This document (the "**Prospectus**") comprises a prospectus for the purposes of Article 6 of Regulation (EU) 2017/1129, as amended, relating to Premier Oil plc ("**Premier**" and together with its subsidiaries, the "**Premier Group**") and has been approved by the Financial Conduct Authority of the United Kingdom (the "**FCA**"), as competent authority under Regulation (EU) 2017/1129, in accordance with section 87A of the Financial Services and Markets Act 2000 of England and Wales, as amended ("**FSMA**"), and prepared and made available to the public in accordance with the Prospectus Regulation Rules of the FCA made under section 73A of FSMA (the "**Prospectus Regulation Rules**"). The FCA only approves this Prospectus as meeting the standards of completeness, comprehensibility and consistency imposed by Regulation (EU) 2017/1129 and such approval should not be considered as an endorsement of 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: (i) been filed with the FCA and made available to the public in accordance with paragraph 3.2.1 of the Prospectus Regulation Rules; and (ii) been prepared to provide details of the Consideration Shares and the Creditor Shares.

The Company, the Directors and the Proposed Directors, whose names appear in section 1 of Part XII, accept responsibility for the information contained in this document. To the best of the knowledge of the Company and the Directors and the Proposed Directors, the information contained in this document is in accordance with the facts and this document makes no omission likely to affect its import.

The distribution of this Prospectus and any accompanying documents into jurisdictions other than the UK may be restricted by law and therefore persons into whose possession this Prospectus comes should inform themselves about and observe any such restrictions. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction. In particular, such documents should not be distributed in, forwarded to or transmitted in or into Australia, Canada, Hong Kong, Indonesia, Japan, New Zealand, Singapore, South Africa or the United States or any other state or jurisdiction in which the same would be unlawful.

PremierOil

PREMIER OIL PLC
(to be renamed HARBOUR ENERGY PLC)

(incorporated and registered in Scotland with registered number SC234781)

Prospectus relating to the readmission of Existing Ordinary Shares, admission of 14,253,203,210 Consideration Shares, admission of up to 3,331,917,634 Creditor Shares and offer of up to 148,085,228 New Equity Warrants, in connection with the Merger with Chrysaor and the Debt Restructuring

Sponsor
RBC Capital Markets

This document should be read as a whole. Your attention is drawn to the letter from the Chairman which is set out in Part I (*Letter from the Chairman of Premier*) of the accompanying Circular and which contains a recommendation from the Directors that Shareholders vote in favour of the Resolutions to be proposed at the General Meeting. The section of this document entitled "Risk Factors" includes a discussion of certain risk factors which should be taken into account when considering the matters referred to in this document. A Notice of the General Meeting to be held at 23 Lower Belgrave Street, London, SW1W 0NR at 2 p.m. on Tuesday 12 January 2021 is set out in Part X (*Notice of General Meeting*) of the Circular. As further detailed in Part X of the Circular, given the current Covid-19 restrictions, the Directors have put in place a number of practical arrangements in relation to the General Meeting to safeguard the health and wellbeing of its shareholders and employees, whilst giving shareholders the maximum opportunity to have their say. This means that shareholders will be unable to be physically present at the General Meeting. To enable shareholders to listen to the General Meeting, a webcast facility will be available at www.premier-oil.com. The webcast will be 'listen only'; any questions for the General Meeting should be submitted in advance.

As the Merger is classified as a reverse takeover under the Listing Rules, the listing of the Existing Ordinary Shares will be cancelled and applications will be made to the FCA for the Existing

Ordinary Shares to be readmitted to the premium listing segment of the Official List and to the London Stock Exchange for the Existing 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 Consideration Shares and Creditor Shares to be admitted to the premium listing segment of the Official List and to the London Stock Exchange for the Consideration Shares and Creditor Shares to be admitted to trading on the London Stock Exchange's main market for listed securities (together, "**Admission**"). Readmission and Admission are expected to take place simultaneously.

No Consideration Shares or Creditor Shares or any other securities in Premier have been marketed to, or are available for purchase, in whole or in part, by the public in the UK or elsewhere in connection with the admission of the Consideration Shares or the Creditor Shares to the premium listing segment of the Official List and the London Stock Exchange's main market for listed securities, except to Chrysaor's shareholders (in respect of the Consideration Shares) and Restructuring Plan Creditors (in respect of the Creditor Shares). Save as aforesaid, 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.

No person has been authorised to give any information or make any representations other than those contained in the Prospectus, the Circular 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 Premier, Chrysaor, the Directors, the Proposed Directors or RBC. Premier will comply with its obligation to publish supplementary prospectuses containing further updated information required by law or by any regulatory authority but assumes no further obligation to publish additional information.

The release, publication or distribution of this Prospectus in jurisdictions other than the UK may be restricted by law and, therefore, any persons who are subject to the laws of any jurisdiction other than the UK should inform themselves about, and observe, any applicable requirements. Failure to comply with any such restrictions may constitute a violation of the securities laws of any such jurisdiction. 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 England.

This Prospectus is not for release, publication or distribution, directly or indirectly, in whole or in part, in, into or from Australia, Canada, Hong Kong, Indonesia, Japan, New Zealand, Singapore, South Africa or the United States or any other state or jurisdiction in which the same would be restricted, unlawful or unauthorised (each an "**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 Premier 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 Company is prohibited from making any invitation to members of the public of the Cayman Islands to subscribe for the Consideration Shares, the Creditor Shares or any other securities in Premier and this Prospectus does not constitute an invitation or offer to members of the public in the Cayman Islands with respect to the Consideration Shares, the Creditor Shares or any other securities in Premier, whether by way of sale or subscription. For these purposes, "members of the public" has the meaning given in the Securities Investment Business Law of the Cayman Islands. However, Consideration Shares, the Creditor Shares or any other securities in Premier may be beneficially owned by persons resident, domiciled, established, incorporated or registered pursuant to the laws of the Cayman Islands. Chrysaor does not undertake business with any person in the Cayman Islands except in furtherance of the business of the company carried on outside of the Cayman Islands.

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 Merger 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 Consideration Shares or Creditor Shares is being made in the United States or any other Restricted Territory.

RBC Europe Limited (trading as RBC Capital Markets) ("**RBC**") which is regulated by the FCA in the United Kingdom and is authorised and regulated by the PRA in the United Kingdom, is acting solely for Premier and no one else in connection with the Merger and the Admission and any other matter referred to in this document and will not be responsible to anyone other than Premier for providing the protections afforded to clients of RBC nor for providing advice in relation to the Merger, Admission or any other matter referred to in this document.

BMO Capital Markets Limited ("**BMO**"), which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting exclusively for Chrysaor E&P Services Limited and no one else in connection with the Merger and will not be responsible to anyone other than Chrysaor E&P Services Limited for providing the protections offered to clients of BMO nor for providing advice in relation to the Merger or any other matters referred to in this document.

Barclays Bank PLC, acting through its Investment Bank ("**Barclays**"), which is authorised by the PRA and regulated in the United Kingdom by the FCA and the PRA, is acting exclusively for Chrysaor E&P Services Limited and no one else in connection with the Merger and will not be responsible to anyone other than Chrysaor E&P Services Limited for providing the protections afforded to clients of Barclays nor for providing advice in relation to the Merger or any other matter referred to in this document.

Apart from the responsibilities and liabilities, if any, which may be imposed on RBC in its capacity as a sponsor by FSMA or the regulatory regime established thereunder, RBC does not accept any responsibility or liability whatsoever for the contents of this Prospectus, including its accuracy, completeness or for any other statement made or purported to be made by it, or on its behalf, in connection with the Premier Group, the Chrysaor Group, the Ordinary Shares (including the Consideration Shares and the Creditor Shares), the Merger or Admission. RBC and each of its subsidiaries, branches and affiliates accordingly disclaim to the fullest extent permitted by law all and any responsibility and liability whether arising in tort, contract or otherwise (save as referred to above) which it might otherwise have in respect of this Prospectus or any such statement. Nothing in this Prospectus excludes, or attempts to exclude, the liability of RBC for fraud or fraudulent misrepresentation.

THE CONTENTS OF THIS PROSPECTUS OR ANY SUBSEQUENT COMMUNICATION FROM PREMIER, CHRYSAOR 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 THEIR OWN SOLICITOR, INDEPENDENT FINANCIAL ADVISER OR TAX ADVISER FOR LEGAL, FINANCIAL OR TAX ADVICE. THIS PROSPECTUS DOES NOT CONSTITUTE AN OFFER OF, AND MAY NOT BE USED FOR THE PURPOSES OF, AN OFFER TO SELL OR AN INVITATION TO SELL, 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 OR INTO ANY JURISDICTION IN CONTRAVENTION OF APPLICABLE LAW.

Capitalised terms have the meanings ascribed to them in the 'Definitions' section of this Prospectus.

This document is dated 16 December 2020.

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SUMMARY

1. Introduction and warnings

1.1 Details of the issuer

The issuer is Premier Oil plc (the "**Company**" or "**Premier**"), a public limited company incorporated in Scotland with registered number SC234781. The Company's registered office is situated at 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh, EH1 2EN and the head office is situated at 23 Lower Belgrave Street, London, SW1W 0NR. The telephone number of the Company's head office is +44 (0)20 7730 1111 and the legal entity identifier of the Company is 213800YPC42DYBKVPF97.

1.2 Details of the securities

The Existing Ordinary Shares are registered with ISIN GB00B43G0577 and are traded on the main market for listed securities of the London Stock Exchange under the ticker symbol "PMO". The ISIN for the New Ordinary Shares will be GB00BLGYGY88. The New Ordinary Shares will trade under ticker symbol "HBR".

1.3 Details of the FCA

This document has been approved by the FCA as the competent authority under the Prospectus Regulation. The head office of the FCA is at 12 Endeavour Square, London, E20 1JN. The telephone number of the FCA is +44 (0)20 7066 1000

1.4 Warnings

This summary should be read as an introduction to this document.

Any decision to invest in the securities should be based on a consideration of the document as a whole. If you decide to invest in the securities, all or part of any capital invested could be lost. Where a claim relating to the information contained in this document is brought before a court, the plaintiff investor might, under national law, have to bear the costs of translating this document before the legal proceedings are initiated.

Civil liability attaches only to those persons who have tabled this summary including any translation thereof, but only where this summary is misleading, inaccurate or inconsistent, when read together with the other parts of this document, or where it does not provide, when read together with the other parts of this document, 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?

The Company was incorporated and registered with the name of Dalglen (No. 836) Limited in Scotland on 31 July 2002 with registered number SC234781. The name of the Company was changed to Premier Oil Group Limited pursuant to a written resolution passed on 13 September 2002. Premier was reregistered as a public limited company on 10 March 2003, and its name was changed from Premier Oil Group Limited to Premier Oil plc pursuant to a special resolution passed on 3 March 2003 and which became effective on 15 July 2003. The legal entity identifier of the Company is 213800YPC42DYBKVPF97.

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

Major shareholders: As at the Latest Practicable Date, Premier had received notification from the following institutions, in accordance with Chapter 5 of the Disclosure Guidance and Transparency Rules, of their significant holdings of voting rights (3 per cent. or more) of Premier's issued share capital:

Shareholder	*Notified number of voting rights*	*Notified percentage of voting rights (%)*
Aberforth Partners	69,389,053	7.50
Schroder Investment Management	46,563,242	5.03
Artemis Investment Management LLP	25,451,951	4.98
Aviva plc and its subsidiaries(1)	3,933,529	4.95
AXA Investment Managers SA	23,907,981	4.68
Ameriprise Financial Inc	24,666,346	4.66
Dimensional Fund Advisors	43,531,400	4.38

Note

(1) Interests shown for Aviva plc and its subsidiaries pre-date the Share Split in 2011.

Immediately following completion of the Merger and the Debt Restructuring, and assuming full take up by Restructuring Plan Creditors of the partial cash alternative and assuming no Top-Up Election, Harbour North Sea Holdings, Ltd. ("**Harbour North Sea**") together with its concert parties will hold up to 40.42 per cent. of the Ordinary Shares in the Company, Purple Green Investment Pte Ltd (a wholly owned subsidiary of GIC (Ventures) Pte Ltd) will hold up to 13.83 per cent. of the Ordinary Shares in the Company and Coller Partners 705 LP Incorporated will hold up to 4.01 per cent. of the Ordinary Shares in the Company (the allocation of Consideration Shares among Chrysaor shareholders, including Harbour North Sea together with its concert parties, Purple Green Investment Pte Ltd and Coller Partners 705 LP Incorporated, will depend on the value of those Consideration Shares in the period up to the completion of the Merger). As such Harbour North Sea will be deemed a controlling shareholder of Premier and, in compliance with the Listing Rules, has agreed to enter into a relationship agreement with the Company.

Key managing directors: Richard Rose (Interim Chief Executive Officer and Finance Director) (as at the date of this document). Linda Cook (Chief Executive Officer designate) and Phil Kirk (President & Chief Executive Officer, Europe designate) (following completion of the Merger and Admission).

Statutory auditors: Ernst & Young LLP of 1 More London Place, London SE1 2AF (since 1 January 2017).

2.2 What is the key financial information regarding the issuer?

Selected historical key financial information: The tables below set out selected key financial information for the Premier Group for the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019 and in respect of the six-month periods ended 30 June 2019 and 30 June 2020.

	Year ended 31 December 2017 (audited)	*Year ended 31 December 2018 (audited)*	*Year ended 31 December 2019 (audited)*	*Six months ended 30 June 2020 (unaudited)*	*Six months ended 30 June 2019 (unaudited)*
			(US$ millions)		
Table 1: Income statement					
Total revenue (1)	1,043.1	1,397.5	1,584.7	530.6	871.3
Operating profit /(loss) (1)	33.8	531.0	455.0	(199.3)	327.5
Profit from discontinued operations	16.4	28.3	9.3	—	8.2
(Loss)/profit after tax	(253.8)	133.4	164.3	(671.5)	120.6
Basic (loss)/earnings per share (cents)	(49.4)	17.3	19.9	(78.9)	14.7
Note: (1) From continuing operations					

	Year ended 31 December 2017 (audited)	Year ended 31 December 2018 (audited)	Year ended 31 December 2019 (audited)	Six months ended 30 June 2020 (unaudited)	Six months ended 30 June 2019 (unaudited)
			(US$ millions)		
Table 2: Balance sheet					
Total assets	6,136.6	5,614.9	6,092.4	5,281.3	6,287.3
Total liabilities	(5,519.7)	(4,588.9)	(4,960.9)	(4,791.1)	(5,177.2)
Net debt	(2,724.2)	(2,330.7)	(1,989.8)	(1,973.9)	(2,151.2)
Total equity	(616.9)	(1,026.0)	(1,131.5)	(490.2)	(1,110.1)
Table 3: Cash flow statement					
Operating cash flows	496.0	722.8	1,108.7	323.7	544.6
Investing cash flows	(115.7)	(296.9)	(262.2)	(155.3)	(115.9)
Financing cash flows	(264.1)	(526.7)	(884.3)	(221.1)	(416.2)
Cash and cash equivalents at the beginning of the period	255.9	365.4	244.6	198.1	244.6
Net increase/(decrease) in cash and cash equivalents	109.5	(120.8)	(46.5)	(58.4)	8.9
Cash and cash equivalents at the end of the period	365.4	244.6	198.1	139.7	253.5

The tables below set out selected key financial information for the Chrysaor Group for the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019 and in respect of the six-month periods ended 30 June 2019 and 30 June 2020.

	Year ended 31 December 2017 (audited)	Year ended 31 December 2018 (audited)	Year ended 31 December 2019 (audited)	Six months ended 30 June 2020 (audited)	Six months ended 30 June 2019 (unaudited)
			(US$ millions)		
Table 1: Income statement					
Total revenue	313.5	1,965.6	2,357.8	1,230.1	1,055.1
Operating profit /(loss)	45.1	802.2	762.5	(180.5)	434.9
Profit/(loss) after tax	259.0	368.9	218.8	(154.5)	174.4
Table 2: Balance sheet					
Total assets	5,462.2	5,424.0	11,328.6	10,221.6	5,333.6
Total liabilities	(5,142.3)	(4,487.8)	(9,419.6)	(8,292.2)	(4,393.8)
Net debt	(1,276.7)	(542.3)	(1,889.8)	(1,466.3)	(332.3)
Total equity	(319.8)	(936.2)	(1,909.0)	(1,929.4)	(939.8)
Table 3: Cash flow statement					
Operating cash flows	54.0	1,447.8	1,518.7	946.1	774.2
Investing cash flows	(2,097.5)	(581.9)	(2,776.0)	(363.2)	(526.3)
Financing cash flows	2,339.3	(847.4)	(1,508.4)	(786.2)	(275.2)
Cash and cash equivalents at the beginning of the period	4.1	299.5	316.3	573.2	316.3
Net increase/(decrease) in cash and cash equivalents	295.8	18.5	251.0	(203.4)	(27.3)
Cash and cash equivalents at the end of the period	299.5	316.3	573.2	369.4	289.4

The tables below set out selected key financial information for the Combined COP Subsidiaries for the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019.

	Year ended 31 December 2017 (audited)	Year ended 31 December 2018 (audited)	Year ended 31 December 2019 (audited)
		(US$ millions)	
Table 1: Income statement			
Total revenue	2,670.9	3,209.8	1,617.6
Operating (loss)/profit	(62.7)	131.3	228.8
(Loss)/profit after tax	(22.6)	214.8	254.5
Table 2: Balance sheet			
Total assets	7,448.5	3,486.0	2,880.6
Total liabilities	(4,645.9)	(2,305.5)	(2,059.9)
Total invested capital	(2,802.6)	(1,180.5)	(820.7)
Table 3: Cash flow statement			
Operating cash flows	267.4	440.1	224.4
Investing cash flows	(1,870.8)	3,222.7	(633.1)
Financing cash flows	(16.3)	(1,663.5)	(109.4)
Cash and cash equivalents at the beginning of the year	121.7	(1,483.6)	498.2
Net (decrease)/increase in cash and cash equivalents	(1,619.8)	1,999.3	(518.2)
Cash and cash equivalents at the end of the year	(1,483.6)	498.2	0.018

There are no qualifications in the auditor's reports on the historical financial information.

Selected *pro forma* key financial information:

The unaudited *pro forma* income statement and statement of net assets have been prepared to illustrate the effect of the Merger and Debt Restructuring on: (i) the consolidated earnings of Premier for six months ended 30 June 2020 as if the Merger and Debt Restructuring had taken place on 1 January 2020; and (ii) the consolidated net assets of Premier as at 30 June 2020 as if the Merger and Debt Restructuring had occurred on 30 June 2020. The unaudited *pro forma* statement of net assets and the unaudited *pro forma* income statement have been prepared for illustrative purposes only. The hypothetical financial position or results included in the *pro forma* financial information may differ from the Combined Group's actual financial position or results.

The Unaudited *Pro Forma* Financial Information has been prepared in a manner consistent with the accounting policies that will be applied by the Combined Group for the year ending 31 December 2020 and in accordance with the requirements of sections 1 and 2 of Annex 20 of Commission Delegated Regulation (EU) 2019/980.

The unaudited *pro forma* profit before tax from continuing operations for the six months ended 30 June 2020 is US$347.8 million. The unaudited consolidated *pro forma* net assets as at 30 June 2020 is US$3.3 billion.

2.3 What are the key risks specific to the issuer?

If the Interim Maturity Extension becomes effective but the Merger and the Debt Restructuring do not proceed, the ability of members of the Premier Group to continue trading will depend on ongoing support from the Premier Group's creditors.

If the Interim Maturity Extension does not become effective and the Merger and the Debt Restructuring do not proceed, the Premier Group's financial position would be materially adversely affected and it is likely that companies within the Premier Group would be placed into insolvency procedures on or before 31 May 2021.

The Debt Restructuring and the Interim Maturity Extension are each subject to a number of conditions that must be satisfied in order for it to proceed.

The Support Letter may be terminated in accordance with its terms on the occurrence of certain specified events

The Merger is conditional upon certain conditions which may not be satisfied, as a result of which the Merger will not be implemented on its current terms or at all.

The business, operating results, financial condition and prospects of the Premier Group (and, following the Merger, the Combined Group) depend substantially upon prevailing hydrocarbon prices, which can be volatile and subject to fluctuations in response to a variety of factors beyond the Premier Group's and the Combined Group's control.

Hydrocarbon exploration, development and production operations may be affected by operational hazards or other factors which may result in unforeseen liabilities and adversely affect future cash flows.

3. Key information on the securities

3.1 What are the main features of the securities?

Type, class and ISIN of the securities: The Existing Ordinary Shares are fully paid ordinary shares with a nominal value of 12.5 pence each. The Company has and, after Admission will have, one class of ordinary shares. The Existing Ordinary Shares are registered with ISIN GB00B43G0577 and are traded on the main market for listed securities of the London Stock Exchange under ticker symbol "PMO".

Following Admission, the New Ordinary Shares issued in connection with to the Merger and the Debt Restructuring will be registered with ISIN GB00BLGYGY88. The ISIN of the New Equity Warrants is GB00BM9GMR34. The New Ordinary Shares will trade under ticker symbol "HBR".

Currency of the securities: Pounds sterling.

Number of issued and fully paid securities: As at the Latest Practicable Date, there were 925,532,676 Ordinary Shares in issue. It is anticipated that 14,253,203,210 Consideration Shares will be issued pursuant to the Merger and up to 3,331,917,634 Creditor Shares will be issued pursuant to the Debt Restructuring. The New Ordinary Shares will have a nominal value of 0.0001 pence each (following the Subdivision referred to below) and will be fully paid.

Rights attaching to the securities: The New Ordinary Shares will, following Admission, rank *pari passu* in all respects with the Existing Ordinary Shares, including in relation to dividends or other distributions. All Ordinary Shares will have equal rights to participate in capital, dividend and distributions. In the event of insolvency, the 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 Ordinary Share. Resolutions put to the meeting will generally be decided on a poll.

Restrictions on free transferability of the securities: There are no restrictions on the transferability of the securities.

Subdivision: As a result of the Subdivision, each Existing Ordinary Share will be subdivided into one Ordinary Share with a nominal value of 0.0001 pence each and one Non-Voting Deferred Share with a nominal value of 12.4999 pence each.

New Equity Warrants: As part of the Debt Restructuring, up to 148,085,228 New Equity Warrants will be granted to Restructuring Plan Creditors who satisfy certain eligibility criteria instead of New Ordinary Shares. Restructuring Plan Creditors electing to receive New Equity Warrants shall be required to pay 0.001 pence per New Ordinary Share to the Company on exercise of the New Equity Warrants, subject to any adjustment of the exercise price of the New Equity Warrants in accordance with the terms of the New Equity Warrants Deed Poll.

Dividend policy: Premier did not pay a dividend for the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019. Under the terms of the Existing Debt Facilities, the Premier Group is subject to restrictive covenants such that it shall not declare, make or pay any dividend or other distribution or redeem or repay any of its share capital. Premier at present has no plans to pay a dividend prior to completion of the Merger and Debt Restructuring.

Going forward, the Directors and Proposed Directors believe the combination of Premier and Chrysaor will create a business with the potential to offer a meaningful dividend for shareholders over time. The Combined Group is expected to generate sufficient free cash flow to support shareholder returns including via a sustainable dividend which, subject to market conditions and Board approval, is expected to be introduced with respect to the financial year ending December 2021.

3.2 Where will the securities be traded?

The Existing Ordinary Shares are admitted, and application will be made for the New Ordinary Shares to be admitted, to the premium listing segment of the Official List of the FCA and to trading on the London Stock Exchange's main market for listed securities. No application has been made or is currently intended to be made for any Ordinary Shares to be admitted to trading on any other exchange. Neither the Non-Voting Deferred Shares nor the New Equity Warrants will be admitted to trading on the main market for listed securities of the London Stock Exchange.

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

Prospective investors should be aware that the value of an investment in the Company may go down as well as up and any fluctuations may be material. The market value of the Ordinary Shares can fluctuate substantially and may not always reflect the underlying value or prospects of the Premier Group.

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

Following the completion of the Merger, Harbour North Sea may be able to influence decision-making within the Company, and its interests may differ from other Shareholders.

The market price of the Ordinary Shares could be negatively affected by sales of substantial amounts of Ordinary Shares by Harbour North Sea or Restructuring Plan Creditors 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 Company will have a more concentrated shareholder base following the completion of the Merger and the Debt Restructuring.

The Company has not declared a dividend since May 2014 and there is no assurance that dividend payments will be made in the future.

4. Key information on the admission to trading on a regulated market

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

Prospective investors should be aware that the value of an investment in the Company may go down as well as up and any fluctuations may be material. The market value of the Ordinary Shares can fluctuate substantially and may not always reflect the underlying value or prospects of the Premier Group or the Combined Group.

No Consideration Shares or Creditor Shares or any other securities in Premier have been marketed to, or are available for purchase, in whole or in part, by the public in the UK or elsewhere in connection with the admission of the New Ordinary Shares to the premium listing segment of the Official List and the London Stock Exchange's main market for listed securities, except to Chrysaor's shareholders (in respect of the Consideration Shares) and Restructuring Plan Creditors (in respect of the Creditor Shares). Save as aforesaid, 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.

4.2 Why is this Prospectus being produced?

This Prospectus has been produced in connection with the Merger and the Debt Restructuring and the application to be made to the FCA for the New Ordinary Shares to be admitted to the premium listing segment of the Official List. An application will also be made to the London Stock Exchange for the New Ordinary Shares to be admitted to trading on its main market for listed securities.

No application has been made for admission of New Ordinary Shares to trading on any other stock exchange (nor is it the current intention of the Company to make any such application in future).

RISK FACTORS

Any investment in Ordinary Shares (including the Consideration Shares and the Creditor Shares) or New Equity Warrants is subject to a number of risks and uncertainties. Each of these risks is expected to continue to be relevant to the Combined Group (and any investment in the New Ordinary Shares) following completion of the Merger.

Before making any investment, prospective investors should carefully consider the factors, risks and uncertainties associated with any such investment and the Premier Group's and, following completion of the Merger, the Combined 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 and the Proposed Directors believe to be most essential to an assessment by a prospective investor of whether to consider an investment in New Ordinary Shares or New Equity Warrants. 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 and the Proposed Directors, or which the Directors and the Proposed Directors would deem immaterial, may (individually or cumulatively) also have a material adverse effect on the Premier Group's and, following completion of the Merger, the Combined Group's business, operating results, financial condition or prospects. If any such risks were to materialise, the price of the New Ordinary Shares could decline as a consequence and investors could lose all or part of their investment.

SECTION A: RISKS RELATING TO THE DEBT RESTRUCTURING

1. If the Interim Maturity Extension becomes effective but the Merger and the Debt Restructuring do not proceed, the ability of members of the Premier Group to continue trading will depend on ongoing support from the Premier Group's creditors

On 6 October 2020, the Company agreed a term sheet with Chrysaor and a sub-set of the Premier Group's creditors in respect of the Debt Restructuring, and the wider group of Private Creditors and XCCY Hedge Counterparties were invited to approve the term sheet and undertake to support the Merger and the Debt Restructuring by entering into the Support Letter. The Merger and the Debt Restructuring are each subject to certain conditions which must be satisfied or waived, as described further in the risk factors entitled "*The Merger is conditional upon certain conditions which may not be satisfied, as a result of which the Merger will not be implemented on its current terms or at all*" and "*The Debt Restructuring and the Interim Maturity Extension are each subject to a number of conditions that must be satisfied in order for it to proceed*". If any of the conditions to the Merger or the Debt Restructuring are not satisfied or waived, the Merger and the Debt Restructuring (other than the Interim Maturity Extension) will not proceed.

In order to allow time for the Merger to complete, or alternatively in the event the Merger and Debt Restructuring Resolutions are not passed to agree and implement an alternative plan for implementation of the Merger and the Debt Restructuring or, if that is not possible, an alternative transaction to address the Existing Debt Facilities, the Participating Creditors have undertaken pursuant to the Support Letter to support, and vote in favour of the Restructuring Plans in order to implement, the Interim Maturity Extension, which will extend the maturity date of the Existing Debt Facilities and XCCY Swaps from 31 May 2021 to 31 March 2022. The Interim Maturity Extension is subject to certain conditions which must be satisfied or waived, including:

(A) the Restructuring Plans (which are inter-conditional) having been approved by the requisite majorities at the Restructuring Plan Creditor Meetings, sanctioned by the relevant Courts and a copy of the sanction orders delivered to the Registrar of Companies for Scotland or the Registrar of Companies for England and Wales (as applicable);

(B) each of the Non-XCCY Hedge Counterparties having given any consents required in connection with the Debt Restructuring, which the Non-XCCY Hedge Counterparties have undertaken to do pursuant to the Non-XCCY Hedging Support Letters;

(C) satisfaction of certain documentary conditions in respect of conditions precedent that are customary for a secured financing transaction and/or are within the control of the Premier Group; and

(D) payment of certain costs associated with the Debt Restructuring.

