer to joint holders, the number of joint holders to whom the uncertificated share is to be transferred exceeds four.

Provisions of the Articles apply to any shares that the Company has in issue which are CREST shares only to the extent that they are consistent with the Company exercising any of its powers or doing anything through CREST.

6.8 **Meetings**

The Articles are silent on the notice period required to call annual general meetings and extraordinary general meetings. The Companies Act 2006 provides that the board of directors has the power to call general meetings, as do Shareholders representing at least 5 per cent. of the Company's paid-up voting share capital. By law the Company may call annual general meetings on 21 clear days' notice, but it must call them on 20 working days if it is to comply with the UK Corporate Governance Code. By law the Company may call general meetings other than annual general meetings on 14 clear days' notice, but must call them on 14 working days if it is to comply with the UK Corporate Governance Code. Where appropriate, changes may be made to the arrangements for general meetings (including the introduction, change or cancellation of electronic facilities) after notice of the meeting has been issued. The Company may give notice of any such changes in any manner considered appropriate (rather than via an advertisement in two national newspapers).

Before a general meeting can start there must be at least two people present who are entitled to vote (Shareholders or proxies or both). Every Director is entitled to speak at the general meeting. The Chair is entitled to adjourn a meeting, whether quorate or not, for any reason so that the business of the meeting can be carried out properly and can also adjourn a quorate meeting with the agreement of the meeting. The Chair of a meeting may also adjourn it if he or she deems that the facilities or security of the meeting have become inadequate or are otherwise not sufficient. Meetings can be adjourned indefinitely and more than once. A general meeting adjourned for lack of quorum must be held at least ten clear days after the original meeting.

The Company can hold general meetings as hybrid meetings (i.e. where there is both a physical place of meeting and an electronic facility to allow shareholders to attend and participate remotely—through conference dial-in, web browser, or app technology, or a combination of these or other methods) if it chooses to do so. However, while hybrid meetings are permitted hybrid, wholly-virtual meetings which are held without a physical place of meeting and where shareholders can only participate electronically are not permitted. Voting at hybrid meetings will, by default, be decided on a poll. Hybrid meetings may be adjourned in the event of a technological failure.

There is also the possibility of satellite/multi-venue meetings, such as the use of overflow rooms. Satellite meetings are legally valid even without such a provision but it has been reflected in the Articles for clarity.

6.9 **Change of name**

The Directors may change the name of the Company by passing a board resolution.

6.10 **Directors**

Appointment of Directors

The Company must have a minimum of two Directors and a maximum of 20 and the Directors are not required to hold shares in the Company. Directors may be appointed by the Company by ordinary resolution or by the Board. The only people who can be appointed as Directors at a general meeting are those Directors retiring during the meeting, persons recommended by the Directors or persons recommended by the Shareholders where the Shareholder is entitled to vote and delivers to the Company notice of their intention to recommend the relevant individual along with the individual's consent.

Removal of Directors

In addition to any power to remove Directors conferred by legislation, the Company can remove a Director before the end of his term in office by passing a special resolution.

Retirement of Directors

At every annual general meeting the following must retire from office; any Director who has been appointed by the Board since the last annual general meeting, any Director who held office at the time of the preceding two annual general meetings and who did not retire then and any Director who has been in office as a non-executive Director for more than nine years at the date of the meeting. This requirement does not apply to Directors in their first year of appointment who were appointed in the period between the notice of the annual general meeting being issued and the annual general meeting itself. Any retiring Director may offer themself up for reappointment and can be reappointed by an ordinary resolution of the Shareholders.

A Director who fails to be re-elected at an annual general meeting will remain in office until (the earlier of) the end of the meeting or a resolution being passed to appoint another person in the Director's place. This ensures that there is a sufficient number of Directors in office to hold a quorate Board meeting if the Directors decide to adjourn the annual general meeting and hold an emergency Board meeting to appoint new Directors.

Vacation of office by Directors

In addition to the legislative provisions on vacation of a Directors' office, any Director automatically vacates their office as Director if; they give the Company written notice of their resignation; they offer to resign and this offer is accepted; all of the other Directors (where there are at least three) pass a resolution requiring them to vacate; they are suffering from a physical or mental health illness and the Directors pass a resolution removing them from office; they have missed Directors' meetings for a continuous six month period without permission and the Directors pass a resolution removing them; or a bankruptcy order is made against them.

Alternate Directors

Any Director can appoint another person to act as a Director in their place. Where this person is not already a Director their appointment requires the approval of the Directors.

Remuneration of Directors

The total fees paid to all of the Directors (excluding any payments made to executive Directors or under any other provision of the Articles) must not exceed £1,500,000 a year or such higher sum decided on by ordinary resolution of the Company. Any Director who is appointed to any executive office will be entitled to receive such remuneration (whether as salary, commission, profit share or any other form of remuneration) as the Board or any committee authorised by the Board may decide, either in addition to or in place of their fees as a Director. In addition, any Director who, in the opinion of the Board or any committee authorised by the Board, performs any special or extra services for the Company, may be paid such extra remuneration as the Board or any committee authorised by the Board may determine. Service on a committee is regarded as services beyond the ordinary duties of a director and as such additional fees can be awarded to a Director who serves on any committee of Directors or devotes special attention to the business. All remuneration payable to Directors will be in accordance with the shareholder approved remuneration policy in place at the time.

Each Director may be paid their reasonable travelling, hotel and incidental expenses of attending and returning from meetings of the Board, or committees of the Board or of the Company or any other meeting which as a Director he is entitled to attend, and will be paid all expenses properly and reasonably incurred by them in connection with the Company's business or in the performance of their duties as a Director. The Company can also fund a Director's expenditure or that of a director of any holding company of the Company for any purpose permitted by the Companies Act 2006 and, as far as permitted by the legislation, can indemnify any Director against any liability.

Pensions and gratuities for Directors

The Board or any committee authorised by the Board may exercise the powers of the Company to provide benefits either by the payment of gratuities or pensions or by insurance or in any other manner for any Director or former Director or his relations or dependents. However, no benefits (except those provided for by the Articles) may be granted to a Director or former Director who has not been employed by or held an executive office or place of profit under the Company or any of its subsidiary undertakings or their respective predecessors in business without the approval of an ordinary resolution of the Company.

Permitted interests of Directors

The Directors may authorise any matter which would otherwise involve a Director breaching their duty under the Companies Act 2006 to avoid conflicts of interest. In order to obtain authorisation the Director must tell the nature and extent of their interest to the Board as soon as possible and in sufficient detail. Any Director (including the conflicted Director) may propose this authorisation. In considering this proposal the conflicted Director will not be entitled to vote and will not count in the quorum and may be excluded from the meeting whilst the decision is taken.

Where authority is given the Board may specify such terms to be imposed on the Director as the Board thinks fit (e.g. the conflicted Director may be excluded from the receipt of certain information). The Board may also provide that the Director is not bound to disclose to the Company any information which he comes into possession of otherwise than in their role as a Director where disclosure would entail a breach of confidence. The Board may provide that the terms of the authorisation be recorded in writing and any authority given may be varied or revoked at any time.

Where a Director is indirectly or directly interested in a contract with the Company this must be disclosed in accordance with the Companies Act 2006. Where this is the case the Director may do the following:

(a) have any kind of interest in a contract with or involving the Company;

(b) hold any office (except that of auditor) with the Company;

(c) do paid professional work for the Company;

(d) become a director of any holding company or subsidiary of the Company; and/or

(e) be a director of any other company so long as the appointment cannot reasonably be regarded as giving rise to a conflict of interest.

Restrictions on voting

A Director cannot vote or be counted in the quorum when the Board is considering their appointment to a position within the Company or a company in which the Company has an interest. Furthermore, except as mentioned below, no Director may vote on, or be counted in a quorum in relation to, any resolution of the Board in respect of any contract in which they have an interest. A Director can only vote where their interest cannot reasonably be regarded as material or where the only material interest they have in it is included in the following list:

(a) a resolution about giving them any security or any indemnity for any money which they, or any other person, have lent at the request, or for the benefit, of the Company or any of its subsidiary undertakings;

(b) a resolution about giving any security or any indemnity to any other person for a debt or obligation which is owed by the Company or any of its subsidiary undertakings, to that other person, if the Director has taken responsibility for some or all of that debt or obligation. The Director can take this responsibility by giving a guarantee, indemnity or security;

(c) a resolution giving them any other indemnity where all Directors are also being offered indemnities on substantially similar terms;

(d) a resolution about the Company funding any expenditure incurred defending proceedings where all Directors are also being offered indemnities on substantially similar terms;

(e) a resolution about any proposal relating to an offer of any shares or debentures or other securities for subscription or purchase by the Company or any of its subsidiary undertakings, if the Director takes part because they are a holder of shares, debentures or other securities, or if they take part in the underwriting or sub-underwriting of the offer;

(f) a resolution about a contract in which they have an interest because of their interest in securities of the Company;

(g) a resolution regarding a contract with a company in which the Director has an interest (including where the Director is a director or shareholder of that other company) as long as they do not hold an interest in shares representing one per cent. or more of any class of equity share capital of that company or of the voting rights in that company;

(h) a resolution relating to a pension fund, superannuation scheme, retirement, death or disability fund where these benefits are provided to employees generally;

(i) any arrangement for the benefit of employees of the Company or any of its subsidiary undertakings which gives them benefits which are also generally given to the employees to whom the arrangement relates; or

(j) a resolution about any proposal relating to any insurance which the Company can buy and renew for the benefit of the Directors or of a group of people which includes the Directors.

Subject to the provisions of the Companies Act 2006, the Company may by ordinary resolution suspend or relax the above provisions to any extent or ratify any contract which has not been properly authorised in accordance with the above provisions.

Borrowing powers

Subject to the Company's Articles, the Companies Act 2006 and any directions given by the Company by special resolution, the business of the Company will be managed by the Board who may use all the Company's powers. In particular, the Board may exercise all the Company's powers to borrow money and to mortgage or charge any of its undertaking, property, assets and uncalled capital, to issue debentures and other securities and to give security for any debt, liability or obligation of the Company or any third party.

The Articles provide for a borrowing restriction which limits the borrowings of the Company and obliges the Company to exercise all voting and other rights or powers of control exercisable by the Company in relation to Harbour Energy so as to ensure that no money is borrowed if the total amount of the borrowings of Harbour Energy then exceeds, or would as a result of such borrowing exceed, a multiple of four times Harbour Energy's adjusted capital and reserves (as defined in the Articles). This borrowing limit can be exceeded if the Shareholders provide consent in advance by passing an ordinary resolution.

At the Company's annual general meeting in 2016, the Shareholders passed an ordinary resolution to increase the borrowing limit such that the total amount of Harbour Energy's borrowings may not exceed an amount equal to the greater of: (i) $10 billion; or (ii) five times the Company's adjusted capital and reserves.

6.11 Changes in capital

If recommended by the Board, the Shareholders can pass an ordinary resolution to capitalise any sum which is part of the Company's reserves or which the Company is holding as net profits. Unless the ordinary resolution states otherwise, the Directors may use this sum to either: (i) pay up some or all of any issued shares which have not already been called or paid in advance; or (ii) to pay up in full unissued shares, debentures or other securities of the Company which would then be allotted or distributed, credited as fully paid, to Shareholders.

6.12 Subdivision

An additional class of shares to account for the non-voting deferred shares as created as a result of the sub-division of share capital that was carried out in connection with the Merger with Chrysaor Holdings Limited. The non-voting deferred shares do not carry any voting or dividend rights.

Any shares resulting from a sub-division of the Company's existing shares may, in addition to having any preference or advantage as compared with the Company's other shares, also have deferred or other rights. This change makes administering any sub-division of shares more straightforward.

7. DIVIDEND POLICY

On 9 December 2021, the Company introduced a dividend policy of $200 million annually to be paid in two equal instalments. On 21 December 2023, as part of the Company's announcement of the Acquisition, the Company announced that it expects the Acquisition to support an increase in the Company's annual dividend from $200 million to c.$455 million, of which c.$380 million will be paid to holders of Ordinary Shares. This will reflect a 5 per cent. increase in dividend per Ordinary Share to 26.25 cents (based on a total expected dividend for 2023 of 25 cents/share (12 cents interim and expected 13 cents final) and 1,440.1 million Ordinary Shares being in existence post-Completion).

8. DIRECTORS' AND OTHER INTERESTS

8.1 The table below sets out the interests of the Directors and the Senior Managers (all of which are beneficial and include interests of persons connected to them) in the share capital of the Company at the Latest Practicable Date:

	As at the Latest Practicable Date		Immediately following Admission	
Name	**Number of Ordinary Shares**	**Percentage of Ordinary Shares**	**Number of Ordinary Shares**	**Percentage of Ordinary Shares**(1)
Directors				
R. Blair Thomas	4,534,797(2)	0.5886	4,534,797(2)	0.3149
Linda Z. Cook	8,875,490(3)	1.1521	8,875,490(3)	0.6163
Alexander Krane	149,507	0.0194	149,507	0.0104
Simon Henry	20,000	0.0026	20,000	0.0014
Belgacem Chariag	—	—	—	—
Alan Ferguson	24,203(4)	0.0031	24,203(4)	0.0017
Andy Hopwood	10,000	0.0013	10,000	0.0007
Louise Hough	6,800	0.0009	6,800	0.0005
Margareth Øvrum	8,500	0.0011	8,500	0.0006
Anne L. Stevens	30,000	0.0039	30,000	0.0021
Senior Managers				
Scott Barr	3,039	0.0004	3,039	0.0002
Philip Whittaker	—	—	—	—
Howard Landes	15,977	0.0021	15,977	0.0011
Steven Cox	13,388	0.0017	13,388	0.0009
Gill Riggs	21,058	0.0027	21,058	0.0015
Gustavo Baquero	—	—	—	—

Notes

(1) Assumes that no further issues of Ordinary Shares occur between the Latest Practicable Date and Admission.

(2) R. Blair Thomas is indirectly interested in 1.07 per cent. of the Company's Ordinary Shares through his interest in certain EIG-managed entities.

(3) Number of Ordinary Shares held by Linda Z. Cook includes 7,144,646 Ordinary Shares held by her spouse, Mr Steven R. Cook.

(4) Number of Ordinary Shares held by Alan Ferguson includes 4,261 Ordinary Shares held by his spouse, Mrs Sarah Ferguson.

9. DIRECTORS' SERVICE CONTRACTS

Details of Executive Directors' service contracts providing for benefits upon termination of employment are set out at pages 92 to 93 (inclusive) of the Harbour Energy Annual Report 2023 which are incorporated by reference into this Prospectus.

10. DIRECTORS' AND SENIOR MANAGERS' COMPENSATION

In the year ended 31 December 2023, the aggregate total remuneration paid (including contingent or deferred compensation) and benefits in kind granted (under any description whatsoever) to the Directors and the Senior Managers by members of Harbour Energy was c. £11 million ($14 million). Of this amount, £4,872,400 was paid to the Directors as set out below and £6,226,023 was paid to the Senior Managers:

Name	Salary / Fees	Taxable Benefits	Pension	Bonus	LTIP	Other Variable / Additional Payments	Travel Allowance and Expenses	Total Remuneration
					(£ thousand)			
R. Blair Thomas . .	300.0	—	—	—	—	—	23.7	323.7
Linda Z. Cook . . .	850.0	615.4	125.6	816	—	—	—	2,407.0
Alexander Krane . .	540.8	132.7	69.7	519.1	—	—	—	1,262.3
Simon Henry	140.0	—	—	—	—	—	3.0	143.0
Margareth Øvrum . .	115.0	—	—	—	—	—	6.0	121.0
Alan Ferguson	120.0	—	—	—	—	—	0.7	120.7
Andy Hopwood . . .	110.0	—	—	—	—	—	3.3	113.3
Anne L. Stevens . .	115.0	—	—	—	—	—	37.4	152.4
Belgacem Chariag .	73.3	—	—	—	—	—	28.4	101.7
Louise Hough	76.7	—	—	—	—	—	0.1	76.8

Former non-executive directors

Name	Salary / Fees	Taxable Benefits	Pension	Bonus	LTIP	Other Variable / Additional Payments	Travel Allowance and Expenses	Total Remuneration
					(£ thousand)			
G. Steven Farris(1) .	34.6	—	—	—	—	—	15.9	50.5

Notes

(1) G. Steven Farris stepped down from the Board on 10 May 2023.

11. OTHER DIRECTORSHIPS

In addition to their directorships of the Company and its subsidiaries and subsidiary undertakings, the Directors and the Senior Managers hold, or have held, the following directorships and are or were members of the following partnerships, within the past five years:

Name	Current directorships / partnerships	Past directorships / partnerships
Directors		
R. Blair Thomas	FS Specialty Lending Fund (fka FS Energy and Power Fund) FS/EIG Advisor, LLC Prumo Logistica S.A. EIG Atacama Holdings (Cayman) GP, Ltd TCW Crescent Mezzanine V Madrono LP EIG Separate Investments, LP EIG Employee Co (Special Retention Vehicle EIG Principals Incentive Carry Vehicle II, LP EIG Principals Incentive Carry Vehicle II-A EIG Asset Management, LLC EIG Credit Management Company, LLC EIG Energy Investors XV (Scotland) Ltd EIG Global Energy (Asia) Limited EIG Global Energy	Chrysaor Holdings Ltd Harbour Direct Holdings ltd. Limetree Bay Energy, LLC EIG Principals Incentive Carry Vehicle III, LP EIG Principals Incentive Carry Vehicle III-A, LP—Limited Partner Breakwater Acquisition Corp

Name	Current directorships / partnerships	Past directorships / partnerships
	(Australia) Pty Limited EIG Global Energy Korea, Ltd EIG Global Energy Partners, LLC EIG Harbour Energy Feeder GP, Ltd EIG Investment Management Company, LLC EIG Management Company, LLC Gateway Debt Holdings Offshore, Ltd Global LNG Holdings Ltd Harbour Energy GP, Ltd Avantus LLC (fka 8minute Power LLC HIF Global LLC Repsol Lux E&P S.a.r.l MidOcean Energy, LLC MidOcean Energy Holdings Pty Ltd MidOcean Energy Parent 4 Pty Ltd MidOcean Holdings II, L.P MidOcean Mako Parent Pty Ltd MidOcean Reef BidCo Pty Ltd MidOcean Reef Parent Pty Ltd EIG Energy Transition Fund, S.C.Sp EIG BTB Co-Investment GP, Ltd Breakwater Energy, LLC	
Linda Z. Cook	BNY Mellon EIG Energy Fund XVII-E, L.P.	EIG Global Partners EIG Swift Co-Investment, L.P EIG Global Energy (Europe) Limited Harbour Direct Holdings Ltd Harbour Energy LP Maverick Natural Resources LLC
Alexander Krane	—	Aker BP
Simon Henry	Rio Tinto plc	PetroChina Company Ltd. Ministry of Defence (Government Department) Lloyds Banking Group plc
Margareth Øvrum	FMC Corporation Technip FMC plc Transocean Ltd Fjordbase Holdings Fox Innovation & Technologies Inc.	Equinor Alfa Laval AB
Alan Ferguson	AngloGold Ashanti Limited	Marshall Motor Holdings Limited
Andrew Hopwood	—	—

Name	Current directorships / partnerships	Past directorships / partnerships
Anne L. Stevens	Aveva Group Limited Aston Martin Lagonda Global Holdings plc	Anglo American plc
Belgacem Chariag	Helmerich & Payne Inc Tunisian Talent United Association	Baker Hughes Schlumberger Ecovyst Inc
Louise Hough	—	UBS
Senior Managers		
Scott Barr	The UK Offshore Energies Association Limited	—
Gustavo Baquero	—	Equinor Apsheron AS Equinor Argentina AS Equinor BTC Caspain AS Equinor Global New Ventures 2 AS Equinor Russia AS Equinor Russia Energy AS Equinor Russia Holding AS Statoil Kharyaga AS Equinor Argentina B.V.
Philip Whittaker	—	—
Howard Landes	—	—
Steve Cox	—	—
Gill Riggs	—	—

12. **MAJOR SHAREHOLDERS**

As at the Latest Practicable Date, the Company had been notified in accordance with Chapter 5 of the Disclosure Guidance and Transparency Rules that the following persons are directly or indirectly interested (within the meaning of the Companies Act) in the Company's Ordinary Shares:

Name	Number of Ordinary Shares as at the Latest Practicable Date	Percentage of Ordinary Shares as at the Latest Practicable Date	Number of Ordinary Shares as at Admission(1)	Percentage of Ordinary Shares as at Admission(1)	Number of Ordinary Shares upon conversion of all Non-Voting Shares(2)	Percentage of Ordinary Shares upon conversion of all Non-Voting Shares(2)
EIG Asset Management, LLC	134,281,887	16.74	134,281,887	9.32	134,281,887	7.94
Control Empresarial de Capitales	54,901,500	7.13	54,901,500	3.81	54,901,500	3.25
Bank of America Corporation	26,720,962	3.47	26,720,962	1.86	26,720,962	1.58

Notes

(1) This assumes that no further issues of Ordinary Shares occur between the Latest Practicable Date and Admission other than the issue of the BASF Consideration Shares.

(2) Assuming conversion of all Non-Voting Shares and no further issues of Ordinary Shares occur between the Latest Practicable Date and the date of conversion of the Non-Voting Shares other than the issue of the BASF Consideration Shares.

Save as disclosed above, the Company is not aware of any person who, as at the Latest Practicable Date, directly or indirectly, has a holding of Ordinary Shares which is notifiable under English law.

Save as set out above, the Company and the Directors are not aware of any persons who, as at the Latest Practicable Date, directly or indirectly, jointly or severally, exercise or could exercise control over the Company nor are they aware of any arrangements the operation of which may at a subsequent date result in a change of control of the Company.

None of the Shareholders referred to in this paragraph has or will have different voting rights from any other Shareholder in respect of any Ordinary Shares (including any BASF Consideration Shares) held by them.

13. SIGNIFICANT SUBSIDIARIES

Harbour Energy plc is the parent company of Harbour Energy.

The following table contains a list of the wholly-owned significant subsidiaries and subsidiary undertakings of the Company:

Name	Country of Incorporation/ Residence
Chrysaor (U.K.) Alpha Limited	United Kingdom(2)
Chrysaor (U.K.) Beta Limited	United Kingdom(2)
Chrysaor (U.K.) Delta Limited	United Kingdom(2)
Chrysaor (U.K.) Sigma Limited	United Kingdom(2)
Chrysaor (U.K.) Theta Limited	United Kingdom(2)
Chrysaor (U.K.) Zeta Limited	United Kingdom(2)
Chrysaor CNS Limited	United Kingdom(2)
Chrysaor Developments Limited	United Kingdom(2)
Chrysaor E&P Finance Limited	United Kingdom(2)
Chrysaor E&P Limited	United Kingdom(2)
Harbour Energy Services Limited (formerly Chrysaor E&P Services Limited)	United Kingdom(2)
Chrysaor Holdings Limited(1)	Cayman Islands(13)
Chrysaor Limited	United Kingdom(2)
Chrysaor Marketing Limited	United Kingdom(2)
Harbour Energy Norge AS (formerly Chrysaor Norge AS)	Norway(3)
Chrysaor North Sea Limited	United Kingdom(2)
Chrysaor Petroleum Company U.K. Limited	United Kingdom(2)
Chrysaor Petroleum Limited	United Kingdom(2)
Chrysaor Production (U.K.) Limited	United Kingdom(2)
Chrysaor Production Holdings Limited	United Kingdom(2)
Chrysaor Production Limited	United Kingdom(2)
Chrysaor Resources (Irish Sea) Limited	United Kingdom(2)
Chrysaor Resources (U.K.) Holdings Limited	United Kingdom(2)
Ebury Gate Limited	Guernsey(10)
EnCore (NNS) Limited	United Kingdom(2)
EnCore Oil Limited	United Kingdom(2)
FP Mauritania A BV	Netherlands(7)
FP Mauritania B BV	Netherlands(7)
Premier Oil (EnCore Petroleum) Limited	United Kingdom(2)
Premier Oil (Vietnam) Limited	British Virgin Islands(7)
Premier Oil Aberdeen Services Limited	United Kingdom(2)
Premier Oil and Gas Services Limited	United Kingdom(2)
Premier Oil Andaman I Limited	United Kingdom(2)
Premier Oil Andaman Limited	United Kingdom(2)
Premier Oil ANS Holdings Limited	United Kingdom(2)
Premier Oil ANS Limited	United Kingdom(2)
Premier Oil Barakuda Limited	United Kingdom(2)
Premier Oil do Brasil Petroleo e Gas Ltda	Brazil(8)
Premier Oil E&P Holdings Limited	United Kingdom(2)
Premier Oil E&P UK Energy Trading Limited	United Kingdom(2)
Premier Oil E&P UK EU Limited	United Kingdom(2)
Premier Oil E&P UK Limited	United Kingdom(2)
Premier Oil Exploration (Mauritania) Limited	Jersey(6)
Premier Oil Exploration and Production Mexico S.A.de C.V.	Mexico(9)
Premier Oil Far East Limited	United Kingdom(2)
Premier Oil Finance (Jersey) Limited	Jersey(6)
Premier Oil Group Holdings Limited	United Kingdom(2)

Name	Country of Incorporation/ Residence
Premier Oil Group Limited	United Kingdom(5)
Premier Oil Holdings Limited	United Kingdom(2)
Premier Oil Mauritania B Limited	Jersey(6)
Premier Oil Mexico Holdings Limited	United Kingdom(2)
Premier Oil Mexico Investments Limited	United Kingdom(2)
Premier Oil Mexico Recursos S.A. de C.V.	Mexico(10)
Premier Oil Natuna Sea BV	Netherlands(7)
Premier Oil Overseas BV	Netherlands(7)
Premier Oil South Andaman Limited	United Kingdom(2)
Premier Oil Tuna BV	Netherlands(7)
Premier Oil UK Limited	United Kingdom(5)
Premier Oil Vietnam 121 Limited	United Kingdom(2)
Premier Oil Vietnam Offshore BV	Netherlands(7)
Chrysaor (U.K.) Britannia Limited	United Kingdom(2)
Chrysaor (U.K.) Eta Limited	United Kingdom(2)
Chrysaor (U.K.) Lambda Limited	Republic of Ireland(4)
Viking CCS Limited	United Kingdom(2)
Chrysaor Investments Limited	United Kingdom(2)
Chrysaor Production Oil (GB) Limited (formerly Harbour Energy Production Limited)	United Kingdom(2)
Chrysaor Supply & Trading Limited	United Kingdom(2)
EnCore (VOG) Limited	United Kingdom(2)
EnCore CCS Limited	United Kingdom(2)
EnCore Natural Resources Limited	United Kingdom(2)
EnCore Oil and Gas Limited	United Kingdom(2)
Harbour Energy Argentina Limited	United Kingdom(2)
Harbour Energy Developments Limited	United Kingdom(2)
Harbour Energy Production Limited	United Kingdom(2)
Harbour Energy Secretaries Limited (formerly Premier Oil Ebury Limited)	United Kingdom(2)
Chrysaor Petroleum Chemicals UK Limited (formerly Harbour Energy Services Limited)	United Kingdom(2)
Premier Oil B Limited	United Kingdom(2)
Premier Oil Belgravia Holdings Limited	United Kingdom(2)
Premier Oil Belgravia Limited	United Kingdom(2)
Premier Oil Bukit Barat Limited	United Kingdom(2)
Premier Oil CCS Limited	United Kingdom(2)
Premier Oil Congo (Marine IX) Limited	Jersey(6)
Premier Oil Exploration and Production (Iraq) Limited	United Kingdom(2)
Premier Oil Exploration Limited	United Kingdom(5)
Premier Oil Exploration ONS Limited	United Kingdom(2)
Premier Oil Investments Limited	United Kingdom(2)
Premier Oil ONS Limited	United Kingdom(2)
Premier Oil Pacific Limited	Hong Kong(11)
Premier Oil Pakistan Offshore BV	Netherlands(7)
Premier Overseas Holdings Limited	United Kingdom(2)
XEO Exploration Limited	United Kingdom(2)

Notes

(1) Chrysaor Holdings Limited is held directly by the Company whilst all other companies are held through a subsidiary undertaking.

(2) The registered office is located at 23 Lower Belgrave Street, London SW1W 0NR, United Kingdom.

(3) The registered office is located at Haakon VII's gate 1, 4th Floor, 0161 Oslo, Norway.

(4) The registered office is located at Riverside One, Sir John Rogerson's Quay, Dublin 2, Ireland.

(5) The registered office is located at 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh EH1 2EN, United Kingdom.

(6) The registered office is located at 46/50 Kensington Place, 1st Floor, Kensington Chambers, St. Helier JE4 0ZE, Jersey.

(7) The registered office is located at Commerce House, Wickhams Cay 1, Road Town, Tortola VG1110, British Virgin Islands.

(8) The registered office is located at Rua Lauro Muller, 116—Sala 3201, Botafogo, Rio de Janeiro, CEP: 22.290-160, Brazil.

(9) The registered office is located at Presidente Masaryk 111, Piso 1, Polanco V Seccion, Mexico City CP 11560, Mexico.

(10) The registered office is located at Level 5, Mill Court, La Charroterie, St Peter Port GY1 1EJ, Guernsey.

(11) The registered office is located at 31/F, Tower Two, Time Square, 1 Matheson Street, Causeway Bay, Hong Kong.

(12) The registered office is located at Cricket Square, Hutchins Drive, PO Box 2681, Grand Cayman KY1-1111, Cayman Islands.

14. RELATED PARTY TRANSACTIONS

14.1 Harbour Energy

Save as disclosed in: (i) note 28 of the 2023 Annual Report and Financial Statements; (i) note 28 of the 2022 Annual Report and Financial Statements; and (i) note 28 of the 2021 Annual Report and Financial Statements, each of which are incorporated by reference into this document, there are no related party transactions between Harbour Energy and its related parties that were entered into during the financial years covered in the historical financial information and from 1 January 2024 up to the Latest Practicable Date.

15. HARBOUR ENERGY MATERIAL CONTRACTS

The following contracts (not being contracts entered into in the ordinary course of business) have been entered into by the Company or another Harbour Energy entity either: (i) within the period of two years immediately preceding the date of this Prospectus which are or may be material to Harbour Energy; or (ii) which contain any provisions under which any Harbour Energy entity has any obligation or entitlement which is, or may be, material to Harbour Energy as at the date of this Prospectus.

15.1 Business Combination Agreement

Parties and Structure

The Business Combination Agreement was entered into on 21 December 2023, and amended on 7 June 2024, between the Company, BASF, BASF TopCo, LetterOne and LetterOne TopCo in relation to the Acquisition.

Consideration

The Company will acquire the Target Portfolio for $11.2 billion comprising:

(a) the porting of existing Wintershall Dea Bonds with a nominal value of c.$4.9 billion and a weighted average coupon of c.1.8 per cent. to the Company;

(b) approximately 921.2 million new Harbour Energy shares to be issued to BASF and LetterOne (the "**Consideration Shares**") at an agreed value of $4.15 billion or 360 pence per Company share such that on Completion:

   (i) BASF will own 46.5 per cent. of the Company's Ordinary Shares; and

   (ii) LetterOne will own 251.5 million non-voting, non-listed convertible ordinary shares with preferential rights (the "**Non-Voting Shares**"). If the Non-Voting Shares were to be converted into Ordinary Shares, the Company's current shareholders would own 45.5 per cent. of Harbour Energy and BASF and LetterOne would own 39.6 per cent. and 14.9 per cent., respectively; and

(c) cash consideration of $2.15 billion to be funded through cash flow generated from the Target Portfolio between the effective date of 30 June 2023 and Completion, and an underwritten bridge facility,

   (the "**Completion Consideration Cash Amount**").

The Completion Consideration Cash Amount is subject to certain adjustments to be agreed between the parties as set out in more detail in the Business Combination Agreement.

Non-Voting Shares

The Non-Voting Shares will have the following conditions to conversion to Ordinary Shares:

(a) each of the (direct or indirect) shareholders of the relevant Non-Voting Shareholder ceasing to be subject to relevant sanctions restrictions (**provided that** the relevant Non-Voting Shareholder is also not subject to such sanctions restrictions); and

(b) either:

   (i) the relevant Non-Voting Shareholder (having taken written advice from external legal counsel and consulted in good faith with the Company) that it is reasonably satisfied confirming that the conversion of the relevant Non-Voting Shares into Ordinary Shares does not require (i) authorisation from any regulatory authority under any foreign direct investment or national security legislation, or mandatory and/or suspensory merger control, antitrust or competition regime or (ii) any mandatory and/or suspensory sector regulatory consent (e.g., oil and gas regulatory change of control approvals); or

   (ii) if the relevant Non-Voting Shareholder considers that any such authorisation is required in respect of the conversion of the relevant Non-Voting Shares into Ordinary Shares (having taken written advice from external legal counsel and consulted in good faith with the Company), the receipt of such authorisation on terms reasonably satisfactory to the relevant Non-Voting Shareholder and the Company,

(the "**Conversion Conditions**").

The dividend payable on each Non-Voting Share will be at a 13 per cent. premium to any dividend payable in respect of each Ordinary Share, reflecting the fact that the Non-Voting Shares are unlisted and do not have voting rights attached to them.

The Non-Voting Shares will be transferable by LetterOne to certain permitted transferees, in certain cases only with the consent of the Company and in accordance with the terms of the Non-Voting Shares.

The rights and rights restrictions attaching to the Non-Voting Shares are set out in full in the Annex to the Notice of General Meeting incorporated by reference into this Prospectus.