Without the financial covenant deferrals contained in the Support Letter (and, prior to the Support Letter, those deferrals contained in the Stable Platform Agreement), the Company and certain of its subsidiaries would have breached certain of the financial covenants contained in the Private Debt Facilities in respect of the testing periods ended 30 June 2020 and 30 September 2020.

The financial covenant deferrals contained in the Support Letter will remain in place until the Interim Maturity Extension becomes effective, unless the Support Letter is terminated in accordance with its terms. The Support Letter is subject to termination rights, including, amongst others, the ability of the Majority Creditors to terminate upon the occurrence of certain events of default under the Existing Debt Facilities, the material breach by Chrysaor or Premier of certain undertakings given in the Support Letter or following a decision by the Board to withdraw its recommendation of the Merger. In addition, the Support Letter will automatically terminate on the earliest to occur of the following: (i) where the Merger Agreement is terminated in accordance with its terms and the Interim Maturity Extension becomes effective; (ii) an insolvency event occurs in relation to certain Premier Group companies; (iii) the Long-Stop Date; and (iv) the Merger and the Debt Restructuring becomes effective. If the Support Letter is terminated in accordance with its terms, the financial covenant deferrals contained in the Support Letter will terminate 45 days after the termination of the Support Letter, other than in certain limited circumstances, including where the Support Letter terminates on the date on which the Debt Restructuring becomes effective or (where the Merger Agreement has terminated) the Interim Maturity Extension becomes effective. Further details in respect of the termination rights under the Support Letter are set out under the Risk Factor entitled "*The Support Letter may be terminated in accordance with its terms on the occurrence of certain specified events.*".

If Premier were unable to secure further deferrals of a similar nature or if Premier were to breach financial covenants in respect of a subsequent testing period without a deferral or waiver in place, there would be an event of default under the Override Agreement.

If an event of default were to occur in these circumstances, the Private Creditors would have the right to declare the Private Debt Facilities (which totalled US$2.2 billion as at 31 October 2020) immediately due and payable, which if exercised would in turn trigger an event of default under the XCCY Swaps and cross-default under the Retail Bonds (which total £150 million). The Private Creditors, the XCCY Hedge Counterparties and the Retail Bondholders would also have the right to take immediate steps to enforce their security over shares in certain Premier Group companies and certain other key assets of the Premier Group.

As a result, if the Debt Restructuring (other than the Interim Maturity Extension) does not proceed and the Premier Group does not secure future financial covenant deferrals, and even if the Interim Maturity Extension does become effective, it is expected that the Premier Group's Existing Debt Facilities and exposures under the XCCY Swaps will become payable before 31 March 2022 as a consequence of the events of default and acceleration of the Premier Group's debt described above. Premier considers that the Premier Group would not be able to repay the Existing Debt Facilities and exposures under the XCCY Swaps in these circumstances. Even if Premier is able to secure future financial covenant deferrals for the period until 31 May 2022, Premier does not consider that the Premier Group will be able to repay the outstanding debt under its Existing Debt Facilities and exposures under the XCCY Swaps when they mature or crystallise (as relevant) on that date in which case the events of default, acceleration and enforcement of security described above could occur.

Therefore, in circumstances where Merger and the Debt Restructuring (other than the Interim Maturity Extension) does not complete but the Interim Maturity Extension becomes effective, the ability of members of the Premier Group to continue trading will depend upon:

– a significant portion of its creditors providing further financial covenant deferrals upon termination of the Support Letter; and

– the Premier Group agreeing, before 31 March 2022, either: (i) an alternative plan for the implementation of the Merger and the Debt Restructuring with its creditors and Chrysaor within the timeframe contained in the Support Letter; or (ii) an alternative transaction to address its Existing Debt Facilities and exposures under the XCCY Swaps with its creditors.

Premier has an obligation under the Support Letter to provide information, access and cooperation in order for Participating Creditors to develop contingency plans for a scenario where the Merger and the Debt Restructuring are not implemented. As outlined above, where the Interim Maturity Extension has become effective but the Merger and Debt Restructuring Resolutions are not passed, and the Premier Group is therefore dependent on support from its creditors to continue trading, the creditors will be able to require Premier to take steps to implement any contingency plans which are developed by the Participating Creditors as a condition to the provision of their continuing support.

In addition to this general obligation in respect of contingency planning, Premier is required under the terms of the Support Letter to work together with Chrysaor and Participating Creditors in good faith to agree and prepare an alternative plan to implement the Merger and the Debt Restructuring in the event that the Merger and Debt Restructuring Resolutions are not passed (which could involve the filing for insolvency of the Company and/or other companies within the Premier Group, and/or the enforcement of security). In addition, Chrysaor and Participating Creditors have agreed that they will not engage in any negotiations with any other party in connection with any similar transaction to the Merger and the Debt Restructuring or alternative transaction relating to the Premier Group, other than an alternative plan to implement the Merger and the Debt Restructuring, for a period of 20 business days after the General Meeting at which the Merger and Debt Restructuring Resolutions are not passed. It is likely that any alternative plan to implement the Merger and the Debt Restructuring would provide for minimal or no recovery for Shareholders.

If no alternative plan to implement the Merger and the Debt Restructuring was agreed, the Board would seek to negotiate an alternative transaction to address its Existing Debt Facilities with its creditors (although these discussions could not start until expiry of the 20-business day period referred to above). There is no certainty that the creditors would engage with the Board in those circumstances or that any negotiations regarding an alternative transaction would be successful. In particular, the following factors are likely to affect the Premier Group's ability to negotiate an alternative transaction:

– although the Premier Group has retained the support of a significant group of its creditors in negotiating and agreeing the terms of the Debt Restructuring, it is likely that, if the Merger and the Debt Restructuring do not become effective, some or all of the creditors who are currently supportive could become less supportive of the Premier Group or could sell their debt-holdings to parties whose interests may not be aligned with the Premier Group;

– any doubt as to the Premier Group's ability to continue as a going concern following the non-completion of the Merger and the Debt Restructuring could have a material and adverse commercial impact on the Premier Group's trading, which could in turn lead to liquidity problems for the Premier Group; and

– the impact of COVID-19, volatile credit markets and/or the outlook for oil and gas prices.

If Premier cannot negotiate an alternative transaction to address its Existing Debt Facilities with its creditors, Premier would likely enter into insolvency proceedings, on or before 31 March 2022, which the Directors consider would likely result in no value being returned to Shareholders. This is because even if the Interim Maturity Extension is implemented, the Premier Group will be dependent on continued deferrals of its financial covenants from a significant portion of its creditors in order to continue to trade. Even if Premier is able to secure financial covenant deferrals for the period until 31 March 2022, the Directors do not consider that the Premier Group will be able to repay its outstanding debt when it matures on that date.

Even if negotiations were successful, the terms of any alternative transaction to address its Existing Debt Facilities are likely to be materially worse for Shareholders than the Merger and the Debt Restructuring, and may result in no value at all for Shareholders. In particular, the creditors may state that, as a condition to their continuing support, any alternative transaction must involve a portion of their existing debt being exchanged for new ordinary shares in Premier, which would lead to very significant dilution for the Shareholders or Shareholders losing their entire interest in the

Premier Group. Alternatively, creditors may indicate that they are only prepared to support the marketing and sale of the Premier Group's assets to a third party purchaser, which may be implemented in conjunction with the filing for insolvency of the Company and/or other companies within the Premier Group, and/or the enforcement of security. Given the value of the Premier Group's assets relative to the amount outstanding under its Existing Debt Facilities and the security granted over such assets in favour of the Premier Group's creditors, it is unlikely that such a sale would result in any value for Shareholders.

2. If the Interim Maturity Extension does not become effective and the Merger and the Debt Restructuring do not proceed, the Premier Group's financial position would be materially adversely affected and it is likely that companies within the Premier Group would be placed into insolvency procedures on or before 31 May 2021

As noted in the previous risk factor, in order to allow time for the Merger to complete, or alternatively in the event the Merger and Debt Restructuring Resolutions are not passed to agree and implement an alternative plan for implementation of the Merger and the Debt Restructuring or, if that is not possible, an alternative transaction to address the Existing Debt Facilities, the Participating Creditors have undertaken pursuant to the Support Letter to support, and vote in favour of the Restructuring Plans in order to implement, the Interim Maturity Extension, which will extend the maturity date to 31 March 2022. The Interim Maturity Extension is subject to certain conditions which must be satisfied or waived, including:

(A) the Restructuring Plans (which are inter-conditional) having been approved by the requisite majorities at the Restructuring Plan Creditor Meetings, sanctioned by the relevant Courts and a copy of the sanction orders delivered to the Registrar of Companies for Scotland or the Registrar of Companies for England and Wales (as applicable);

(B) each of the Non-XCCY Hedge Counterparties having given any consents required in connection with the Debt Restructuring, which the Non-XCCY Hedge Counterparties have undertaken to do pursuant to the Non-XCCY Hedging Support Letters;

(C) satisfaction of certain documentary conditions in respect of conditions precedent that are customary for a secured financing transaction and/or are within the control of the Premier Group; and

(D) payment of certain costs associated with the Debt Restructuring.

If any of the conditions described above were not satisfied or waived, the Interim Maturity Extension would not become effective, and it would be likely that the Premier Group would enter into insolvency proceedings on or before 31 May 2021.

If neither the Debt Restructuring nor the Interim Maturity Extension becomes effective by 31 May 2021, the outstanding debt under the Premier Group's Existing Debt Facilities and exposures under the XCCY Swaps will mature or crystallise on that date. Premier does not consider that it will be able to repay this outstanding debt, in which case the Private Creditors, the XCCY Hedge Counterparties and the Retail Bondholders could take immediate steps to enforce their security over shares in the companies comprising the Premier Group and other key assets of the Premier Group. The amount outstanding under the Premier Group's financing arrangements which would be required to be repaid on 31 May 2021 is US$2.2 billion.

Further, the Premier Group's leverage and interest cover financial covenants for the testing periods ended on 30 June 2020 and 30 September 2020 have been deferred under the Support Letter (and, prior to that, under the Stable Platform Agreement). The Support Letter waives the Premier Group's financial covenants through to the earlier of: (a) the date on which the Debt Restructuring becomes effective or (where the Merger Agreement has terminated) the Interim Maturity Extension becomes effective; and (b) the date that is 45 days following the termination of the Support Letter. Details in respect of the termination rights under the Support Letter are set out under the Risk Factor entitled "*The Support Letter may be terminated in accordance with its terms on the occurrence of certain specified events.*".

If the deferrals contained in the Support Letter (and, prior to that, the Stable Platform Agreement) had not been obtained, the Premier Group would have breached the financial covenants contained in the Override Agreement in respect of the testing periods ended on 30 June 2020 and 30 September 2020. Accordingly if the Support Letter terminates (other than as a result of the Debt

Restructuring becoming effective or (where the Merger Agreement has terminated) the Interim Maturity Extension becoming effective), there will be an event of default 45 days after such termination unless the Premier Group is able to secure further deferrals of a similar nature. If an event of default were to occur in these circumstances, the Private Creditors would have the right to declare the Private Debt Facilities (which totalled US$2.2 billion as at 31 October 2020) immediately due and payable, which if exercised would in turn trigger an event of default under the XCCY Swaps and cross-default under the Retail Bonds (the principal value of which amounts to £150 million in aggregate). The Private Creditors, the XCCY Hedge Counterparties and the Retail Bondholders would also have the right to take immediate steps to enforce their security over shares in certain Premier Group companies and certain other key assets of the Premier Group.

As a result, if the Support Letter terminates (other than as a result of the Debt Restructuring becoming effective or (where the Merger Agreement has terminated) the Interim Maturity Extension becoming effective) prior to 31 May 2021, and the Premier Group does not secure further financial covenant deferrals, it is expected that the Premier Group's Existing Debt Facilities and exposures under the XCCY Swaps will become payable before 31 May 2021 as a consequence of the events of default and acceleration of the Premier Group's debt described above. Premier considers that the Premier Group would not be able to repay the Existing Debt Facilities and exposures under the XCCY Swaps in these circumstances. The amount outstanding under the Premier Group's Existing Debt Facilities and exposures under the XCCY Swaps which could be required to be repaid following a breach of its financial covenants was approximately US$2.2 billion as at 31 October 2020.

In such circumstances, the ability of members of the Premier Group to continue trading will therefore depend upon:

– a significant portion of its creditors providing further financial covenant deferrals upon termination of the Support Letter; and

– the Premier Group agreeing, before 31 May 2021, either: (i) an alternative plan for the implementation of the Debt Restructuring with its creditors and Chrysaor within the timeframe contained within the Support Letter; or (ii) an alternative transaction to address its Existing Debt Facilities and exposures under the XCCY Swaps with its creditors.

While Premier has obligations under the Support Letter in respect of the preparation and agreement of contingency plans for a scenario where the Debt Restructuring does not complete, there is no certainty that any alternative plan for the implementation of the Debt Restructuring or alternative transaction to address its Existing Debt Facilities and XCCY Swaps will be agreed and implemented prior to 31 May 2021. The factors outlined above as being likely to affect negatively the Premier Group's ability to negotiate an alternative transaction will be more pronounced where the Premier Group has less than six months until the Existing Maturity Date (which is the position as at the date of this Prospectus), and will become more pronounced still the closer the Premier Group gets to the Existing Maturity Date. It would therefore be likely, in the event that the Debt Restructuring does not complete, that the Premier Group would enter into insolvency proceedings on or before the existing maturity date under the Existing Debt Facilities and the XCCY Swaps of 31 May 2021, which the Directors consider would likely result in no value being returned to Shareholders.

3. The Debt Restructuring and the Interim Maturity Extension are each subject to a number of conditions that must be satisfied in order for it to proceed

The Debt Restructuring (other than the Interim Maturity Extension) is inter-conditional with the completion of the Merger, and subject to certain conditions which must be satisfied or waived, including:

(A) the Merger and Debt Restructuring Resolutions having been passed by Shareholders at the General Meeting;

(B) the Restructuring Plans (which are inter-conditional) having been approved by the requisite majorities at the Restructuring Plan Creditor Meetings, sanctioned by the relevant Courts and a copy of the sanction orders delivered to the Registrar of Companies for Scotland or the Registrar of Companies for England and Wales (as applicable);

(C) each of the Non-XCCY Hedge Counterparties having given any consents required in connection with the Debt Restructuring, which the Non-XCCY Hedge Counterparties have undertaken to do pursuant to the Non-XCCY Hedging Support Letters;

(D) satisfaction of certain documentary conditions in respect of conditions precedent that are customary for a secured financing transaction and/or are within the control of the Premier Group;

(E) the FCA and the London Stock Exchange each having approved the applications for Admission to take place (by not later than the Long Stop Date); and

(F) payment of certain costs associated with the Debt Restructuring.

If any of these conditions are not satisfied or waived (to the extent applicable) the Debt Restructuring will not proceed. For the consequences of the Debt Restructuring (other than the Interim Maturity Extension) not proceeding, please refer to the Risk Factor entitled "*If the Interim Maturity Extension becomes effective but the Merger and the Debt Restructuring do not proceed, the ability of members of the Premier Group to continue trading will depend on ongoing support from the Premier Group's creditors*".

In order to allow time for the Merger to complete, or alternatively in the event the Merger and Debt Restructuring Resolutions are not passed to agree and implement an alternative plan for implementation of the Merger and the Debt Restructuring or, if that is not possible, an alternative transaction to address the Existing Debt Facilities, the Participating Creditors have undertaken pursuant to the Support Letter to support, and vote in favour of the Restructuring Plans in order to implement, the Interim Maturity Extension. The Interim Maturity Extension is subject to certain conditions which must be satisfied or waived, including:

(A) the Restructuring Plans (which are inter-conditional) having been approved by the requisite majorities at the Restructuring Plan Creditor Meetings, sanctioned by the relevant Courts and a copy of the sanction orders delivered to the Registrar of Companies for Scotland or the Registrar of Companies for England and Wales (as applicable);

(B) each of the Non-XCCY Hedge Counterparties having given any consents required in connection with the Debt Restructuring, which the Non-XCCY Hedge Counterparties have undertaken to do pursuant to the Non-XCCY Hedging Support Letters;

(C) satisfaction of certain documentary conditions in respect of conditions precedent that are customary for a secured financing transaction and/or are within the control of the Premier Group; and

(D) payment of certain costs associated with the Debt Restructuring.

If any of the conditions described above were not satisfied or waived, the Interim Maturity Extension would not become effective, and it would be likely that the Premier Group would enter into insolvency proceedings on or before 31 May 2021. For the consequences of the Interim Maturity Extension not becoming effective, please refer to the Risk Factor entitled "*If the Interim Maturity Extension does not become effective and the Merger and the Debt Restructuring do not proceed, the Premier Group's financial position would be materially adversely affected and it is likely that companies within the Premier Group would be placed into insolvency procedures on or before 31 May 2021*".

4. The Support Letter may be terminated in accordance with its terms on the occurrence of certain specified events

The Support Letter contains termination provisions allowing for termination in certain, specified circumstances. In particular, the Support Letter may be terminated at the election of the Majority Creditors in certain circumstances, including, if:

– the Merger and Debt Restructuring Resolutions are not approved by Shareholders at the General Meeting and an alternative plan for implementation of the Merger and the Debt Restructuring has not been agreed between Premier, Chrysaor and the Participating Creditors within 20 business days of the General Meeting;

- an event of default arises under the Existing Debt Facilities or the XCCY Swaps (other than an event of default which has been remedied or waived or has arisen, or deemed to have arisen, directly as a result of the implementation of the Merger and the Debt Restructuring), such events of default being customary for financing arrangements of the size and nature of the Existing Debt Facilities, including events of default relating to non-payment, insolvency, insolvency proceedings, misrepresentation and cross-default, among other things;
- relevant members of the Premier Group breach the terms of the Support Letter in any material respect or any representation or warranty by the relevant members of the Premier Group under the Support Letter is materially incorrect or misleading;
- Chrysaor breaches certain undertakings given by it under the Support Letter in any material respect. These undertakings include, among other things: (i) to support the Debt Restructuring; (ii) not to take any action which would be inconsistent with the Merger or the Debt Restructuring in any material respect; and (iii) to instruct its legal advisers to negotiate the documentation required to implement the Debt Restructuring on the terms of the agreed term sheets in good faith;
- the Board decides to withdraw, suspend, qualify or adversely modify or amend, the recommendation of the Merger set out in the Circular in circumstances where Chrysaor has not elected to terminate the Merger Agreement and an alternative plan for implementation of the Merger and the Debt Restructuring has not been agreed between Premier, Chrysaor and the Participating Creditors;
- at any Restructuring Plan Creditor Meeting the requisite majorities by value of creditors entitled to vote on such Restructuring Plan have not voted for such Restructuring Plan such that any of the Restructuring Plans are not approved;
- certain milestones are not completed (including the posting of the explanatory statement relating to the Restructuring Plans to the Restructuring Plan Creditors by 28 February 2021 and the Merger and Debt Restructuring Resolutions being approved by Shareholders by 30 April 2021) within the relevant timeframe (as may be extended) other than where Premier has provided evidence that this is as a result of a breach by Chrysaor of its obligation under the Support Letter to provide reasonable assistance to enable Premier meet those milestones;
- either the English Court or the Scottish Court issues a judgment refusing to sanction all or any of the Restructuring Plans which is either (a) not appealed by any party within the period of time in which to bring such an appeal under Scottish or English law (as applicable), or (b) appealed within such period of time and such appeal is unsuccessful;
- either the English Court or the Scottish Court issues an order preventing the Company, POUK or POHL from implementing the Debt Restructuring or Restructuring Plans which is either (a) not appealed by any party, or (b) appealed and such appeal is unsuccessful; or
- where Chrysaor has notified the Company that the Company has breached the Merger Agreement in a manner which provides any of the Harbour/Chrysaor Parties the right to terminate the Merger Agreement and none of the Harbour/Chrysaor Parties exercises its termination right, or the Merger and Debt Restructuring Resolutions are not approved by shareholders at the General Meeting, an alternative plan for implementation of the Merger and the Debt Restructuring has not been agreed between Premier, Chrysaor and the Participating Creditors within 20 business days of such notification.

In addition, the Support Letter will automatically terminate on the earliest to occur of the following: (i) where the Merger Agreement has terminated in accordance with its terms and the Interim Maturity Extension becomes effective; (ii) an insolvency event occurs in relation to certain Premier Group companies; (iii) the Long-Stop Date; and (iv) the Debt Restructuring becomes effective.

The Long Stop Date for completion of the Merger and the Debt Restructuring, as set out in the Support Letter, is 30 September 2021 or such later date as Premier, Chrysaor and the Majority Creditors agree provided such date is not later than 1 December 2021. If any of the conditions to the Debt Restructuring becoming effective summarised in the Risk Factor entitled "*The Debt Restructuring and the Interim Maturity Extension are each subject to a number of conditions that* *must be satisfied in order for it to proceed*" above does not take place by the Long Stop Date (as amended or extended), then the Debt Restructuring will not proceed.

Should the Support Letter terminate, the parties to it would not be obliged to support the Debt Restructuring (or the Interim Maturity Extension), including by voting in favour of the Restructuring Plans. For the consequences of the Debt Restructuring (other than the Interim Maturity Extension) not proceeding, please refer to the Risk Factor entitled "*If the Interim Maturity Extension becomes effective but the Merger and the Debt Restructuring do not proceed, the ability of members of the Premier Group to continue trading will depend on ongoing support from the Premier Group's creditors*". For the consequences of the Interim Maturity Extension not becoming effective, please refer to the Risk Factor entitled "*If the Interim Maturity Extension does not become effective and the Merger and the Debt Restructuring do not proceed, the Premier Group's financial position would be materially adversely affected and it is likely that companies within the Premier Group would be placed into insolvency procedures on or before 31 May 2021*".

SECTION B: RISKS RELATING TO THE MERGER

1. The Merger is conditional upon certain conditions which may not be satisfied, as a result of which the Merger and the Debt Restructuring would not be implemented on its current terms or possibly at all

The Merger is subject to the satisfaction (or waiver, where applicable) of certain conditions contained in the Merger Agreement (which is summarised in more detail in the Circular), including, among other things, the approval of the Merger and Debt Restructuring Resolutions by Shareholders at the General Meeting, the Restructurings Plans having been sanctioned by the relevant Courts and delivered to Companies House, consent having been obtained from the regulatory authorities in the United Kingdom, Norway and the Falkland Islands and competition clearances having been obtained from the European Commission and the relevant competition authorities in Mexico and Vietnam. While the required competition clearance has been received from the European Commission and conditional approval has been received from the relevant regulatory authorities in Norway, there is no guarantee that the remaining outstanding conditions will be satisfied (or waived, if applicable), in which case the Merger and the Debt Restructuring would not be implemented on its current terms or possibly at all.

If the Merger and Debt Restructuring Resolutions are not approved by Shareholders at the General Meeting, the Merger and the Debt Restructuring cannot proceed on their current terms, and Premier is required under the terms of the Support Letter to work together with Chrysaor and Participating Creditors in good faith to agree and prepare an alternative plan to implement the Merger and the Debt Restructuring (which could involve the filing for insolvency of the Company and/or other companies within the Premier Group, and/or the enforcement of security). In addition, Chrysaor and Participating Creditors have agreed that they will not engage in any negotiations with any other party in connection with any similar transaction to the Merger and the Debt Restructuring or alternative transaction relating to the Premier Group, other than an alternative plan to implement the Merger and the Debt Restructuring, for a period of 20 business days after the General Meeting at which the Merger and Debt Restructuring Resolutions are not passed. It is likely that any alternative plan to implement the Merger and the Debt Restructuring would provide for minimal or no recovery for Shareholders. As such, it is very important that Shareholders vote in favour of each of the Merger and Debt Restructuring Resolutions at the General Meeting so that the Merger and the Debt Restructuring can proceed.

On 11 November 2020, the UK Government published the UK National Security and Investment Bill (the "**UK NS&I Bill**"), which, amongst other things, proposes that acquisitions of shares or voting rights above certain thresholds in entities in specified sensitive sectors ("**notifiable acquisitions**") will be subject to mandatory notification to the DBEIS. The proposed list of relevant sectors, which is currently subject to an ongoing consultation process, includes the energy sector and therefore would capture the Premier Group and, following completion of the Merger, the Combined Group. If passed into law before the completion of the Merger, the UK NS&I Bill could require that the Merger is notified under its provisions and this might delay completion. In addition, once passed into law, the UK NS&I Bill will also have retrospective effect from 12 November 2020 and the Secretary of State will have the power to call-in for review any transactions which have closed after 12 November 2020 but prior to the commencement date, which might therefore apply to the Merger. If the Merger were called-in for review after completion had occurred, it is possible that the

Secretary of State would (subject to the final terms of the UK NS&I Bill once enacted), have a wide range of remedies available to it, possibly including the ability to unwind the Merger. However, as the Merger does not give rise to substantive national security concerns, it is unlikely that such actions would be taken by the Secretary of State, and as such, the risk of the UK NS&I Bill having retrospective effect on the Merger is considered low. For more detail, please see the Risk Factor entitled "*The ability of Shareholders to sell their Ordinary Shares, particularly in a takeover offer, may be negatively affected by the proposed UK National Security and Investment Bill*".

If the Merger does not proceed to completion, the benefits expected to result from the Merger will not materialise either at all or in part. The market price of the Ordinary Shares may decline if, among other reasons, the Merger does not proceed to completion.

2. The anticipated benefits from the Merger will depend on the Combined Group's ability to integrate the Premier Group and the Chrysaor Group

The Combined Group may encounter integration challenges in connection with the Merger, including challenges which are not currently foreseeable or which relate to the COVID-19 pandemic.

The integration process may take longer than expected, or difficulties relating to the integration, of which the Directors and the Proposed Directors are not yet aware, including unforeseen operating difficulties, may arise and pose management, administrative and financial challenges. In particular, the integration process may be made more challenging as a result of any restrictions put in place by governments in the UK and elsewhere in response to the COVID-19 pandemic which are continuing at the time of completion of the Merger. In addition, unanticipated costs may be incurred in respect of the integration of the Premier Group and the Chrysaor Group. This could adversely affect the delivery of the anticipated benefits from the Merger, and the Combined 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.

Furthermore, the Directors and Proposed Directors believe the combination of the businesses of the Premier Group and the Chrysaor Group has the potential to generate significant synergies through operating, financing and other cost savings. However, there is a risk that such synergy benefits will fail to materialise, for example, if the Merger is not completed as contemplated, or that such synergy benefits may be materially lower than may otherwise have been possible, which would have a significant impact on the profitability of the Combined Group in the future The ability to achieve the potential synergies is dependent upon a significant number of factors, some of which may be beyond the control of the Combined Group. These factors include, for example, the ability of Premier Group personnel and Chrysaor Group personnel to work together effectively to put in place a new efficient organisation. Workplace practices and cultures are likely to differ between the Premier Group and the Chrysaor Group, and given the two parties' workforces have not worked together in the past, these differences may be counter-productive. This may result in synergy benefits taking longer to materialise or being diminished.

The market price of the Ordinary Shares may decline as a result of the Merger if, among other reasons, the integration of the Premier Group and the Chrysaor Group is delayed or unsuccessful or potential synergy benefits fail to materialise.

3. The Premier Group and, following completion of the Merger, the Combined Group may be subject to unforeseen liabilities and risks arising from the Merger

Whilst the Premier Group has had access to certain publicly available information on the Chrysaor Group and has reviewed information disclosed by Chrysaor during the sale process, there can be no assurance that material assets held by members of the Chrysaor Group are not subject to third party rights and liabilities of which the Premier Group is unaware. Whilst some warranty protection is provided for by Chrysaor management under the Management Warranty Deed, which has been insured through warranty and indemnity insurance, these warranties, protections and insurance are subject to financial and other customary limitations and exclusions and there is no certainty that Premier would be able to enforce its contractual or other rights against Chrysaor management or recover the full amount of any losses suffered by the Combined Group from insurers. The market price of Ordinary Shares may decline as a result of the Merger if, among other reasons, material assets held by members of the Chrysaor Group are subject to liabilities or third party rights of which the Premier Group is unaware or if Premier is unable to enforce its contractual or other rights against Chrysaor management as and when expected, or at all, or unable to recover the full amount of any losses suffered by the Combined Group from insurers. Further details of the Merger Agreement and the Management Warranty Deed are set out in the Circular.

The Combined Group may also be subject to personnel-related risks arising from the Merger. In particular, members of the Premier Group workforce may become disengaged from maintaining the performance of the Premier Group as a result of uncertainty associated with the Merger. The Premier Group's business delivery could be negatively impacted by this and, absent any mitigation efforts, there may also be a deterioration in health, safety and environmental performance of the Combined Group.

4. Merger-related costs, including transition and integration costs, may exceed Premier's expectations

Premier expects to incur costs in relation to the Merger, including transition, integration and post-completion costs in order to integrate the Premier Group and the Chrysaor Group. 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 Merger and the Debt Restructuring. In addition, Premier will incur legal, accounting and transaction fees and other costs relating to the Merger and the Debt Restructuring, some of which are payable whether or not the Merger and the Debt Restructuring is completed. The market price of the Ordinary Shares may decline as a result of the Merger and the Debt Restructuring if, among other reasons, the effect of the Merger and the Debt Restructuring on Premier's financial results, including the actual costs of the transition and integration process (for example, in connection with ensuring effective workforce integration) and Merger-related costs, is not consistent with the expectations of investors.

5. The Merger Agreement contain covenants and warranties in favour of the Harbour/Chrysaor Parties

Premier has given covenants and warranties to the Harbour/Chrysaor Parties, which are customary for a transaction of this nature. Further details of the Merger Agreement are set out in the Circular. If Premier is required to make payments under any of the provisions described above, this could have an adverse effect on its, and, following the completion of the Merger, the Combined Group's, cash flow and financial condition. The market price of the Ordinary Shares may decline as a result of the Merger if, among other reasons, the effect of the Merger on Premier's financial results, including the effect on the Combined 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

The Merger and the Debt Restructuring are each conditional upon (among other things) the FCA and the London Stock Exchange having confirmed to Premier that applications relating to Admission have been approved by no later than the Long Stop Date of 30 September 2021 (or such later date as is agreed by the relevant parties).

Readmission of the Existing Ordinary Shares and Admission of the New Ordinary 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 Existing Ordinary Shares and the New Ordinary 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.

7. A break fee may be payable by Premier if the Merger is terminated in certain circumstances

If Premier is not in an offer period (as defined in the Takeover Code) and (i) the recommendation of the Merger by the Board of Premier is withdrawn, suspended, qualified or adversely modified or amended; (ii) the Merger does not complete because Premier is in breach of certain of its obligations under the Merger Agreement; (iii) the Support Letter is terminated by Chrysaor in circumstances where creditor(s) holding a significant proportion of the debt take action in breach of the Support Letter which effectively blocks the Restructuring Plans; or (iv) the Premier Shareholders do not vote in favour of the Merger at the General Meeting (except in circumstances where a third party announces an offer under Rule 2.7 of the Takeover Code and the Board decides to recommend such offer), and, if Chrysaor decide to terminate on the occurrence of one of the events listed above, Premier has agreed to pay a break fee equal to 1 per cent. of Premier's market capitalisation on 6 October 2020 to Chrysaor, which would amount to US$1.8 million.

However, Premier will not be obliged to pay a break fee (i) during any offer period (as defined in the Takeover Code) unless and until the third party offer or possible offer that commenced that offer period and all competing third party offers subsequently lapse or are withdrawn; or (ii) if the third party offer or possible offer becomes unconditional as to acceptances (in accordance with the Takeover Code) or if an implementing scheme of arrangement in respect of such offer becomes effective. Premier will also not be obliged to pay a break fee if the parties to the Merger Agreement agree to disregard the break fee trigger event following a Rule 21.2 determination by the Takeover Panel.

SECTION C: RISKS RELATING TO THE PREMIER GROUP AND, FOLLOWING THE COMPLETION OF THE MERGER, THE COMBINED GROUP AS A RESULT OF THE MERGER

1. Potential health, safety, environmental and security risks may materialise

As an international operator of oil and gas fields, the Premier Group is, and, following completion of the Merger, the Combined Group will be, exposed to a wide range of HSES risks. These include:

- major accidents;
- failure to comply with approved policies and local regulation;
- effects of natural disasters and pandemics (including the COVID-19 pandemic);
- social unrest;
- civil war and terrorism;
- exposure to general operational hazards;
- health and safety of personnel;
- crime; and
- cyber security attacks.

The consequences of such risks materialising could include injuries to personnel, loss of life, environmental accidents, damage to operating assets and disruption to business activities. Depending on cause and severity, the materialisation of such risks may give rise to liabilities and may materially affect the Premier Group's or, following the completion of the Merger, the Combined Group's reputation, business, prospects, results of operations and financial condition. For example, the COVID-19 pandemic has resulted in travel restrictions, quarantines and similar measures being imposed by governments and organisations with a view to containing the spread of the pandemic. Such measures have depressed global economic activity, leading to a sharp decline in both the demand for and the price of hydrocarbons, including in countries that are major consumers of hydrocarbons produced by the Premier Group. Moreover, the quarantine of personnel, the inability or unwillingness of personnel to access sites offshore, restrictions on business travel and reduced productivity that may arise from remote working due to various factors, including potential technical limitations, may adversely affect the Premier Group's reputation, business, prospects, results of operations and financial condition and, following the completion of the Merger, those of the Combined Group.

In addition, failure by the Premier Group or, following the completion of the Merger, the Combined 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 licences may include more stringent HSES requirements. The obtaining of exploration, development or production licences 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 the Premier Group's and the Combined Group's business, operating results, financial condition or prospects.

2. *Hydrocarbon exploration, development and production operations may be affected by operational hazards or other factors which may result in unforeseen liabilities and adversely affect future cash flows*

The delivery of production plans depends on the successful continuation of existing field production operations and the development of new field operations. Both of these involve risks normally incidental to such activities including:

- loss of well control arising from the influx of formation fluids into the wellbore which could potentially lead to uncontrollable flows of oil, gas or well fluids;
- explosions or fires;
- equipment damage or failure;
- integrity issues of ageing infrastructure;
- effects of natural disasters and pandemics;
- geological uncertainties;
- impacts of adverse weather conditions;
- pollution and other environmental risks;
- hazards inherent to marine operations, including capsizing, sinking, grounding and vessel collision;
- lack of availability of technology or engineering capacity;
- lack of availability of skilled or competent workers; and
- other technical, fiscal, regulatory and political risks.

Such risks may result in delays to project schedules, increases in project costs or reduction in operating profitability. Such potential obstacles may also impair the continuation of the Premier Group's and, following completion of the Merger, the Combined Group's existing field production and delivery of key projects and, in turn, the operational performance, cash flows and financial position (including the financial impact from failure to fulfil contractual commitments related to project delivery) of the Premier Group and, following completion of the Merger, the Combined Group.

Occurrence of these hazards could also lead to injury to personnel, loss of life and environmental damage. These events could also cause substantial damage to the Premier Group's and the Combined Group's property and reputation and put at risk some or all of their interests in licences. These events could also result in fines, penalties and criminal sanctions against the Premier Group and the Combined Group and their management, as well as other governmental and third party claims. Moreover, should these risks materialise, the Premier Group and the Combined Group may 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 investigation and penalties, increased public interest in the Premier Group's and the Combined Group's performance and suspension of operations. The production performance of the reservoirs and wells may also be different from that forecast due to normal geological or mechanical uncertainties.

In addition, the Premier Group and the Combined Group may face interruptions or delays in the availability of infrastructure, including rigs, platforms, floating, production, storage and offloading ("**FPSO**") vessels, terminals and pipelines, on which exploration and production activities are dependent. Additionally, to the extent that the Premier Group and following completion of the Merger, the Combined Group, is not the operator of an oil and gas asset, they are, or will be, dependent on the relevant operator for the timing of activities related to such assets and may be subject to risk of interruptions or delays that are out of their control. Any such interruptions, delays or performance differences could result in disruptions or changes to the Premier Group's, the Chrysaor Group's and/or or the Combined Group's existing production and projects, lower production and increased costs, and may have a material adverse effect on their business, operating results, financial condition or prospects.

3. ***The Premier Group and, following completion of the Merger, the Combined Group may face interruptions or delays in the availability of infrastructure, including pipelines and storage facilities, on which exploration and production activities are dependent; production performance may also differ from that forecast***

The Premier Group's production activities are and, following the completion of the Merger, the Combined 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 the Premier Group's and will be faced by the Combined Group's following completion of the Merger. The Premier Group production assets in the mature Central and Southern North Sea basins, rely on access to the Central Area Transmission System (the "**CATS**"), the Forties Pipeline System (the "**FPS**") and the Shearwater Elgin Area Line (the "**SEAL**"). In addition, the Premier Group's assets in the Catcher Area are reliant on the Catcher FPSO (which is currently operated by BWO) and, once the Tolmount development produces first gas (scheduled for Q2 2021), the Premier Group and the Combined Group will be dependent on the Easington Terminal (currently operated by Centrica) in order to utilise the Tolmount Area. Moreover, gas produced from the Premier Group's offshore gas fields in Indonesia is exported to Singapore via the 540 kilometre West Natuna Transportation System pipeline (the "**WNTS**"), which is the only means of exporting gas from these fields. The Chrysaor Group's assets also rely on third-party operated infrastructure such as the CATS, the FPS, the Glen Lyon FPSO, the Scottish Area Gas Evacuation ("**SAGE**") System, the West of Shetlands Pipeline, the Frigg UK Pipeline and the Norpipe Oil Pipeline.

If any of these pipelines, terminals, systems or FPSO (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, the Premier Group's and/or the Combined Group's ability to transport oil could be severely affected.

Furthermore, for assets that use the services of different hosts for transportation and processing of their production the Premier Group and the Combined 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 Combined Group direct control. For example, the existing tariffing arrangements with CATS and FPS could be replaced with more expensive cost sharing arrangements as production levels in the host systems decrease.

4. ***The Combined Group's production will be concentrated in UKCS offshore fields, which may make it vulnerable to risks associated with having the substantial majority of its production in one region***

In the financial year ended 31 December 2019, 69.1 per cent. of the Premier Group's production came from offshore fields situated within the UK Continental Shelf (the "**UKCS**"), with the remainder of production in Indonesia and Vietnam, and all of the Chrysaor Group's production came from offshore fields situated within the UKCS. As a result of the Merger, approximately 91 per cent. of the Combined Group's production will be from UKCS offshore fields, which may make it vulnerable to risks associated with having the substantial majority of its production in one region.

The UKCS is prone to difficult weather conditions that in some cases may prevent the Premier Group or, following the completion of the Merger, the Combined Group, from transporting supplies, personnel and fuel to facilities, which may cause production shut-downs or slow-downs. For example, during the winter of 2018, sub-zero temperatures and snowfall across Europe caused UK gas outages at British sites supplying gas from the North Sea, as a result of which the Chrysaor Group was required to shut-in operated platforms at the Armada, Everest and Lomond fields for approximately two weeks in late February 2018. If mechanical problems, storms or other events curtail production or cause damage to any of the Premier Group's or the Combined Group's facilities, this may have a material adverse effect on the Premier Group's or the Combined Group's business, operating results, financial condition or prospects.

As a result of the Combined Group's increased concentration in the UKCS following the completion of the Merger, the Combined Group 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, governmental regulation, availability of equipment, equipment failure, facilities, personnel or services market limitations, weather events or interruption of the processing or transportation of oil, each of which or in combination may have a material adverse effect on the Combined Group's business, operating results, financial condition or prospects.

Finally, as the Combined Group's production will be substantially UK-focused, it may be disproportionately impacted by changes to governmental regulation of oil production which could occur following the UK's planned withdrawal from the European Union. In addition, following completion of the Merger, a substantial number of the Combined Group's assets will be located in what might be considered to be the territorial waters of any future Scottish state, following any future second independence referendum. For further detail, see the Risk Factor entitled "*Political, security, economic, legal, regulatory and social uncertainties and changes to the Premier Group's and/or, following completion of the Merger, the Combined Group's relationship with governments, regulators and communities where they operate may affect business in key territories*."

5. The Premier Group and, following the completion of the Merger, the Combined Group may not be able to sanction development projects required to convert their resources into production and may face delays or cost overruns in executing sanctioned development projects

The Premier Group has a number of development and pre-development projects, including Sea Lion in the Falkland Islands, Zama in Mexico and Tolmount in the UK. Furthermore, following completion of the Merger, the Combined Group will have additional development and pre-development projects that are in various phases of development without current production, including the Chrysaor Group's projects in the Talbot field and the Clair South field in the UK, and the Grevling discovery in Norway. The Premier Group's and the Combined Group's ability to sanction or execute development 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) its ability to reduce its exposure to development costs and risk by farming down part of its interest or through other appropriate means. With a larger number of development and pre-development projects competing for capital and resources, the Combined Group may also seek to manage its pipeline of projects in order to spread the Combined Group's capital requirements, prioritise projects which are regarded as strategically more important or which are expected to deliver higher returns, and ensure it can dedicate sufficient resources to the projects that are underway at any one time.

Failure to sanction or execute development projects would mean that the Premier Group and, following the completion of the Merger, the Combined Group will be unable to realise the value of their resources by converting them into production. Development projects may also be subject to delays or cost overruns that could result in them being less profitable than forecast, generating cash later than expected or requiring additional expenditure. 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 the Premier Group's or the Combined Group's business, operating results, financial condition or prospects.

In response to changes in market conditions during the first half of 2020, Premier has taken action to defer development activity across its portfolio to reduce expenditure, for instance in relation to Sea Lion, Zama and Tolmount. There is also a risk that, if market conditions, and the effects of COVID-19 (for instance, the quarantine of personnel, the inability or unwillingness of personnel to access sites offshore and restrictions on business) persist, these developments may not deliver the anticipated upsides.

In the context of market conditions and following a proactive review of each of its assets and related capital and decommissioning expenditure plans, significant reductions and deferrals were identified for Chrysaor's 2020 programme, representing an overall US$575 million / 44 per cent. reduction in planned capital and decommissioning expenditure for the year.

6. *Political, security, economic, legal, regulatory and social uncertainties and changes to the Premier Group's and/or, following completion of the Merger, the Combined Group's relationship with governments, regulators and communities where they operate may affect business in key territories*

The Premier Group operates, and in the future the Combined Group will operate, in some countries where political, security, public health, economic, legal, regulatory and social transition is taking place. Changes in politics, security, laws and regulations in the countries in which the Premier Group operates, and in which the Combined Group will operate, or which affect third parties with whom the Premier Group does business and with whom the Combined Group will do business, could affect operations and earnings. Such circumstances could include:

- forced divestment of assets, including expropriation and nationalisation of property;
- limits on production or cost recovery;
- import and export restrictions;
- imposition of sanctions or similar measures in respect of countries in which the Premier Group or the Combined Group operate or in respect of partners, suppliers or customers of the Premier Group or the Combined Group;
- changes to legislation due to climate change and other environmental regulations;
- international conflicts including war;
- civil unrest and local security concerns that threaten the safe operation of the Premier Group's or the Combined Group's facilities;
- price controls;
- lack of predictability and adverse changes to the operational, regulatory, legal or fiscal regime, including changes in oil or gas pricing or taxation policy, suspension of projects or the renegotiation or nullification of existing concession contracts;
- uncertain implementation of legislation and difficulties in ascertaining (or enforcing) the Premier Group's or the Combined Group's legal obligations and rights, including adverse retrospective amendment and/or cancellation of contractual rights;
- excessive local content requirements;
- measures taken, including changes in legislation or economic policy, to contain the spread of COVID-19; and
- outbreak of severe communicable diseases, such as COVID-19, which may be widespread and uncontrolled.

On 23 June 2016, a majority of voters in the UK voted in favour of the UK's withdrawal from the EU (commonly referred to as "**Brexit**"). Pursuant to legislation approved by the UK Parliament and the EU Parliament in January 2020, the UK withdrew from the EU with effect from 11.00 p.m. on 31 January 2020 on the terms of a withdrawal agreement agreed between the UK and the EU in October 2019 (the "**Withdrawal Agreement**"). The Withdrawal Agreement provides that the UK's withdrawal is followed by a "transition period", during which, in summary, the UK is not a member of the EU but most EU rules and regulations continue to apply to the UK. During the transition period, the UK and the EU are seeking to negotiate the terms of a long-term trading relationship between the UK and the EU based on a "Political Declaration" agreed between the UK and the EU in October 2019. The transition period provided for in the Withdrawal Agreement will expire on 31 December 2020 (unless the period of transition is extended by mutual agreement).

As a result of a long-term trading relationship not yet having been agreed and no guarantee that any such agreement will be reached, the UK's future relationship with the EU remains unclear. The future applicability and treatment of EU derived laws and regulations also remains uncertain, and there could be significant changes to the fiscal, monetary and regulatory landscape in the UK, which could affect the Premier Group's and the Combined Group's operations and earnings.

The result of the EU referendum in the UK, the UK 2019 general election and, more recently, the UK's withdrawal from the EU and to a degree differing responses from the UK Government and the Scottish Government to the COVID-19 pandemic has revived political uncertainty regarding Scottish independence. Such uncertainty might potentially result in additional risks to the Premier Group (with Premier, among other members of the Premier Group, being incorporated in Scotland) and the Combined Group, each of which has operations in Scotland and interests in assets located on the UKCS, which are territorially within the United Kingdom but might be claimed by a future government of an independent Scotland as part of its territorial waters. There is no guarantee that current UK laws and regulations regarding licensing and other matters will not change should Scotland become independent from the UK and any changes in the regulatory regime as a result of Scottish independence could result in increased costs to comply with new regulations or a change in the standards of the Premier Group's and the Combined Group's operations.

The Premier Group's prospective operations in the Falkland Islands may be delayed if a future Argentine government escalates the dispute with the UK about the Falkland Islands' sovereignty. In such a scenario, potential joint venture partners and supply chain contractors with significant business interests in Argentina, or Latin America more broadly, may be less willing to co-operate with the Premier Group and the Combined Group on any project.

Certain countries in which the Premier Group has, and the Combined Group will following completion of the Merger 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 the Premier Group operates, or in which the Combined Group may operate following completion of the Merger, and third parties such as partners, customers and suppliers with whom the Premier Group does business or with whom the Combined Group may do business following completion of the Merger, could become subject to trade, economic or other sanctions or similar measures affecting the ability of the Premier Group or the Combined Group to carry on business in relevant countries or with relevant third parties or otherwise disrupting the operations of the Premier Group or Combined Group.

It is difficult to predict the timing or severity of these occurrences or their potential effect. However, if such risks materialise they could have a material adverse effect on the employees, reputation, business, operating results, financial condition or prospects of the Premier Group and the Combined Group.

It is difficult to predict the timing or severity of these occurrences or their potential effect. If such risks materialise they could have a material adverse effect on the employees, reputation, business, operating results, financial condition or prospects of the Premier Group and the Combined Group.

To maintain the Premier Group's existing licences to operate and its ability to secure access to new reserves and resources, it is important that the Premier Group and, following completion of the Merger, the Combined Group maintain strong and positive relationships with the governments and communities in the countries where their business is conducted. For instance, the Premier Group has, and the Combined Group will have, a number of assets on the UKCS which are territorially within the United Kingdom. Accordingly, the Premier Group and the Combined Group must engage constructively with its regulators and the UK and Scottish governments, including for example, the OGA and the Department for Business, Energy and Industrial Strategy ("**DBEIS**"). Failure to maintain a good working relationship and comply with the requirements of these and other regulatory bodies could impede efforts to comply with the UK regulatory regime, which in turn could result in penalties, a negative reputational impact and/or other impediments to the Premier Group's and the Combined Group's UK operations.

The Premier Group's values and policies govern how the Premier Group conducts its affairs. Failure, real or perceived, to follow these values and policies, or the materialisation of any of the risk factors described in this document, could harm the reputation of the Premier Group or the Combined Group, which could, in turn, impact the Premier Group's and the Combined Group's licence to operate, financing and access to new opportunities. This could have a material adverse effect on the business, operating results, financial condition or prospects of the Premier Group and the Combined Group.

7. *The Premier Group's ability to operate depends and, following the completion of the Merger, the Combined Group's ability to operate will depend on satisfying licensing and other regulatory requirements*

Activities undertaken in countries in which the Premier Group currently operates or may operate or, following the completion of the Merger, the Combined Group will or may operate are subject to licences, regulations and approvals of governmental authorities. These include those relating to the exploration, development, operation, production, marketing, pricing, transportation and storage of oil and gas, taxation, environmental, and health and safety matters (including with regard to eventual decommissioning of production assets).

The Premier Group has, and the Combined Group will have, limited control over, among other things: (i) whether or not necessary approvals or licences are granted or renewed or extended; (ii) the timing of obtaining (or renewing) such licences or approvals; (iii) the terms on which they are granted; or (iv) the tax regime to which the Premier Group or the Combined Group or the relevant assets in which they have interests will be subject.

As a result, the Premier Group or the Combined Group may have limited control over the nature and timing of exploration and development of oil and gas fields in which they have or seek interests. There can also be no assurance that the Premier Group or the Combined Group will not in the future incur additional decommissioning charges since local or national governments may require decommissioning to be carried out in circumstances where there is no express obligation to do so, particularly in case of future licence renewals.

Other than Chrysaor's interests in Norway, all of the assets held by the Chrysaor Group are in the United Kingdom, which is a jurisdiction in which the Premier Group is also present and therefore the applicable regulatory requirements are well understood. However, by expanding its footprint in the UKCS, the Combined Group will become more exposed to potential changes in the existing regulations (for example, with respect to carbon emissions and the standards required for decommissioning). In the Norwegian Continental Shelf ("**NCS**"), all exploration and production licenses have incorporated detailed and mandatory work programs that are required to be fulfilled within a specific timespan. These may include seismic surveys to be performed, wells to be drilled and development decisions to be taken. Failure to comply with the obligations under the licenses may lead to fines, penalties, restrictions, revocation of licenses and termination of related agreements.

It is possible that, in the future, the Combined Group may be unable or unwilling to comply with the terms or requirements of a licence in circumstances that entitle the relevant authority to suspend or withdraw the terms of such licence. Moreover, some of the exploration and production licences which are currently held by the Premier Group (and which will be held, following completion of the Merger, by the Combined Group) may expire before the end of what Premier estimates to be the productive life of the licensed fields. There can be no assurance that renewals or extensions will be granted in relation to such licences. Any failure to receive such extensions or any premature termination, suspension or withdrawal of licences may have a material adverse effect on the Premier Group's and, following completion of the Merger, the Combined Group's reserves, business, operating results, financial condition or prospects.

8. *If the Premier Group, and following completion of the Merger, the Combined Group are unable to replace their proved plus probable reserves as they are produced, their reserves will decline*

Future oil and gas production will depend on the Premier Group's and, following the completion of the Merger, the Combined Group's access to new reserves through exploration and appraisal; negotiations with governments; awards at licensing rounds; and acquisitions and farm-ins. Insufficient activity or success in these areas may limit the Premier Group's or the Combined Group's ability to replace reserves or to maintain or grow oil and gas production, which, in turn, could have an adverse effect on the business, operating results, financial condition and prospects of the Premier Group and the Combined Group.

The Premier Group and the Chrysaor Group hold exploration licences in a number of countries worldwide and within these there is an ongoing evaluation process whereby identified exploration and appraisal opportunities are progressed depending on the outcome of such evaluation process. In response to changes in market conditions during the first half of 2020, Premier has taken action to defer exploration activity across its portfolio to reduce expenditure. This includes the deferral of drilling activities in Mexico (Sureste Basin), Brazil (Ceará Basin), and Indonesia (Tuna and the Andaman Sea). Following completion of the Merger, the Combined Group may also seek to manage its exploration portfolio in order to spread the Combined Group's capital requirements and prioritise projects which are regarded as strategically more important or which offer the potential to deliver higher returns.

Exploration and appraisal activities are capital intensive and the results are inherently uncertain as there can be no assurance that future exploration expenditure will result in the discovery of commercially producible hydrocarbons. 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. Appraisal and development activities may also be subject to delays in obtaining governmental approvals or consents, lender consents, agreeing development plans with joint venture partners, obtaining sufficient access to storage or transportation facilities or other constraints, which could materially adversely affect the Premier Group's and, following completion of the Merger, the Combined Group's replacement of reserves and long-term oil and gas production.

9. The Premier Group faces and the Combined Group will face inherent uncertainty as to the success of any development and drilling activities

The Premier Group, and following completion of the Merger, the Combined Group, are dependent on finding, acquiring, developing and producing oil and gas reserves that are economically recoverable, the success of which is subject to significant uncertainty. Oil and gas exploration and production activities are capital intensive and subject to financing limitations and inherent uncertainty in their outcome. Further, significant expenditure is required to establish the extent of the oil and gas reserves through seismic and other surveys and drilling. Therefore, there can be no certainty that further commercial quantities of oil and gas will be discovered or acquired by the Premier Group, and following completion of the Merger, the Combined Group. The Premier Group's, and following completion of the Merger, the Combined Group's, existing and future oil and gas appraisal and exploration projects may therefore involve unprofitable efforts, either from dry wells or from wells that are productive but do not produce sufficient net revenues to return a profit after development, operating and other costs.

Even if the Premier Group, and following completion of the Merger, the Combined Group, are 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. Development activities may be subjected to unexpected problems and delays and incur significant costs, which can differ significantly from estimates, with no guarantee that such expenditure will result in the recovery of oil and gas in sufficient quantities to justify investments. The Premier Group, and following completion of the Merger, the Combined Group, may be required to curtail, delay or cancel any development operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, breaches of security, title problems, adverse weather conditions, compliance with governmental requirements or failure to comply with work commitments under license, labour disputes and shortages or delays in the availability of drilling rigs, ancillary support vessels and the delivery of equipment. Any such curtailment, delay or cancellation could delay production or prevent production from taking place, which reduces cash flows and can lead to impairment charges.

Appraisal and development activities involving the drilling of wells across a field may be unpredictable and may not result in the outcome planned, targeted or predicted, as only by extensive testing can the properties of an entire field be more fully understood. The Premier Group, and following completion of the Merger, the Combined 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, 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. For example, in December 2017 a crack was discovered in an onshore part of the FPS operated by INEOS FPS Limited, one of the hydrocarbon transportation systems used in the Chrysaor Group's operations. As a result, the system was shut down, leading to a corresponding reduction in daily production of over 70 kboepd for approximately three weeks. In addition, much of the success of the Premier Group is and of the

Combined Group will be dependent on bringing new developments of oil fields to production on budget and on schedule.

Completion of the Premier Group's, and following completion of the Merger, the Combined 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 of operations to be recovered. In addition, various field operating conditions may also adversely affect production from successful wells including delays in obtaining governmental approvals, permits, licenses, authorisations or consents, shut ins of connected wells, insufficient or uneconomic storage or transportation capacity or other unusual or unexpected geological, oceanographic and mechanical conditions.

10. The Premier Group's and the Combined Group's development projects require substantial capital expenditures. The Premier Group and the Combined Group may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in oil and gas reserves

The Premier Group makes, and the Directors and the Proposed Directors expect the Combined Group to continue after completion of the Merger to make, substantial capital expenditures for the development, production and acquisition of oil and natural gas reserves. The Combined Group intends to finance the majority of its future capital expenditures with cash flow from operations and, if necessary, borrowings under the New RBL Facility. Longer-term, additional sources of liquidity may also include debt and equity from its shareholders, funding in the capital markets and disposal proceeds from any portfolio management activity. The Premier Group's, and following completion of the Merger, the Combined Group's, cash flows from operations and access to capital are subject to a number of variables which they do not control, including:

- Proved plus probable reserves (2P);
- the level of oil and natural gas the Premier Group and following completion of the Merger, the Combined Group, is able to produce from existing wells;
- the price at which oil and gas are sold; and
- the Premier Group's, and following completion of the Merger, the Combined Group's, ability to acquire, locate and produce new reserves.

If the Premier Group's, and following completion of the Merger, the Combined Group's, revenues or the borrowing base under the New RBL Facility decrease as a result of lower oil or gas prices, operating difficulties, declines in reserves, increased costs or for any other reason, the Premier Group, and following completion of the Merger, the Combined Group, may have limited ability to obtain the capital necessary to invest in development opportunities or sustain operations at current levels. The New RBL Facility restricts the Chrysaor Group's, and following completion of the Merger, the Combined Group's, ability to obtain certain new financing. If additional capital is needed, the Combined Group may not be able to obtain debt or equity financing. If cash generated by operations or cash available under the New RBL Facility is not sufficient to meet its capital requirements, the failure to obtain additional financing could result in a curtailment of its operations relating to development of 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 obliged to carry out the project contrary to its desire or with negative economic impact. Further, the Premier Group, and following completion of the Merger, the Combined Group, may fail to make required cash calls and breach license obligations, which again could lead to adverse consequences. All of the above could adversely affect the Premier Group's, and following completion of the Merger, the Combined Group's, production, revenues and results of operations as well as having a material adverse effect on the Premier Group's or the Combined Group's ability to service its indebtedness.

11. The Premier Group faces and, following completion of the Merger, the Combined Group will face uncertainty as to the estimation of reserves, resources and production profiles and these may prove inaccurate

The estimation of oil and gas reserves, and their anticipated production profiles, involves subjective judgments and determinations based on available geological, technical, contractual and economic information. They are not exact determinations and may change based on new information from production or drilling activities or changes in economic factors, as well as from activities such as acquisitions and disposals, new discoveries and extensions of existing fields and the application of improved oil and gas recovery techniques. Many of these factors will be beyond the control of the Premier Group or, following completion of the Merger, the Combined Group. Published reserve estimates are also subject to correction for errors in the application of published rules and guidance.