Contingent Payments

BASF and LetterOne are entitled to up to six contingent payments from the Company, in an aggregate amount of up to $300,000,000, dependent on the price of Brent oil during the relevant assessment periods (each a "**Contingent Payment**"). The Contingent Payments are required to be made at six monthly intervals commencing from 18 months following Completion. If the price of Brent oil during the relevant assessment period is greater than $100 per barrel, then the Contingent Payment required to be paid by the Company will be $50,000,000. The Contingent Payment will be $30,000,000 for the relevant assessment period if the price per barrel of brent oil is greater than or equal to $86 but less than or equal to $100, and no Contingent Payment will be payable if the price per barrel of brent oil is below $86 for the relevant assessment period.

The Company will be under no obligation to make a Contingent Payment following the disposal of any Consideration Shares by LetterOne and BASF (the "**Sellers**"), **provided that** if the disposal has been made by only one of BASF and LetterOne, then the non-disposing Seller will entitled to the Contingent Payment that would otherwise have been due and payable to such Seller.

Conditions

Completion is subject to, and can only occur upon satisfaction or waiver of, amongst other things, the following conditions:

(a) the Prospectus and Circular having been approved by the FCA and, in the case of the Circular (to the extent required) the Takeover Panel, in each case in a form approved by BASF, BASF TopCo, LetterOne and LetterOne Topco;

(b) the passing of the Resolutions by the requisite majorities at the General Meeting;

(c) the FCA having confirmed to the Company or the Sponsor that the application for the readmission of the Ordinary Shares and admission of all of the BASF Consideration Shares, in each case to the premium listing segment of the Official List of the FCA (or a listing on the single category for ESCCs if such new listing category as contemplated in FCA Consultation Paper CP23/31 has been implemented by the FCA and taken effect at the relevant time) has been approved and will become effective as soon as the FCA's decision to re-admit the Ordinary Shares and to admit the BASF Consideration Shares is announced;

(d) the London Stock Exchange having confirmed to the Company or the Sponsor that the application for the re-admission of the Ordinary Shares and admission of all of the BASF Consideration Shares, in each case to trading on the main market for listed securities of the London Stock Exchange has been approved and will become effective subject to and concurrently with the re-admission of all of the Ordinary Shares and admission of the BASF Consideration Shares in each case to the premium listing segment of the Official List of the FCA (or the segment of the Official List for ESCCs, if applicable at the time of application);

(e) the Takeover Panel having waived, subject to the passing by the requisite majority at the General Meeting of the terms of such waiver, any obligation which might fall on BASF or any person acting in concert (as defined in the Takeover Code) with it under Rule 9 of the Takeover Code to make an offer for Harbour Energy as a result of the issue of the BASF Consideration Shares;

(f) the Spin-off having been registered with the commercial register (*Handelsregister*) of Wintershall Dea and thereby having become effective;

(g) consent having been obtained from the relevant regulatory authorities, including amongst others in the United Kingdom, Mexico, Denmark and Algeria;

(h) merger control clearances or non-objections having been obtained from the relevant competition authorities in, amongst others, COMESA, Mexico and Ukraine;

(i) foreign direct investment clearance having been obtained from the relevant authority in the UK;

(j) a clearance having been obtained from the European Commission under the Foreign Subsidies Regulation (Regulation (EU) 2022/2560); and

(k) no party to the Business Combination Agreement being subject to certain sanctions restrictions and Completion not causing any party to the Business Combination Agreement to be in violation of certain sanctions laws.

(together, the "**Conditions to Completion**")

LetterOne Purchase Option and Right of First Refusal

The Business Combination Agreement provides LetterOne and LetterOne TopCo with an option (the "**LetterOne Purchase Option**") to acquire Ordinary Shares from BASF in an amount equal to between 3 per cent. and 5 per cent. (inclusive) of the Company's issued share capital on a fully diluted basis. The LetterOne Purchase Option will be exercisable for a period of six months (the "**LetterOne Option Period**") commencing on the day that is six months following Completion and is subject to satisfaction of certain conditions including receipt of relevant regulatory approvals (if applicable). BASF and BASF TopCo have agreed to give an undertaking that during the LetterOne Option Period, BASF will hold an adequate number of Ordinary Shares sufficient to satisfy the LetterOne Purchase Option in full.

Pursuant to the Business Combination Agreement, LetterOne and LetterOne TopCo will also have a right of first refusal (the "**Right of First Refusal**") in respect of Ordinary Shares that BASF and BASF TopCo intend to dispose of, up to a maximum of 5 per cent. of the Company's issued share capital on a fully diluted basis. The Right of First Refusal will apply from the day that is six months following Completion and is subject to satisfaction of certain conditions, including receipt of relevant regulatory approvals (if applicable). The Right of First Refusal will provide LetterOne with the right to purchase the Ordinary Shares that BASF and BASF TopCo intend to dispose, at a price that BASF and BASF TopCo reasonably believes it can achieve in prevailing market conditions, **provided that** if LetterOne chooses not to utilise the Right of First Refusal and BASF and BASF TopCo subsequently agrees to sell the relevant Ordinary Shares to a third party at a price less than the price it offered them to LetterOne and LetterOne TopCo for, LetterOne and LetterOne TopCo will have the right to purchase the relevant Ordinary Shares on equivalent terms to those agreed between BASF, BASF TopCo and the third party.

The maximum number of Ordinary Shares that may be acquired by LetterOne and/or LetterOne TopCo from BASF and/or BASF TopCo shall be equal in aggregate to such number of Ordinary Shares that amounts to up to 5 per cent. of the Company's ordinary share capital on a fully diluted basis.

Warranties

The Business Combination Agreement contains fundamental warranties given by BASF, BASF TopCo, LetterOne and LetterOne Topco to the Company. These include, amongst other matters, warranties in respect of (i) their power and authority to enter into and perform their obligations under the Business Combination Agreement, (ii) the composition of and any rights or restrictions on the share capital of the Target Company, and (iii) compliance with laws and regulations.

Harbour Energy has given equivalent fundamental warranties to BASF, BASF TopCo, LetterOne and LetterOne TopCo including, amongst other matters, warranties in respect of (i) its power and authority to enter into and perform its obligations under the Business Combination Agreement, (ii) the composition of and any rights or restrictions on its share capital, (iii) compliance with laws and regulations and (iv) the Consideration Shares in issue will be duly authorised, validly issued and fully paid or credited as fully paid.

The warranties were given at signing of the Business Combination Agreement and will be repeated by each party immediately prior to Completion.

Covenants Regarding the Conduct of Business

The Company has agreed to ensure and BASF, BASF TopCo, LetterOne and LetterOne TopCo has each agreed to procure, respectively, that prior to Completion, the businesses of the Company and the businesses related to the Target Portfolio shall be carried on in all material respects in the ordinary course as disclosed by each party unless otherwise agreed. In addition, the Company has agreed to certain customary restrictions regarding the conduct of its business, and LetterOne, LetterOne TopCo, BASF and BASF TopCo have each agreed to procure that certain customary restrictions are complied with respect to the conduct of the business of the Target Portfolio, in each case in the period to Completion.

Leakage Undertakings

Each of the Company, BASF and LetterOne has warranted and agreed to give customary "no leakage" undertakings in respect of the period between 30 June 2023 and Completion. In the Company's case, the undertakings relate to payments to Shareholders that are not in the ordinary course of business or included within an agreed list of permitted items. In the case of BASF and LetterOne, the undertakings relate to payments to Wintershall Dea's direct and indirect shareholders that are not in the ordinary course of business or included within an agreed list of permitted items.

Governing Law

The Business Combination Agreement is governed by the laws of England and Wales.

15.2 **BASF Relationship Agreement**

The BASF Relationship Agreement will take effect on Admission and will remain in full force and effect unless and until BASF and its associates cease to own at least 10 per cent. of the Ordinary Shares. BASF may terminate the BASF Relationship Agreement in certain circumstances, including where the Ordinary Shares cease to be admitted to trading on the London Stock Exchange's main market for listed securities.

The BASF Relationship Agreement provides, in accordance with Listing Rule 6.5.4, that:

(a) all transactions, arrangements and relationships between the Company or any other member of the Group on the one hand and BASF or any of its associates on the other hand shall be conducted at arm's length and on normal commercial terms;

(b) BASF shall not (and shall procure that its associates will not) take any action that would have the effect of preventing the Company from complying with its obligations under the Listing Rules; and

(c) BASF shall not (and shall procure that its associates will not) propose or procure the proposal of a shareholder resolution of the Company which is intended or appears to be intended to circumvent the proper application of the Listing Rules.

Furthermore, under the BASF Relationship Agreement, BASF undertakes that it shall not (and shall procure that its associates will not):

(a) exercise any of its voting rights in the Company in a way that would be inconsistent with, or breach any of the provisions of, the BASF Relationship Agreement;

(b) influence the day-to-day running of the Company at an operational level and shall allow the Company to operate on an independent basis; and

(c) act in a manner which would be inconsistent with the independence of the Board being maintained in accordance with the rules of the London Stock Exchange or the FCA applicable to the Company, including the Listing Rules.

Director Appointment Rights

Pursuant to the BASF Relationship Agreement, BASF will be entitled to nominate two non-executive directors to the Board for so long as it (together with any of its associates) holds 25 per cent. or more of the Ordinary Shares, and will be able to appoint one non-executive director to the Board for so long as it (together with any of its associates) holds 10 per cent. or more, but less than 25 per cent. of the Ordinary Shares, provided in each case that BASF will be required to take into account certain factors and consult with the Chair and the Nomination Committee before nominating a director.

Cooperation and Information Rights

The BASF Relationship Agreement provides that subject to applicable law, BASF will have the opportunity on a quarterly basis to meet with the Chief Executive Officer, the Chief Financial Officer and/or the Chair of the Company to discuss the performance of the Company. In addition, BASF will also have certain information rights for the purposes of its tax or other legal or regulatory requirements. The information received by BASF under the BASF Relationship Agreement is subject to customary confidentiality undertakings.

Pursuant to the BASF Relationship Agreement, the Company is also required to provide, subject to certain limitations and exceptions, reasonable cooperation and assistance to BASF in the event of an offering of the Ordinary Shares held by BASF and BASF will pay and reimburse the Company for all reasonable out-of-pocket costs and expenses incurred by the Company in connection with such cooperation and assistance.

15.3 **LetterOne Relationship Agreement**

A relationship agreement to be entered into between the Company and LetterOne (the "**LetterOne Relationship Agreement**") will take effect on Admission and will remain in full force and effect unless and until LetterOne and its associates cease to own Ordinary Shares or Non-Voting Shares representing (in the case of Non-Voting Shares assuming conversion at the applicable conversion rate) in aggregate, at least 10 per cent. of the Ordinary Shares. LetterOne may terminate the LetterOne Relationship Agreement in certain circumstances, including where the Ordinary Shares cease to be admitted to trading on the London Stock Exchange's main market for listed securities.

The LetterOne Relationship Agreement provides, that from the date on which LetterOne (together with its associates) holds 10 per cent. or more of the Ordinary Shares (the "**LetterOne Effective Date**"), in accordance with Listing Rule 6.5.4:

(a) all transactions, arrangements and relationships between the Company or any other member of the Group on the one hand and LetterOne or any of its associates on the other hand shall be conducted at arm's length and on normal commercial terms;

(b) LetterOne shall not (and shall procure that its associates will not) take any action that would have the effect of preventing the Company from complying with its obligations under the Listing Rules; and

(c) LetterOne shall not (and shall procure that its associates will not) propose or procure the proposal of a shareholder resolution of the Company which is intended or appears to be intended to circumvent the proper application of the Listing Rules.

Furthermore, under the LetterOne Relationship Agreement, LetterOne undertakes that it shall not (and shall procure that its associates will not):

(a) exercise any of its voting rights in the Company in a way that would breach any of the provisions of the LetterOne Relationship Agreement;

(b) influence the day-to-day running of the Company at an operational level and shall allow the Company to operate on an independent basis; and

(c) act in a manner which would be inconsistent with the independence of the Board being maintained in accordance with the rules of the London Stock Exchange or the FCA applicable to the Company, including the Listing Rules.

Director appointment rights

Pursuant to the LetterOne Relationship Agreement, LetterOne will be entitled to nominate two non-executive directors to the Board for so long as it (together with any of its associates) holds 25 per cent. or more of the Ordinary Shares, and will be able to appoint one non-executive director to the Board for so long as it (together with any of its associates) holds 10 per cent. or more, but less than 25 per cent. of the Ordinary Shares, provided in each case that LetterOne will be required to take into account certain factors and consult with the Chair and the Nomination Committee before nominating a director.

LetterOne will not have any rights to nominate non-executive directors on Completion because (i) the right to nominate non-executive directors is dependent on percentage of Ordinary Shares (instead of Non-Voting Shares) held by LetterOne and its associates; and (ii) as part of the consideration for the Acquisition, on Completion the Company will issue and allot Non-Voting Shares to LetterOne and hence LetterOne will not hold any Ordinary Shares on Completion.

Cooperation, information rights and other provisions

The LetterOne Relationship Agreement provides that from the LetterOne Effective Date or for so long as LetterOne (together with its associates) holds Non-Voting Shares which if converted would represent at least 10 per cent. of the Ordinary Shares and, subject to applicable law, LetterOne will have the opportunity on a quarterly basis to meet with the Chief Executive Officer, the Chief Financial Officer and/or the Chair of the Company to discuss the performance of the Company. In addition, from the LetterOne Effective Date, LetterOne will also have certain information rights for the purposes of its tax or other legal or regulatory requirements. The information received by LetterOne under the LetterOne Relationship Agreement is subject to customary confidentiality undertakings.

Pursuant to the LetterOne Relationship Agreement, the Company is also required to provide, subject to certain limitations and exceptions, reasonable cooperation and assistance to LetterOne in the event of an offering of any Ordinary Shares held by LetterOne and LetterOne will pay and reimburse the Company for all reasonable out-of-pocket costs and expenses incurred by the Company in connection with such cooperation and assistance.

The holders of Non-Voting Shares, subject to compliance with certain economic sanctions law, will be entitled to participate in all new issuances of Ordinary Shares or other securities in proportion to their existing holdings on a pro-rata basis **provided that** the holders of Non-Voting Shares, instead of subscribing for Ordinary Shares or other securities, subscribe for Non-Voting Shares representing their entitlement to Ordinary Shares (calculated by reference to the applicable conversion ratio at the time of issuance of new Ordinary Shares) ("**Pro-Rata Basis**"). The holders of Non-Voting Shares shall also be entitled to participate in purchases by the Company of its own securities or other returns of capital on a Pro-Rata Basis (all such participation rights being, the "**Participation Rights**").

In addition, the LetterOne Relationship Agreement provides that until the first annual general meeting of the Company following satisfaction of the relevant conditions to conversion, the Company undertakes that at each annual general meeting of the Company at which an on-market buy-back resolution is proposed to the holders of Ordinary Shares seeking authority to for the Company to purchase Ordinary Shares, the Company will also propose an inter-conditional off-market buy-back resolution seeking authority to purchase Non-Voting Shares on a pro-rata basis (the "**Buyback Rights**").

The Participation Rights and the Buyback Rights will survive the termination of the LetterOne Relationship Agreement for so long as (i) there are Non-Voting Shares in issuance and (ii) LetterOne (together with its associates) holds at least 25,000,000 Non-Voting Shares.

15.4 **BASF Lock-Up Agreement**

In accordance with the Business Combination Agreement, BASF and the Company will enter into a lock-up agreement at Completion which will take effect on Admission whereby BASF undertakes that it will not sell its Ordinary Shares for a period of six months following Completion subject to customary exceptions.

15.5 **LetterOne Lock-Up Agreement**

In accordance with the Business Combination Agreement, LetterOne and the Company will also enter into a lock-up agreement at Completion which will take effect on Admission whereby LetterOne undertakes that, in the event that LetterOne converts its Non-Voting Shares into Ordinary Shares, it will not sell its Ordinary Shares for a period of six months following Completion subject to customary exceptions.

15.6 **LetterOne Standstill Agreement**

In accordance with the Business Combination Agreement, the Company and LetterOne will enter into a standstill agreement at Completion whereby LetterOne undertakes that it will not and will procure that its associates and concert parties (excluding BASF entities) will not, directly or indirectly, among other things:

(a) acquire or make an offer for Ordinary Shares for a period of six months following Completion subject to customary exceptions; and

(b) hold in aggregate more than (i) 19.99 per cent. of the issued share capital of Harbour Energy or (ii) 5 per cent. of the issued Ordinary Shares (on a fully diluted basis) for the period commencing on Completion and ending on the first date on which both (x) none of the (direct or indirect) shareholders of LetterOne is subject to certain sanctions restrictions; and (y) LetterOne is not subject to certain sanctions restrictions (as is currently the case).

15.7 **Transitional Services Agreement**

In connection with the Acquisition, the Company and Wintershall Dea entered into a transitional services agreement (the "**TSA**"), effective 19 April 2024, pursuant to which Wintershall Dea provides transitional support services to the Company.