If the assumptions upon which the estimates of Premier's hydrocarbon reserves, resources or production profiles have been based prove to be incorrect, the Premier Group and the Combined Group may be unable to recover and produce the estimated levels or quality of hydrocarbons set out in this document and the business, operating results, financial condition or prospects of the Premier Group and the Combined Group could be materially adversely affected.

12. A proportion of the equipment and third-party infrastructure upon which the Premier Group's, and following completion of the Merger, the Combined Group's, operations rely is old, and requires maintenance and repair

All fields require ongoing maintenance to ensure continued operational integrity. The Directors and the Proposed Directors expect the Combined Group to incur significant planned expenditure on its assets used to service production from its operated fields. Despite significant planned operating and capital expenditure, there can be no guarantee that assets owned or used by the Premier Group, and following completion of the Merger, the Combined Group, 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 assets owned or used by the Premier Group, and following completion of the Merger, the Combined Group, do not operate at or above expected efficiencies, substantial expenditure investments beyond the amounts budgeted may be required. For example, the Chrysaor Group's products at Erskine and Lomond were shut in from January 2018 to September 2018 and October 2018, respectively, due to a stuck pig in the Lomond to Everest condensate export pipeline. The cause of the incident was a wax build up in the pipeline. Under previous operators, the pipeline had not been regularly pigged since 2009, a recognized risk at the time of the acquisition of the pipeline. As a result of the pipeline blockage, Erskine and Lomond only produced 3.1 kboepd net during the year ended 31 December 2018 (2017: 6.8 kboepd). Any material damage to the Premier Group's or the Combined Group's equipment or significant capital expenditure on the Chrysaor Group's equipment for improvement or maintenance may have a material adverse effect on the Premier Group's, and following completion of the Merger, the Combined Group's, results of operations and financial condition and, as with planned operating and capital expenditure, there is no guarantee that the amounts expended will ensure continued operation without fault or address the effects of wear and tear, severe weather conditions, natural disasters or industrial accidents.

In addition, while the Premier Group, and following completion of the Merger, the Combined Group, may endeavour to repair, re-use, retrofit or refurbish producing assets where possible to maximize operational efficiency while avoiding significant expenses associated with purchasing new equipment, it cannot be guaranteed that such repair, re-use, retrofitting or refurbishment will be commercially feasible to undertake in the future and cannot assure that there will be no unexpected costs during the re-use, retrofitting or refurbishment process.

Further, a substantial portion of the production of the Premier Group is, and following completion of the Merger, that of the Combined Group will be, reliant on some third-party owned and controlled infrastructure which has been in operation for a number of years. For example, the Chrysaor Group relies, and following completion of the Merger, the Combined Group will rely, on the FPS for the offtake of oil and condensate produced at the Armada Area, Elgin-Franklin Area, Everest Area, Britannia Area and Buzzard fields. In October 2017, the FPS and the Kinneil Terminal were acquired by INEOS. As the FPS has been extensively used, it requires frequent 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 to repair a crack.

If the owners or operators of these pipelines, as well as of other, old third-party infrastructure upon which the Premier Group relies, and following completion of the Merger, the Combined Group operations will rely, fail to adequately maintain their integrity or fail to invest into such infrastructure to ensure that uptime levels are maintained, the Premier Group, and following completion of the Merger, the Combined Group, may not be able to efficiently deliver oil to onshore terminals for sale.

Furthermore, use of third-party infrastructure exposes the Premier Group, and following completion of the Merger, the Combined Group, to the possibility that such infrastructure will cease to provide services or be decommissioned and therefore prevent economic production, which in turn could also have a material adverse effect on the Premier Group's, and following completion of the Merger, the Combined Group's, business. A reduction or potential stoppage in oil deliveries of oil or operational efficiency could have a material adverse effect on the Premier Group's, and following completion of the Merger, the Combined Group's, results of operations and financial condition.

13. The majority of the Combined Group's production will be sold to Shell under long-term offtake agreements. Any changes to, disagreements in respect of or termination of these offtake agreements may have a material adverse effect on the Combined Group's business, results of operations, financial condition and/or prospects

The Chrysaor Group is currently party to eight offtake arrangements with Shell International Trading and Shipping Company Limited ("**STASCO**"), a subsidiary of Shell (the "**STASCO Offtake Arrangements**"), pursuant to which the Chrysaor Group has agreed to sell and STASCO has agreed to buy the Chrysaor Group's production across various fields and products which in aggregate equated to approximately 94 per cent. of the Chrysaor Group's production across all fields and products for the year ended 31 December 2019 (including all the crude oil produced by the Chrysaor Group), and which in aggregate represented approximately 95 per cent. of the Chrysaor Group's revenues for the year ended 31 December 2019. In addition to being obliged to purchase the majority of Chrysaor's current production, under the STASCO Offtake Arrangements, STASCO will automatically be required to purchase the additional production (i.e. new to Chrysaor) from any field in respect of which an equity interest was originally acquired by Chrysaor from Shell under the Shell Acquisition where Chrysaor acquires an additional equity interest in such field. In addition, STASCO has a right to match the terms offered by third parties to Chrysaor for production from any field in respect of which Chrysaor acquires a new or additional equity interest where Chrysaor did not acquire an equity interest in such field under the Shell Acquisition (provided such production is not already contracted to another party). As such, on completion of the Merger, under the STASCO Offtake Arrangements, STASCO will automatically be required to purchase some of Premier's production (in particular the production of the Elgin Franklin field), which would have equated to approximately 8 per cent. of Premier's production for the year ended 31 December 2019 and will have a right to match the terms offered by third party offtakers for the production of Premier's other fields for certain products, which would have equated to approximately 64 per cent. of Premier's production for the year ended 31 December 2019.

Accordingly, on a Combined Group basis, under the STASCO Offtake Arrangements STASCO would be required to purchase approximately 63 per cent. of the Combined Group's production, which would have represented approximately 58 per cent. of the Combined Group's revenues on a combined basis for the year ended 31 December 2019. In addition, STASCO would have been entitled to purchase (if it had exercised all of its rights to match) approximately 86 per cent. of the Combined Group's production, which would have represented approximately 91 per cent. of the Combined Group revenues on a combined basis for the year ended 31 December 2019.

As the STASCO Offtake Arrangements will remain in force following completion of the Merger, the Combined Group will be reliant on STASCO for most of its revenue and hence subject to the increased risk of delayed payment for delivered production volumes, counterparty default or suspension or termination of the sales agreement by STASCO. An absence of competitors for the purchase of oil and gas produced by the Combined Group on comparable terms to those agreed with existing offtakers may expose the Combined Group to adverse pricing or other less favourable contractual terms. Such delays, defaults, difficulties or adverse pricing or other less favourable contractual terms could adversely affect the Combined Group's business, operating results, financial condition or prospects. Chrysaor is able to terminate the STASCO Offtake Arrangements on repayment of the Chrysaor Junior Facility (but no earlier than 31 October 2024). STASCO is able to terminate the STASCO Offtake Arrangements from 31 October 2022 and in certain other limited and customary circumstances, including in the event that Chrysaor fails to deliver STASCO's entitlement to Chrysaor's production which is available for delivery in accordance with the arrangements or Chrysaor through wilful default is in material breach of its obligations under the arrangements (and fails to remedy such breach within an agreed period). The STASCO Offtake Arrangements also include mutual termination rights in the event of various insolvency and financial distress related events in respect of either party or in the event that either party has failed to pay undisputed amounts due (subject to notice periods).

If the offtake arrangements were terminated by action of either party, the Combined Group would need to negotiate and enter into new contract(s) with alternative purchaser(s) for the sale of substantially all of its production in the North Sea and the Combined Group may need to adopt alternative marketing strategies in order to achieve this. During any such negotiations, which may take a significant amount of time to conclude, the Combined Group may not be able to sell some or all of such production, which would have an adverse effect on the Combined Group's business, results of operations, financial condition and/or prospects.

While the Directors and the Proposed Directors believe that the Combined Group would be able to secure alternative purchasers for the oil and gas currently produced by the Combined Group if needed, there can be no assurance that the Combined Group would be able to negotiate and enter into agreements with purchasers for the sale of oil and gas on equivalent terms to those with STASCO, or at all. Any such delays, defaults, reduction in oil volumes purchased or adverse pricing or other contractual terms could adversely affect the Combined Group's business, results of operations, financial condition and/or prospects.

14. The timing and costs of decommissioning is uncertain

The Premier Group has, and following completion of the Merger the Combined Group will have, obligations in respect of the decommissioning of some of the fields in which they have, or in the past have had, licence interests and related infrastructure. The oil and gas industry currently has little experience of decommissioning petroleum infrastructure on the UKCS and it is difficult to forecast accurately the costs that the Premier Group and the Combined Group will incur in satisfying its decommissioning obligations. The Premier Group and the Combined Group are expected to assume additional decommissioning obligations in relation to future operations. These obligations derive from legislation and regulatory requirements concerning the decommissioning of wells and production facilities.

In addition, should Scotland become independent from the United Kingdom, the decommissioning regulatory regime of a future independent Scotland may be subject to change so that it is different from that in place in the United Kingdom. The Directors and the Proposed Directors cannot assure investors that any changes to the decommissioning regime in Scotland would not result in additional decommissioning costs. For further detail, see the Risk Factor above entitled "*Political, security, economic, legal, regulatory and social uncertainties and changes to the Premier Group's and/or, following completion of the Merger, the Combined Group's relationship with governments, regulators and communities where they operate may affect business in key territories*".

The Premier Group contains, and the Combined Group will contain, several fields in the UKCS which are in mid- to late production stages of their lifecycles. It is possible that several assets might have to cease production and move into decommissioning at the same time and, therefore, careful planning will be required to ensure sufficient funding is available to fund several decommissioning projects simultaneously.

The Premier Group's accounts make, and the Combined Group's accounts will make, provision for decommissioning costs, but there can be no assurance that the cost of decommissioning will not exceed the value of such provision. When decommissioning liabilities for a field crystallise, the Premier Group and, following completion of the Merger, the Combined Group will be jointly and severally liable for them with other former or current partners in the field. If other partners default on their obligations, the Premier Group's or the Combined Group's liabilities could be increased significantly.

Any significant increase in the actual or estimated decommissioning costs that the Premier Group and the Combined Group incur, or an acceleration of the time at which these costs become payable, may materially adversely affect their business, operating results, financial condition or prospects. In addition, the likelihood of these risks materialising is greater given the changes in market conditions during the first half of 2020.

This risk may also materialise from the Premier Group's other assets in the UK North Sea that are being decommissioned, or from the Premier Group's assets in Asia if the payments it has made into escrow do not cover the committed decommissioning costs.

15. *There may be a lack of sufficient letter of credit facilities, bank guarantees or other similar security to enable the Premier Group and, following the completion of the Merger, the Combined Group, to meet their decommissioning security arrangements*

The various decommissioning security arrangements to which the Premier Group is, and the Combined Group will be, party typically permit the Premier Group to make provision for decommissioning security in the form of letters of credit, bank guarantees 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 the Premier Group's and the Chrysaor Group'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 will 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 will only be willing to do so on more onerous terms for the Premier Group and the Combined Group.

If these developments continue or worsen, or if the Premier Group or the Combined Group does not have sufficient letter of credit facilities available to enable them to meet these decommissioning obligations, it may not be possible or it may be more difficult and/or costly for the Premier Group or the Combined 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, the Premier Group and the Combined 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 the Premier Group's and the Combined Group's business, operating results or financial condition.

Members of the Premier Group are party to, and the Combined Group will be party to, various decommissioning security arrangements relating to certain oil and gas fields in the United Kingdom which require them to, among other things, make provision for their share of the anticipated future decommissioning costs relating to these fields. To date, the highest amounts of decommissioning security for the Premier Group have been posted in respect of the Balmoral, Brenda, Huntington, Glamis, Johnston, Caledonia, Kyle, Stirling and Ravenspurn North fields and for the Chrysaor Group have been posted in respect of the Thistle, J-Area, Beryl, Brodgar and Britannia fields. In respect of a number of other fields, the Chrysaor Group has also entered into bilateral security arrangements with Shell and ConocoPhillips. 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.

16. *The actions of joint ventures, partners and contractual counterparties, may be outside of the Premier Group's and, following the completion of the Merger, the Combined Group's control*

Oil and gas operations globally are typically conducted in joint ventures. Some of the Premier Group's major assets are operated, and some of the Combined Group's major assets will be operated, by a partner in the relevant joint venture.

For example, Apache acts as operator of the Beryl Area fields, CNOOC is operator of the Buzzard field, Total is operator of the Elgin-Franklin Area fields, BP is operator of the Clair and Schiehallion fields, Ithaca is operator of the Alder field, Chevron is the operator of the Erskine field, Shell is operator of the Galleon field, and the Chrysaor Group's interests in the East Irish Sea Area fields Dalton, Millom and Calder are managed under contract by Spirit Energy and utilise Spirit Energy's wholly owned assets in the area, including the North Morecambe Terminal. In respect of the J-Area fields and Britannia fields (except for the Alder field), while the Chrysaor Group is, and following completion of the Merger, the Combined Group will be, the operator of these fields, approval from partners in each field is required for any improvement or enhancement projects planned for the area. Similarly, in respect of, among others, the Balmoral, Catcher and Johnston fields, while the Premier Group is, and following completion of the Merger, the Combined Group will be, the operator of these fields, approval from partners in the field is required for any improvement or enhancement projects planned for the area.

The ability of the Premier Group, and following completion of the Merger, the Combined Group, to influence their partners will sometimes be limited due to their percentage ownership in non-operated development and production operations. Non-alignment on various strategic decisions in joint ventures may result in operational or production inefficiencies or delay and the potential for increasing operating costs, which erode value. Further, while the terms of the Premier Group's, and following completion of the Merger, the Combined Group's, operating agreement generally impose standards and requirements in relation to the operatorship of the oil field, there can be no assurance that the operator will observe such standards or requirements.

Operators of fields may use different host services for transporting and processing production. There is a risk that existing tariff arrangements could be replaced with more expensive arrangements as production levels in the host systems decrease or as a result of a change of operator, thereby increasing the likelihood of earlier cessation of production and impacting the value of the Premier Group's and the Combined Group's assets. Default by a partner may also result in the Premier Group or, following completion of the Merger, the Combined Group bearing a disproportionate share of the funding, risk or liabilities associated with the relevant asset(s).

The Premier Group has entered into or is subject to agreements with a number of contractual counterparties in relation to the sale and supply of hydrocarbon production volumes. Therefore, members of the Premier Group are subject to, and following completion of the Merger, members of the Combined Group may be subject to, the risk of delayed payment for delivered production volumes or counterparty default. Such delays or defaults could have a material adverse effect on the business, operating results, financial condition or prospects of the Premier Group and the Combined Group.

17. The Premier Group's and, following the completion of the Merger, the Combined Group's insurance and indemnities may not adequately cover all risks and expenses

The Premier Group and, following the completion of the Merger, the Combined Group may be subject to substantial liability claims due to the inherently hazardous nature of their business or for acts and omissions of supply chain contractors or subcontractors, operators or joint venture partners. Any indemnities that the Premier Group or the Combined Group may receive from such parties may be difficult to enforce if they lack adequate resources. Some potential risks (such as terrorism risks in some jurisdictions) are not readily insurable or insurance against such risks is not available at an acceptable price. There can be no assurance that the proceeds of insurance applicable to covered risks will be adequate to cover expenses relating to losses or liabilities or in certain circumstances such proceeds will be available to the Premier Group or the Combined Group rather than their respective creditors. Accordingly, the Premier Group and the Combined Group may suffer material losses from uninsurable or uninsured risks or insufficient insurance coverage.

18. The Premier Group and the Combined Group may be subject to currency fluctuations and exchange controls

The Premier Group operates, and following the completion of the Merger, the Combined Group will operate, in a number of different countries and territories throughout the world. The Premier Group and the Combined Group is therefore 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 the Premier Group's and the Combined Group's business, operating results, financial condition or prospects. The Premier Group hedges its exchange rate risk as described in the following risk factor.

The functional currency of the Premier Group is, and that of the Combined Group will be US dollars. The Premier Group and the Chrysaor Group both mainly receive revenues in US dollars and convert funds to foreign currencies to meet payment obligations which are contracted in currencies other than US dollars, such as labour and employee costs in pounds sterling. Exchange rates between the pound sterling and the US dollar have fluctuated significantly in the past and may do so in the future. Consequently, construction, exploration, development, operating, administration and other costs may be higher in US dollars than anticipated.

19. Hedging activities may inadequately protect the Premier Group and, following the completion of the Merger, the Combined Group from hydrocarbon price, exchange rate and interest rate volatility

The Premier Group seeks to mitigate and, following the completion of the Merger, the Combined Group will seek to mitigate the impact of volatility in hydrocarbon prices and currency exchange rates by maintaining oil and gas price and foreign exchange hedging to underpin its financial strength and protect its capacity to fund future developments and operations. Oil and gas hedging can be undertaken with swaps, collar options, reverse collars and hedges embedded in long-term crude offtake agreements. Oil is hedged using Dated Brent oil price options and UK gas using UK NBP gas options. Indonesian gas is hedged by the Premier Group using HSFO Singapore fuel oil 180cst futures. The Premier Group seeks to mitigate the impact of exchange rate volatility by selling US dollars and purchasing GBP forward up to six months based on forecast expenditure.

The Premier Group seeks to mitigate, and the Combined Group will seek to mitigate, exposure to interest rate volatility through the interest rate swap market by converting a portion of their floating rate debt to fixed rate. The Combined Group's hedging programme will be primarily driven by minimum hedging requirements under the New RBL Facility. However, no assurance can be given that the Premier Group's or the Combined Group's hedging policies will sufficiently protect against volatility in commodity prices, exchange rates or interest rates or that the Premier Group or the Combined Group will be able to put hedging in place with counterparties on acceptable terms in order to successfully implement their hedging policies.

Furthermore, hedging policies could adversely affect the Premier Group and the Combined 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, and the high level of transaction costs and subsequent exposure to financial risk. If the Premier Group or the Combined Group are unable to hedge their hydrocarbon price or foreign exchange risks effectively or experience a loss as a result of their hedging activities, this could have a material adverse effect on the business, operating results, financial condition or prospects of the Premier Group and the Combined Group.

20. The Premier Group has considerable UK tax losses, the benefit of which could be lost

The Premier Group had approximately US$4.1 billion of unutilised UK tax losses as at 31 December 2019. There are tax rules which prevent the use of such losses where, over the course of any period of five years starting up to three years before a change in ownership of a company, there is a major change in the nature or conduct of a trade carried on by the company. The allotment and issue of the Consideration Shares and the Creditor Shares may result in a change in ownership with respect to the Company and its subsidiaries. Whether there has been a major change in the nature or conduct of a trade depends on all of the specific facts and circumstances of the individual case in question, and may occur if there is a significant change in the property dealt in, the services or facilities provided by, or in customers or markets supplied by, the relevant company. The Premier Group focuses on upstream oil and gas activities and this will continue to be the case for the Premier Group and the Combined Group following completion of the Merger. HMRC has published guidance indicating that it would generally be unusual for it to take the view that there has been a major change in the nature or conduct of a trade in the context of this industry (that is, in the context of ring-fence trades).

The Premier Group currently does not pay UK corporation tax or supplementary charge on profits arising from its ring-fence activities due to the ability to set these tax losses against taxable profits. If there were a major change in the nature or conduct of the trade carried on by the relevant company, these losses could be extinguished in full and as a result it could start having to pay tax on its ring-fence profits and this could have a materially adverse effect on the business, financial condition and results of operations of the Premier Group and, following the completion of the Merger, the Combined Group.

21. *The Premier Group, and following completion of the Merger, the Combined Group, may be adversely affected by changes to tax legislation or its interpretation or increases in effective tax rates in the jurisdictions in which they do business*

The Premier Group does, and following completion of the Merger, the Combined Group will do, business in more than one jurisdiction and their profits are 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. The Premier Group's, and following completion of the Merger, the Combined Group's, tax rate, including their effective tax rate and the rate of value added tax ("**VAT**"), may be affected by changes in tax laws 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, the Premier Group's, and following completion of the Merger, the Combined Group's, tax rate may increase in future periods, which could have a material adverse effect on the Premier Group's, and following completion of the Merger, the Combined Group's, financial results and, specifically, their net income, cash flow and earnings may decrease. See also the risk factor immediately above regarding the Premier Group's UK tax losses.

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 the Premier Group's, and following completion of the Merger, the Combined 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 the Premier Group's, and following completion of the Merger, the Combined Group's, profits from activities in those jurisdictions may be subject to additional tax or additional unexpected transactional taxes (e.g. stamp duty, VAT 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 the Premier Group's, and following completion of the Merger, the Combined Group's, business, prospects, financial condition or results of operations.

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 and the Proposed Directors cannot assure investors that any changes to the tax regime in Scotland would not result in additional tax costs. Furthermore, changes to current tax law and regulations could occur following the UK's withdrawal from the European Union.

22. *The Premier Group relies, and following the completion of the Merger, the Combined Group will rely, heavily on IT systems for their operations*

The Premier Group is, and following the completion of the Merger, the Combined Group will be, dependent on the secure and continued effective operation of their IT systems (including back-up measures) and their use of data. Such systems, including those provided by third party service providers, may fail and/or sensitive data held by them may be lost.

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. The operations of the Premier Group, and following the completion of the Merger the Combined Group, will be dependent on the use of internal data and customer data. The Premier Group has incurred, and following the completion of the Merger the Combined Group will incur, 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 information data. Failure to comply with such data privacy laws and regulations may result in fines, penalties, claims and reputational damage. Additionally, if data security controls fail, there is a risk that protected, sensitive or personal data, including important intellectual property, may be unintentionally disclosed which could lead to the violation of confidentiality agreements, reputational harm and the loss of critical data, and which in turn could lead to fines and/or claims. Any of the foregoing could have a material adverse effect on the business, financial condition and results of operations of the Premier Group and, following the completion of the Merger, the Combined Group.

23. *There will be risks inherent in the Combined Group's acquisitions of oil and gas assets*

The Premier Group increases and, following the completion of the Merger, it is anticipated that the Combined Group will increase oil and gas reserves through strategic business acquisitions and farm-ins. The Chrysaor Group has undertaken a number of acquisitions of oil and gas assets (and of companies holding such assets) in recent years, including the acquisition of UKCS assets previously held by Shell and ConocoPhillips.

The Combined 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 integration of the operations and personnel of the acquired business following any potential acquisition will be successful. There may be problems with minority shareholders in acquired companies or with other field participants or co-venturers. It may also be difficult to secure the services of suitably qualified personnel to manage the acquired businesses or interests. Acquisitions may also cause potential disruption to the Premier Group's or the Combined Group's own business. Furthermore, the value of any business that the Premier Group or the Combined Group acquires or invests in or farm-in that it makes may be less than the amount it pays.

Although the Premier Group conducts, and the Combined Group will conduct, due diligence on all material potential target acquisitions, even an in-depth review of all properties and records may not reveal existing or potential problems, nor will it always permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Physical inspections may not be performed on every well, and structural or environmental problems are not necessarily observable even when an inspection is undertaken. Following the integration process, the Premier Group or the Combined Group may become aware of additional information relating to the acquired asset 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 the Premier Group's or the Combined Group's business, operating results, financial condition or prospects.

In addition, successful acquisitions of oil and gas assets require an assessment of a number of 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 cannot be made with a high degree of accuracy. In connection with these assessments, the Combined Group will perform a review of the acquired assets. However, such a review will not reveal all existing or potential problems. In addition, any such review may not allow sufficient familiarity with the assets to fully assess their deficiencies and capabilities.

There can be no assurance that acquisitions will perform in accordance with expectations or that expectations with respect to integration or cost savings as a result of such acquisition will materialise. A failure to accurately assess a target's business, assets and liabilities and unanticipated events relating to such businesses could have a material adverse effect on the Combined Group's results of operations, financial condition and cash flow. Such failures to achieve acquisition target performance goals could in turn have material adverse effects on the Combined Group's revenue, results of operations, financial condition and cash flow.

24. *The Premier Group and the Combined Group may be subject to work stoppages or other labour disturbances*

Work stoppages or other labour disturbances, such as industrial action, with the Premier Group's, and following completion of the Merger, the Combined Group's, employees or those of their contractors, suppliers and customers may occur in the future. If this occurred, the Premier Group, and following completion of the Merger, the Combined Group, or their 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 the Premier Group's, and following completion of the Merger, the Combined Group's, business, prospects, financial condition and results of operations.

25. The Premier Group depends, and the Combined Group will depend, on their board of directors, key members of management, independent experts, technical and operational service providers and on their ability to retain and hire such persons to effectively manage a growing business.

The Premier Group's, and following completion of the Merger, the Combined Group's, future operating results depend in significant part upon the continued contribution of the board of directors, key senior management and technical, financial and operations personnel. Management of the Combined Group's growth will require, among other things, stringent control of financial systems, compliance environment and operations, the continued development of management control, the ability to attract and retain sufficient numbers of qualified management and other personnel, the continued training of such personnel and the presence of adequate supervision.

The Premier Group's, and following completion of the Merger, the Combined Group's, success is dependent on the ability of the board of directors and management to operate their growing business and to manage the ongoing changes from potential future acquisitions. Failure to manage the Combined Group's growth and development effectively, could materially and adversely affect the Combined Group's, business, prospects, financial condition and results of operations.

In addition, the personal connections and relationships of the Directors, the Proposed Directors and key management are important to the conduct of the Premier Group's, and following completion of the Merger, the Combined Group's, business. If the Premier Group, or following completion of the Merger, the Combined Group, were to unexpectedly lose a key management member or fail to maintain one of the key management team's strategic relationships, the Premier Group's, and following completion of the Merger, the Combined Group's, business and results of operations could be materially adversely affected.

The Premier Group uses, and following completion of the Merger, the Combined Group will use, independent contractors to provide them with certain technical, financial, commercial and legal assistance and services. In certain cases, the Premier Group, and following completion of the Merger, the Combined Group, may exercise limited control over the activities and business practices of these providers and any inability on the Premier Group's, and following completion of the Merger, the Combined Group's, part to maintain satisfactory commercial relationships with them or their failure to provide quality services could materially adversely affect the Premier Group's, and following completion of the Merger, the Combined Group's, business, prospects, results of operations and financial condition.

Attracting and retaining additional skilled personnel will be fundamental to the continued growth of the Combined Group's business after completion of the Merger. The Premier Group requires, and following completion of the Merger, the Combined Group will require, skilled personnel in the areas of exploration and development, operations, engineering, business development, oil marketing, finance and accounting relating to their 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 the Premier Group's operate, and following completion of the Merger, the Combined Group's, will operate. Due to, amongst other things, uncertainty arising from the announcement of the Merger, the Premier Group, and following completion of the Merger, the Combined Group, may not successfully attract new personnel and retain existing personnel required to continue to expand the business and to successfully execute and implement their business strategy.

SECTION D: RISKS RELATING TO THE OIL AND GAS INDUSTRY

1. The business, operating results, financial condition and prospects of the Premier Group and following completion of the Merger, the Combined Group depend substantially upon prevailing hydrocarbon prices, which can be volatile and subject to fluctuations in response to a variety of factors, including geopolitical and macro-economic circumstances, which are beyond the Premier Group's and the Combined Group's control

The revenues, operating results, profitability, future rate of growth and carrying value of the oil properties of the Premier Group depend and, following the completion of Merger, those of the Combined Group's oil properties will depend heavily on the prices received for oil and gas sales. Commodity prices also affect the cash flows available for future capital investments and other items, including the economic viability of unsanctioned projects and the value of reserves. No assurance can be given that commodity prices will increase above or remain at levels which enable the

Premier Group, and will enable the Combined Group, to do business profitably or at levels that make it economically viable to produce from certain wells.

A sustained period of low hydrocarbon prices could materially adversely affect the business, operating results, financial condition or prospects of the Premier Group and the Combined Group, which could result in exploration or growth projects being cancelled or deferred, assets being impaired and any proved oil or gas reserves that are uneconomic being debooked. In addition, it could adversely affect the Premier Group's or the Combined Group's ability to meet its financing obligations and financial covenants under the terms of its financing documents.

Hydrocarbon prices are frequently subject to volatility for many reasons, including:

- changes in global and regional supply and demand for hydrocarbons, the effects and competitiveness of expected future supply and demand and actions taken by consumers and producers of hydrocarbons in response to prevailing or expected supply and demand conditions (including in relation to the COVID-19 pandemic and the implementation of measures intended to contain the spread of COVID-19);
- uncertainty in the geopolitical and macro-economic outlook, including but not limited to, the occurrence of recessions and inflation, unstable or adverse credit markets, changes in governmental regulations, such as increased taxation or the introduction of new regulations, and fluctuations in exchange rates;
- the ability of OPEC members and other major oil producing nations to limit levels of production and thereby influence prices;
- changes in supply caused by new discoveries or technologies, such as the increase in shale gas;
- changes in supply caused by political, economic and military developments in oil and gas producing nations, including actual or threatened acts of aggression or war, cyber security attacks and/or acts of terrorism;
- weather conditions, natural disasters and environmental incidents and long term effects of climate change;
- availability of infrastructure for the storage and transportation of hydrocarbons;
- competition from alternative fuels and energy sources, including relative prices and availability and the overall pace of transition to a low-carbon energy mix;
- cost and availability of new oil field technology;
- actions by oil and gas importing nations to source more fuel and energy domestically;
- governmental or regulatory action and, in particular, changes to export restrictions, fuel duties, boundary disputes, supply chain interference, environmental regulation and uncertainty (for example, in the implementation of IMO2020 regulations), which may impact fuel oil pricing for the Premier Group's, and following completion of the Merger, the Combined Group's, interests; and
- speculative activities by investors in hydrocarbons and hydrocarbon derivatives on the world markets.

The COVID-19 pandemic has had a significant negative impact on the level of global economic activity. This has resulted in a substantial decline in demand for hydrocarbons, which has contributed to a steep decline in Brent crude oil prices. In April 2020, prices for certain West Texas Intermediate crude oil contracts dropped below zero due to decreased demand and limited available storage capacity in the United States. There can be no assurance that these combined factors of decreased demand and limited storage capacity will not cause similar, precipitous declines in other oil price benchmarks, such as Brent crude. Although the growth of the COVID-19 pandemic has been contained in certain countries resulting in a recovery in demand for hydrocarbons, the exact scale and duration of its impact on hydrocarbon prices remains uncertain.

2. *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*

The consequences of the effects of global climate change, and the continued political and societal attention afforded to mitigating the effects of climate change, may generate:

- adverse investor and stakeholder sentiment towards the hydrocarbon industry and negatively impact the investability of the sector;
- longer term reduction in the demand for hydrocarbon products due to the pace of commercial deployment of alternative energy technologies;
- longer term reduction in the demand for hydrocarbon products due to shifts in consumer preference for lower greenhouse gas emission products; and
- longer term disruption to the Premier Group's and the Combined Group's projects and operations as a result of changing weather patterns and more frequent extreme weather events,

any of which may have a material adverse effect on the hydrocarbon industry.

Continued political attention to the role of human activity in climate change and potential mitigation through regulation could have a material impact on the hydrocarbon industry.

In the United Kingdom, where a significant proportion of the hydrocarbons produced by the Premier Group, and following the completion of the Merger by the Combined Group, are 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. Furthermore, the Norwegian Parliament in June 2017 passed legislation with the objective of reducing carbon emissions by at least 40 per cent. (compared to 1990 levels) in Norway by 2030. Multiple plans have also been proposed in the Norwegian parliament to reduce carbon emissions from companies operating in certain sectors, including the oil and gas industry, and create a carbon trading system linked to the EU ETS.

Such legislation or regulatory initiatives, could have a material adverse effect by increasing the costs associated with complying with climate change related operational regulations and disclosure requirements and/or diminishing the demand for oil, thereby increasing the industry's cost structure or causing disruption to operations by regulators, and in turn discouraging institutional investment in the industry. 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. Significant liability could be imposed on the Premier Group and, following the completion of the Merger, the Combined Group in the event of environmental damage caused by previous owners of properties purchased or used by the Premier Group or the Combined Group or on account of any breaches of environmental laws or regulations.

The industry may be subject to activism from environmental campaigners, which could affect its reputation, disrupt operations or development programmes or otherwise negatively impact business.

3. *The hydrocarbons supply chain sector is capacity-constrained, which may affect the Premier Group's and, following the completion of the Merger, the Combined Group's ability to source capital equipment from third party contractors in a timely manner and at a cost effective price*

The Premier Group is, and the Combined Group will be, heavily dependent on supply chain providers to deliver services and products to time, cost and quality criteria, however, the supply chain sector has limited delivery capacity. Potential adverse impacts include limited competition in the supply chain market (hence the Premier Group's and, following the completion of the Merger, the Combined Group's reduced ability to control costs through competitive tendering) and failure by the supply chain companies to deliver project-critical goods and services to contractual schedule, cost and quality requirements and safety standards. The Premier Group and the Chrysaor Group contract or lease services and capital equipment (including, for example, all the drilling rigs and heavy lift vessels) from third party contractors and providers. Such services and equipment can be scarce and may not be delivered in a safe or ethical manner or readily available at the times and places required.

In addition, the costs of third party services and equipment may rise. In particular, scarcity of equipment and services and increased prices may result from any significant increase in regional exploration and development activities. There is a heightened risk during any extended period of downturn in the upstream services sector (such as is currently being experienced) of supply chain counterparties' ability to deliver. This is particularly the case in light of the effects of COVID-19, which may comprise the ability of third parties to deliver their services given the absence of staff due to the quarantine of personnel, the inability or unwillingness of personnel to access sites offshore, restrictions on business travel and reduced productivity.

In the event that there is a sharp increase in underlying oil and gas prices before the Premier Group enters into contracts for the delivery of a suitable drilling rig or supporting service 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 the Premier Group's or the Combined Group's projects, including the Premier Group's and the Combined Group's development and pre-development projects, and therefore have a material adverse effect on the business, operating results, financial condition or prospects of the Premier Group and the Combined Group.

4. The hydrocarbons industry is highly competitive and the Premier Group and, following the completion of the Merger, the Combined Group may be unable to compete effectively

The Premier Group operates and, following the completion of the Merger, the Combined Group will operate in a very challenging business environment and faces intense competition in respect of access to:

- exploration acreage and production licences, or interests in such licences;
- producing hydrocarbon assets;
- oil and gas markets;
- scarce equipment and associated services;
- skilled technical and managerial personnel;
- bank lending and other forms of finance; and
- leading technologies.

Competitors include companies with, in many cases, greater financial resources, local contacts, staff and facilities than those of the Premier Group or the Combined Group. Competitors with greater financial resources may be better able to diversify and absorb increased regulatory or legal burdens. They may also be better prepared to withstand sustained periods of low oil prices. Competition for exploration and production licences as well as other regional investment or acquisition opportunities may increase in the future. This may lead to increased costs in the pursuit of the Premier Group's or the Combined Group's activities and reduced available growth opportunities. Any failure by the Premier Group or the Combined Group to compete effectively could materially adversely affect their business, operating results, financial condition or prospects.

5. The Premier Group and, following completion of the Merger, the Combined Group may not be able to keep pace with technological developments in the oil and gas industry

The oil and gas industry is characterised by rapid and significant technological advancements and the introduction of new products and services using new technologies. As others use or develop new technologies, the Premier Group, and following completion of the Merger, the Combined 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 the Premier Group, and following completion of the Merger, the Combined Group, is 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 that the Premier Group, and following completion of the Merger, the Combined Group, use now or in the future were to become obsolete, the Premier Group's, and following completion of the Merger, the Combined Group's, business, prospects, financial condition and results of operations could be materially adversely affected. In addition, any new technology that is implemented may have unanticipated or unforeseen adverse consequences, either to the Premier Group's, and following completion of the Merger, the Combined Group's, business or the industry as a whole.

SECTION E: RISKS RELATING TO READMISSION AND ADMISSION AND AN INVESTMENT IN NEW ORDINARY SHARES OR NEW EQUITY WARRANTS

1. The price of the New Ordinary Shares may fluctuate

Prospective investors should be aware that the value of an investment in Premier 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:

- changes in market sentiment regarding the Ordinary Shares;
- any regulatory changes affecting the Premier Group's and the Combined Group's operations;
- variations in the Premier Group's and the Combined Group's operating results;
- business developments of the Premier Group and the Combined Group, their competitors, or the hydrocarbons industry;
- the operating and share price performance of other companies in the industries and markets in which the Premier Group operates and in which the Combined Group will operate;
- the use of investment strategies by the investment community, such as shorting;
- speculation about the Premier Group's and the Combined Group's business in the press, media or investment community: and
- litigation against the Premier Group and the Combined 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 the Premier Group's or the Combined Group's operating performance or prospects. Prospective investors should not rely on Premier's or Chrysaor's results to date as an indication of future performance. Furthermore, the Premier Group's and the Combined 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 the Premier Group or, after completion of the Merger, those of the Combined Group.

As the New Equity Warrants are convertible into Ordinary Shares, the value of the New Equity Warrants will depend on the value of the Ordinary Shares from time to time. Therefore the New Equity Warrants are exposed to the risks relating to the Ordinary Shares.

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

If Admission occurs, it will result in the issue and allotment of 14,253,203,210 Consideration Shares, up to 3,331,917,634 Creditor Shares and up to 148,085,228 New Equity Warrants. If the Merger and the Debt Restructuring completes, therefore, Shareholders will suffer an immediate dilution as a result of Admission, following which they will hold:

- assuming that the maximum number of Creditor Shares are issued and allotted and no New Equity Warrants are taken up, approximately 5 per cent. of the enlarged share capital of the Company; and
- assuming that the minimum number of Creditor Shares are issued and allotted and the maximum number of New Equity Warrants are taken up, approximately 5.45 per cent. of the enlarged share capital of the Company.

Other than pursuant to the Merger and the Debt Restructuring, and except for Ordinary Shares issued to executives and employees in connection with the Employee Share Schemes, Premier has no current plans for a subsequent offering of Ordinary Shares. However, Premier 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 Premier 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.

Premier will be obliged to issue up to 33,996,748 additional Ordinary Shares to holders of the outstanding Existing Equity Warrants and Convertible Equity Warrants, and up to 148,085,228 additional Ordinary Shares to holders of New Equity Warrants (assuming maximum take-up), if the holders of those instruments decide to exercise their rights in accordance with the terms set out therein. If the maximum number of Existing Equity Warrants, Convertible Equity Warrants and New Equity Warrants (assuming maximum take-up) were exercised for a cash price, this would increase the number of Ordinary Shares from a total of 16,983,635,668 Ordinary Shares at Admission (on the assumption that no further Ordinary Shares are issued as a result of the exercise of any options under any share plan, warrant or otherwise, between the date of this document and Admission and assuming full take-up of the Partial Cash Alternative) to a total of 17,165,717,644 Ordinary Shares, representing an increase of approximately 1 per cent. In addition, this would have the effect of reducing the proportional ownership and voting interests in the Ordinary Shares of the existing shareholders as at Admission from 5.45 per cent. to 5.39 per cent.. The increase in Premier's total issued share capital may also adversely affect the market price of the Ordinary Shares and may make it more difficult for Shareholders to sell their Ordinary Shares at a time and price which they deem appropriate.

3. Following the completion of the Merger, Harbour North Sea may be able to influence decision-making within the Company, and its interests may differ from other Shareholders

Upon completion of the Merger, Harbour North Sea is expected to hold between 36.50 and 39.78 per cent. of the enlarged share capital of the Company (the allocation of Consideration Shares among Chrysaor shareholders, including Harbour North Sea together with its concert parties, will depend on the value of those Consideration Shares in the period up to the completion of the Merger). Due to the size of its shareholding in the Combined Group following completion of the Merger, Harbour North Sea will hold more than 30 per cent. of the shares of the Combined Group and will, therefore, be deemed a controlling shareholder for the purposes of the Listing Rules. As a result, the Company will enter into a relationship agreement prior to the completion of the Merger (but conditional on Admission) with Harbour North Sea (referred to in this document as the 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. While Harbour North Sea 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. Harbour North Sea, 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, Harbour North Sea 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 Relationship Agreement will take effect upon Admission and will continue in force unless and until Harbour North Sea and its affiliates 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 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.

4. The market price of the Ordinary Shares could be negatively affected by sales of substantial amounts of Ordinary Shares by Harbour North Sea or certain Restructuring Plan Creditors 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 Company will have a more concentrated shareholder base following the completion of the Merger and the Debt Restructuring

Neither Readmission nor Admission should be taken as implying that there will be a liquid market for the Ordinary Shares (including the New Ordinary Shares) and there is no guarantee that there will be an active trading market in the Ordinary Shares after Readmission and Admission.

Upon completion of the Merger, Harbour North Sea is expected to hold between 36.50 and 39.78 per cent. of the enlarged share capital of the Company (the allocation of Consideration Shares among Chrysaor shareholders, including Harbour North Sea together with its concert parties, will depend on the value of those Consideration Shares in the period up to the completion of the Merger). Harbour North Sea's shares will be subject to a twelve-month lock-up from completion and a further twelve-month orderly marketing covenant. Shares held by affiliates of EIG and certain Chrysaor minority shareholders will be subject to a six-month lock-up from completion and an orderly marketing covenant.

Upon completion of the Debt Restructuring, Restructuring Plan Creditors and their designated nominees are expected to hold between 10.6 and 18.0 per cent. of the enlarged share capital of the Company. Creditor Shares held by Restructuring Plan Creditors and their designated nominees whose holdings represent more than 2.7 per cent. of the enlarged share capital of the Company on Admission will be subject to a lock-up period of three months in respect of fifty per cent. of their Creditor Shares and a further three-month lock-up period in respect of their remaining Creditor Shares.

The cumulative effect of the issue of the Consideration Shares, the Creditor 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 Harbour North Sea, its concert parties and Chrysaor shareholders, Restructuring Plan Creditors and their designated nominees in the public market, 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, merger, consolidation, takeover or other business combination, which could in turn have an adverse effect on the trading price of the Ordinary Shares.

5. There is no guarantee that there will be an active trading market for the Ordinary Shares and an active and liquid market for the New Equity Warrants may never develop

Admission of the New Ordinary 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

Before the issue of the New Equity Warrants there has not been a market for the New Equity Warrants, nor will the New Equity Warrants be admitted to trading or listed on any market for securities. Premier cannot predict the extent to which investor interest will lead to the development of an active and liquid market for the New Equity Warrants. Market-makers are under no obligation to make a market for the New Equity Warrants and may discontinue any market-making activities undertaken by them at any time. In addition, the New Equity Warrants will be subject to restrictions on transfer and to restrictions on their holders' ability to exercise them. The transfer restrictions and restrictions on exercise of the New Equity Warrants could have an adverse impact on the ability of the holders of New Equity Warrant from time to time to sell their securities.

6. The Company has not declared a dividend since May 2014 and there is no assurance that dividend payments will be made in future

The ability of a company to pay dividends is limited under Scottish company law, which limits a company to making distributions (including paying cash dividends) only to the extent that it has distributable reserves (and, if required, cash) available for this purpose. As a holding company, the Company's ability to pay dividends in the future is affected by a number of factors, principally its ability to receive sufficient dividends, and generate sufficient cash flows, from subsidiaries. The payment of dividends to the Company by its subsidiaries is, in turn, subject to restrictions, including certain regulatory requirements, applicable tax laws, covenants in debt facilities and the existence of sufficient distributable reserves and cash in such subsidiaries. These laws and restrictions could limit the payment of future dividends and distributions by subsidiaries, which could restrict the ability of the Company to fund other operations or to pay a dividend to holders of Ordinary Shares (including the Consideration Shares and the Creditor Shares).

The Company has not declared a dividend since 2014. Going forward, the Directors and Proposed Directors believe the combination of Premier and Chrysaor will create a business with the potential to offer a meaningful dividend for shareholders over time. The Combined Group is expected to generate sufficient free cash flow to support shareholder returns including via a sustainable dividend which, subject to market conditions and Board approval, is expected to be introduced with respect to the financial year ending December 2021. However, noting the foregoing paragraph, there is no guarantee than any such dividend will be paid.

7. The ability of Shareholders to sell their Ordinary Shares, particularly in a takeover offer, may be negatively affected by the proposed UK National Security and Investment Bill

On 11 November 2020, the UK Government published the UK National Security and Investment Bill (the "**UK NS&I Bill**"), which, amongst other things, proposes that acquisitions of shares or voting rights above certain thresholds in entities in specified sensitive sectors ("**notifiable acquisitions**") will be subject to mandatory notification to the DBEIS. The proposed list of relevant sectors, which is currently subject to an ongoing consultation process, includes the energy sector and therefore would capture the Premier Group and, following completion of the Merger, the Combined Group.

Assuming the UK NS&I Bill is passed into law, acquisitions of shares or voting rights in qualifying entities within the specified sectors will be subject to a mandatory notification requirement where a trigger event takes place, including where a person acquires additional shares or voting rights such that as a result of the transaction the person will gain control of the qualifying entity (defined to mean where their shareholding or percentage of voting rights in the qualifying entity would increase through certain thresholds, namely 25 per cent., 50 per cent. or 75 per cent., or the acquisition would enable that person to either secure or prevent the passage of a shareholder resolution) or the person will acquire more than 15 per cent. of the shares or voting rights of the qualifying entity. The UK NS&I Bill also proposes that transactions may be voluntarily notified where there is a national security concern. Where transactions are notified to the DBEIS, the Secretary of State will have broad information gathering powers, be able to impose interim remedies and where a national security risk is identified, be able to impose remedies to mitigate that risk, which may include prohibiting the transaction or imposing certain conditions.

Such additional regulatory scrutiny could therefore make it more difficult for a buyer, particular a non-UK person where there may national security concerns (for example, because of the nationality of such person) to acquire a significant shareholding in the Company or make a successful takeover offer for the Combined Group. This could therefore have an adverse effect on the trading price of the Ordinary Shares and Shareholders may be unable to sell their Ordinary Shares at a price they may otherwise have been willing to accept.

If passed into law before the completion of the Merger, the UK NS&I Bill could require that the Merger is notified under its provisions and this might delay completion. In addition, once passed into law, the UK NS&I Bill will also have retrospective effect from 12 November 2020 and the Secretary of State will have the power to call-in for review any transactions which have closed after 12 November 2020 but prior to the commencement date, which might therefore apply to the Merger. If the Merger were called-in for review after completion had occurred, it is possible that the Secretary of State would (subject to the final terms of the UK NS&I Bill once enacted), have a wide range of remedies available to it, possibly including the ability to unwind the Merger. However, as the Merger does not give rise to substantive national security concerns, it is unlikely that such actions would be taken by the Secretary of State, and as such, the risk of the UK NS&I Bill having retrospective effect on the Merger is considered low. For more detail, please see the Risk Factor entitled "*The Merger is conditional upon certain conditions which may not be satisfied, as a result of which the Merger and the Debt Restructuring would not be implemented on its current terms or possibly at all*".

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

Premier is a public limited company incorporated in Scotland. The rights of Premier'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, the Proposed 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 United Kingdom to effect service of process outside the United Kingdom the Company, the Directors, the Proposed Directors and/or executive officers.

9. 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 share, 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 Merger and the Debt Restructuring, the share capital of the Company will be increased and New 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

1. General

No person has been authorised to give any information or make any representations other than those contained in this document or incorporated by reference herein and, if given or made, such information or representations must not be relied upon as having been authorised by the Proposed Directors, the Directors, Premier, Chrysaor or the Sponsor. None of the Proposed Directors, the Directors, Premier, Chrysaor or the Sponsor takes any responsibility for, or can provide assurance as to the reliability of, other information that Shareholders may be given. Subject to FSMA, the Listing Rules, the Disclosure Guidance and Transparency Rules, the Prospectus Regulation Rules and the Market Abuse Regulation, neither the delivery of this document nor any subscription or sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of Premier or Chrysaor since the date of this document or that the information in this document is correct as at any time subsequent to its date. Without limitation, the contents of the Premier Group's and the Chrysaor Group's websites do not form part of this document.

2. Presentation of technical information

The reserves, resources and production profile data contained in this document are estimates only and should not be construed as representing exact quantities. They are based on production data, prices, costs, ownership, geophysical, geological and engineering data, and other information assembled by the Premier Group or the Chrysaor Group (as applicable). The estimates may prove to be incorrect and Shareholders should not place undue reliance on the forward-looking statements contained in this document concerning the Premier Group's and the Chrysaor Group's reserves and resources or production levels or those attributed to the Premier Group or the Chrysaor Group.

3. Presentation of financial information relating to the Premier Group

Prospective investors should consult their own professional advisers to gain an understanding of the financial information relating to the Premier Group contained in this document. An overview of the basis for presentation of financial information in this document is set out below.

The historical financial information relating to the Premier Group contained in this document has been presented in accordance with the requirements of the Prospectus Regulation.

Unless otherwise indicated, all financial information relating to the Premier Group contained in this document has been extracted from the Premier Group's audited consolidated financial statements included in the Annual Reports and Accounts of Premier for the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019 together with the audit reports thereon or the Premier Group's unaudited interim financial statements for the six months ended 30 June 2020 together with the independent review report thereon, are incorporated by reference into this document, as explained in Part VII of this document. All of the Premier Group's financial statements have been prepared in accordance with IFRS as adopted by the EU.

Where information has been extracted from Premier's audited consolidated financial statements, the information is audited unless otherwise stated. Where the information has been extracted from Premier's unaudited interim financial statements, the information is unaudited.

4. Non-IFRS financial measures used by the Premier Group

This document contains certain unaudited supplementary financial measures that are not defined by or recognised under IFRS or any other generally accepted accounting principles, including EBITDAX, operating cost per barrel, DD&A per barrel, net debt and liquidity. Non- IFRS measures used by Premier and Chrysaor may differ and/or may be defined in a different way by Premier and Chrysaor. Definitions of non-IFRS measures used by each of Premier and Chrysaor are provided below.

The definition of each of these non-IFRS measures is given below, and the non-IFRS measures are reconciled to IFRS measures in Part VII of this document:

- **EBITDAX**: This measure, when used in this document, represents earnings before interest, tax, depreciation, amortisation, impairment, exploration spend and certain other one-off items. These exceptional and non-trading items are set out on the face of the consolidated profit and loss account of the consolidated historical financial information of the Premier Group incorporated by reference in Part VII of this document and, in the respective periods, were related exclusively to profit and/or loss on disposal of assets. EBITDAX is presented to enhance a prospective investor's understanding of the Premier Group's results of operations and financial condition and to enhance a prospective investor's evaluation of the Premier Group's ability to deploy its earnings towards capital expenditures, working capital and repayment of debt. The Directors consider EBITDAX to be a useful indicator of the underlying business performance of the Premier Group and believe that this measure provides additional useful information for prospective investors on the Premier Group's performance, and enhances comparability from period to period and with other companies, and is consistent with how business performance is measured internally.

- **Net debt**: This measure represents the net of cash and cash equivalents and long-term debt recognised on the Premier Group's balance sheet. The Directors consider net debt to be a useful indicator of the Premier Group's indebtedness and capital structure.
- **Liquidity**: This measure represents the sum of cash and cash equivalents on the Premier Group's balance sheet, and the undrawn amounts available to the Premier Group on its principal facilities, including letters of credit facilities, less the Premier Group's JV partners' share of cash balances. The Directors consider liquidity to be a key measure of the Premier Group's financial flexibility and ability to fund day-to-day operations.

The Directors believe that these non-IFRS measures provide valuable information to readers of the historical financial information because it enables them to understand how the Directors, *inter alia*, manage the Premier Group's business, develop its budgets and evaluate the performance of the Premier Group against those budgets.

The non-IFRS measures used in this document should not be considered superior to, nor a substitute for, measures calculated in accordance with IFRS. Readers should not consider these non-IFRS measures in isolation, but in conjunction with measures calculated in accordance with IFRS. Non-IFRS measures reported by the Premier Group may not be comparable to similarly titled measures reported by other companies as those companies may define and calculate such measures differently from the Premier Group.

5. Presentation of financial information relating to the Chrysaor Group and the Combined COP Subsidiaries

Prospective investors should consult their own professional advisers to gain an understanding of the financial information relating to the Chrysaor Group and the Combined COP Subsidiaries contained in this document. An overview of the basis for presentation of financial information relating to the Chrysaor Group and the Combined COP Subsidiaries in this document is set out below.

The historical financial information relating to the Chrysaor Group and the Combined COP Subsidiaries contained in this document has been presented in accordance with the requirements of the Prospectus Regulation.

Unless otherwise indicated, all financial information relating to the Chrysaor Group contained in this document has been extracted from the Chrysaor Group's audited consolidated historical financial information for the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019 and the six months ended 30 June 2020 together with the unaudited comparative financial information for the six months ended 30 June 2019, together with the opinion thereon, which are set out in Part VIII of this document.

Unless otherwise indicated, all financial information relating to the Combined COP Subsidiaries contained in this document has been extracted from the Combined COP Subsidiaries' audited combined historical financial information for the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019, which together with the opinion thereon, are set out in Part VIII of this document.

The consolidated historical financial information relating to the Chrysaor Group and the combined historical financial information relating to the Combined COP Subsidiaries have been prepared in accordance with the requirements of the Prospectus Regulation and the Listing Rules, in accordance with IFRS as adopted by the EU, the Companies Act applicable to companies reporting under IFRS and with standards for investment reporting and on a basis consistent with the accounting policies adopted by Premier Group in its latest published annual report.

Where information has been extracted from the Chrysaor Group's audited consolidated historical financial information or the Combined COP Subsidiaries' audited combined historical financial information, the information is audited unless otherwise stated.

6. Non-IFRS financial measures used by the Chrysaor Group

The Chrysaor Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. There may be differences in the method for calculating non-IFRS measures between the Premier and Chrysaor Groups.

- **EBITDAX**: This measure is defined as earnings before tax, interest, depreciation and amortisation, remeasurements and exploration expenditure and is used as an indicator of underlying business performance.
- **Operating Cost Per Barrel:** This measure is defined as direct operating costs (excluding over/underlift) for the year including tariff expense and insurance costs less tariff income, divided by working interest production. This is used as an indicator of ongoing operating costs from the Chrysaor Group's producing assets.
- **Depreciation, Depletion and Amortisation Per Barrel (DD&A)**: this measure is defined as the depreciation and amortisation of oil and gas properties for the year divided by working interest production. This is used as an indicator of ongoing rates of depreciation and amortisation of the Chrysaor Group's producing assets.
- **Free Cash Flow:** This is defined as EBITDAX less capital expenditure.
- **Net Debt**: This measure is defined as the cash and cash equivalents less total senior and junior debt recognised on the consolidated balance sheet. This is used as an indicator of the Chrysaor Group's indebtedness and contribution to capital structure.

The Directors and the Proposed Directors believe that these non-IFRS measures provide valuable information to readers of the historical financial information because it enables readers to understand how Chrysaor's board, *inter alia*, manages the Chrysaor Group's business, develops its budgets and evaluates the performance of the Chrysaor Group against those budgets.

The non-IFRS measures used in this document should not be considered superior to, nor a substitute for, measures calculated in accordance with IFRS. Readers should not consider these non-IFRS measures in isolation, but in conjunction with measures calculated in accordance with IFRS. Non-IFRS measures reported by the Chrysaor Group may not be comparable to similarly titled measures reported by other companies as those companies may define and calculate such measures differently from the Chrysaor Group.

7. Rounding

Percentages and certain amounts included in this document have been rounded for ease of presentation. Accordingly, figures shown as totals in certain tables may not be the precise sum of the figures that precede them.

8. Currencies

Unless otherwise indicated in this document, all references to:

- "**pounds sterling**" or "**£**" or "**pence**" are to the lawful currency of the UK;
- "**US dollars**", "**dollars**", "**US$**", "**$**" or "**cents**" are to the lawful currency of the United States; and
- "**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. The Premier Group and the Chrysaor Group present their financial statements in US dollars.

9. Forward-looking statements

This document incorporates by reference or contains certain statements that are, or may be deemed to be, "forward-looking statements". In some cases, these forward-looking statements can be identified by the use of forward-looking terminology, including the terms "believes", "estimates", "plans", "prepares", "anticipates", "expects", "intends", "may", "will", "would", "could", "target" or "should" or, in each case, their negative or other variations or comparable terminology, but all statements other than statements of historical fact may be forward-looking statements. These forward-looking statements appear in a number of places throughout this document and the information incorporated by reference into this document and include statements regarding the intentions, beliefs or current expectations of the Directors (the Proposed Directors, Premier and/or Chrysaor (as the context requires) concerning, among other things, the operating results, financial condition, prospects, growth, leverage, strategies and dividend policy of the Premier Group or the Combined Group, and the industry in which it operates.

Investors should specifically consider the factors identified in this document, which could cause actual results to differ, before making an investment decision. Forward-looking statements are not guarantees of future performance, and such forward-looking statements involve known and unknown risks, uncertainties and other factors, which may cause the actual results, performance or achievements of the Premier Group, the Combined Group or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements.