Under the TSA, Wintershall Dea is required to provide the transitional services in accordance with the same standards and volumes as achieved in respect of the same services during the six-month period immediately before the date of Completion, as well as in accordance with good industry practice and applicable law. The services are typical transitional support services, including accounting, reporting, treasury, tax data provisions, access and maintenance of critical systems and human resources services. In consideration for the services, the Company pays Wintershall Dea service charges on an "at cost" basis (plus a margin of 5 per cent.). Specific service terms have been agreed in respect of each service (mostly in the region of 12 months).

In addition to providing the above services, Wintershall Dea also provides the Company with migration support, with the objective of migrating the services to the Company prior to the expiry of the relevant service term (such that the Company, or another third party service provider, can provide those services without continued assistance from Wintershall Dea).

That TSA contains standard terms regarding omitted services, third party consents, intellectual property, liability, and termination. The TSA is governed by German law and any disputes will be settled under the rules of arbitration of the International Chamber of Commerce.

15.8 **Sponsor's Agreement**

In connection with the Acquisition, the Company and the Sponsor entered into a sponsor's agreement on or around the date of this Prospectus (the "**Sponsor's Agreement**"), pursuant to which the Company appointed Barclays as sole sponsor in connection with the Acquisition, the production and publication of this Prospectus and the Circular and Admission.

Under the Sponsor's Agreement, the Sponsor has been granted all powers, authorities and discretions which are necessary for or incidental to the performance of their responsibilities as sponsor under the Listing Rules. The Company has agreed to deliver certain documents to the Sponsor relating to the Acquisition, the Circular, the Prospectus and the Sponsor's responsibilities under the Listing Rules. The Company has given customary representations, warranties (including certain warranties in respect of the Target Portfolio), undertakings and indemnities to the Sponsor.

The Sponsor has the right to terminate the Sponsor's Agreement in certain circumstances prior to Admission. These circumstances include (amongst others): (i) where any statement in this document and certain associated documents and announcements is or has become untrue, inaccurate or misleading; and (ii) the breach by the Company of any of the warranties or undertakings contained in the Sponsor's Agreement, in each case in a manner which the Sponsor considers (acting in good faith) is material in the context of the Enlarged Group, the Acquisition, or the Admission. The Company has agreed to bear all of the Sponsor's fees, costs, charges and expenses of, or which are incidental to the Acquisition, including without limitation, the fees and expenses of its professional advisers, the costs of preparation, printing and distribution of this document and all other documents in connection with the Acquisition; and any CREST charges and the fees of the FCA and London Stock Exchange.

15.9 **Reserve Base Lending Facility**

Overview

On 23 November 2023, the Company and certain of its subsidiaries entered into an amendment and restatement agreement with, among others, DNB Bank ASA, London Branch as facility agent, which amended and restated the senior secured revolving borrowing base facility agreement which was originally entered into on 30 January 2017 and as amended and restated from time to time and pursuant to which an up to $2,750,000,000 reserve-based lending facility (the "**RBL Facility**") is made available by the lenders thereunder. The facility commitments are subject to incremental step downs until the maturity date.

The RBL Facility includes a letter of credit sub-limit of up to $1,750,000,000 and a separate accordion facility of up to $1,000,000.000 (which would increase the total aggregate commitments up to $3,750,000,000) subject to satisfaction of certain conditions set out in the applicable accordion provisions contained in the RBL Facility. The maximum available amount under the RBL Facility will be an amount equal to the lower of the aggregate total commitments under the facility (being $2,750,000,000 as at the effective date of the amendment and restatement agreement) and the borrowing base amount. The borrowing base amount of the RBL Facility will be based on Harbour Energy's reserves, in particular the reserves of specific nominated borrowing base assets. The RBL Facility is what is known as a net present value facility, with the borrowing base amounts based on the expected net present value of future cash flows from the borrowing base assets, taking into account, among other things, the 2P and 1P reserves relating to the borrowing base assets, production profiles and cost and operating expenditure profiles for such borrowing base assets. The borrowing base amount is determined at least once a year.

Security

The RBL Facility is secured by (i) share charges, debentures, charges over certain bank accounts and assignment agreements governed by English law; (ii) share pledges and bonds and floating charges governed by Scottish law; (iii) share charges governed by Dutch law; and (iv) bank account pledges and a fiduciary assignment of receivables governed by Indonesian law.

Repayment and Maturity

The final maturity date of the RBL Facility is 31 December 2029. If, however, the remaining reserves attributable to Harbour Energy's borrowing base assets are forecast to amount to 25 per cent. or less than Harbour Energy's revised approach reserves (as may be subsequently revised), the RBL Facility will mature on the last day of the relevant calculation period.

Total aggregate commitments under the RBL Facility will reduce to $2,444,444,444.44 on 1 January 2026, to $2,138,888,888.89 on 1 July 2026. to $1,833,333,333.33 on 1 January 2027, to

$1,527,777,777.78 on 1 July 2027, to $1,222,222,222.22 on 1 January 2028, to $916,666,666.67 on 1 July 2028, to $611,111,111.11 on 1 January 2029 and to $305,555,555.56 on 1 July 2029.

It is anticipated that the RBL will be refinanced and replaced by the RCF (as defined below) in full on Completion.

Interest and Fees

The rate of interest payable on loans under the RBL Facility is the rate per annum equal to the aggregate of the applicable margin plus the relevant compounded rate for the currency of the loan (SONIA for Sterling and SOFR for U.S. Dollars). The compounded rate is in each case subject to a zero floor. The applicable margin is 3.2 per cent. per annum for the first two years after the 2023 amendment and restatement becomes effective (and subject to two step ups of 0.2 per cent., each lasting for a duration of two years), subject to certain adjustments relating to the carbon emissions associated with the operated borrowing base assets of the group over the relevant calculation period. Default interest is also payable, at a rate of two per cent. per annum higher than the standard rate of interest payable on loans under the RBL Facility.

Certain fees are payable to the lenders under the RBL Facility, including an ongoing commitment fee in respect of the availability of the facility, a commission payable in respect of letters of credit issued from time to time and various fees payable to the administrative finance parties, including the agent, security trustee, account bank, technical banks and modelling banks, for the performance of their functions.

The borrowers shall pay commitment fees on a quarterly basis as follows: (i) an amount equal to the percentage rate per annum which is equal to 20 per cent. of the applicable margin on the daily amount by which the aggregate commitments exceeds the higher of the total outstanding utilisations and the maximum available amount (being the lower of such aggregate commitments or the borrowing base amount); and (ii) an amount equal to the percentage rate per annum which is equal to 40 per cent. of the applicable margin on the daily amount of the difference by which the maximum available amount (as defined above) exceeds the then outstanding utilisations.

A letter of credit commission is payable: (i) where the letter of credit is not issued to support the performance of obligations not primarily for the payment of money, calculated at the applicable margin on the daily amount that the letter of credit exposure exceeds any cash cover; (ii) where the letter of credit is issued to support the performance of obligations not primarily for the payment of money, calculated at 50 per cent. of the applicable margin on the daily amount that the letter of credit exposure exceeds any cash cover; and (iii) in respect of all letters of credit at the rate of 0.30 per cent. per annum on the daily amount of the letter of credit exposure where cash cover has been provided.

Representations, Warranties, Covenants and Events of Default

Representations

The RBL Facility contains customary representations, including (but not limited to) as to status, binding obligations, non-conflict with other obligations, power and authority, the status of security and material project documents, environmental matters, ownership, the accuracy of information, borrowing base projections, anti-bribery and sanctions and in certain cases are subject to knowledge and/or materiality qualifications.

Financial Covenants

The RBL Facility requires obligors thereunder to ensure that on each 30 June and 31 December the historic ratio of consolidated total net debt to consolidated EBITDAX for the relevant period is less than 3:1. In the event of non-compliance with the applicable ratio, an event of default will occur under the RBL Facility unless waived in accordance with the RBL Facility.

General Covenants

The RBL Facility contains customary undertakings which are in certain cases subject to certain exceptions and/or materiality qualifications. Among others, the general undertakings contain restrictions and obligations on obligors thereunder in relation to disposals of assets, acquisitions, the maintenance and exploitation of borrowing base assets (including restrictions on changes in operatorship and abandonment), corporate existence and change of business, incurrence of financial indebtedness, the provision of credit and the incurrence of guarantees and indemnities, the provision of security, the making of distributions, entry into hedging agreements, group liquidity, environmental matters, the sale of petroleum from borrowing base assets on the best terms reasonably available, and *pari passu* ranking. The RBL Facility also contains customary covenants relating to the provision of information to the lenders.

Events of Default

The RBL Facility contains customary events of default including (but not limited to) in respect to breach of financial covenants, qualification of financial statements, non-payment of any amount under the finance documents, insolvency and analogous proceedings, cross-default, misrepresentation, ownership of the obligors, the qualification of accounts, expropriation, repudiation and effectiveness, litigation and material adverse change. There are additional events of default relating to the borrowing base assets and material project documents, each of which is qualified by reference to material adverse effect.

Mandatory Prepayment Events

The RBL Facility is to be prepaid in full immediately upon the occurrence of certain events, including a springing maturity linked to the maturity of any issued high yield notes or on the sale of all or substantially all of the assets of the obligors. There are also separate prepayment obligations which may be triggered upon receipt of certain proceeds of disposals, insurance claims and claims under the Acquisition documents.

15.10 **Bridge Facility Agreement**

Overview

On 5 March 2024, the Company and certain of its subsidiaries entered into a bridge facility agreement (the "**BFA**") with, among others, DNB Bank ASA, London Branch as facility agent, pursuant to which an up to $1,500,000,000 bridge facility is made available by the lenders thereunder.

The purpose of the BFA is to fund a proportion of the purchase price of the Acquisition, and any associated Acquisition costs, and it is expected to be drawn at Completion. It is a condition precedent to drawdown that the lenders have received evidence that the Enlarged Group has achieved, or will achieve as a result of Completion having occurred, an Investment Grade Rating. The BFA contains customary certain funds provisions to protect the ability of Harbour Energy to fund the Acquisition by restricting the recourse of lenders to certain drawstop and acceleration rights during the period in which the bridge facility is available to be drawn down.

Security

The BFA is an unsecured facility.

Repayment and Maturity

The BFA matures on the date falling 12 months after the earlier of (i) Completion and (ii) the date falling 6 months after the date of the BFA. The BFA also contains two 6 month committed extension options. The loans shall mature in full on the maturity date.

Interest and Fees

The rate of interest payable on loans under the BFA is the rate per annum equal to the aggregate of the applicable margin plus the compounded rate for the currency of the loan (SOFR for U.S. Dollars). The compounded rate is subject to a zero floor. The opening margin is 1.00 per cent. per annum, increasing in increments of 0.25 per cent. after the expiration of each of the first three successive 3-month periods after the date of the BFA, increasing in increments of 0.35 per cent. after the expiration of each of the fourth and fifth successive 3-month periods after the date of the BFA and increasing in increments of 0.50 per cent. after the expiration of each of the sixth and seventh successive 3-month periods after the date of the BFA. The margin then remains at 3.45 per cent. per annum until the maturity date. Default interest is also payable, at a rate of two per cent. per annum higher than the standard rate of interest payable on loans under the BFA.

Certain fees are payable to the lenders under the BFA, including an ongoing commitment fee in respect of the availability of the facility, as well as upfront fees payable on or around the signing date and funding fees on the date of drawdown of the facility. Various fees are also payable to the administrative finance parties, including the agent, for the performance of their functions.

Harbour Energy shall pay commitment fees on a quarterly basis in an amount equal: (i) the first two months after the date of the BFA, 0 per cent. of the applicable margin (ii) the third month after the date of the BFA, 10 per cent. of the applicable margin (iii) the fourth month after the date of the BFA, 15 per cent. of the applicable margin and (iv) for the remaining duration of the BFA, 30 per cent. of the applicable margin, in each case on the lenders' available (i.e. undrawn) commitments.

Representations, Warranties, Covenants and Events of Default

Representations

The BFA contains customary representations for an investment grade facility agreement, including (but not limited to) as to status, binding obligations, non-conflict with other obligations, power and authority, environmental matters, ownership, the accuracy of information, anti-bribery and sanctions and in certain cases are subject to knowledge and/or materiality qualifications.

Financial Covenants

The BFA requires Harbour Energy to ensure that on each 30 June and 31 December (i) the historic ratio of consolidated total net debt to consolidated EBITDAX for the relevant period is less than 3.5:1 and (ii) the historic ratio of EBITDA to consolidated total net finance charges for the relevant period will not be less than 3.5:1. In the event of non-compliance with the applicable ratio, an event of default will occur under the BFA unless waived in accordance with the BFA.

General Covenants

The BFA contains customary undertakings for an investment grade facility agreement which are in certain cases subject to certain exceptions and/or materiality qualifications. Among others, the general undertakings contain restrictions and obligations on obligors thereunder in relation to disposals of assets, acquisitions, corporate existence and change of business, incurrence of financial indebtedness, the making of distributions, environmental matters, *pari passu* ranking, sanctions and anti-bribery and compliance with the Acquisition-related documents. The BFA contains an obligation on Harbour Energy to ensure that any issuer, borrower or guarantor under the RBL Facility, the RCF (as referred to below), the high yield notes of Harbour Energy or the notes of the target under the Acquisition shall accede to the BFA within specified time periods. The BFA also contains customary covenants relating to the provision of information to the lenders.

The restriction relating to the making of acquisitions is limited to transactions defined as "Class 1 Transactions" under the Listing Rules of the UK Listing Authority (or, if the Listing Rules are amended so as to remove the requirement to seek shareholder approvals for Class 1 Transactions, the restriction shall be limited to any acquisition where the consideration for which (when aggregated with any financial indebtedness of the target) exceeds 25 per cent. of the market capitalisation of the Company or which would require approval of the Company's shareholders.

Events of Default

The BFA contains customary events of default including (but not limited to) in respect of breach of financial covenants, breach of the sanctions covenant, non-payment of any amount under the finance documents, insolvency and analogous proceedings, cross-default, misrepresentation, ownership of the obligors and expropriation.

Mandatory Prepayment Events

The BFA is to be prepaid at the option of the lenders upon the occurrence of a change of control (more than 50 per cent. of the ownership of Harbour Energy or effective control over the board of directors or other equivalent officers). There are also separate prepayment obligations which may be triggered upon receipt of certain proceeds of disposals, insurance claims, claims under the Acquisition documents and in the event of the issuance of new debt.

15.11 Revolving Credit Facility

Overview

On 5 March 2024, the Company and certain of its subsidiaries entered into a revolving credit facility agreement (the "**RCF**") with, among others, DNB Bank ASA, London Branch as facility agent, pursuant to which an up to $3,000,000,000 revolving credit facility is made available by the lenders thereunder. The RCF includes a letter of credit sub-limit of up to $1,750,000,000.

The purpose of the RCF is to fund the refinancing of the RBL Facility and the general corporate purposes of Harbour Energy and, following Completion, the Enlarged Group. It is a condition precedent to drawdown that the lenders have received evidence that the Enlarged Group has achieved, or will achieve as a result of Completion having occurred, an Investment Grade Rating. The RCF contains certain funds provisions to protect the ability of Harbour Energy to fund the refinancing of the RBL Facility.

Security

The RCF is an unsecured facility.

Repayment and Maturity

The RCF matures on the date falling 5 years after the date of the RCF. The loans shall mature in full on the maturity date.

Interest and Fees

The rate of interest payable on loans under the RCF is the rate per annum equal to the aggregate of the applicable margin plus the relevant term rate (EURIBOR for Euro and the Norwegian Interbank Offered Rate for Norwegian Krone) or compounded rate (SOFR for U.S. Dollars and SONIA for Sterling) for the currency of the loan. The term rate or the compounded rate (as applicable) is in each case subject to a zero floor. The opening margin is 1.45 per cent. per annum, subject to, on and from the date when the most recently published long term corporate credit rating of Harbour Energy, a margin ratchet tied to such corporate credit rating of up to a maximum of 2.50 per cent. per annum. Default interest is also payable, at a rate of two per cent. per annum higher than the standard rate of interest payable on loans under the RCF.

Certain fees are payable to the lenders under the RCF, including an ongoing commitment fee in respect of the availability of the facility and a corresponding utilisation fee, a commission payable in respect of letters of credit issued from time to time and various fees payable to the administrative finance parties, including the agent and the issuing bank, for the performance of their functions.

Harbour Energy shall pay commitment fees on a quarterly basis in an amount equal to the percentage rate per annum which is equal to 35 per cent. of the applicable margin on the lenders' available commitments. The obligation to pay commitment fee commences after the Acquisition closing date, before which a ticking fee is incurred at 0 per cent. of the applicable margin for the first two months after the date of the RCF and increasing to a maximum of 30 per cent. of the applicable margin from the date that is four months after the date of the RCF until Completion.