Such forward-looking statements are based on beliefs, expectations and assumptions of the Directors, the Proposed Directors and other members of senior management regarding the Premier Group's and the Combined Group's present and future business strategies and the environment in which the Premier Group or the Combined Group will operate in the future. Although the Directors, the Proposed Directors and other members of senior management believe that these beliefs and assumptions are reasonable, by their nature, forward-looking statements involve risks and uncertainties because they relate to events and depend on circumstances that may or may not occur in the future or are beyond the Premier Group's or the Combined Group's control. The Premier Group's or the Combined Group's actual operating results, financial condition, dividend policy and the development of the oil and gas industry may differ materially from the impression created by the forward-looking statements contained in this document and/or the information incorporated by reference into this document. In addition, even if the operating results, financial condition and dividend policy of the Premier Group and the Combined Group and the development of the oil and gas industry, are consistent with the forward-looking statements contained in this document and/or the information incorporated by reference into this document, those results or developments may not be indicative of results or developments in subsequent periods. Important factors that could cause these differences include, but are not limited to, general economic and business conditions, industry trends, competition, changes in government and other regulation, including in relation to the environment, health and safety and taxation, labour relations and work stoppages, changes in political and economic stability and changes in business strategy or development plans and other risks. Such risks, uncertainties and other factors are set out more fully in the section headed "Risk Factors".

Prospective investors should carefully review the section of this document entitled "Risk Factors" for a discussion of factors that could cause the Premier Group's and the Combined Group's actual results to differ materially from those expected before making an investment decision. In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements in this document and/or the information incorporated by reference into this document may not occur.

These forward-looking statements speak only as at the date of this document. Except as required by the FCA, the London Stock Exchange or applicable law (including as may be required by the FCA's Listing Rules, the Disclosure Guidance and Transparency Rules and the Prospectus Regulation Rules), Premier and Chrysaor expressly disclaim any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements contained in this document, whether as a result of any change in events, conditions or circumstances or otherwise on which any such statement is based.

10. Profit forecasts

Unless otherwise stated, no statement in this document is intended as a profit forecast or estimate and no statement in this document should be interpreted to mean that earnings per share for the most recent, current or future financial years would necessarily match or exceed the historical published earnings per share. As at the date of this document, there are no outstanding profit forecasts or estimates.

11. Warrants

This document relates not only to the issue of New Ordinary Shares but also sets out information relating to: (i) New Warrant Shares issued and to be issued to Warrant Holders pursuant to the Existing Equity Warrant and Convertible Equity Warrant, including any adjustments consequent upon the Merger and Debt Restructuring to the number of Ordinary Shares which may be issued pursuant to those instruments; and (ii) the New Equity Warrants proposed to be issued to Restructuring Plan Creditors who meet certain eligibility criteria as part of the Debt Restructuring.

12. Presentation of reserves and resources

Unless otherwise stated, statements in this document relating to the reserves and resources attributed to the Premier Group, the Chrysaor Group or the Combined Group have been prepared using the classification system set out in the Petroleum Resources Management System ("**PRMS**") published in 2007 and jointly sponsored by the Society of Petroleum Engineers, the American Association of Petroleum Geologists, the World Petroleum Council and the Society of Petroleum Evaluation Engineers, as updated by the Society of Petroleum Engineers in 2018. These standards of reporting may be different from those adopted in the United States and other jurisdictions. Investors, therefore, should not assume that the data found in the reserves and resources information set forth in this document is directly comparable to similar information that has been prepared in accordance with the reserve and resource reporting standards of other jurisdictions.

All references to "reserves" are to proved plus probable ("**2P reserves**") and all references to "contingent resources" are to best estimate 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 Chrysaor Group, and forward-looking production estimates and other geological information in relation thereto, has been extracted without material adjustment from the Chrysaor CPR in Part X (*Competent Person's Report on the Chrysaor Group*). Unless otherwise stated, all information about the oil and gas reserves and resources attributable to the Premier Group, and forward-looking production estimates and other geological information in relation thereto, has been extracted without material adjustment from the Premier Group's 2019 Annual Report and Financial Statements.

13. No incorporation of website information

Neither the contents of Premier's or Chrysaor's website nor the content of any website accessible from hyperlinks on Premier's or Chrysaor's website is incorporated into, or forms part of, this document and investors should not rely on them, without prejudice to the documents incorporated by reference into this document which will be made available on Premier's or Chrysaor's website.

14. Third party information

Premier confirms that all third party information contained in this document has been accurately reproduced and, as far as Premier is aware and is able to ascertain from information published by that party, no facts have been omitted which would render the reproduced information inaccurate or misleading. Where third party information is cited in this document, the source of such information is identified.

15. Chrysaor Information

The information in this document relating to the Chrysaor Group and the Combined COP Subsidiaries has been provided by the board of directors of Chrysaor.

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Each of the times and dates in the table below is indicative only and may be subject to change. (1)(2)(3)

Announcement of the Merger and the Debt Restructuring	**6 October 2020**
Publication and posting of this document, the Circular, the Notice of General Meeting and Forms of Proxy	**16 December 2020**
Latest time and date for receipt of Forms of Proxy	2 p.m. on 8 January 2021
General Meeting	**12 January2021**
English Court hearing to convene the English Restructuring Plan Creditor Meetings	**19 January 2021**
Scottish Court hearing to convene the Scottish Restructuring Plan Creditor Meetings	**25 January 2021**
Latest time and date for receipt of proxy and election forms and account holder letters in respect of voting and elections by Restructuring Plan Creditors in connection with the Debt Restructuring	**18 February 2021**
Restructuring Plan Creditor Meetings	**22 February 2021**
English Court hearing to sanction the English Restructuring Plan	**9 March 2021**
Scottish Court hearing to sanction the Scottish Restructuring Plans	**19 March 2021**
Subdivision Record Date	25 March 2021
Existing Ordinary Shares subdivided into Ordinary Shares and Non-Voting Deferred Shares	26 March 2021
Readmission and Admission and dealings in New Ordinary Shares, fully paid, commence on the London Stock Exchange	**by 8.00 a.m. on 29 March 2021**
New Ordinary Shares issued in connection with the Merger and the Debt Restructuring credited to CREST accounts (uncertificated holders only)	as soon as practicable after 8.00 a.m. on 29 March 2021
Completion of the Merger and Debt Restructuring becomes effective	**29 March 2021**

Notes:

(1) These times and dates and those mentioned throughout this document may be adjusted by Premier in consultation with Chrysaor and the Sponsor, in which event details of the new times and dates will be notified to the FCA, the London Stock Exchange and, where appropriate, Shareholders.

(2) References to times in this timetable are to London time.

(3) The timing of completion of the Merger and the Debt Restructuring remains uncertain and subject to the satisfaction or waiver of certain conditions contained in the Merger Agreement, including the receipt of certain regulatory consents and antitrust clearances, details of which are set out in section 4.8 of Part I (*Background to and Reasons for the Merger and the Debt Restructuring*) of this document and Part III (*Terms and Conditions of the* Merger) in the Circular.

(4) The timing of the dates relating to the Subdivision also uncertain and may change in light of the timing of completion of the Merger and the Debt Restructuring.

ISSUE STATISTICS

Number of Existing Ordinary Shares in issue as at 14 December 2020, being the Latest Practicable Date	925,532,676
Number of Consideration Shares to be issued pursuant to the Merger	14,253,203,210
Number of Creditor Shares to be issued by the Company pursuant to the Debt Restructuring, assuming:	
(i) no take-up of Partial Cash Alternative or New Equity Warrants	3,331,917,634
(ii) maximum take-up of Partial Cash Alternative and New Equity Warrants	1,804,899,782
Number of Ordinary Shares in issue immediately following Admission, assuming:	
(i) no take-up of Partial Cash Alternative or New Equity Warrants	18,510,653,520
(ii) maximum take-up of Partial Cash Alternative and New Equity Warrants	16,983,635,668
New Ordinary Shares as a percentage of the enlarged share capital immediately following Admission, assuming:	
(i) no take-up of Partial Cash Alternative or New Equity Warrants	95 per cent.
(ii) maximum take-up of Partial Cash Alternative and New Equity Warrants	94.55 per cent.
Estimated total expenses of the Merger (inclusive of VAT)	US$20.5 million

Unless otherwise stated, for the purposes of the table above and this document, the number of Ordinary Shares in issue immediately following Admission is stated on the assumption that no further Ordinary Shares are issued as a result of the exercise of any options under any share plan, warrant or otherwise, between the date of this document and Admission.

DIRECTORS, COMPANY SECRETARY, REGISTERED OFFICE AND ADVISERS

DIRECTORS	Roy A Franklin (*Non-Executive Chairman*) Richard Rose (*Interim Chief Executive Officer and Finance Director*) Dave Blackwood (*Non-Executive Director*) Anne Marie Cannon (*Senior Independent Non-Executive Director*) Iain Macdonald (*Non-Executive Director*) Mike Wheeler (*Non-Executive Director*) Elisabeth Proust (*Non-Executive Director*) *The business address of each of the Directors is 23 Lower Belgrave Street, London SW1W 0NR.* *Each of the Directors (other than Anne Marie Cannon) are expected to resign from the Board with effect from completion of the Merger and the Debt Restructuring.*
PROPOSED DIRECTORS	Linda Cook (*Chief Executive Officer*) Phil Kirk (*President; Chief Executive Officer, Europe*) R. Blair Thomas (*Chairman*) G. Steven Farris (*Non-Executive Director*) Simon Henry (*Senior Independent Non-Executive Director*) Anne Stevens (*Independent Non-Executive Director*) *The business address of each of the Proposed Directors immediately after the completion of the Merger will be 23 Lower Belgrave Street, London SW1W 0NR.*
COMPANY SECRETARY	Rachel Rickard
SPONSOR, FINANCIAL ADVISER AND JOINT CORPORATE BROKER TO PREMIER	RBC Europe Limited 100 Bishopsgate London EC2N 4AA
JOINT FINANCIAL ADVISER TO CHRYSAOR E&P SERVICES LIMITED	Barclays Bank PLC, acting through its Investment Bank 5 The North Colonnade Canary Wharf London E14 4BB
JOINT FINANCIAL ADVISER TO CHRYSAOR E&P SERVICES LIMITED	BMO Capital Markets Limited 95 Queen Victoria Street London EC4V 4HG
LEGAL ADVISERS TO PREMIER AS TO ENGLISH LAW	Slaughter and May One Bunhill Row London EC1Y 8YY
LEGAL ADVISERS TO PREMIER AS TO US LAW	Fried, Frank, Harris, Shriver & Jacobson LLP 100 Bishopsgate London EC2N 4AG
LEGAL ADVISERS TO THE SPONSOR AS TO ENGLISH LAW	White & Case LLP 5 Old Broad Street London EC2N 1DW
LEGAL ADVISERS TO CHRYSAOR AND HARBOUR AS TO ENGLISH AND US LAW	Clifford Chance LLP 10 Upper Bank Street London E14 5JJ
AUDITOR AND REPORTING ACCOUNTANT TO PREMIER	Ernst & Young LLP 1 More London Place London SE1 2AF

REPORTING ACCOUNTANTS	PricewaterhouseCoopers LLP 1 Embankment Place London WC2N 6RH
AUDITOR TO CHRYSAOR	PricewaterhouseCoopers LLP The Capitol 431 Union Street Aberdeen AB11 6DA
COMPETENT PERSON	ERC Equipoise Limited Eastbourne House 2 Saxbys Lane Lingfield Surrey RH7 6DN
RECEIVING AGENT	Link Asset Services Corporate Actions The Registry 34 Beckenham Road Beckenham Kent BR3 4TU
REGISTRAR	Link Asset Services The Registry 34 Beckenham Road Beckenham Kent BR3 4TU

PART I

BACKGROUND TO AND REASONS FOR THE MERGER AND THE DEBT RESTRUCTURING

1. Introduction and summary of the Merger

1.1 Overview

On 6 October 2020, Premier and Chrysaor announced that they had reached agreement regarding a proposed all-share merger (referred to in this document as the Merger) and the reorganisation of Premier's Existing Debt Facilities and XCCY Swaps (referred to in this document as the Debt Restructuring) to create the Combined Group.

In order to effect the Merger, Premier will acquire Chrysaor in consideration for the issue of 14,253,203,210 new Ordinary Shares to Chrysaor's shareholders at completion of the Merger (referred to in this Prospectus as the Consideration Shares).

As part of the Debt Restructuring, the Restructuring Plan Creditors will receive an upfront cash payment of US$1.23 billion (subject to certain adjustments) in satisfaction of part of the Premier Group's Existing Debt Facilities and XCCY Swaps (the "**Upfront Cash Consideration**") and Premier will issue up to 3,331,917,634 new Ordinary Shares to the Restructuring Plan Creditors (the "**Creditor Shares**") or, for Senior Creditors and Senior XCCY Hedge Counterparties which so elect, a further cash payment the aggregate amount of which is capped at approximately US$175 million (the "**Partial Cash Alternative**"), to satisfy the balance of the Premier Group's Existing Debt Facilities and XCCY Swaps. If the Partial Cash Alternative is oversubscribed, the amount payable to Senior Creditors and Senior XCCY Hedge Counterparties choosing this option would be scaled down on a *pro rata* basis, and those Senior Creditors and Senior XCCY Hedge Counterparties would be entitled to receive Creditor Shares or, subject to the satisfaction of certain eligibility requirements receive, up to 148,085,228 New Equity Warrants in respect of the amount which they do not receive in cash due to the oversubscription. Taking into account the Upfront Cash Consideration, the Partial Cash Alternative and the current market value of Premier's Ordinary Shares, Restructuring Plan Creditors (on average) will not receive a full par recovery on their claims under the Existing Debt Facilities and XCCY Swaps by virtue of the Debt Restructuring.

The cash payments to Restructuring Plan Creditors will be funded through a combination of the Premier Group's and the Chrysaor Group's existing cash balances and a US$4.5 billion reserve based lending facility (the "**New RBL Facility**") entered into with, among others, Bank of Montreal (London Branch), BNP Paribas, DNB (UK) Limited and Lloyds Bank plc. The Upfront Cash Consideration will be subject to certain adjustments, including to reflect drawdowns and repayments of the Premier Group's debt from and including 1 July 2020 to completion of the Debt Restructuring. Further details regarding the New RBL Facility are included within section 8 of Part II (*Details of the Debt Restructuring*) below.

The Debt Restructuring also involves the cancellation of all undrawn commitments under the Premier Group's Existing Debt Facilities, and the replacement of the Premier Group's outstanding letters of credit of approximately US$400 million. As part of the Debt Restructuring, Senior Creditors and Senior XCCY Hedge Counterparties will also be invited to subscribe in cash at US$0.1144 per share for those Creditor Shares which would have been issued to Senior Creditors and Senior XCCY Hedge Counterparties had they not elected to take the Partial Cash Alternative (the "**Top-Up Election**"). Further details regarding the Debt Restructuring, including the Top-up Election, are included within Part II (*Details of the Debt Restructuring*) below.

The Debt Restructuring (other than the Interim Maturity Extension described below) is inter-conditional with, and would only take place upon completion of, the Merger. In order to allow time for the Merger to complete, or alternatively in the event the Merger and Debt Restructuring Resolutions are not passed to agree and implement an alternative plan for implementation of the Merger and the Debt Restructuring or, if that is not possible, an alternative transaction to address the Existing Debt Facilities, the Debt Restructuring would also involve, at the Premier Group's option (but subject to the conditions described in paragraph 5.3 of this Part I (*Background to and Reasons for the Merger and the Debt Restructuring*)), an extension of the existing maturity date of the Existing Debt Facilities and XCCY Swaps from 31 May 2021 to 31 March 2022 (the "**Interim Maturity Extension**"). If the Merger and the Debt Restructuring proceed in accordance with the

Expected Timetable of Principal Events (as set out above), then the Interim Maturity Extension would not be necessary and would not come into effect.

Immediately following completion of the Merger and the Debt Restructuring, and assuming full take up by Restructuring Plan Creditors of the Partial Cash Alternative and assuming no Top-Up Election, the shares in the Company would be held as follows:

– Harbour North Sea Holdings, Ltd. ("**Harbour North Sea**"), its concert parties and other Chrysaor shareholders: 83.92 per cent (of which Harbour North Sea together with its concert parties: 40.42 per cent); and

– Premier stakeholders: 16.08 per cent, comprising: (i) Premier shareholders: 5.45 per cent; and (ii) Restructuring Plan Creditors: 10.63 per cent.

Immediately following completion of the Merger and the Debt Restructuring, and assuming no take up by Restructuring Plan Creditors of the Partial Cash Alternative, the shares in the Combined Group would be held as follows:

– Harbour North Sea, its concert parties and other Chrysaor shareholders: 77 per cent (of which Harbour North Sea together with its concert partiesr: 37.09 per cent); and

– Premier stakeholders: 23 per cent, comprising: (i) Premier shareholders: 5 per cent, and (ii) Restructuring Plan Creditors: 18 per cent.

The allocation of Consideration Shares among Chrysaor shareholders, including Harbour North Sea, together with its concert parties, will depend on the value of those Consideration Shares in the period up to the completion of the Merger.

The Merger and the Debt Restructuring (other than the Interim Maturity Extension) are inter-conditional. The Debt Restructuring is a consensual restructuring of Premier, which is urgently required to address the Existing Debt Facilities and XCCY Swaps which currently mature on 31 May 2021. The Merger and the Debt Restructuring also provide the opportunity to transition to a more sustainable debt structure with the New RBL Facility and the significantly expanded borrowing base represented by the Combined Group. The Debt Restructuring is also required to avoid a default under the Existing Debt Facilities and XCCY Swaps. Such a default, were it to occur, would be expected to have material adverse consequences for all stakeholders and, in particular, for existing Shareholders. Paragraph 5.2 of Part I of this document explains the potential implications of a default in so far as Shareholders are concerned, and why the Directors consider that the Merger and the Debt Restructuring are in the best interests of the Company and the Shareholders as a whole.

The value of the consideration for the Merger is £3,078,691,893.36, based on the number of Consideration Shares to be issued and the share price of 21.60 pence per Ordinary Share as at the Latest Practicable Date. The value of the consideration for the Debt Restructuring is up to £1,017,360,618.19, based on the maximum cash payment payable to Restructuring Plan Creditors and the maximum number of Creditor Shares and New Equity Warrants to be issued to Restructuring Plan Creditors and the share price of 21.60 pence per Ordinary Share as at the Latest Practicable Date.

1.2 Harbour North Sea whitewash waiver

It is anticipated that, immediately following the completion of the Merger, Harbour North Sea, as the largest shareholder of Chrysaor, together with its concert parties, as determined in accordance with the Takeover Code, will hold up to 40.42 per cent. of the Ordinary Shares of the Combined Group (depending on take up by Senior Creditors and Senior XCCY Hedge Counterparties of the Partial Cash Alternative and assuming no subscription by the Restructuring Plan Creditors for the Top-Up Election). However, as the allocation of Consideration Shares among Chrysaor shareholders, including Harbour North Sea together with its concert parties, will depend on the value of those Consideration Shares in the period up to completion of the Merger, the maximum holding of the Concert Party could be 45.14 per cent. of the Enlarged Share Capital. As a consequence, since this exceeds the 30 per cent. trigger for a mandatory offer under the Takeover Code, the Merger is also conditional on a Rule 9 whitewash waiver from the Takeover Panel in order to disapply mandatory offer requirements. This whitewash waiver will require approval by Premier's independent shareholders at the General Meeting.

Harbour North Sea's shares will be subject to a twelve-month lock-up from completion and a further twelve-month orderly marketing covenant. Shares held by affiliates of EIG ("**EIG**") and certain Chrysaor minority shareholders will be subject to a six-month lock-up from completion and an orderly marketing covenant.

Due to the size of its shareholding in the Combined Group, Harbour North Sea will hold more than 30 per cent. of the shares of the Combined Group and will, therefore, be deemed a controlling shareholder for the purposes of the Listing Rules. As a result, Premier will enter into a relationship agreement prior to the completion of the Merger (but conditional on Admission) with Harbour North Sea (the "**Relationship Agreement**"). Notwithstanding Harbour North Sea's position as a controlling shareholder, the Directors believe that the Combined Group will be able to carry on as an independent business for the purpose of the Listing Rules.

The Relationship Agreement will take effect on Admission and will continue in force unless and until Harbour North Sea and its affiliates 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 Relationship Agreement in certain circumstances, including where the Ordinary Shares cease to be admitted to the premium listing segment of the Official List and admitted to trading to the London Stock Exchange's main market for listed securities. In addition, the Relationship Agreement shall comply with the independence provisions set out in Listing Rules 6.5.4R and 9.2.2GR.

Under the 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 the Company from complying with its obligations under the Listing Rules;

(B) 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;

(C) 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 Relationship Agreement;

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

(E) vote its Ordinary Shares and shall use its reasonable endeavors 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 and the UK Corporate Governance Code.

Other than Harbour North Sea, the Combined Group is not expected to have any other controlling shareholders at Admission and Readmission.

1.3 Application of the Listing Rules

Due to the size of the Merger relative to the size of Premier, the Merger is classified as a reverse takeover of Premier pursuant to the Listing Rules. As a result of the Merger's classification as a reverse takeover pursuant to the Listing Rules, Premier will, through the Sponsor, apply to the FCA and to the London Stock Exchange for:

(A) the current listing of the Existing Ordinary Shares to be cancelled and the Existing Ordinary Shares to be readmitted upon completion of the Merger to the premium listing segment of the Official List and to trading on the main market for listed securities of the London Stock Exchange;

(B) the Consideration Shares to be admitted upon completion of the Merger to the premium listing segment of the Official List and to trading on the main market for listed securities of the London Stock Exchange; and

(C) the Creditor Shares (including Creditor Shares pursuant to the Top-Up Election) to be admitted upon completion of the Debt Restructuring to the premium listing segment of the Official List and to trading on the main market for listed securities of the London Stock Exchange.

Given that the completion of the Merger is conditional on Admission, if Admission does not occur, completion of the Merger will not take place and the Merger Agreement will terminate. The completion of the Debt Restructuring (other than the Interim Maturity Extension) and the completion of the Merger are inter-conditional and so if completion of the Merger does not take place the Creditor Shares will not be issued and Debt Restructuring will not occur.

The Merger, due to its classification as a reverse takeover of Premier pursuant to the Listing Rules, requires the approval of Shareholders. The separate Circular prepared by Premier in connection with the Merger and the Debt Restructuring, contains, at Part X, the Notice of General Meeting and provides further details regarding the Resolutions to be proposed at the General Meeting.

1.4 Creditor approval

Premier is seeking consent from Restructuring Plan Creditors for the Debt Restructuring by means of Court-approved Restructuring Plans. Restructuring Plan Creditors will be invited to vote in favour of the Restructuring Plans at the Creditor Meetings, expected to be held on 22 February 2021.

Each Restructuring Plan requires approval from either (i) 75 per cent. in value of each class of Restructuring Plan Creditors in that Restructuring Plan, or (ii) 75 per cent. in value of at least one class of Restructuring Plan Creditors in that Restructuring Plan who would receive a payment, or have a genuine economic interest in Premier, POUK or POHL (as relevant) in the event of the relevant alternative to that Restructuring Plan, present and voting either in person or by proxy at the relevant meeting ordered to be summoned by (in the case of Premier and POUK) the Scottish Court and (in the case of POHL) the English Court. If (ii) applies, then the Scottish Court and the English Court (as applicable) may only sanction the Restructuring Plans if, among other things, none of the members of the dissenting class of classes of Restructuring Plan Creditors would be any worse off under the Restructuring Plan than they would be in the event of the relevant alternative.

The classes of Restructuring Plan Creditors in each Restructuring Plan are:

(A) Super Senior XCCY Restructuring Plan Creditors;

(B) Super Senior RCF/LC Restructuring Plan Creditors; and

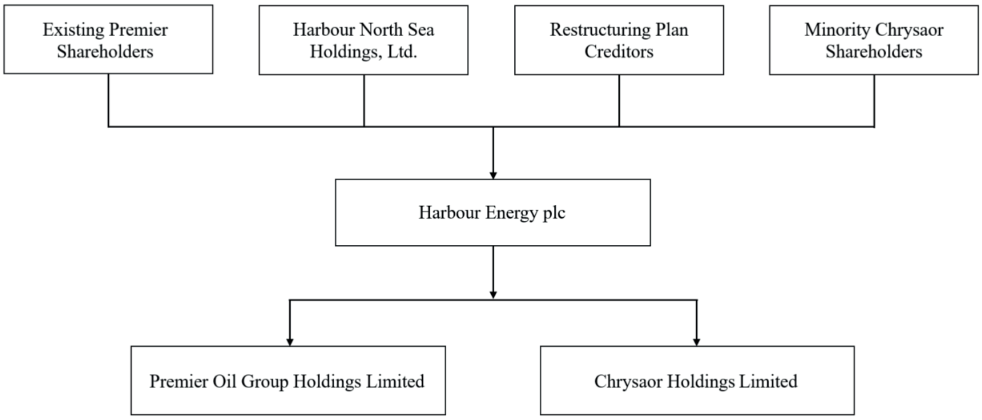
(C) Senior Restructuring Plan Creditors.

Super Senior XCCY Restructuring Plan Creditors representing 100 per cent. of the aggregate of the estimated Super Senior XCCY Exposures as at 30 November 2020, Super Senior RCF/LC Restructuring Plan Creditors representing 92 per cent. of the aggregate outstanding commitments under the Super Senior Secured RCF/LC Facilities and Senior Restructuring Plan Creditors representing 86 per cent. of the aggregate of (i) outstanding commitments under the Senior Secured Debt Facilities, and (ii) the aggregate of the Senior XCCY Exposures, have entered into the Support Letter (the terms of which are described in section 8.1 of Part XIII (*Additional Information*)) whereby they have undertaken to support the Debt Restructuring, including by voting in favour of the Restructuring Plans.

The Non-XCCY Hedge Counterparties have undertaken to consent to the aspects of the Debt Restructuring which require their consent, having respectively entered into separate support letters.

2. Structure of the Combined Group

The organisational chart below provides a simplified illustration of the legal structure of the Combined Group as upon completion of the Merger.



3. Background to the Merger and the Debt Restructuring

Prior to the announcement of the Merger and the Debt Restructuring on 6 October 2020, Premier had undertaken extensive discussions with potential lenders about the possibility of refinancing its Existing Debt Facilities and the XCCY Swaps in their entirety through a new secured RBL facility and subordinated public debt instrument. However, Premier concluded that based on those discussions the Premier Group's combined debt capacity under such facility and such instruments would be significantly lower than the Premier Group's current debt levels. Given the fully secured nature of the Premier Group's existing capital structure and the complex intercreditor arrangements that were put in place as part of the 2017 Refinancing, the Directors considered that it would not be possible to refinance part of the Existing Debt Facilities and the XCCY Swaps through third party facilities prior to their existing maturity on 31 May 2021 (the "**Existing Maturity Date**"). In the absence of other options to refinance the Existing Debt Facilities and the XCCY Swaps in part or in full, the Premier Group concluded that the appropriate course was to seek an extension of the Existing Maturity Date, which it attempted to do through the schemes of arrangement proposed by Premier and POUK with certain of their creditors earlier this year (the "**2020 Schemes**").

Under the 2020 Schemes the Premier Group sought to implement a transaction which, had it gone ahead, would have involved the acquisition of the Andrew and Shearwater assets in the North Sea from BP and an additional interest in the Tolmount field, the funding of those acquisitions through a US$500 million equity raise, and an extension of the Existing Maturity Date to 30 November 2023. The intention had been that successful implementation of that transaction (each element of which was inter-conditional on the others) would have created a period in which the Premier Group could continue to deleverage its balance sheet and seek to increase its debt capacity, with a view to being able to refinance through new third party debt facilities on or before 30 November 2023.

Although the 2020 Schemes were actively opposed by one of the Premier Group's creditors, ARCM, they were approved by the requisite majorities of scheme creditors on 12 February 2020 and were sanctioned by the Scottish Court on 29 April 2020. However, as a result of the collapse in commodity prices due to factors including COVID-19, implementation of the acquisitions and the equity raise contemplated by the 2020 Schemes ceased to be commercially viable and the documentation executed in connection with the 2020 Schemes terminated in accordance with its terms. That in turn meant, due to the inter-conditional terms of the transaction, that the extension of the Existing Maturity Date to 30 November 2023 did not take place.

As a result of the collapse in commodity prices, and despite actions taken by the Premier Group to reduce costs, the Premier Group forecasted breaches of its financial covenants contained within the Override Agreement in respect of the testing period ended 30 June 2020. To address this, on 8 July 2020 the Premier Group entered into a stable platform agreement (the "**Stable Platform Agreement**") with the requisite majorities of its private creditors (being the creditors under the Existing Debt Facilities other than the Retail Bondholders) which, subject to certain conditions waived those financial covenants until 30 September 2020 (excluding in relation to the testing period ended on 30 September 2020).

The Premier Group's financial statements for the testing period ended 30 June 2020 subsequently showed that the Premier Group would have breached the financial covenants under the Override Agreement if they had not been temporarily waived pursuant to the Stable Platform Agreement. Pursuant to a consent letter dated 29 September 2020, the Stable Platform Agreement (including the financial covenant waivers thereunder) was extended to 5 November 2020, such that it covered the testing period ended on 30 September 2020 as well as the one ended on 30 June 2020. The Stable Platform Agreement was subsequently terminated and replaced with the Support Letter, which provides a waiver for the financial covenants contained in the Override Agreement in respect of the testing periods ended on 30 June 2020 and 30 September 2020 and any testing period ending during the period in which the Support Letter is in force.

In parallel with negotiating and signing the Stable Platform Agreement, Premier continued to engage with a subset of its largest creditors on options to address the Existing Maturity Date. These negotiations were led on the creditor side by the IWG and ARCM. As part of the discussions that took place, a range of possible options was considered. One option which emerged (the "**Standalone Transaction**") was an extension of the Existing Maturity Date until 31 March 2025, which would be supported by an equity raise of up to US$530 million via a placing and open offer and the acquisition from BP of the Andrew or Andrew and Shearwater assets on amended terms. Up to a maximum of US$205 million of the equity raise would be underwritten by the creditors under the Existing Debt Facilities, who would convert a *pro rata* portion of their debt claims into new ordinary shares in the Company to the extent that the equity raise was not fully subscribed. Certain other amendments would also be made to the Existing Debt Facilities, including a reset of the financial covenants under the Override Agreement and the repricing of the Existing Debt Facilities.

On 20 August 2020 Premier announced that it had agreed heads of terms for the Standalone Transaction with a sub-set of its creditors, being the IWG members and ARCM. The announcement stated that the Standalone Transaction remained subject to a number of matters, including shareholder approval, finalisation of a detailed term sheet for credit approval processes, long-form documentation, the implementation through restructuring plans under Part 26A of the Companies Act 2006 and total take-up under the equity raise being not less than US$325 million. A detailed term sheet for the Standalone Transaction was subsequently finalised and posted to the Private Creditors and the XCCY Hedge Counterparties on 9 September 2020, who were invited to enter into a support letter whereby they would undertake (among other things) to support the Standalone Transaction and vote in favour of the restructuring plans.

In parallel to developing and progressing the Standalone Transaction, and as required by the terms of the Stable Platform Agreement, the Company ran a process to determine whether a strategic investor might be interested in investing in the Premier Group. As part of this process, the Company invited six potential strategic investors, including Chrysaor, to submit an expression of interest regarding the subscription for a significant minority stake in the Company. Two potential strategic investors (including Chrysaor) submitted an expression of interest; however, instead of indicating an interest in subscribing for a minority stake, Chrysaor proposed a merger of the Premier Group and the Chrysaor Group and a reorganisation of the Existing Debt Facilities. The Company entered into discussions regarding alternatives to the Standalone Transaction with both of the parties which had submitted expressions of interest, as was confirmed by the Company's announcement on 15 September 2020 following press speculation that the Company was in discussions with Chrysaor. Whereas discussions with the second party were not successful, discussions with Chrysaor developed into the Debt Restructuring and the Merger.

Taking into account the challenging macroeconomic conditions, and following discussions with a subset of Premier's largest creditors, the Board announced on 6 October 2020 that the Merger and the Debt Restructuring provided broadly comparable value for the Shareholders as compared to the Standalone Refinancing with greater execution certainty. As part of this announcement, Premier also announced that it, Chrysaor and a sub-set of creditors had entered into the Support Letter with creditors representing over 43 per cent. of its debt facilities and cross-currency swaps. Since then, additional creditors have entered into the Support Letter, as further described in paragraph 1.4 above and Part XIII (*Additional Information*).

4. Reasons for the Merger

4.1 Introduction

The Merger would create the largest independent oil and gas company listed on the London Stock Exchange and would result in a financially strong enterprise committed to value creation for all stakeholders. The Directors and Proposed Directors believe the Combined Group would possess scale, a diverse asset portfolio, deep organisational competence, a strong balance sheet, the cash flow to grow through existing and new investment opportunities in the UK and internationally, and resilience to commodity price cycles. Together these attributes would enable the Combined Group to compete effectively amongst a group of international peers and aspire to a leadership position in ESG.

The Directors and Proposed Directors believe the combination of Premier and Chrysaor would:

- bring together two complementary businesses to create the largest London-listed independent oil and gas company by production and reserves, including:
  - combined production as at 30 June 2020 of over 250 kboepd and 2P reserves of 717 mmboe, alongside 2020 H1 revenue of US$1.76 billion and EBITDAX of US$1.27 billion
- result in significant scale and diversification through the combination of material interests in multiple cash generative production hubs in the UK North Sea including
  - operated positions in Britannia, J-Area, AELE, Catcher and Tolmount, as well as non-operated equity in other key hubs including Clair, Buzzard, Beryl, Elgin-Franklin and Schiehallion
- create the foundation for a more geographically balanced portfolio with growth potential in Southeast Asia and Latin America, building on Premier's existing global footprint
  - the strengthened financial position would enable funding for attractive organic and inorganic investment opportunities internationally with the aim of supplementing existing assets in Indonesia, Vietnam, Mexico, the Falkland Islands and Brazil in order to achieve scale in Southeast Asia and Latin America
- create a business with competitive low-cost production and resilience to compete in a low commodity price environment
  - the Combined Group will have competitive operating costs which rank in the top quartile of its leading European listed independent oil and gas peer group companies, alongside a high degree of operating control (the Combined Group will operate 63 per cent. of its assets by reserves), which would provide the opportunity to pursue further cost efficiencies across the portfolio
- transform Premier's financial position, to deliver a Combined Group with a strong and sustainable financing structure
  - the Combined Group would benefit from a strong balance sheet alongside a simplified capital structure; accounting net debt (excluding letters of credit) is expected to be approximately US$3.2 billion on completion (assuming full take up of the Partial Cash Alternative by Restructuring Plan Creditors), bringing leverage ratios in line with the leading European listed independent oil and gas companies
- create a business with the potential to offer a meaningful dividend for shareholders over time
  - it is expected that the Combined Group would generate sufficient free cash flow to support shareholder returns including via a sustainable dividend which, subject to market conditions and Board approval, would be introduced with respect to the financial year ending December 2021
- create potential to realise substantial operational and financial synergies
  - including through the opportunity for improved capital allocation driving higher returns across the portfolio, various operational and other efficiencies in the UK North Sea, corporate level cost savings and lower financing costs
- create a business committed to ESG leadership including strategies to further address the carbon footprint of its operations in order to position itself for the energy transition

- the Combined Group would have a lower carbon intensity than the average of UK oil and gas producers, with targets in place for further improvement and a commitment to achieving 'Net Zero' from a greenhouse gas emissions standpoint by 2035.

4.2 Synergies

By combining the two businesses, the Directors and Proposed Directors believe the Merger will provide the potential to generate significant synergies through operating, financing and other cost savings, which is highly attractive in the current oil price environment and will position the Combined Group well for the future.

As a result of the scale achieved by the combination, the Directors and Proposed Directors believe there will be opportunities for operating efficiencies through the integration of Premier's and Chrysaor's operations. In particular, Premier and Chrysaor have significant and over-lapping activity in the UK North Sea region, including in areas such as procurement, logistics, materials, drilling and subsea operations. Premier and Chrysaor's combined UK North Sea operating costs and capital expenditures totaled US$855 million in the first half of 2020. Incremental efficiency gains across this combined portfolio could therefore generate material annual cost reductions. Initial efficiency gains are expected to come from the integration of suppliers and contracting strategies. Some of the benefits realised in the UK may also deliver further efficiency gains across the international portfolio.

In addition, further savings are expected through elimination of duplicate activities in corporate functions, redundant office locations, and efficiencies with respect to other areas of corporate expense such as IT, hedging and insurance. The Combined Group would expect to generate the majority of savings in relation to these efficiencies in the first 12 to 24 months post completion.

The Directors and Proposed Directors also believe that the combination and improved cash flows from the synergies identified above could result in the utilisation of a significant portion of Premier's c.US$4.1 billion of UK tax losses, which could support continued material investment in the UK North Sea. The timeframe for any such utilisation is not certain and will necessarily depend on a wide range of factors (including, amongst other things, commodity prices, oil and gas production levels and operating costs), but is currently expected to be within the first five years following completion of the Merger.

The Directors and Proposed Directors have also identified debt financing costs as an area that could generate significant savings for the Combined Group. Premier's effective interest rate, as reported in its H1 2020 interim results, was 7.9 per cent. on drawn funds of US$2,114 million. Drawings under the new $4.5 billion reserve-based lending facility for the Combined Group will be funded at a margin of 3.25 per cent. over the LIBOR benchmark. The new financing structure for the Combined Group should therefore generate material savings going forward.

4.3 Purpose and Strategy of the Combined Group

The Combined Group's purpose is to play a role in meeting the world's energy needs through the safe, efficient and sustainable production of hydrocarbons whilst delivering competitive returns for shareholders.

The Combined Group's goal is to be a leading, global, independent oil and gas company that is trusted by its stakeholders, with material producing operations in its established regions supported by a focus on four strategic pillars:

- **Safe, Reliable & Environmentally Responsible Operations** – to ensure the Combined Group earns the trust of all stakeholders
  - Conduct the Combined Group's operations in such a way as to protect the safety and wellbeing of its people, the communities in which it operates and the environment
  - Continuously improve the Combined Group's health, safety and environmental performance
  - Deliver progress towards the Combined Group's 'Net Zero' commitment
  - Measure, verify and report the data necessary to support the Combined Group's goals, and include relevant metrics in the incentive compensation program

- **Full-Cycle Capability** – an organisation with global capability across exploration, development, production and decommissioning, as well as M&A
  - Leverage full-cycle capabilities and M&A expertise to expand the investment opportunity set in regions where the Combined Group has an established presence
  - Deep organisational competence and a strong preference for operatorship in order to drive standards, efficiencies and control over capital expenditure levels
- **High Quality Portfolio of Reserves and Resources** – build a low cost, diverse and geographically balanced portfolio providing access to a range of profitable investment opportunities
  - Producing assets with competitive operating costs, enabling positive margins in times of low commodity prices
  - A portfolio of near term, profitable drilling and development opportunities, providing options to maintain production at desired levels
  - A diverse resource base in the Combined Group's target regions and near existing infrastructure, providing longer term options for investment including exploration in proven basins in addition to inorganic opportunities
  - Backed by a rigorous prioritisation and capital allocation process to drive high-grading of investment decisions and financial returns
- **Financial Strength** – resilient to commodity price cycles with sufficient free cash flow to manage borrowings and reinvest in the Combined Group's resource base
  - Maintain a strong balance sheet, with the potential for an Investment Grade credit rating
  - Disciplined annual budget and long-term planning processes with stress-testing for low commodity price environments
  - Active commodity price hedging programme to manage price volatility and protect against downside movements
  - Create a path to a sustainable dividend

4.4 The Combined Group's Commitment to Environmental, Social & Corporate Governance (ESG)

The Combined Group will build on the progress already made in both Premier and Chrysaor in the areas of Environmental, Social and Corporate Governance. The Combined Group's overall aim will be to deliver value in a responsible manner for all stakeholders in accordance with key global standards and ensured through strong corporate governance.

Environmental & Climate Change

The Directors and Proposed Directors share the concerns around climate change and acknowledge the regulatory, societal and political framework in which the Combined Group will operate. The Directors and the Proposed Directors therefore believe that it is imperative to address the environmental impact of the Combined Group's operations and assets around the world and are committed to playing a role in the transition to a lower carbon economy. As a reflection of this, the Combined Group will commit to attaining the goal of "Net Zero" no later than 2035, well in advance of the UK government goal of 2050. The Combined Group's Net Zero commitment includes:

- Scope 1 emissions – those emissions directly related to assets in which the Combined Group has an interest
- Scope 2 emissions – those emissions from the generation of purchased electricity
- The Combined Group's net share of emissions from both operated and non-operated assets, as this is how oil and gas production, reserves and resources, and financial results are tracked and reported
- The purchase of offsets for an increasing portion of the Combined Group's residual emissions year-on-year so that the Combined Group makes continuous progress towards achieving its goal of Net Zero by 2035

The Combined Group's other commitments include:

- Tracking and target-setting for emissions and emissions intensity, the results to be verified by an independent third party
- Inclusion of emissions-related metrics in the Combined Group's incentive compensation program
- Incentives in the Combined Group's main debt facility tied to progress in reducing emissions
- Investment in CO2 capture & storage initiatives with industry partners as well as in nature-based offset projects
- Transparent reporting of the Combined Group's emissions and progress against its targets and commitments; its reporting will be compliant with the disclosures recommended by the Task Force on Climate-Related Financial Disclosure and the Global Reporting Initiative by 2022

Social Initiatives

As a publicly listed company, the Combined Group will maintain and actively promote the social provisions of the UK Corporate Governance Code throughout its operations, representing the interests of stakeholders including its workforce and the communities in which the Combined Group operates.

The Combined Group will be proud to support the communities where it works and contribute to charitable causes and other social initiatives. As a company with international operations, the Combined Group will remain vigilant to local content and workforce nationalisation requirements. The Combined Group's operations in Vietnam and Indonesia are examples of its commitment to local employment and the development of indigenous talent.

The Combined Group will strive for a culture of inclusion and to ensure the values of diversity and equality are reflected in its policies, procedures and the way it works. The Combined Group will recruit, retain and promote staff based on competence alone and regardless of age, disability, gender, race, religion and belief, marriage or civil partnerships, pregnancy, maternity or sexual orientation.

Corporate Governance

The Combined Company will be governed by a Board made up of the Directors and the Proposed Directors identified in Part XII (*Directors, Employees and Corporate Governance*). The Board will be collectively responsible for the governance of the Combined Group on behalf of shareholders and is accountable to them for the long-term success of the Combined Group. The Board will govern the Combined Group in accordance with the authority set out in Premier's Articles of Association and in compliance with the main Principles of the UK Corporate Governance Code.

The Board of the Combined Group will continue the committee structure already established by the Premier Group, and will include Audit and Risk, Remuneration, Nomination and Health, Safety, Environment and Security ("**HSES**") Committees. Each Committee has formal terms of reference, copies of which are available on Premier's website.

The Board will set the Combined Group's strategic objectives and ensure they are properly pursued within a sound framework of internal controls and risk management. The Board will monitor the Combined Group's risk management and internal control systems throughout the year and, on an annual basis, carry out a review of their effectiveness. The Board will operate with a structured agenda for the year ensuring all relevant matters are considered, with sufficient time allowed for discussion. Agenda topics will include: strategic issues (both setting the strategy and reviewing its execution); corporate targets and budget approval; HSES and risk; internal controls and risk management; corporate responsibility; financing; investor relations; corporate reporting; Board Committee-related activity including executive compensation and matters requiring Board sanction; and other corporate governance matters. The Board will meet at least six times each year with additional meetings or conference calls as needed.

The highest standards of integrity are fundamental to how the Combined Group conducts its business. This approach extends to behaviour in the workplace where no form of bribery, corruption, misconduct or wrongdoing in the Combined Group's business dealings will be tolerated. Compliance with all relevant laws in the jurisdictions in which the Combined Group operates will be essential in maintaining its core values, ensuring a safe and sustainable business whilst protecting its reputation. The Combined Group will continue to ensure its staff receive the appropriate training to understand and comply with the Combined Group's Corporate Ethics and Compliance Policy.

4.5 Consideration Shares and Creditor Shares

Immediately following Admission, assuming that the maximum number of Creditor Shares are issued and allotted and no take-up of New Equity Warrants, it is expected that Premier will have 18,510,653,520 fully paid Ordinary Shares in issue (none of which will be held in Treasury).

If Admission occurs, it will result in the issue and allotment of 14,253,203,210 Consideration Shares, up to 3,331,917,634 Creditor Shares and up to 148,085,228 New Equity Warrants. Existing Shareholders will suffer an immediate dilution as a result of Admission, following which they will hold:

– assuming that the maximum number of Creditor Shares are issued and allotted and no take-up of New Equity Warrants, approximately 5 per cent. of the enlarged share capital of the Company; and

– assuming that the minimum number of Creditor Shares are issued and allotted and maximum take-up of New Equity Warrants, approximately 5.45 per cent. of the enlarged share capital of the Company.

4.6 Integration review

The Directors and the Proposed Directors, having reviewed and analysed the potential benefits of the Merger, note that, to achieve some of the expected benefits of the Merger, it will be necessary to undertake a review of how best to integrate the Premier Group and the Chrysaor Group. The review has now commenced and a steering committee has been established to coordinate integration planning. However, the Premier Group and the Chrysaor Group remain separate and data sharing is subject to certain restrictions for commercial and competition law reasons until completion of the Merger and the Debt Restructuring.

4.7 Financial effects of the Merger

On a *pro forma* basis and assuming that the Merger and the Debt Restructuring had taken place, in each case on 30 June 2020, the Combined Group would have had net assets of US$3,255.3 million and net debt to EBITDA of x1.28, compared with net assets reported by Premier as at 30 June 2020 of US$490.2 million and net debt to EBITDA of x3.33.

The unaudited *pro forma* statement of net assets has been prepared to illustrate the effect on the consolidated net assets of Premier as at 30 June 2020 as if the Merger and the Debt Restructuring had each taken place on 30 June 2020. The unaudited *pro forma* income statement has been prepared to illustrate the effect on the consolidated earnings of Premier for the six month period ended 30 June 2020 as if the Merger and the Debt Restructuring had each taken place on 1 January 2020. For further detail on the Unaudited *Pro forma* Financial Information, please see Part IX (*Unaudited Pro Forma* Financial Information) of this document.

4.8 Conditions

Completion of the Merger is subject to, and can only occur upon the satisfaction or waiver of, the following conditions by no later than 30 September 2021 (unless agreed otherwise by the parties to the Merger Agreement):

(A) the Prospectus and the Circular having been approved by the FCA and, in the case of the Circular, the Takeover Panel, in each case in a form approved by the Harbour/Chrysaor Parties;

(B) the Merger and Debt Restructuring Resolutions having been approved by Shareholders at the General Meeting;

(C) the FCA having confirmed to Premier that its application for the readmission of all of the Existing Ordinary Shares and admission of all of the New Ordinary Shares, in each case to the premium listing segment of the Official List of the FCA has been approved;

(D) the London Stock Exchange having confirmed to Premier that its application for the re-admission of all of the Existing Ordinary Shares and admission of all of the New Ordinary Shares, in each case to trading on the main market for listed securities of the London Stock Exchange have been approved;

(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 a seller under the Merger Agreement or any person acting in concert (as defined in the Takeover Code) with it under Rule 9 of the Takeover Code to make a general offer for the Company as a result of the issue of the Consideration Shares;

(F) the Restructuring Plans having been sanctioned by the relevant Courts with or without modification (but subject to any such modification being acceptable to the Harbour/Chrysaor Parties, acting reasonably) and an office copy of the relevant court orders having been delivered to the Registrar of Companies;

(G) receipt of regulatory approvals from the OGA in the UK, the Norwegian Ministry of Petroleum and Energy and (if applicable) the Norwegian Ministry of Finance and the Falkland Islands Government;

(H) receipt by Premier of the competition authority clearances from each of the European Commission, the Mexican Federal Economic Competition Commission and the competition authorities in Vietnam; and

(I) Premier not having committed a material breach of certain of its respective interim covenants and warranties under the Merger Agreement.

As at the date of this document, conditions (B), (C), (D), (F), (G) and (H) remain outstanding, although the Company has received the required competition clearance from the European Commission and has received conditional approval from the Norwegian Ministry of Petroleum and Energy for the Merger. In order to satisfy each of these outstanding conditions, Premier intends to:

(A) pass the Merger and Debt Restructuring Resolutions at a General Meeting to be held on 12 January 2021;

(B) obtain approval for the Restructuring Plans from Restructuring Plan Creditors at the Restructuring Plan Creditor Meetings to be held on 22 February 2021 as part of the Restructuring Plans process and present the Restructuring Plans for sanction by the relevant Courts;

(C) make the applications to the FCA and the London Stock Exchange required for Admission and Readmission;

(D) liaise with the OGA, Norwegian Ministry of Petroleum and Energy and Department of Mineral Resources of the Falkland Islands, as well as any other relevant regulatory bodies in those jurisdictions (as applicable) to provide any additional information they may require in order to provide the necessary approvals in respect of the Merger and the Debt Restructuring; and

(E) liaise with the Mexican Federal Economic Competition Commission and the relevant competition authorities in Vietnam, as well as any other relevant regulatory bodies in those jurisdictions (as applicable) to provide any additional information they may require in order to provide the necessary approvals in respect of the Merger and the Debt Restructuring.

4.9 Admission

The Company intends to proceed with the completion of the Merger and the Debt Restructuring, and to apply for the admission of the New Ordinary Shares in connection therewith for listing on the premium listing segment of the FCA's Official List and admission to trading on the main market of the London Stock Exchange, as soon as reasonably practicable once: (i) each of the Restructuring Plans has been sanctioned by the relevant Courts and delivered to Companies House; and (ii) all of the other conditions to the completion of the Merger have been satisfied (save for those relating to Admission).

5. Reasons for the Debt Restructuring

5.1 Introduction

The proposed terms of the Debt Restructuring, which will be implemented through three Court-sanctioned Restructuring Plans, were agreed with a sub-set of Premier's creditors on 6 October 2020. Given the level of support received from the Super Senior XCCY Restructuring Plan Creditors, Super Senior RCF/LC Restructuring Plan Creditors and Senior Restructuring Plan Creditors which have entered into the Support Letter, the Directors are able to confirm that Premier has secured sufficient commitments from the requisite majorities to obtain the creditor approvals required for the Debt Restructuring.

It is anticipated that the Restructuring Plan Creditor Meetings will be convened following a hearing at the English Court scheduled to be held on 19 January 2021 and a hearing at the Scottish Court scheduled to be held on 25 January 2021. If the Restructuring Plan Creditor Meetings are convened by the relevant Courts as expected, it is anticipated that the Restructuring Plan Creditor Meetings will be held on 22 February 2021.

If the Debt Restructuring completes, Restructuring Plan Creditors will receive the following in satisfaction of their drawn commitments or exposure (as applicable) under the Existing Debt Facilities and XCCY Swaps:

– an upfront cash payment (funded through a combination of the New RBL Facility and Premier's and Chrysaor's existing cash resources) of US$1.23 billion (subject to certain adjustments);

– Creditor Shares or, subject to meeting eligibility requirements, New Equity Warrants or, for Senior Creditors and Senior XCCY Hedge Counterparties which so elect, a further cash payment pursuant to the Partial Cash Alternative (capped at approximately US$175 million).

As announced on 6 October 2020, the Upfront Cash Consideration and the refinancing of the Premier Group's outstanding letters of credit of approximately US$400 million together represent approximately 61 cents on the dollar for Restructuring Plan Creditors (on average across all Restructuring Plan Creditors). If a Senior Creditor elects for the Partial Cash Alternative, they will receive an additional payment of up to 14 cents on the dollar, approximately, instead of receiving Creditor Shares.

In addition, the Debt Restructuring will involve:

– the cancellation of all undrawn commitments under the Super Senior Secured RCF/LC Facility Agreement, the Senior RCF/LC Facility Agreement and the Nelson Bilateral LC Facility Agreement;

– the replacement of all outstanding letters of credit under the Super Senior Secured RCF/LC Facility Agreement, the Senior RCF/LC Facility Agreement and the Nelson Bilateral LC Facility Agreement with the cancellation of all commitments in relation to such letters of credit;

– Senior Creditors and Senior XCCY Hedge Counterparties will be able to subscribe for unallocated Creditor Shares through the Top-Up Election; and

– in order to allow time for the Merger to complete, or alternatively in the event the Merger and Debt Restructuring Resolutions are not passed to agree and implement an alternative plan for implementation of the Merger and the Debt Restructuring or, if that is not possible, an alternative transaction to address the Existing Debt Facilities, the Interim Maturity Extension.

Furthermore, as part of the Debt Restructuring, certain creditors of the Premier Group will enter into the Creditor Lock-Up Agreement, conditional on Admission and Readmission occurring. Under the terms of the Creditor Lock-Up Agreement, Creditor Shares (which shall include the New Equity Warrants and the New Warrant Shares but shall exclude any Creditor Shares issued pursuant to the Top-Up Election) held by Restructuring Plan Creditors and their designated nominees whose holdings represent more than 2.7 per cent. of the enlarged share capital of the Company on completion of the Merger and the Debt Restructuring will be subject to a lock-up period of three months in respect of fifty per cent. of their Creditor Shares and a further three-month lock-up period in respect of their remaining Creditor Shares. For further details on the Creditor Lock-Up Agreement, please see section 5.1 of Part XIII (*Additional Information*).

Moreover, following completion of the Merger and the Debt Restructuring, certain shareholders of the Company will be subject to lock-up restrictions, preventing them from selling any Ordinary Shares (or other securities) of the Company for certain periods of time. The table below sets out the nature of, and minimum percentage of investors subject to, the lock-up restrictions expected to be in place at completion of the Merger and their duration.

Shareholder	**Percentage of the Combined Group's share capital held immediately after Admission (assuming no take up of the Partial Cash Alternative by Restructuring Plan Creditors)**	**Percentage of the Combined Group's share capital held immediately after Admission (assuming full take up of the Partial Cash Alternative by Restructuring Plan Creditors)**	**Subject to lock-up restrictions?**	**Duration[(1)]**
Harbour North Sea[(2)]	**36.50%**	**39.78%**	**Yes**	**Twelve month lock-up, with a further twelve month orderly marketing covenant**
Certain Chrysaor minority shareholders[(2)]	**28.49%**	**31.05%**	**Yes**	**Six month lock-up, in certain cases with a further twelve month orderly marketing covenant**
Restructuring Plan Creditors	**18.00%**	**10.63%**	**Yes, provided that the Restructuring Plan Creditor (and any of their designated nominees), holds more than 2.7 per cent of the enlarged share capital of the Company as described in the paragraph above**	**Three months lock-up in respect of fifty per cent. of their Creditor Shares and a further three-month lock-up in respect of their remaining Creditor Shares**
Existing Premier Shareholders	**5.00%**	**5.45%**	**No**	**N/A**

(1) All lock-up periods shall commence on the date on which completion of the Merger and the Debt Restructuring occurs.

(2) The allocation of Consideration Shares among Chrysaor shareholders will depend on the value of those Consideration Shares in the period up to the completion of the Merger.

The principal terms of the Merger are described in more detail in the Circular.

For further details on the effects of the Debt Restructuring, please see paragraph 1 of Part II (*Details of the Debt Restructuring*). The Debt Restructuring is subject to a number of conditions that must be satisfied or waived to proceed which are described further in paragraph 5.3 below.

5.2 Consequences of the Debt Restructuring not being implemented

The Directors and the Proposed Directors believe that the Debt Restructuring will provide Premier with a more sustainable and suitable debt structure and provide the Combined Group with a strong foundation that will enable it to deliver on the objectives described in this Part I (*Background to and reasons for the Merger and the Debt Restructuring*).

In addition to these benefits of the Debt Restructuring, the Directors believe that the implementation of the Debt Restructuring is critical to the future success of Premier for the reasons outlined below.

(A) Debt Restructuring does not complete; Interim Maturity Extension completes

If the Debt Restructuring (other than the Interim Maturity Extension) does not proceed, Participating Creditors will still be obliged to support, and vote in favour of the Restructuring Plans in order to implement, the Interim Maturity Extension. Support for the Interim Maturity Extension from the Participating Creditors has been obtained, subject to certain conditions as outlined in paragraph 13 of Part I (*Letter from the Chairman of Premier*) of the Circular, to allow time for the Merger to complete, or alternatively in the event the Merger and Debt Restructuring Resolutions are not passed to agree and implement an alternative plan for implementation of the Merger and the Debt Restructuring or, if that is not possible, an alternative transaction to address the Existing Debt Facilities. Once effective, the Interim Maturity Extension will extend the maturity date of Premier's Existing Debt Facilities from 31 May 2021 to 31 March 2022. The consequences for the Premier Group if the Interim Maturity Extension does not become effective are outlined below in the section titled "*Neither Debt Restructuring nor Interim Maturity Extension completes*".