Each borrower shall pay a utilisation fee on the aggregate amount of outstanding utilisations of (i) 0.10 per cent. per annum where the amount of such utilisations is less than one third of total commitments (ii) 0.20 per cent. per annum where the amount of such utilisations is equal to or greater than one third of total commitments but less than two thirds and (iii) 0.40 per cent. per annum where the amount of such utilisations are equal to or greater than two thirds of total commitments.

For an explanation of the letter of credit commission provisions see paragraph 15.9 (Reserve Base Lending Facility) in this Part XIV (*Additional Information*).

Representations, Warranties, Covenants and Events of Default

For an explanation of the representations, warranties, covenants, financial covenants and events of default see paragraph 15.10 (Bridge Facility Agreement) in this Part XIV (*Additional Information*). The RCF does not contain provisions in relation to the Acquisition documents.

Mandatory Prepayment Events

For an explanation of the mandatory prepayment events see paragraph 15.10 (Bridge Facility Agreement) in this Part XIV (*Additional Information*).

15.12 **Existing Harbour Notes**

Overview

On 18 October 2021 the Company issued USD 500 million aggregate principal amount of its 5½ per cent. Senior Notes due 2026 (the "**Existing Harbour Notes**") under an indenture dated 18 October 2021 (the "**Existing Harbour Notes Indenture**") among, *inter alios*, the Company, the guarantors named therein and Glas Trust Company LLC. As of the date hereof, there were USD 500 million aggregate principal amount of the Existing Harbour Notes issued and outstanding.

Ranking

The Existing Harbour Notes are general obligations of the Company and rank equal 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 Existing Harbour Notes, are guaranteed on a senior subordinated basis by the Existing Harbour Notes Guarantors (as defined below), rank effectively subordinated to all existing and future secured obligations of the Company to the extent of the value of the property and assets securing such obligations, unless such assets also secure the Existing Harbour Notes on an equal and rateable or senior basis and rank senior in right of payment to all existing and future obligations of the Company expressly subordinated in right of payment to the Existing Harbour Notes. In addition, the Existing Harbour Notes are effectively subordinated in right of payment to all existing and future indebtedness and other liabilities of, including trade payables and letters of credit issued by, the subsidiaries of the Company that are not the Existing Harbour Notes Guarantors.

Interest Rates, Payment Dates and Maturity

The Existing Harbour Notes bear interest at a rate of 5.500 per cent. per annum. Interest on the Existing Harbour Notes is payable semi-annually in arrear on 15 April and 15 October of each year. The Existing Harbour Notes will mature on 15 October 2026.

Guarantees

The Existing Harbour Notes are guaranteed on a senior subordinated basis by Chrysaor E&P Finance Limited, Chrysaor Limited, Chrysaor Holdings Limited, Chrysaor CNS Limited, Chrysaor E&P Limited, Chrysaor E&P Services Limited, Chrysaor North Sea Limited, Chrysaor Developments Limited, Chrysaor Petroleum Company UK Limited, Chrysaor Petroleum Limited, Chrysaor Production Holdings Limited, Chrysaor Production (U.K.) Limited, Chrysaor Resources (Irish Sea) Limited, Chrysaor Resources (U.K.) Holdings Limited, Chrysaor (U.K.) Alpha Limited, Chrysaor (U.K.) Beta Limited, Chrysaor (U.K.) Sigma Limited, Chrysaor (U.K.) Theta Limited, Premier Oil Group Holdings Limited, Premier Oil Group Limited, Premier Oil E&P UK Limited, Premier Oil E&P UK EU Limited, Premier Oil UK Limited, Premier Oil (Vietnam) Limited, Premier Oil Natuna Sea B.V., Premier Oil Tuna B.V., Premier Oil Vietnam Offshore B.V., Premier Oil Andaman Limited, Premier Oil Andaman I Limited and Premier Oil South Andaman Limited (collectively, the "**Existing Harbour Notes Guarantors**"). The guarantees of the Existing Harbour Notes by the Existing Harbour Notes Guarantors are subordinated in right of payment to outstanding senior obligations pursuant to a guarantee subordination agreement.

Security

The Existing Harbour Notes are unsecured.

Optional Redemption and Change of Control

The Existing Harbour Notes are subject to redemption at any time on or after 15 October 2023 at the option of the Company, in whole or in part, at the following redemption prices (expressed as percentages of the aggregate principal amount), if redeemed during the twelve-month period beginning on 15 October of the year indicated below:

Year	Redemption Price (per cent.)
2023	102.7500
2024	101.3750
2025 and thereafter	100.0000

together with certain additional amounts, if applicable, and accrued and unpaid interest, if any, to the redemption date (subject to the rights of holders of record on relevant record dates to receive interest due on an interest payment date).

In connection with any tender offer for, or other offer to purchase, all of the Existing Harbour Notes, if holders of not less than 90 per cent. of the aggregate principal amount of the then outstanding Existing Harbour Notes validly tender and do not validly withdraw such Existing Harbour Notes in such tender offer and the Company, or any other person making such tender offer in lieu of the Company, purchases all of the Existing Harbour Notes validly tendered and not validly withdrawn by such holders, the Company or such other person will have the right, subject to certain notice requirements, to redeem all (but not less than all) Existing Harbour Notes that remain outstanding following such purchase at a price equal to the price (excluding any early tender premium or similar payment) paid to each other holder in such tender offer, plus, to the extent not included in the tender offer payment, accrued and unpaid interest thereon and certain additional amounts, to, but not including, the date of such redemption.

Upon the occurrence of certain change of control events, each holder of Existing Harbour Notes may require the Company to repurchase all or a portion of its Existing Harbour Notes at a purchase price equal to 101 per cent. of the principal amount of such Existing Harbour Notes, plus certain additional amounts and accrued and unpaid interest to, but not including, the date of purchase.

In addition, in the event that the Company becomes obligated to pay additional amounts to holders of the Existing Harbour Notes as a result of changes affecting withholding taxes applicable to payments on the Existing Harbour Notes, it may redeem the Existing Harbour Notes in whole but not in part at any time at 100 per cent. of the principal amount of the Existing Harbour Notes plus accrued and unpaid interest, if any, to, but not including, the redemption date.

Covenants

The Existing Harbour Notes Indenture contains covenants that, among other things, limit the ability of the Company and certain of its subsidiaries to:

(a) incur or guarantee additional indebtedness and issue certain preferred stock;

(b) create or permit to exist certain liens;

(c) consolidate, amalgamate, merge or transfer all or substantially all of the Company's assets and the assets of its Subsidiaries on a consolidated basis; and

(d) amend certain documents.

These covenants are subject to a number of important limitations and exceptions.

Events of Default

The Existing Harbour Notes Indenture contains customary events of default, including, among others, the non-payment of principal, interest or certain additional amounts on the Existing Harbour Notes, certain failures to perform or observe any other obligation under the Existing Harbour Notes Indenture or the guarantee subordination agreement, the failure to pay certain indebtedness or judgments and the bankruptcy or insolvency of the Company or any specified significant subsidiary. The occurrence of any of the events of default would permit or require the acceleration of all obligations outstanding under the Existing Harbour Notes.

Governing Law

The Existing Harbour Notes are governed by New York law.

15.13 **Terminated Sale and Purchase Agreements relating to the Sale of Interests in Vietnam**

In 2023, Harbour Energy announced that it had entered into Sale and Purchase Agreements (the "**Block 12W SPAs**") to sell its business in Vietnam, which included a 53.125 per cent. operated interest in Offshore Block 12W ("**Block 12W**"), to Big Energy from the effective date of 1 January 2023. The Block 12W SPAs have now terminated in accordance with their terms and the sale has not been consummated. Harbour Energy intends to re-assess its options with regards to realising the best value from its Vietnam business.

Harbour's 53.125 per cent interest in Block 12W, which contains the Chim Sao and Dua fields, is made up of a 28.125 per cent operated interest held through Premier Oil Vietnam Offshore BV and a 25 per cent interest held through Premier Oil (Vietnam) Ltd.

15.14 **EIG Relationship Agreement**

The Company entered into a relationship agreement (the "**EIG Relationship Agreement**") with Harbour North Sea on 31 March 2021 which will continue in force unless and until Harbour North Sea and its associates cease to own at least ten per cent. or more of the Ordinary Shares or the voting rights attaching to the Ordinary Shares. Harbour North Sea may terminate the EIG Relationship Agreement in certain circumstances, including where the Ordinary Shares cease to be admitted to the premium segment of the Official List and cease to be admitted to trading to the London Stock Exchange's main market for listed securities.

Under the EIG Relationship Agreement, Harbour North Sea undertakes that it shall not (and shall procure that its associates will not):

(a) take any action that would have the effect of preventing Harbour Energy from complying with its obligations under the Listing Rules;

(b) propose or procure the proposal of a shareholder resolution of Harbour Energy which is intended or appears to be intended to circumvent the proper application of the Listing Rules;

(c) exercise any of its voting rights in Harbour Energy in a way that would be inconsistent with, or breach any of the provisions of, the EIG Relationship Agreement;

(d) influence the day-to-day running of Harbour Energy at an operational level and shall allow Harbour Energy to operate on an independent basis;

(e) vote its Ordinary Shares and shall use its reasonable endeavours to procure that any director appointed by it does not vote his or her shares in a manner that would prevent the Company from operating and making decisions for the benefit of shareholders of the Company as a whole; and

(f) act in a manner which would be inconsistent with the independence of the Board being maintained in accordance with the rules of the London Stock Exchange or the FCA applicable to the Company, including the Listing Rules.

It is anticipated that the EIG Relationship Agreement will terminate upon Completion as a result of Harbour North Sea together with its associates holding less than ten per cent. of the Ordinary Shares (or the voting rights attaching to the Ordinary Shares) following the issue of the BASF Consideration Shares to BASF.

16. **TARGET COMPANY GROUP MATERIAL CONTRACTS**

The following contracts (not being a contract entered into in the ordinary course of business) (i) have been entered into by the Target Company or any member of the Target Company Group within the period of two years immediately preceding the date of this Prospectus which is or may be material to the Target Company Group; or (ii) contain provisions under which any member of the Target Company Group has an obligation or entitlement which is, or may be, material to the Target Company Group as at the date of this Prospectus.

16.1 **Wintershall Dea Senior Notes**

Overview

On 25 September 2019, Wintershall Dea Finance B.V. (the "**Senior Notes Issuer**") issued €1,000,000,000 0.840 per cent. notes due 2025 (the "**2025 Senior Notes**"), €1,000,000,000 1.332 per cent. notes due 2028 (the "**2028 Senior Notes**") and €1,000,000,000 1.823 per cent. notes due 2031 (the "**2031 Senior Notes**", and together with the 2025 Senior Notes and the 2028 Senior Notes, the "**Senior Notes**") governed by certain terms and conditions (the "**Senior Notes Terms and Conditions**"). As of the date hereof, the 2025 Senior Notes, 2028 Senior Notes and 2031 Senior Notes are still in issue and outstanding. Pursuant to a bondholder consent solicitation exercise successfully undertaken in February 2024 and implemented in April 2024, Wintershall Dea will, conditional upon Completion, be replaced by the Company as the guarantor providing an unconditional and irrevocable guarantee in respect of the Senior Notes (the "**Senior Notes Guarantor**").

Ranking

The obligations under the Senior Notes constitute unsubordinated and, subject to the respective Senior Notes Guarantees (as defined below), unsecured obligations of the Senior Notes Issuer ranking *pari passu* among themselves and, in the event of the insolvency, dissolution or liquidation of the Senior Notes Issuer or any proceeding to avoid insolvency of the Senior Notes Issuer, *pari passu* with all other present and future unsubordinated and unsecured obligations of the Senior Notes Issuer, save for such obligations which may be preferred by applicable law.

Interest Rates, Payment Dates and Maturity

The 2025 Senior Notes bear interest at 0.840 per cent. per annum, the 2028 Senior Notes bear interest at 1.332 per cent. per annum, and the 2031 Senior Notes bear 1.823 per cent. per annum. Interest on the Senior Notes is payable annually on 25 September each year. The Senior Notes will mature on:

(a) in the case of the 2025 Senior Notes, 25 September 2025;

(b) in the case of the 2028 Senior Notes, 25 September 2028; and

(c) in the case of the 2031 Senior Notes, 25 September 2031.

Guarantees

The Senior Notes are unsecured and unsubordinated obligations of the Senior Notes Issuer and rank equally in right of payment with the Senior Notes Issuer's existing and future unsecured and unsubordinated obligations. The Senior Notes are unconditionally and irrevocably guaranteed by Wintershall Dea (and following Completion, by the Senior Notes Guarantor) pursuant to unconditional and irrevocable guarantees (each of these guarantees, a "**Senior Notes Guarantee**", and collectively, the "**Senior Notes Guarantees**"). The Senior Notes Guarantees are unsecured and unsubordinated debt obligations of Wintershall Dea (and following Completion, by the Senior Notes Guarantor) and rank equally in right of payment with all existing and future unsecured and unsubordinated obligations of Wintershall Dea (and following Completion, of the Senior Notes Guarantor).

Security

The Senior Notes are unsecured.

Covenants

The Senior Notes Terms and Conditions contain covenants that, among other things, limit the ability of the Senior Notes Issuer and the Senior Notes Guarantor to:

(a) incur or guarantee additional indebtedness and issue certain preferred stock; and

(b) create or permit to exist certain liens.

These covenants are subject to a number of important limitations and exceptions.

Change of Control

The Senior Notes Terms and Conditions contain a change of control provision that was tailored to the shareholders of Wintershall Dea prior to Completion. Pursuant to a bondholder consent solicitation exercise undertaken in February 2024 and implemented in April 2024, conditional upon Completion, the change of control provision is modified to apply to the Company and thus the Company's shareholders.

Events of Default

The Senior Notes Terms and Conditions contain customary events of default, including, among others, the non-payment of principal, interest or certain additional amounts on the Senior Notes, certain failures to perform or observe any other obligation under the Senior Notes Terms and Conditions or the guarantee subordination agreement, the failure to pay certain indebtedness or judgments and the bankruptcy or insolvency of the Senior Notes Issuer or any of its subsidiaries, the failure to pay certain indebtedness or judgments and the bankruptcy or insolvency of the Senior Notes Issuer. The occurrence of any of the events of default would permit or require the acceleration of all obligations outstanding under the Senior Notes.

Governing Law

The Senior Notes are governed by laws of the Federal Republic of Germany.

16.2 Wintershall Dea Subordinated Notes

Overview

On 20 January 2021, Wintershall Dea Finance 2 B.V. (the "**Subordinated Notes Issuer**") issued €650,000,000 undated subordinated resettable 2.4985 per cent. notes (the "**2026 Subordinated Notes**") and €850,000,000 undated subordinated resettable 3.000 per cent. notes (the "**2029 Subordinated Notes**" and together with the 2026 Subordinated Notes, the "**Subordinated Notes**") governed by certain terms and conditions (the "**Subordinated Notes Terms and Conditions**"). As of the date hereof, the 2026 Subordinated Notes and 2029 Subordinated Notes are still in issue and outstanding. Pursuant to a bondholder consent solicitation exercise successfully undertaken in February 2024 and implemented in April 2024, Wintershall Dea will, conditional upon Completion, be replaced by the Company as the guarantor providing a guarantee on a subordinated basis (the "**Subordinated Notes Guarantor**").

Ranking

The obligations of the Subordinated Notes Issuer under the Subordinated Notes constitute unsecured and subordinated obligations of the Subordinated Notes Issuer ranking subordinated to all present and future unsubordinated and subordinated obligations of the Subordinated Notes Issuer *pari passu* amongst themselves and *pari passu* with all other present and future unsecured obligations of the Subordinated Notes Issuer ranking subordinated to all unsubordinated and subordinated obligations of the Subordinated Notes Issuer (including any present or future security or other instrument which ranks or is expressed to rank *pari passu* with the notes of the Subordinated Notes Issuer), except for any subordinated obligations required to be preferred by mandatory provisions of law, and senior only to the rights and claims of holders of junior securities of the Subordinated Notes Issuer.

Interest Rates, Payment Dates and Maturity

The 2026 Subordinated Notes are undated instruments and bear interest at a rate of 2.498 per cent. per annum and the 2029 Subordinated Notes bear interest at a rate of 3.000 per cent. per annum. Interest on the Subordinated Notes is payable annually in arrear on 20 July each year (for 2026 Subordinated Notes) and 20 January each year (for 2029 Subordinated Notes). The 2026 Subordinated Notes are subject to an interest rate step-up mechanism in 2026 and the 2029 Subordinated Notes are subject to an interest rate step-up mechanism in 2029.

Guarantees

The Subordinated Notes will be unconditionally and irrevocably guaranteed by Wintershall Dea (and following Completion, by the Subordinated Notes Guarantor) on a subordinated basis. The obligations of Wintershall Dea (and following Completion, of the Subordinated Notes Guarantor) under the Subordinated Notes constitute unsecured obligations of Wintershall Dea (and following Completion, of the Subordinated Notes Guarantor) ranking subordinated to all present and future unsubordinated and subordinated obligations of Wintershall Dea (and following Completion, of the Subordinated Notes Guarantor), *pari passu* among themselves and *pari passu* with all other present and future unsecured obligations of Wintershall Dea (and following Completion, of the Subordinated Notes Guarantor) ranking subordinated to all unsubordinated and subordinated obligations of Wintershall Dea (and following Completion, of the Subordinated Notes Guarantor), except for any subordinated obligations required to be preferred by mandatory provisions of law, and senior only to the rights and claims of holders of junior securities of Wintershall Dea (and following Completion, of the Subordinated Notes Guarantor).

Security

The Subordinated Notes are unsecured.

Covenants

There are no covenants in the Subordinated Notes Terms and Conditions.

Events of Default

The Subordinated Notes are hybrid bonds and accordingly no events of default clause is included in the Subordinated Notes Terms and Conditions.

Governing Law

The Subordinated Notes are governed by laws of the Federal Republic of Germany.

16.3 **Ghasha Sale and Purchase Agreement**

On 10 June 2024, Wintershall Dea Middle East GmbH (as the seller) ("**WDME**"), PTTEP MENA LIMITED (as the purchaser) and Wintershall Dea (as the guarantor) entered into a sale and purchase agreement (the "**Ghasha SPA**") relating to the sale of a 10 per cent. interest held by WDME in the Ghasha offshore concession located in the Arabian Gulf, offshore Abu Dhabi (the "**Ghasha Transaction**").

The Ghasha SPA contains customary warranties from WDME, including fundamental warranties relating to, amongst other things, powers and obligations of WDME, title to the interests in the Ghasha concession, complete and accurate disclosure of documents in the data room by WDME and compliance with permits, licences and applicable law and tax warranties. WDME's liability for a warranty claim under the Ghasha SPA is subject to the value of the claims exceeding a minimum threshold and is thereafter capped at differing thresholds for a breach of a fundamental warranty or a breach of other warranties. WDME shall not be liable unless it has been given written notice of a claim within certain time periods which vary depending on the nature of the claim.

Wintershall Dea has guaranteed WDME's obligations under the Ghasha SPA (including those arising from any breach of warranties) following completion of the Ghasha Transaction and up to an amount specified in the Ghasha SPA. Wintershall Dea's guarantee under the Ghasha SPA will be novated to Harbour Energy upon Completion.

The Ghasha SPA is governed by English law. Any dispute arising out of or in connection with the Ghasha Transaction will be resolved by the International Chamber of Commerce (the "**ICC**") in accordance with the rules of arbitration of the ICC.

17. **EMPLOYEE SHARE SCHEMES**

Harbour Energy currently operates three employee share schemes: (i) the 2017 Long Term Incentive Plan (the "**2017 LTIP**"); (ii) a Share Incentive Plan ("**SIP**"); and (iii) a Save As You Earn ("**SAYE**") share option scheme (the "**Employee Share Schemes**").

The principal features of the Employee Share Schemes are summarised below.

17.1 **2017 LTIP**

Overview

Approved by Shareholders in 2017, amended in 2020 and further amended in 2021, the 2017 LTIP is an 'umbrella' arrangement which, to give the Remuneration Committee maximum flexibility, allows various types of award to be granted including: (i) performance share awards; (ii) conditional share awards; (iii) deferred bonus awards; (iv) restricted share awards; and (v) value share awards. Restricted share awards and value share awards are legacy Premier Oil awards that are no longer granted under the 2017 LTIP.

As at the Latest Practicable Date, a total of 41,441,304 Ordinary Shares (excluding cash settled awards) were the subject of the outstanding awards under the 2017 LTIP.

Eligibility

All employees of the Company and its subsidiaries (including Executive Directors) are eligible to participate in the 2017 LTIP, subject to the following restrictions, though Executive Directors will only be eligible to be granted conditional share awards on recruitment.

Grant of Options/Awards

Awards may be granted in the form of: (i) nil (or nominal) cost options to acquire Ordinary Shares; (ii) contingent rights to receive Ordinary Shares; or (iii) cash-based awards.

Performance Conditions

Performance share awards normally vest based on the Company's total shareholder return performance relative to two peer groups (a comparator group of international oil and gas sector peers and the FTSE 100 index). Up to 25 per cent. vests for median performance, with full vesting for upper quartile performance and straight-line vesting in between.

Overall Limits

(a) Performance share awards—up to 300 per cent. of salary.

(b) Conditional share awards—based on the value of the buyout/recruitment award.

(c) Deferred bonus awards—based on the value of the annual bonus deferred into Ordinary Shares under the 2017 LTIP.

Vesting

Performance share awards will normally vest on the third anniversary of grant, subject to the satisfaction of the performance targets.

Conditional share awards will vest on the date as determined by the Remuneration Committee at the time of grant and have normally vested on the third anniversary of grant.

Deferred bonus awards will normally vest three years after grant.

Performance share awards made to Executive Directors are granted subject to a post-vesting holding period which will prevent participants from selling any Ordinary Shares received pursuant to their award (other than those sold to raise funds to discharge the tax liabilities arising on vesting) for a minimum of two years. The post-vesting holding period will apply notwithstanding that the award-holder has ceased employment with the Company's group (although the Remuneration Committee may terminate the post-vesting holding period early if the cessation occurs due to death, ill-health, injury or disability). In addition, if the award-holder is dismissed for gross misconduct, they will forfeit without payment any Ordinary Shares received pursuant to the 2017 LTIP which remain subject to the post-vesting holding period. Performance share awards granted to Executive Directors are always subject to a post-vesting holding period.

Participants receive dividend equivalent share awards on any share awards made under the 2017 LTIP. Dividend equivalent share awards made on unvested performance share awards vest to the same extent, and at the same time, that the related performance share awards vests.

Cessation of Employment

Awards lapse on cessation unless the participant is a 'good leaver'. A participant is a 'good leaver' if they leave due to death, ill-health, injury, disability, redundancy, sale of employing company or business, retirement or otherwise at the Remuneration Committee's discretion.

Performance share awards held by good leavers vest at the normal time, subject (where applicable) to the performance target being achieved and a time *pro rata* reduction.

The Remuneration Committee can vest performance share awards on cessation and/or waive any performance targets (other than in respect of performance share awards held by Executive Directors) and/or time prorating.

Deferred bonus awards held by good leavers vest in full at cessation.

Conditional share awards held by good leavers vest on cessation. The Remuneration Committee can vest conditional share awards on the normal vesting date and/or waive any time prorating.

Takeovers

All awards vest on a takeover subject, where applicable, to any performance targets being satisfied. All awards (other than deferred bonus awards, which vest in full) are subject to a time *pro rata* reduction. The Remuneration Committee can waive the time *pro rata* requirement if it sees fit. The Remuneration Committee can, however, compel participants to rollover their awards so that they become awards over shares in the buyer.

Variation of Capital

In the event of any variation of the Company's share capital or any form of demerger, special dividend or similar event, the Remuneration Committee may, if it sees fit, adjust the number of shares under any award and/or the exercise price per share accordingly.

Malus and Clawback

Malus and clawback can be operated until the later of: (i) two years after vesting; and (ii) the completion of the second audit after vesting in the event of (a) a material misstatement of the Company's financial results, (b) material error in the calculation of performance conditions (c) gross misconduct, (d) corporate failure, or (e) in such other exceptional circumstances as the Remuneration Committee sees fit.

Alterations

Except as noted above, the Remuneration Committee may at any time alter the 2017 LTIP or the terms of any award granted under it. Save for minor alterations to benefit the administration of the 2017 LTIP, to take account of a change in legislation or to obtain or maintain favourable tax, exchange control or regulatory treatment, no alteration to the advantage of an individual participant shall be made to the provisions governing eligibility, individual or overall limits, the basis for determining the participant's entitlement to shares, the ability to adjust on a variation of capital and the power of amendment without the prior approval of Shareholders in general meeting.

17.2 **SIP**

Overview

The SIP is an HMRC approved scheme. An equivalent, unapproved scheme operates for Harbour Energy's expatriate employees. Employees may buy shares, known as "partnership shares" under the rules of the SIP ("**partnership shares**"), using gross pay and the Company may then grant matching shares. Under the SIP, free shares may also be granted. Dividends may accrue on any shares and be automatically reinvested.

Eligibility

Under the SIP, all UK resident employees are eligible to participate (including Executive Directors). Participation in the SIP is voluntary and dependent upon completion of a partnership share agreement. Non-UK resident employees (excluding Executive Directors) are eligible to participate in the equivalent expatriate scheme.

Matching Shares

For every one partnership share an employee buys, the Company will award matching shares free of charge on a ratio of 1 for 1. Matching shares are purchased in the market by the Company and allocated to participants in proportion to the number of partnership shares purchased. Matching shares will be lost if, within three years of the matching shares being awarded, the employee takes their partnership shares out of the SIP or the employee leaves the Company.

Performance Conditions

No performance conditions apply.

Alterations

Except as noted below, the Board may at any time alter the SIP. Save for minor alterations to benefit the administration of the scheme, to take account of a change in legislation or to obtain or maintain favourable tax, exchange control or regulatory treatment, no alteration to the advantage of an individual participant shall be made to the provisions governing eligibility, individual and overall limits, the basis for determining a participant's entitlement to shares, the ability to adjust on a variation of capital and the power of amendment without the prior approval of the Shareholders in general meeting.

17.3 **SAYE**

Overview

The SAYE is an HMRC approved scheme open to all employees of nominated Harbour Energy companies with the relevant qualifying period of service.

As at the Latest Practicable Date, a total of 3,796,054 Ordinary Shares were the subject of the outstanding options under the SAYE scheme.

Eligibility

Under the SAYE, all employees of nominated Harbour Energy companies (including Executive Directors) who have continuous service equal to or greater than one month are eligible to participate in the SAYE.

Eligible employees are able to acquire shares in the Company at a discount of up to 20 per cent. of the market value at grant if they agree to enter into a savings contract for a three year period.

Performance Conditions

Consistent with the relevant legislation, no performance conditions apply.

Vesting

In normal circumstances, at the end of their savings contract, participants may use the proceeds of that contract to exercise their option. An option, to the extent it becomes exercisable, may be exercised during the period of six months (12 months in the case of death) after which, to the extent unexercised, the option will lapse automatically.

Variation of capital

On any variation of the share capital of the Company, the Board may make adjustments to the number of shares in respect of which any option may be exercised and/or the option price, but only to the extent necessary to take account of the variation.

Alterations

Except as noted above, the Board may at any time alter the SAYE or the terms of any option granted under it. Save for minor alterations to benefit the administration of the SAYE, to take account of a change in legislation or to obtain or maintain favourable tax, exchange control or regulatory treatment, no alteration to the advantage of an individual participant shall be made to the provisions governing eligibility, individual and overall limits, the basis for determining a participant's entitlement to shares, the ability to adjust on a variation of capital and the power of amendment without the prior approval of Shareholders in general meeting.

18. PENSION BENEFITS

All Harbour Energy UK employees are invited to participate in a personal pension plan which is a defined contribution pension. A 20 per cent. company contribution is made, conditional upon a 5 per cent. employee contribution. The only pensionable element of pay is salary.

Employees may elect to take a cash allowance in lieu in the following circumstances: (i) they can provide formal annual evidence they have reached their lifetime allowance; or (ii) they can take taxable cash in lieu of any contribution value above their tapered tax allowance.

19. WORKING CAPITAL

The Company is of the opinion that, taking into account the existing debt available to the Target Company Group and the RCF, the Enlarged Group has sufficient working capital for its present requirements, that is for the next 12 months from the date of this Prospectus.

20. NO SIGNIFICANT CHANGE

20.1 Harbour Energy

There has been no significant change in the financial performance or financial position of Harbour Energy since 31 December 2023, being the date to which the audited consolidated financial information of Harbour Energy for the year ended 31 December 2023, which is incorporated by reference into, and forms part of, this Prospectus was published.

20.2 Target Company Group

There has been no significant change in the financial performance or financial position of the Target Company Group since 31 December 2023, being the date to which the audited historical financial information for the Target Portfolio set out in Part IX (*Historical Financial Information relating to the Target Portfolio*) for the year ended 31 December 2023 of this Prospectus was published.

21. LEGAL AND ARBITRATION PROCEEDINGS

21.1 Harbour Energy

Other than as set out below, there are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) during the 12 months preceding the date of this Prospectus which may have, or have had in the recent past, significant effects on the financial position or profitability of the Company and/or Harbour Energy.

Determination by referee in STASCO dispute

Harbour Energy is a party to long term hydrocarbon sales and lifting agreements (the "**HSLAs**") with Shell International Trading Company Limited ("**STASCO**"), a subsidiary of Shell plc. Harbour Energy has notified STASCO of its right to terminate the HSLAs from 31 October 2024, in accordance with their terms. Pursuant to the HSLAs, Harbour Energy has agreed to sell and STASCO has agreed to buy Harbour Energy's production across various fields and products, including in respect of crude oil from the Clair and Schiehallion fields in the North Sea. The pricing of the crude oil from the Clair and Schiehallion fields under the HSLAs was partly based on the Urals crude oil price assessment published by Platts. Following the Russian invasion of Ukraine in February 2022, the price of the Urals materially weakened relative to other benchmarks.

In response to the European Union's sanctions against Russia in November 2022, Platts made a material change to the Urals crude oil price assessment which allowed the Company to seek an alternative pricing benchmark under the HSLAs. The HSLAs also provided that if the parties were unable to agree the alternative pricing benchmark then a referee could be appointed to make this determination. The Company and STASCO were unable to agree the terms of reference of the referee and the Company therefore brought a claim against STASCO in the High Court on 13 April 2023 seeking a declaration that no further explanation or instruction to the referee would be required before the referee was able to perform its function under the contractual referee procedure. On 20 December 2023, the High Court found in favour of the Company and declined to intervene in the pricing dispute.

On 9 May 2024, the referee gave its written determination in Harbour Energy's favour and ruled that the alternative pricing benchmark proposed by the Company should be adopted.

Harbour Energy has since received cash funds from STASCO of $55.9 million in settlement of the backward-looking element of the pricing dispute. All future liftings (and liftings in respect of which STASCO has not yet been invoiced) until the termination of the HSLAs will also be priced using the pricing benchmark determined by the referee.

21.2 Wintershall Dea Global Holding GmbH and the Target Company Group

There are no, nor have there been any, governmental, legal or arbitration proceedings (including such proceedings which are pending or threatened of which the Company is aware) during the 12 months prior to the date of this Prospectus which may have, or have had in the recent past, a significant effect on the financial position or profitability of Wintershall Dea Global Holding GmbH and/or the Target Company Group.

22. MANDATORY TAKEOVER BIDS, SQUEEZE-OUT RULES, SELL-OUT RULES AND TAKEOVER BIDS

22.1 Mandatory takeover bids

The Takeover Code applies to the Company. Under the Takeover Code, if an acquisition of interests in shares were to increase the aggregate holding of an acquirer and persons acting in concert with it to an interest in shares carrying 30 per cent. or more of the voting rights in the Company, the acquirer and, depending upon the circumstances, persons acting in concert with it, would be required (except with the consent of the Takeover Panel) to make a cash offer for the outstanding shares at a price not less than the highest price paid for any interest in shares by the acquirer or his concert parties during the previous 12 months. A similar obligation to make such a mandatory offer would also arise on the acquisition of an interest in shares by a person holding (together with any persons acting in concert) an interest in shares carrying between 30 per cent. and 50 per cent. of the voting rights in the Company if the effect of such acquisition were to increase that person's percentage of the voting rights.

22.2 Squeeze-out rules

Under the Companies Act, if a "takeover offer" (as defined in section 974 of the Companies Act) is made for the Ordinary Shares and the offeror were to acquire, or unconditionally contract to acquire, not less than 90 per cent. in value of the shares to which the offer relates (the "**Offer Shares**") and not less than 90 per cent. of the voting rights attached to the Offer Shares, within three months of the last day on which its offer can be accepted, it could acquire compulsorily the outstanding shares not assented to the offer. It would do so by sending a notice to outstanding shareholders telling them that it will acquire compulsorily their shares and then, six weeks later, it would execute a transfer of the outstanding shares in its favour and pay the consideration to the Company, which would hold the consideration on trust for outstanding shareholders. The consideration offered to the shareholders whose shares are acquired compulsorily under the Companies Act must, in general, be the same as the consideration that was available under the takeover offer.

22.3 Sell-out rules

The Companies Act also gives minority shareholders a right to be bought out in certain circumstances by an offeror who has made a takeover offer. If a takeover offer related to all the Ordinary Shares and at any time before the end of the period within which the offer could be accepted the offeror held or had agreed to acquire not less than 90 per cent. of the Ordinary Shares to which the offer relates, any holder of Ordinary Shares to which the offer related who had not accepted the offer could by a written communication to the offeror require it to acquire those Ordinary Shares. The offeror would be required to give any shareholder notice of his right to be bought out within one month of that right arising. The offeror may impose a time limit on the rights of the minority shareholders to be bought out, but that period cannot end less than three months after the end of the acceptance period. If a shareholder exercises his or her rights, the offeror is bound to acquire those Ordinary Shares on the terms of the offer or on such other terms as may be agreed.

22.4 Takeover bids

No public takeover bid has been made in relation to the Company during the last financial year or the current financial year.

23. **STATUTORY AUDITOR**

Ernst & Young LLP is the statutory auditor to the Company. Ernst & Young LLP is registered to carry out audit work in the United Kingdom by the Institute of Chartered Accountants in England and Wales. Ernst & Young LLP's registered address is 1 More London Place, London SE1 2AF, United Kingdom.

24. **COSTS AND EXPENSES**

The aggregate costs and expenses of the Acquisition and Admission (including the listing fees of the FCA and the London Stock Exchange, professional fees and expenses and the costs of printing and distribution of documents) payable by the Company are estimated to be $150 million.

25. **TARGET COMPANY CPR**

No material changes have occurred since 31 December 2023, being the effective date of the Target Company CPR, the omission of which would make the Target Company CPR misleading.

26. **CONSENTS**

The Company has received the following written consents, which are available for inspection at the times and locations set out in section 19 of Part XI (*Competent Person's Report on the Target Company's Portfolio*), in connection with the publication of this Prospectus:

(a) Ernst & Young LLP has given and not withdrawn its written consent to the inclusion in this Prospectus of its report included in Section A of Part X (*Unaudited Pro Forma Financial Information*), and has authorised the contents of this report as part of this Prospectus for the purposes of Prospectus Regulation Rule 5.3.2R(2)(f) and item 1.3 of Annex 1 of the UK Prospectus Delegated Regulation;

(b) KPMG LLP has given and has not withdrawn its written consent to the inclusion in this Prospectus of its report included in Part IX (*Historical Financial Information relating to the Target Portfolio*) and has authorised the contents of this report as part of the document for the purposes of Rule 5.3.2R(2)(f) of the Prospectus Regulation Rules and item 1.3 of Annex 1 of the UK Prospectus Delegated Regulation; and

(c) DeGolyer and MacNaughton has given and not withdrawn its written consent to the inclusion in this document of the Target Company CPR in Part XI (*Competent Person's Report on the Target Company's Portfolio*) and has authorised the contents of this report for the purposes of this document for the purposes of Rule 5.3.2R(2)(f) of the Prospectus Regulation Rules and item 1.3 of Annex 1 of the UK Prospectus Delegated Regulation.

27. **DOCUMENTS AVAILABLE FOR INSPECTION**

Copies of the following documents will be available for inspection for a period of 12 months following Admission on the Company's website at http://www.harbourenergy.com. Should you require a hard copy version of the documents below, please contact the Company Secretary:

(a) the Articles of Association;

(b) The Business Combination Agreement;

(c) the report from KPMG LLP on the combined historical financial information of the Target Portfolio set out in Part IX *(Historical Financial Information relating to the Target Portfolio*) of this Prospectus;

(d) the report from Ernst & Young LLP on the unaudited pro forma financial information set out in Section A of Part X (*Unaudited Pro Forma Financial Information*) of this Prospectus;

(e) the Target Company CPR contained in Part XI (*Competent Person's Report on the Target Company's Portfolio*);

(f) the consent letters referred to in paragraph 26 of this Part XIV (*Additional Information*);

(g) the Harbour Energy Annual Report 2023, the Harbour Energy Annual Report 2022 and the Harbour Energy Annual Report 2021;

(h) the Circular; and

(i) this Prospectus.

PART XV
DEFINITIONS AND INTERPRETATION

Definitions

The following definitions apply throughout this Prospectus unless the context otherwise requires:

"1P"	means low estimate of reserves (i.e. proved reserves);
"2C"	means best estimate of contingent resources;
"2P"	means the best estimate of reserves (i.e. the sum of proved plus probable reserves);
"3P"	means proved-plus-probable-plus-possible reserves;
"3-D Seismic"	means seismic data acquired as multiple, closely spaced traverses;
"Acquisition"	means the proposed acquisition by the Company of the Target Portfolio;
"Admission"	means the admission of the BASF Consideration Shares to the premium listing segment of the Official List (or the segment of the Official List for equity shares of commercial companies, if applicable at the time of application) and to trading on the London Stock Exchange's main market for listed securities;
"AELE"	means the operated Armada Area fields, the Everest and Lomond fields and the non-operated Erskine field;
"Agreement for Storage Activities"	means an agreement for storage activities regulating the joint activities under the Storage Licence;
"Announcement"	means the announcement by the Company on 21 December 2023 that it had reached an agreement with BASF and LetterOne for the Acquisition;
"Anticlinal Structure"	means an arched shaped structure in which the strata are convex upwards;
"Apache"	means the Apache Corporation;
"APA"	means Norway's Award in Pre-Defined Areas;
"APE"	means Aguada Pichana Este;
"API"	means American Petroleum Institute gravity, a measure of how heavy or light a petroleum liquid is compared to water;
"Appraisal well"	means a well drilled as part of an appraisal of a field;
"Articles of Association"	means the articles of association of the Company;
"ÅTS"	means the Åsgard Transportation System;
"Band Limit"	means where an individual Shareholder who is resident in the UK for UK tax purposes and whose total taxable gains and income in a given tax year, including any gains made on the disposal or deemed disposal of their Ordinary Shares, are less than or equal to the upper limit of the income tax basic rate band applicable to them in respect of that tax year;
"Barrel"	means a unit of volume measurement used for petroleum and its products one barrel of oil; one barrel = 35 Imperial gallons (approx.), or 159 litres (approx.); 7.5 barrels = one tonne (approximately depending upon the oil density); 6.29 barrels = one cubic metre;
"BASF"	means Basf Handels-und Exportgesellschaft Mit Beschränkter Haftung, a limited liability company (*Gesellschaft mit*

	beschränkter Haftung) established under the laws of Germany registered with the commercial register (*Handelsregister*) of the local court (*Amtsgericht*) of Ludwigshafen am Rhein under registration number HRB 3535 with its registered seat in Ludwigshafen am Rhein, Germany;
"BASF Consideration Shares"	means the 669,714,027 new Ordinary Shares to be issued to BASF pursuant to the Business Combination Agreement;
"BASF Relationship Agreement" . . .	means the relationship agreement entered into between Harbour Energy and BASF;
"BASF TopCo"	means BASF SE, a European stock corporation (*Societas Europaea*) established under the laws of Germany, registered with the commercial register of the local court (*Amtsgericht*) of Ludwigshafen am Rhein under registration number HRB 6000 with its registered seat in Ludwigshafen am Rhein, Germany;
"Barclays"	Barclays Bank PLC;
"BCA" or **"Business Combination Agreement"**	means the business combination agreement between the Company, BASF, LetterOne, BASF TopCo and LetterOne TopCo dated 21 December 2023, as amended on 7 June 2024;
"bcf"	means billion cubic feet;
"BFA"	means the bridge facility agreement entered into between certain members of Harbour Energy with, among others, DNB Bank ASA, London Branch as facility agent, pursuant to which an up to $1,500,000,000 bridge facility is made available by the lenders thereunder;
"BG"	means BG Group plc (now called BG Group Limited, a wholly owned subsidiary of Shell plc);
"Big Energy"	means the Big Energy Joint Stock Company;
"Block"	term commonly used to describe areas over which there is a petroleum or production licence or PSC or PSA;
"Block 12W"	means Offshore Block 12W, Vietnam;
"Block 12W SPAs"	means the now terminated sale and purchase agreements entered into by Harbour Energy to sell its business in Vietnam;
"BMS"	means the Business Management System of Harbour Energy;
"Board"	means the board of directors of the Company from time to time;
"BOE"	means a quantity of hydrocarbon (in any form) with a total calorific energy equal to that of one (1) barrel of oil;
"BOP"	means the blow-out preventer;
"BPS"	means the Brent Pipeline System;
"Brent"	means a benchmark crude oil from the UK North Sea against which other crude oils are priced. It is widely used as an indicator of the price of oil beyond energy markets;
"Business Day"	means a day other than a Saturday, Sunday or public holiday in England and Wales;
"Buyback Rights"	means an inter-conditional off-market buy-back resolution seeking authority to purchase Non-Voting Shares on a pro-rata basis;
"Catcher Area"	means the Catcher area of the UK North Sea;
"CATS"	means the Central Area Transmission System;

"CCS"	means carbon capture and storage;
"CCS Directive"	means the EU Directive 2009/31/EC on the geological storage of carbon dioxide;
"CCUS"	means carbon capture usage and storage;
"CES"	means the Crown Estate Scotland;
" CESL Terminal"	means the Centrica Energy Storage Limited Easington Terminal;
"CGUs"	means Cash Generating Units;
"CGR"	means condensate-gas ratio;
"Chrysaor"	means Chrysaor Holdings Limited;
"CIF"	means the Carbon Capture and Storage Infrastructure Fund;
"Circular"	means the circular issued by Harbour Energy in connection with the Acquisition, containing the Notice of General Meeting;
"Closure"	means the height from the apex of a reservoir structure to the lowest contour that contains the reservoir structure (spill). Measurements of both the areal closure and the distance from the apex to the lowest closing contour are typically used for the calculations of the estimated hydrocarbon content of a trap;
"CMA-1"	means Cuenca Marina Austral 1;
"CMS"	means the Caister Murdoch System;
"CNH"	means the Comisión Nacional de Hidrocarburos, or National Hydrocarbons Commission;
"CNOOC"	means the China National Offshore Oil Corporation;
"COA"	means a contract of affreightment;
"Code"	means the UK Corporate Governance Code;
"COMESA"	means the Common Market for Eastern and Southern Africa;
"Companies Act"	means the Companies Act 2006, as amended from time to time;
"Company"	means Harbour Energy plc, public limited company incorporated under the laws of Scotland and registered under number SC234781, whose registered address is at 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh, EH1 2EN;
"Completion"	means completion of the Acquisition in accordance with the terms of the Business Combination Agreement;
"Completion Consideration Cash Amount"	means the cash consideration of $2.15 billion to be funded through cash flow generated from the Target Portfolio between the effective date of 30 June 2023 and Completion, and an underwritten bridge facility;
"Condensate"	means hydrocarbons which are in the gaseous state under reservoir conditions and which become liquid when temperature or pressure is reduced. A mixture of pentanes and higher hydrocarbons;
"Conditions to Completion"	has the meaning given to it in paragraph 15.1 (Business Combination Agreement) of Part XIV (*Additional Information*)
"Consideration Shares"	means approximately 921.2 million new Harbour Energy shares to be issued to BASF and LetterOne;
"Contingent Payment"	means each of up to six contingent payments to which BASF and LetterOne are entitled to receive from the Company, in an

	aggregate amount of up to $300,000,000, dependent on the price of Brent oil during the relevant assessment periods;
"Contingent Resources"	means those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies;
"Conversion Conditions"	has the meaning given to it in paragraph 15.1 (Business Combination Agreement) of Part XIV (*Additional Information*);
"COP Acquisition"	means Chrysaor's acquisition of ConocoPhillips' UK oil and gas business for a price of $2.675 billion which completed on 30 September 2019;
"Cretaceous"	means the final period of the Mesozoic era ranging from approximately 65 to 144 million years ago;
"Cost Recovery Oil"	means the net oil production in each period to a maximum percentage of net production;
"Cost Recovery Petroleum"	means the net petroleum production in each year up to a maximum percentage of net production;
"COVID-19 pandemic"	means the novel strain of the coronavirus identified in late 2019;
"CS Licence"	means a CO_2 appraisal and storage licence;
"CS Licence Clauses"	means the general terms and conditions that will normally be set out in a CS Licence document;
"CT"	means the ordinary company tax;
"DBEIS"	means the UK Department for Business, Energy and Industrial Strategy;
"Decommissioning Notice"	means a notice from the Secretary of State under the Petroleum Act to a wide variety of persons including the operator of the field and each of the licensees (and potentially a holding or associated company) requiring them to prepare, submit and (once approved) carry out a decommissioning programme in relation to offshore oil and gas installations and pipelines;
"DESNZ"	means the UK Department for Energy Security and Net Zero;
"DECC"	means the UK Department for Energy and Climate Change;
"DGOG"	means the Indonesian Directorate General of Oil & Gas;
"Dip"	means the angle at which a rock stratum or structure is inclined from the Horizontal;
"Directors"	means the directors of the Company as at the date of this Prospectus and "**Director**" means any one of them;
"Disclosure Guidance and Transparency Rules"	means the Disclosure Guidance and Transparency Rules made by the FCA under section 73 of the FSMA, as amended from time to time;
"Discovery"	means an exploration well which has encountered oil and gas for the first time in a structure;
"DRD"	means the decommissioning relief deed introduced by the Finance Act 2013;
"E&E"	means exploration and evaluation;
"EGAS"	means the Egyptian Natural Gas Holding Company;
"EGPC"	means the Egyptian General Petroleum Corporation;

"EIG Relationship Agreement"	means a relationship agreement entered into between the Company and Harbour North Sea on 31 March 2021;
"Employee Share Schemes"	means a share option scheme;
"Enlarged Group"	means Harbour Energy following Completion;
"EPL"	means the Energy Profits Levy;
"ESIM"	means the Energy Security Investment Mechanism;
"ESP"	means electric submersible pumps;
"ETS"	means the Esmond Transportation System;
"EU"	means the European Union;
"EU ETS"	means the European Union's Emissions Trading System;
"EUWA"	means the European Union (Withdrawal) Act 2018;
"**euros**" or "**€**"	means the lawful currency of the European Union (as adopted by certain member states);
"Existing Harbour Notes"	means USD 500 million aggregate principal amount of its 5.5 per cent. Senior Notes due 2026 issued by the Company on 18 October 2021;
"Existing Harbour Notes Guarantors"	means, collectively, Chrysaor E&P Finance Limited, Chrysaor Limited, Chrysaor Holdings Limited, Chrysaor CNS Limited, Chrysaor E&P Limited, Chrysaor E&P Services Limited, Chrysaor North Sea Limited, Chrysaor Developments Limited, Chrysaor Petroleum Company U.K. Limited, Chrysaor Petroleum Limited, Chrysaor Production Holdings Limited, Chrysaor Production (U.K.) Limited, Chrysaor Resources (Irish Sea) Limited, Chrysaor Resources (UK) Holdings Limited, Chrysaor (U.K.) Alpha Limited, Chrysaor (U.K.) Beta Limited, Chrysaor (U.K.) Sigma Limited, Chrysaor (U.K.) Theta Limited, Premier Oil Group Holdings Limited, Premier Oil Group Limited, Premier Oil E&P UK Limited, Premier Oil E&P UK EU Limited, Premier Oil UK Limited, Premier Oil (Vietnam) Limited, Premier Oil Natuna Sea B.V., Premier Oil Tuna B.V., Premier Oil Vietnam Offshore B.V., Premier Oil Andaman Limited, Premier Oil Andaman I Limited and Premier Oil South Andaman Limited;
"Existing Harbour Notes Indenture"	means an indenture dated 18 October 2021 relating to the Existing Harbour Notes;
"Exploration Well"	means a well in an unproven area or prospect;
"Fault"	means a displacement (vertical, inclined or lateral) below the earth surface that acts to offset rock layers relative to one another. Faulting can create traps for hydrocarbons;
"**FCA**" or "**Financial Conduct Authority**"	means the Financial Conduct Authority, including in its capacity as the competent authority for the purposes of Part VI of the FSMA;
"FCA Handbook"	means the FCA's handbook of rules and guidance;
"FEED"	means Front-end engineering design;
"Field"	means a geographical area under which either a single oil or gas reservoir or multiple oil or gas reservoirs lie, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition;
"FLAGS"	means the Far North Liquids and Associated Gas System;

"Formation"	means a body of rock identified by lithic characteristics and stratigraphic position which is mappable at the earth's surface or traceable in the subsurface;
"Fortress"	means Fortress Investment Group LLC;
"FPS"	means the Forties Pipeline System;
"FPSO"	means floating production storage and offloading;
"FSMA"	means the UK Financial Services and Markets Act 2000, as amended;
"GAEL"	means the Graben Area Export Line;
"GBA"	means the Greater Britannia Area;
"General Meeting"	means the general meeting of the Company, including any adjournments thereof, proposed to be held at Clifford Chance LLP, 10 Upper Bank Street, London, E14 5JJ at 10.00 a.m. on 5 July 2024 to approve the Resolutions, the notice of which is contained in Part X (*Notice of General Meeting*) of the Circular;
"GHG"	means greenhouse gas;
"Ghasha SPA"	means the sale and purchase agreement relating to the Ghasha Transaction;
"Ghasha Transaction"	means the sale of a 10 per cent. interest held by WDME in the Ghasha offshore concession located in the Arabian Gulf, offshore Abu Dhabi;
"GOR"	means gas/oil ratio;
"GRN"	means the Groupement Reggane Nord;
"GWC"	means gas/water contact;
"H_2S"	means hydrogen sulphide;
"Habitats Regulations"	means the Offshore Petroleum Activities (Conservation of Habitats) Regulation 2001 (as amended);
"Harbour Argentina"	means Harbour Energy Argentina Limited Sucursal Argentina;
"Harbour Energy"	means the Company together with its subsidiaries and subsidiary undertakings from time to time;
"Harbour Energy Business"	means the Harbour Energy business prior to the Premier Merger;
"Harbour North Sea"	means Harbour North Sea Holdings, Ltd;
"HC"	means hydrocarbon;
"HGS"	means the Humber Gathering System;
"HSES"	means health, safety, environment and security;
"HSLAs"	means hydrocarbon sales and lifting agreements;
"IASB"	means the International Accounting Standards Board;
"ICC"	means International Chamber of Commerce;
"ICP"	means the Indonesian Official Selling prices;
"IFRS"	means the International Financial Reporting Standards as adopted by the United Kingdom;
"Investment Grade Rating"	means a long-term corporate rating of at least BBB- (or equivalent) from at least two of Moody's Investors Services Limited, Standard & Poor's Ratings Services and Fitch Ratings Ltd.;

"ISA"	means an individual savings account;
"JAA"	means a standard Joint Accounting Agreement;
"JOA"	means a joint operating agreement;
"J.P. Morgan"	means J.P. Morgan Securities plc (which conducts its UK investment banking activities under the marketing name J.P. Morgan Cazenove);
"Jurassic"	refers to a geologic period of the Mesozoic Era from approximately 199 million to 145 million years ago
"kboepd"	means thousand barrels of oil equivalent per day;
"KSpG"	means the Federal Carbon Dioxide Storage Act;
"Latest Practicable Date"	means 7 June 2024, being the latest practicable date prior to the publication of this Prospectus;
"LDC"	means the distribution companies who supply gas to residential and commercial customers;
"LetterOne"	means L1 Energy Capital Management Services S. À R. L., a Luxembourg limited company (*société à responsabilité limitée*) with registered seat in Luxembourg, and registered with the company register of Luxembourg under B185442, whose registered address is at 1-3 Boulevard de la Foire, L-1528 Luxembourg;
"LetterOne Effective Date"	means the date on which LetterOne (together with its associates) holds 10 per cent. or more of the Ordinary Shares, in relation to the LetterOne Relationship Agreement;
"LetterOne Purchase Option"	means the date on which LetterOne (together with its associates) holds 10 per cent. or more of the Ordinary Shares, in relation to the LetterOne Relationship Agreement;
"LetterOne Relationship Agreement"	means the relationship agreement entered into between Harbour Energy and LetterOne;
"LetterOne TopCo"	means LetterOne Holdings S.A.;
"Listing Rules"	means the listing rules made under section 73A of the FSMA, as amended from time to time;
"LOGGS"	means the Lincolnshire Offshore Gas Gathering System;
"London Protocol"	means the 1996 Protocol to the Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter, 1972;
"London Stock Exchange"	means London Stock Exchange plc;
"Longstop Date"	means 21 June 2025 as the date on which the Business Combination Agreement will be capable of being terminated if Completion has not occurred on or before such date;
"LPG"	means liquefied petroleum gas;
"LTIR"	means the lost time injury rate per million hours worked, in relation to the Target Portfolio;
"M&A"	means liquefied petroleum gas;
"MEMR"	means the Indonesian Minister of Energy and Mineral Resources;
"Merger"	means the Chrysaor and Premier Oil all share merger creating Harbour Energy plc;
"Minister"	means the Danish Minister of Climate, Energy and Utilities;

"Miocene"	means a geological time frame from approximately 5 to 23 million years ago;
"mmbbl"	means million barrels;
"mmboe"	means million barrels of oil equivalent;
"Model Clauses"	means the terms and conditions of every UK Seaward Production Licences as prescribed;
"MoE"	means the Norwegian Ministry of Energy;
"MtCO$_2$"	means megatonnes of carbon dioxide;
"Mtpa"	means million tonnes per annum;
"Natuna Sea Block A"	means the Natuna Sea Block A offshore fields in Indonesia, comprising the Anoa oil field and substantial undeveloped gas fields, as well as exploration prospects;
"NCS"	means the Norwegian continental shelf;
"net zero target"	means the law passed by the UK Parliament setting a target for at least a 100 per cent. reduction in greenhouse gas emissions (compared to 1990 levels) in the UK by 2050;
"NGR"	means net-to-gross ratio;
"NLGP"	means the Northern Leg Gas Pipeline;
"Norwegian Storage Regulations"	means the Norwegian Storage Regulations 2014;
"NPA"	means the Norwegian Petroleum Act 1996;
"Non-Voting Shareholder"	means a holder of Non-Voting Shares;
"Non-Voting Shares"	means the 251,488,211 non-voting, non-listed convertible ordinary shares with preferential rights to be issued to LetterOne pursuant to the Business Combination Agreement on the terms, and with the rights, as set out in the Annex to the Notice of General Meeting contained in Part X (*Notice of General Meeting*) of the Circular;
"Notice of General Meeting"	means the notice of General Meeting contained in Part X of the Circular;
"NSBA"	means Natuna Sea Block A;
"NSTA"	means the UK North Sea Transition Authority;
"NWSG"	means the North West Sidi Ghazi;
"Official List"	means the list maintained by the FCA in accordance with section 74(1) of the FSMA for the purposes of Part VI of the FSMA;
"OGA"	means the UK Oil and Gas Authority;
"OGMP 2.0"	means the Oil & Gas Methane Partnership 2.0;
"OOIP"	means original oil in place;
"OGIP"	means original gas in place;
"OPEC"	means the Organisation of the Petroleum Exporting Countries;
"OPEC+"	means OPEC and its allies;
"Operator"	means the company that has legal authority to drill wells and undertake production of oil and gas. The operator is often part of a consortium and acts on behalf of this consortium;

"Ordinary Shares"	means the ordinary shares of 0.002 pence each in the capital of the Company, including, where the context requires, the BASF Consideration Shares;
"Participation Rights"	means the rights of the holders of Non-Voting Shares to be entitled to participate in purchases by the Company of its own securities or other returns of capital on a pro-rata basis;
"Partnership shares"	means shares that the Company employees may buy under the rules of the SIP;
"P10"	means at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate;
"P50"	means at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate;
"P90"	means at least a 90% probability that the quantities actually recovered will equal or exceed the estimate;
"PCI"	means a Project of Common interest;
"Petroleum Act"	means the UK Petroleum Act 1998;
"POD"	means plan of development;
"pounds sterling", **"£"**or **"pence"**	means the lawful currency of the United Kingdom;
"PPC"	means Petroleum Pipelines Company
"PRA"	means the UK Prudential Regulatory Authority;
"PRT"	means petroleum revenue tax charged under the UK Oil Taxation Act 1975;
"Premier Merger"	means the all share merger of Premier Oil plc and Chrysaor Holdings Limited through a reverse takeover which completed on 31 March 2021 to create Harbour Energy;
"PRMS"	Petroleum Resource Management System;
"Prospectus"	means this document;
"Prospectus Regulation Rules"	means the prospectus regulation rules made by the FCA under Part VI of the FSMA (as set out in the FCA Handbook), as amended from time to time;
"Proved Reserves"	means those quantities of petroleum, 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;
"PSA"	means a production sharing agreement or contract under which the contractor agrees to fund and carry out pre-agreed work programmes on behalf of the concession owner in return for a share of production revenues;
"Purple Green"	means Purple Green Investment Pte Ltd;
"Q1 2024 Update"	means the unaudited trading and operations update for the first quarter of 2024 issued by the Company on 9 May 2024;
"RCF"	the revolving credit facility agreement dated 5 March 2024 entered into by the Company and certain members of Harbour Energy with, among others, DNB Bank ASA, London Branch as facility agent, pursuant to which an up to US$3,000,000,000 revolving credit facility is made available by the lenders thereunder;

"RCFT"	means the UK ring fence corporation tax;
"Readmission"	means the readmission of the Ordinary Shares to the premium listing segment of the Official List (or the segment of the Official List for equity shares of commercial companies, if applicable at the time of application) and to trading on the London Stock Exchange's main market for listed securities;
"Registrar"	means Equiniti Limited with its registered office at Aspect House, Spencer Road, Lancing, West Sussex, BN99 6DA, United Kingdom;
"Regulatory Information Service"	means one of the regulatory information services authorised by the FCA to receive, process and disseminate regulatory information from listed companies;
"Resolutions"	means each of the resolutions 1 to 3, which are set out in the Notice of General Meeting in the Circular and "**Resolution**" shall be construed accordingly;
"Restricted Territory"	means any jurisdiction where the extension or availability of any transaction contemplated by the Acquisition would breach any applicable law or regulation;
"RFCT"	means corporation tax charged under the provisions of the UK Corporation Tax Act 2009 and the UK Corporation Tax Act 2010 in respect of ring fence trades and any other tax on profits which is introduced in addition to or as a replacement for such corporation tax (but excluding Supplementary Charge)
"Right of First Refusal"	means the right of first refusal provided to LetterOne and LetterOne TopCo pursuant to the Business Combination Agreement;
"SAGE"	means the Scottish Area Gas Evacuation System;
"SAYE"	means the Save As You Earn Harbour Energy employee share scheme;
"SEAL"	means the Shearwater Elgin Area Line;
"SEC"	means the U.S. Securities and Exchange Commission;
"Senior Managers"	means the senior managers of the Company;
"Senior Notes"	means the 2025 Senior Notes, 2028 Senior Notes and 2031 Senior Notes;
"Senior Notes Guarantees"	means the unconditional and irrevocable guarantees pursuant to which the Senior Notes are unconditionally and irrevocably guaranteed by Wintershall Dea (and following Completion, by the Senior Notes Guarantor) and "**Senior Note Guarantee**" shall be construed accordingly;
"Senior Notes Guarantor"	means Wintershall Dea and, following Completion, the Company;
"Senior Notes Issuer"	means Wintershall Dea Finance B.V.;
"Senior Notes Terms and Conditions"	means the terms and conditions which govern the Senior Notes;
"Shareholder"	means a holder of Ordinary Shares registered on the register of members of the Company from time to time;
"Shell Acquisition"	means Chrysaor's acquisition of a collection of oil and gas assets in the UK North Sea from Shell for a price of \$3.0 billion which completed on 1 November 2017;
"SILK"	means the SEAL Interconnector Link Pipeline;

"SIP"	means the Harbour Energy Share Incentive Plan;
"Skarv Satellite Project"	means the third party subsea development Ørn (operated by Aker BP), which is being developed in parallel with Alve Nord and Idun Nord and hosted on the FPSO;
"SKKMIGAS"	means the Special Task Force for Upstream Oil and Gas Business Activities Republic of Indonesia;
"Source Rock"	means a rock rich in organic matter which, if given the right conditions, will generate oil or gas. Typical source rocks, usually shales or limestones, contain at least 0.5% total organic carbon (TOC), although a rich source rock might have as much as 10% organic matter. Access to a working source rock is necessary for a complete petroleum system;
"spar platform"	means a floating platform with a vertical cylindrical hull moored to the seabed;
"Spin-off"	means a spin-off for assumption (*Abspaltung zur Aufnahme*), pursuant to which Wintershall Dea will transfer to the Target Company certain assets of the Target Portfolio;
"Sponsor"	means Barclays Bank PLC;
"Sponsor's Agreement"	means the agreement between the Company and the Sponsor dated 12 June 2024 in connection with the applications for Admission and the publication of this Prospectus and the Circular;
"SPT"	means the special petroleum tax;
"SR"	means San Roque;
"STASCO"	means Shell International Trading Company Limited;
"Storage Licence"	means an exploration licence and an exploitation licence;
"Storage Regulations"	means the UK Storage of Carbon Dioxide (Licensing etc.) Regulations 2010;
"St Fergus"	means the SAGE gas terminal at St Fergus on the north east coast of Scotland;
"Supplementary Charge"	means the charge in respect of ring fence trades imposed by Chapter 6 of Part 8 of the UK Corporation Tax Act 2010;
"Subordinated Notes"	means the 2026 and 2029 Subordinated Notes;
"Subordinated Notes Guarantor"	means Wintershall Dea and, following Completion, the Company;
"Subordinated Notes Issuer"	means Wintershall Dea Finance 2 B.V.;
"Subordinated Notes Terms and Conditions"	means the terms and conditions which govern the Subordinated Notes;
"subsidiary"	has the meaning given in section 1159 of the Companies Act;
"subsidiary undertaking"	has the meaning given in section 1162 of the Companies Act;
"Subsoil Act"	means the Subsoil Act 2019;
"SVT"	means the Sullom Voe Terminal;
"Takeover Code"	means the City Code on Takeovers and Mergers as from time to time amended and interpreted by the Takeover Panel;
"Target Company"	Wintershall Dea Holding GmbH, a limited liability company (*Gesellschaft mit beschränkter Haftung*) established under the laws of Germany which will be owned 72.7 per cent. by BASF and

	27.3 per cent. by LetterOne following registration with the commercial register (*Handelsregister*);
"Target Company CPR"	means the Target Company's competent person's report;
"Target Company Group"	means Wintershall Dea Global Holding GmbH, together with each of its subsidiaries and subsidiary undertakings from time to time and, following registration of the Spin-off with the commercial register (*Handelsregister*) of Wintershall Dea (which will occur on or prior to Completion) means the Target Company together with its subsidiaries and subsidiary undertakings from time to time;
"Target Portfolio"	means substantially all of Wintershall Dea's upstream oil and gas assets, including those in Norway, Germany, Denmark, Argentina, Mexico, Egypt, Libya and Algeria as well as Wintershall Dea's CCS licences in Europe;
"TCE"	means the Crown Lease from The Crown Estate;
"TCFD"	means the Taskforce on Climate-related Financial Disclosures;
"Tertiary"	means the Tertiary Period is a geological period from approximately 65 million to 2.5 million years ago;
"Trap"	means a configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not migrate;
"TSA"	means the transitional services agreement entered into on 19 April 2024 between the Company and Wintershall Dea pursuant to which Wintershall Dea provides transitional support services to the Company;
"TTF"	means title transfer facility;
"UDP"	means the Zama Unit development plan;
"UK ETS"	means the United Kingdom Emissions Trading System;
"UK Market Abuse Regulation"	means the Market Abuse Regulation (Regulation (EU) No. 2014/596) as it forms part of UK domestic law by virtue of the EUWA;
"UK NBP"	means the UK National Balancing Point;
"UK Prospectus Regulation"	means Regulation (EU) No. 2017/1129 as it forms part of UK domestic law by virtue of the EUWA;
"UK Prospectus Delegated Regulation"	means Commission Delegated Regulation (EU) 2019/980 which forms part of UK domestic law by virtue of the European Union (Withdrawal) Act 2018;
"UKCS"	means the UK Continental Shelf;
"uncertificated" or **"in uncertificated form"**	means, in relation to a share or other security, a share or other security title to which is recorded in the relevant register of the share or other security concerned as being held in uncertificated form that is, in CREST and title to which may be transferred by using CREST;
"United Kingdom" or **"UK"**	means the United Kingdom of Great Britain and Northern Ireland;
"United States" or **"US"**	the United States of America, its territories and possessions, any state of the United States of America, the District of Columbia, and all other areas subject to its jurisdiction;

"US dollars", **"dollars"**, **"US$"**, **"$"** or **"cents"**	means the lawful currency of the United States;
"US Securities Act"	means the United States Securities Act of 1933, as amended from time to time;
"UT"	means the temporary union of companies;
"WAG"	means water-alternating-gas injection wells;
"WDCMS"	means Wintershall Dea Carbon Management Solutions B.V.;
"Wintershall Dea"	means Wintershall Dea AG;
"Wintershall Dea Bonds"	means the Senior Notes and the Subordinated Notes;
"WND"	means the West Nile Delta;
"WoSPS"	means the West of Shetland Pipeline system;
"2017 LTIP"	means the 2017 Long Term Incentive Plan Harbour Energy employee share scheme;
"2018 LTIP"	means the 2017 Long Term Incentive Plan;
"2025 Senior Notes"	means the €1,000,000,000 0.840 per cent. notes due 2025;
"2026 Subordinated Notes"	means the €650,000,000 undated subordinated resettable 2.4985 per cent. notes;
"2028 Senior Notes"	means the €1,000,000,000 1.332 per cent. notes due 2028;
"2029 Subordinated Notes"	means the €850,000,000 undated subordinated resettable 3.000 per cent. notes.; and
"2031 Senior Notes"	means the €1,000,000,000 1.823 per cent. notes due 2031.

Interpretation

All times referred to are London time unless otherwise stated.

All references to legislation in this Prospectus are to the legislation of England and Wales unless the contrary is indicated. Any reference to any provision of any legislation shall include any amendment, modification, re-enactment or extension thereof.

Words importing the singular shall include the plural and *vice versa*, and words importing the masculine gender shall include the feminine or neutral gender.

Toppan Merrill, London
24-11947-7