The Support Letter, and the financial covenant deferrals contained in the Support Letter, will remain in place until the Interim Maturity Extension becomes effective, unless the Support Letter is terminated earlier in accordance with the termination provisions contained therein. As further detailed in the Risk Factor entitled "*The Support Letter may be terminated in accordance with its terms on the occurrence of certain specified events*", the Support Letter may be terminated at the election of the Majority Creditors in certain circumstances, including, if:

- the Merger and Debt Restructuring Resolutions are not approved by Shareholders at the General Meeting and an alternative plan for implementation of the Merger and the Debt Restructuring has not been agreed between Premier, Chrysaor and the Participating Creditors within 20 business days of the General Meeting;
- an event of default arises under the Existing Debt Facilities or the XCCY Swaps(other than an event of default which has been remedied or waived or has arisen, or deemed to have arisen, directly as a result of the implementation of the Merger and the Debt Restructuring), such events of default being customary for financing arrangements of the size and nature of the Existing Debt Facilities, including events of default relating to non-payment, insolvency, insolvency proceedings, misrepresentation and cross-default, among other things;
- relevant members of the Premier Group breach the terms of the Support Letter in any material respect or any representation or warranty by the relevant members of the Premier Group under the Support Letter is materially incorrect or misleading;
- Chrysaor breaches certain undertakings given by it under the Support Letter in any material respect. These undertakings include, among other things: (i) to support the Debt Restructuring; (ii) not to take any action which would be inconsistent with the Merger or the Debt Restructuring in any material respect; and (iii) to instruct its legal advisers to negotiate the documentation required to implement the Debt Restructuring on the terms of the agreed term sheets in good faith;
- the Board decides to withdraw, suspend, qualify or adversely modify or amend, the recommendation of the Merger set out in the Circular in circumstances where Chrysaor has not elected to terminate the Merger Agreement and an alternative plan for implementation of the Merger and the Debt Restructuring has not been agreed between Premier, Chrysaor and the Participating Creditors;

- at any Restructuring Plan Creditor Meeting the requisite majorities by value of creditors entitled to vote on such Restructuring Plan have not voted for such Restructuring Plan such that any of the Restructuring Plans are not approved;
- certain milestones are not completed (including the posting of the explanatory statement relating to the Restructuring Plans to the Restructuring Plan Creditors by 28 February 2021 and the Merger and Debt Restructuring Resolutions being approved by Shareholders by 30 April 2021) within the relevant timeframe (as may be extended) other than where Premier has provided evidence that this is as a result of a breach by Chrysaor of its obligation under the Support Letter to provide reasonable assistance to enable Premier meet those milestones;
- either the English Court or the Scottish Court issues a judgment refusing to sanction all or any of the Restructuring Plans which is either (a) not appealed by any party within the period of time in which to bring such an appeal under Scottish or English law (as applicable), or (b) appealed within such period of time and such appeal is unsuccessful;
- either the English Court or the Scottish Court issues an order preventing the Company, POUK or POHL from implementing the Debt Restructuring or Restructuring Plans which is either (a) not appealed by any party, or (b) appealed and such appeal is unsuccessful; or
- where Chrysaor has notified the Company that the Company has breached the Merger Agreement in a manner which provides any of the Harbour/Chrysaor Parties the right to terminate the Merger Agreement and none of the Harbour/Chrysaor Parties exercises its termination right, or the Merger and Debt Restructuring Resolutions are not approved by shareholders at the General Meeting, an alternative plan for implementation of the Merger and the Debt Restructuring has not been agreed between Premier, Chrysaor and the Participating Creditors within 20 business days of such notification.

In addition, the Support Letter will automatically terminate on the earliest to occur of the following: (i) where the Merger Agreement is terminated in accordance with its terms and the Interim Maturity Extension becomes effective; (ii) an insolvency event occurs in relation to certain Premier Group companies; (iii) the Long-Stop Date; and (iv) the Merger and the Debt Restructuring becomes effective. If the Support Letter is terminated in accordance with its terms, the financial covenant deferrals contained in the Support Letter will terminate 45 days after the termination of the Support Letter, other than in certain limited circumstances, including where the Support Letter terminates on the date on which the Debt Restructuring becomes effective or (where the Merger Agreement has terminated) the Interim Maturity Extension becomes effective. Further details in respect of the termination rights under the Support Letter are set out under the Risk Factor entitled "*The Support Letter may be terminated in accordance with its terms on the occurrence of certain specified events.*".

If Premier were unable to secure further deferrals of a similar nature or if Premier were to breach financial covenants in respect of a subsequent testing period without a deferral or waiver in place, there would be an event of default under the Override Agreement. If an event of default were to occur in these circumstances, the Private Creditors would have the right to declare the Private Debt Facilities (which totalled US$2.2 billion as at 31 October 2020) immediately due and payable, which if exercised would in turn trigger an event of default under the XCCY Swaps and cross-default under the Retail Bonds (which total £150 million). The Private Creditors, the XCCY Hedge Counterparties and the Retail Bondholders would also have the right to take immediate steps to enforce their security over shares in certain Premier Group companies and certain other key assets of the Premier Group.

As a result, if the Debt Restructuring (other than the Interim Maturity Extension) does not proceed and the Premier Group does not secure future financial covenant deferrals, and even if the Interim Maturity Extension does become effective, it is expected that the Premier Group's Existing Debt Facilities and exposures under the XCCY Swaps will become payable before 31 March 2022 as a consequence of the events of default and acceleration of the Premier Group's debt described above. Premier considers that the Premier Group would not be able to repay the Private Debt Facilities and exposures under the XCCY Swaps in these circumstances. Even if Premier is able to secure future financial covenant deferrals for the period until 31 March 2022, Premier does not consider that the Premier Group will be able to repay the outstanding debt under its Existing Debt Facilities and exposures under the XCCY Swaps when they mature, or crystallise (as relevant) on that date in which case the events of default, acceleration and enforcement of security described above could occur.

As a result, in circumstances where the Debt Restructuring (other than the Interim Maturity Extension) does not complete but the Interim Maturity Extension does complete, the ability of members of the Premier Group to continue trading will depend upon:

– a significant portion of its creditors providing further financial covenant deferrals upon termination of the Support Letter; and

– the Premier Group agreeing, before 31 March 2022, either: (i) an alternative plan for the implementation of the Merger and the Debt Restructuring with its creditors and Chrysaor within the timeline contained within the Support Letter; or (ii) an alternative transaction to address its Existing Debt Facilities and exposures under the XCCY Swaps with its creditors.

Premier has an obligation under the Support Letter to provide information, access and cooperation in order for Participating Creditors to develop contingency plans for a scenario where the Merger and the Debt Restructuring are not implemented. In a scenario where the Merger and Debt Restructuring Resolutions are not passed, and the Premier Group is therefore dependent on support from its creditors to continue trading, the creditors will be able to require Premier to take steps to implement any contingency plans which are developed by the Participating Creditors as a condition to the provision of their continuing support.

In addition to this general obligation in respect of contingency planning, Premier is required under the terms of the Support Letter to work together with Chrysaor and Participating Creditors in good faith to agree and prepare an alternative plan to implement the Merger and the Debt Restructuring in the event that the Merger and Debt Restructuring Resolutions are not passed (which could involve the filing for insolvency of the Company and/or other companies within the Premier Group, and/or the enforcement of security). In addition, Chrysaor and Participating Creditors have agreed that they will not engage in any negotiations with any other party in connection with any similar transaction to the Merger and the Debt Restructuring or alternative transaction relating to the Premier Group, other than an alternative plan to implement the Merger and the Debt Restructuring, for a period of 20 business days after the General Meeting at which the Merger and Debt Restructuring Resolutions are not passed. It is likely that any alternative plan to implement the Merger and the Debt Restructuring would provide for minimal or no recovery for Shareholders.

If no alternative plan to implement the Merger and the Debt Restructuring was agreed, the Board would seek to negotiate an alternative transaction to address its Existing Debt Facilities with its creditors (although these discussions could not start until expiry of the 20-business day period referred to above). There is no certainty that the creditors would engage with the Board in those circumstances or that any negotiations regarding an alternative transaction would be successful. In particular, the following factors are likely to affect negatively the Premier Group's ability to negotiate an alternative transaction:

– although the Premier Group has retained the support of a significant group of its creditors in negotiating and agreeing the terms of the Debt Restructuring, it is likely that, if the Merger and the Debt Restructuring do not become effective, some or all of the creditors who are currently supportive could become less supportive of the Premier Group or could sell their debt-holdings to parties whose interests may not be aligned with the Premier Group;

– any doubt as to the Premier Group's ability to continue as a going concern following the non-completion of the Merger and the Debt Restructuring could have a material and adverse commercial impact on the Premier Group's trading, which could in turn lead to liquidity problems for the Premier Group; and

– the impact of COVID-19, volatile credit markets and/or the outlook for oil and gas prices.

If Premier cannot negotiate an alternative transaction to address its debt facilities with its creditors, Premier would likely enter into insolvency proceedings, on or before 31 March 2022, which the Directors consider would likely result in no value being returned to Shareholders. This is because even if the Interim Maturity Extension is implemented, the Premier Group will be dependent on continued deferrals of its financial covenants from a significant portion of its creditors in order to continue to trade. Even if Premier is able to secure financial covenant deferrals for the period until

31 March 2022, the Directors do not consider that the Premier Group will be able to repay its outstanding debt when it matures on that date.

(B) Neither Debt Restructuring nor Interim Maturity Extension completes

The Directors and the Proposed Directors believe that, given the undertakings by Participating Creditors pursuant to the Support Letter and the limited number of conditions to the effectiveness of the Interim Maturity Extension, it is very likely that the Interim Maturity Extension will have completed by 31 May 2021. However, if any of the conditions to the Interim Maturity Extension were not satisfied or waived, the Interim Maturity Extension would not become effective and accordingly the outstanding debt under the Premier Group's Existing Debt Facilities and exposures under the XCCY Swaps will mature or crystallise on 31 May 2021. Premier does not consider that it will be able to repay this outstanding debt, in which case the Private Creditors, the XCCY Hedge Counterparties and the Retail Bondholders could take immediate steps to enforce their security over shares in certain Premier Group companies and certain other key assets of the Premier Group.

Further, the Support Letter may be terminated if the Interim Maturity Extension does not become effective as a result of the Restructuring Plans not being approved by the requisite majorities of creditors or not being sanctioned by either the English Court or the Scottish Courts. If the Support Letter were to terminate in these circumstances, the financial covenant deferrals contained in the Support Letter would terminate 45 days after the termination of the Support Letter. The consequences if those financial covenant deferrals terminate and the Premier Group does not secure future financial covenant deferrals are outlined above.

As a result, in circumstances where neither the Debt Restructuring nor the Interim Maturity Extension completes, the ability of members of the Premier Group to continue trading will depend upon:

– a significant portion of its creditors providing further financial covenant deferrals upon termination of the Support Letter; and

– the Premier Group agreeing, before 31 May 2021, either: (i) an alternative plan for the implementation of the Merger and the Debt Restructuring with its creditors and Chrysaor within the timeframe contained within the Support Letter; or (ii) an alternative transaction to address its debt facilities with its creditors.

While Premier has obligations under the Support Letter in respect of the preparation and agreement of contingency plans for a scenario where the Merger and the Debt Restructuring does not complete (as noted above), it is unlikely that any alternative plan for the implementation of the Merger and the Debt Restructuring or alternative transaction to address its debt facilities will be agreed and implemented prior to 31 May 2021. The factors outlined above as being likely to affect negatively the Premier Group's ability to negotiate an alternative transaction will be more pronounced where the Premier Group has less than six months until the Existing Maturity Date (which is the position as at the date of this Prospectus), and will become more pronounced still the closer the Premier Group gets to the Existing Maturity Date. It would therefore be likely that the Premier Group would enter into insolvency proceedings on or before the existing maturity date under the Existing Debt Facilities and XCCY Swaps of 31 May 2021, which the Directors consider would likely result in no value being returned to Shareholders.

5.3 Conditions to the Debt Restructuring

The Debt Restructuring (other than the Interim Maturity Extension) is inter-conditional with the completion of the Merger, and subject to certain conditions which must be satisfied or waived, including:

(A) the Merger and Debt Restructuring Resolutions having been passed by Shareholders at the General Meeting;

(B) the Restructuring Plans (which are inter-conditional) having been approved by the requisite majorities at the Restructuring Plan Creditor Meetings, sanctioned by the relevant Courts and a copy of the sanction orders delivered to the Registrar of Companies for Scotland or the Registrar of Companies for England and Wales (as applicable);

(C) each of the Non-XCCY Hedge Counterparties having given any consents required in connection with the Debt Restructuring, which the Non-XCCY Hedge Counterparties have undertaken to do pursuant to the Non-XCCY Hedging Support Letters;

(D) satisfaction of certain documentary conditions in respect of conditions precedent that are customary for a secured financing transaction and/or are within the control of the Premier Group;

(E) the FCA and the London Stock Exchange each having approved the applications for Admission (by not later than 30 September 2021, or such later date as may be agreed by Premier, Chrysaor and the Majority Creditors provided that such later date may not be later than 1 December 2021) (the "**Long-Stop Date**"); and

(F) payment of certain costs associated with the Debt Restructuring.

As at the date of this document, each of the conditions listed above remain outstanding. The Directors and the Proposed Directors believe that, based on the level of support which the Debt Restructuring has received to date, and subject to the remaining conditions of the Merger Agreement being satisfied and Shareholders resolving to pass the Merger and Debt Restructuring Resolutions at the General Meeting, the risk of the conditions described in (B), (C), (D) and (F) above not being satisfied is remote and that it is therefore likely that the Debt Restructuring will have completed by 31 May 2021. Likewise, the Directors and the Proposed Directors have no reason to believe that Admission will not occur and accordingly consider the non-satisfaction of this condition to be very low risk.

In order to satisfy each of these outstanding conditions Premier intends to:

(A) pass the Merger and Debt Restructuring Resolutions at a General Meeting to be held on 12 January 2021;

(B) obtain approval for the Restructuring Plans from Restructuring Plan Creditors at the Restructuring Plan Creditor Meetings to be held on 22 February 2021 as part of the Restructuring Plans process and present the Restructuring Plans for sanction by the relevant Courts;

(C) facilitate and arrange the delivery of the relevant conditions precedent;

(D) make the applications to the FCA and the London Stock Exchange required for Admission; and

(E) arrange that the relevant costs associated with the Debt Restructuring are paid prior to or at completion of the Merger and Debt Restructuring.

If any of the conditions to the Debt Restructuring are not satisfied or waived (to the extent applicable) the Debt Restructuring will not complete. For further details on the implications of the Debt Restructuring not completing, please see paragraph 5.2 of Part I (*Background to and reasons for the Merger and the Debt Restructuring*), particularly the sub-paragraph titled "*Debt Restructuring does not complete; Interim Maturity Extension completes*".

If, prior to the English Court hearing to convene the English Restructuring Plan Creditor Meetings, the Shareholders have voted against the Merger and Debt Restructuring Resolutions or the Merger Agreement otherwise terminates, then Premier will proceed with the Restructuring Plans but solely to implement the Interim Maturity Extension.

The conditions to the Interim Maturity Extension are:

(A) the Restructuring Plans (which are inter-conditional) having been approved by the requisite majorities at the Restructuring Plan Creditor Meetings, sanctioned by the relevant Courts and a copy of the sanction orders delivered to the Registrar of Companies for Scotland or the Registrar of Companies for England and Wales (as applicable);

(B) each of the Non-XCCY Hedge Counterparties having given any consents required in connection with the Debt Restructuring, which the Non-XCCY Hedge Counterparties have undertaken to do pursuant to the Non-XCCY Hedging Support Letters;

(C) satisfaction of certain documentary conditions in respect of conditions precedent that are customary for a secured financing transaction and/or are within the control of the Premier Group; and

(D) payment of certain costs associated with the Debt Restructuring.

Once conditions (A) to (D) listed above have been satisfied, there are no further circumstances which could lead to the Interim Maturity Extension not completing. If any of the conditions to the Interim Maturity Extension are not satisfied or waived (to the extent applicable) the Interim Maturity Extension will not complete. For further details on the implications of the Debt Restructuring not completing, please see paragraph 5.2 of Part I (*Background to and reasons for the Merger and the Debt Restructuring*), particularly the sub-paragraph titled "Neither Debt Restructuring nor Interim Maturity Extension completes" as well as the Risk Factor titled "*If the Interim Maturity Extension does not become effective and the Merger and the Debt Restructuring do not proceed, the Premier Group's financial position would be materially adversely affected and it is likely that companies within the Premier Group would be placed into insolvency procedures on or before 31 May 2021*" above.

5.4 Reorganisation of Share Capital

Reasons for the Subdivision

Pursuant to the terms of the Debt Restructuring, the Company will issue up to 148,085,228 New Equity Warrants to Restructuring Plan Creditors who elect to receive New Equity Warrants instead of New Ordinary Shares in circumstances where the Partial Cash Alternative is oversubscribed, provided that the subscription by such electing Restructuring Plan Creditors to the New Ordinary Shares is restricted by any law or regulation to which such electing Restructuring Plan Creditor is subject to or would give rise to liability for such electing Restructuring Plan Creditor to any governmental, banking, taxation, municipality or other regulatory authority. As such, in order to ensure that such Restructuring Plan Creditors receive an instrument which is economically equivalent to the Creditor Shares as possible subject to the constraints of Scottish company law and will be issued in substitution for Creditor Shares, the Company has agreed to offer eligible Restructuring Plan Creditors the opportunity to receive New Equity Warrants instead of New Ordinary Shares.

Restructuring Plan Creditors who do elect to receive New Equity Warrants shall be required to pay 0.001 pence per New Ordinary Share to the Company on exercise of the New Equity Warrants, subject to any adjustment of the exercise price of the New Equity Warrants in accordance with the terms of the New Equity Warrant Deed Poll. Under the Companies Act companies incorporated in Scotland are not permitted to issue shares at a price below their existing nominal value. As the New Equity Warrant Exercise Price is below the current nominal value of the Existing Ordinary Shares (which, at the date of this document, is 12.5 pence), it is therefore necessary for the Company to complete the Subdivision prior to the Debt Restructuring taking place in order to reduce the nominal value of each Ordinary Share to an amount below the New Equity Warrant Exercise Price.

Accordingly, it is proposed that, pursuant to the terms of the Subdivision, each Existing Ordinary Share in existence as at the Subdivision Record Date will be subdivided into:

(a) one Ordinary Share with a nominal value of 0.0001 pence each; and

(b) one Non-Voting Deferred Share with a nominal value of 12.4999 pence each.

Non-Voting Deferred Share

The Non-Voting Deferred Shares will be effectively worthless. They will have no voting or dividend rights and, on a return of capital or on a winding up of the Company, will have the right to receive the amount paid up thereon only after holders of all Ordinary Shares have received, in aggregate, any amounts paid up on each Ordinary Share plus £10 million on each Ordinary Share. The Non-Voting Deferred Shares will not give the holder the right to receive notice of, nor attend, speak or vote at, any general meeting of the Company.

No share certificates will be issued in respect of the Non-Voting Deferred Shares, nor will CREST accounts of Shareholders be credited in respect of any entitlement to Non-Voting Deferred Shares, nor will they be listed on the Official List or admitted to trading on the London Stock Exchange or any other investment exchange. As such, the Non-Voting Deferred Shares will not be transferable at any time (other than with the prior written consent of the Directors). The rights attaching to, and restrictions upon, the Non-Voting Deferred Shares are set out in Resolution 4 in the Notice of General Meeting.

New Ordinary Shares

The effect of the Subdivision will mean that each New Ordinary Share will have a nominal value of 0.0001 pence and the number of ordinary shares of the Company listed on the Official List and admitted to trading on the London Stock Exchange's main market for listed securities shall remain the same. Each Shareholder's proportionate interest in the Company's issued ordinary share capital, and the number of Ordinary Shares held, will remain unchanged as a result of the Subdivision. However, the number of Ordinary Shares and Shareholder's proportionate interest in the Company's issued ordinary share capital will change following Admission of the Consideration Shares and the Creditor Shares issued pursuant to the Merger and the Debt Restructuring.

Aside from the change in nominal value, the rights attaching to the Ordinary Shares (including voting and dividend rights and rights on a return of capital) will be identical in all respects to those of the Existing Ordinary Shares. No new share certificates will be issued in respect of the Ordinary Shares arising from the Subdivision as existing share certificates for Existing Ordinary Shares will remain valid in respect of the same number of such Ordinary Shares.

6. Financing of the Combined Group following the Merger

The Premier Group has the following debt facilities in place:

– the Super Senior Secured RCF/LC Facilities, comprising a US$25.84 million cash loan facility and a US$15.15 million letter of credit facility;

– the Senior RCF Facilities, comprising a US$1,346 million cash loan facility and a US$434.85 million letter of credit facility;

– the Term Loan Facilities, comprising a £100 million Term Loan Facility A and a US$150 million Term Loan Facility B;

– the USPP Notes, comprising the €35 million Series A 2011 notes, the US$13 million Series B 2011 notes, the US$128 million Series C 2011 notes, Series C 2011 notes, the €25 million Series A 2012 notes, the US$35 million Series B 2012 notes, the US$84 million Series C 2012 notes, the US$38 million Series D 2012 notes and the make-whole notes issued as part of the 2017 Refinancing;

– the Converted Facility, comprising a US$60 million Converted Facility A, a US$50 million Converted Facility B and a US$20 million Converted Facility C;

– the Nelson Bilateral LC Facility (£4.4 million); and

– the Retail Bonds (£150 million).

In addition to the Existing Debt Facilities, the Premier Group has various hedging transactions in place, including cross-currency swaps (the "**XCCY Swaps**"), commodity swaps and options and interest rate swaps. Where hedging transactions are entered into with institutions which are party to the Override Agreement and the Intercreditor Agreement in their capacity as hedge counterparties, the relevant hedging transactions benefit from the same guarantee and security package as the Existing Debt Facilities. Under the Intercreditor Agreement, the guaranteed and secured hedging transactions rank senior save that any increase in a Hedge Counterparty's hedging exposure since 15 March 2016 ranks super senior. As at 30 November 2020, the XCCY Swaps represented a liability of the Premier Group of US$109.0 million, of which US$49.1 million ranked super senior (the "**Super Senior XCCY Swaps**") and US$59.9 million ranked senior (the "**Senior XCCY Swaps**").

As a result of the Debt Restructuring, all of the Existing Debt Facilities and the XCCY Swaps will be repaid, released and/or cancelled pursuant to the Debt Restructuring and certain members of the Premier Group will accede to the New RBL Facility and provide guarantees and security over their assets.

On 23 November 2020, certain members of the Chrysaor Group entered into a US$4.5 billion amended and restated reserves-based lending facility agreement in connection with the Merger and the Debt Restructuring (referred to in this document as the New RBL Facility) with, among others, Bank of Montreal, London Branch, BNP Paribas, DNB (UK) Limited, and Lloyds Bank plc, which includes a letter of credit facility of up to US$1,250 million and an accordion facility of up to US$750 million. The New RBL Facility is based primarily on the existing Chrysaor RBL Facility Agreement that it replaced, which was originally entered into on 30 January 2017 and amended and restated on 3 June 2020. The New RBL Facility is supported by the reserves of the Combined Group. Further details regarding the New RBL Facility are included within section 8 of Part II.

7. Current trading and prospects

7.1 Premier Group

Premier issued its trading update for the 11 months ended 30 November 2020 (the "**December Trading and Operations Update**") on 16 December 2020.

The key highlights of the December Trading and Operations Update are listed below:

- Production averaged 61.2 kboepd for the 11 month period and Premier is on track to meet its full year guidance of 61 to 64 kboepd.
- Premier expects 2021 production to be in the range of 61 to 66 kboepd. This reflects new production from Premier's operated Tolmount gas field (due on-stream in Q2 2021) offset by natural decline and maintenance shutdowns deferred from 2020.
- Production at Premier's operated Catcher Area has been restored to rates in excess of 60 kboepd (gross) following a seven day unplanned outage in mid-November.
- The Solan P3 well was brought on-stream in September and subsequently produced at rates of over 10 kboepd in mid-November with the ESP online. In early December, production from the Solan field was shut in following the failure of the emergency generator and Premier is actively progressing its repair.
- The Tolmount platform was installed during October and batch drilling of the four wells is underway. First gas is forecast for Q2 2021 with Tolmount expected to add 20 to 25 kboepd (net) once on plateau with all four wells completed, anticipated during Q4 2021.
- Premier has retained significant growth optionality within its portfolio:
  - Zama (Mexico) unitisation and development plan negotiations progressing with Pemex
  - Tuna (Indonesia) farm-out agreement signed with Zarubezhneft in September. Fully-carried two well appraisal programme planned for 2021
  - Premier continues to assess the potential of the resources associated with the Sea Lion project (Falkland Islands) which represents a material opportunity for the Group
  - Highly encouraging results from new 3D seismic data sets in Mexico and Indonesia
- Forecast 2020 opex (ex-lease costs) unchanged at $12/boe and full year capex (including abex) guidance now $315 million, reflecting full year savings and deferrals of c. $250 million.
- Premier forecasts 2021 opex (ex-lease costs) of US$15/boe. This includes the tariff to be paid for the Tolmount infrastructure. 2021 total capex (including abex) is expected to be US$274 million. 2021 guidance is provided on a standalone basis and does not account for any optimisation that may occur post completion of the Transaction.
- Net debt at the end of November was US$2.06 billion.

Premier also notes that Tony Durrant stepped down from the Board of Directors on 16 December 2020. In addition, Richard Rose will be the Interim Chief Executive until completion of the Transaction, in addition to his current role as Finance Director. Stuart Wheaton, currently Chief Operating Officer, will assume the role of interim Deputy Chief Executive.

Trading for the period from 30 November 2020 to the date of this Prospectus has been and is in line with the expectations of the Directors and there has been no material change to the financial position of the Premier Group since that date.

7.2 Chrysaor Group

Chrysaor has shown resilience in the challenging business environment created by the COVID-19 pandemic and the commodity price collapse. Its operational performance and diverse and flexible portfolio together with its strong balance sheet and robust hedging programme, have allowed Chrysaor to maintain production and deliver strong financial results during 2020.

Production

Chrysaor's production averaged 174 kboepd to the end of November 2020, with reduced levels of drilling and rephasing of operational activities offset by a shortening of planned shutdowns. Chrysaor forecasts full year 2020 production of approximately 174 kboepd, in line with full year guidance of 170-180 kboepd.

2021 production is expected to average in the range of 140-155 kboepd. This reflects an expected 2020 second-half production forecast of approximately 160 kboepd and an unusually high level of asset shutdowns during 2021. The unusually high-level of 2021 shutdown activity is largely driven by COVID-19-related 2020 maintenance deferrals. These include a planned shutdown of the Forties Pipeline System, deferred from summer 2020 to summer 2021, which affects several of Chrysaor's key production hubs. In addition, both J-Area platforms will experience partial outages in 2021 due to planned separator inspections. In total, over half of Chrysaor's production is expected to be shut-in during 2021 for over 45 days.

2021 production is further impacted by the COVID-19 related suspension of some drilling activities in 2020. As drilling has now resumed at normal levels, the deferred contribution from these wells will be reflected in future years production.

Operated production operations

The Chrysaor-operated J-Area averaged 31 kboepd (net) to the end of November 2020, with the impact of water breakthrough in the Palaeocene wells ameliorated by an active drilling and workover programme which is expected to continue into 2021. The Valaris 120 heavy duty jack up successfully drilled and completed the Joanne Chalk S16 well with stimulation operations underway and first production expected at the turn of the year. The Valaris 120 will then move to the Jasmine West Limb well (S17) followed by the S15 well intervention. In addition, the joint venture partners are currently exploring the potential to add a second drilling unit in late 2021 to appraise the Talbot discovery located southwest of the Judy Central Processing Platform, and to drill the Dunnottar exploration prospect located to the east of the Judy field.

Production from the Greater Britannia Area averaged 40 kboepd (net) for the first 11 months of the year, benefitting from excellent facilities uptime and better than expected well performance from the Brodgar satellite field. The Transocean Paul B Lloyd Jnr has successfully drilled the Callanish F5 well with first production anticipated in Q1 2021.

In the AELE area, production averaged 31 kboepd (net) to the end of November 2020. While production levels and efficiencies have been maintained, the Hawkins and Seymour Horst wells, which were brought on stream in October 2020, are performing below pre-drill expectations. However, well performance is not yet conclusive and remedial actions may be undertaken. In December 2020, Chrysaor sanctioned the LAD infill development well at Everest East with drilling scheduled for Q3 2021.

Non-operated production operations

The Beryl Area fields averaged 17 kboepd (net) for the first eleven months of the year, supported by an ongoing well intervention programme and continued infill drilling. Exploration activity in the Beryl area Tertiary play has been positive so far with two successful wells drilled on the Solar and Corona prospects. The currently drilling Gamma/Losgann well results are also encouraging. Each discovery in this area improves the potential for a possible development with several scenarios under consideration including co-development with adjacent Norwegian discoveries.

Production from the CNOOC operated Buzzard field averaged 19 kboepd (net) to the end of November 2020. Phase 1 infill drilling has delivered on or above target while Buzzard Phase 2 drilling results have been towards the lower end of expectations. Drilling has now been paused and further wells and side-track activity will wait until after the Phase 2 wells have been brought onto production, now expected in December 2021.

Production from the Chrysaor-owned, Spirit Energy-managed East Irish Sea area averaged 6 kboepd (net) for the first 11 months of the year. This was below expectations with the fields experiencing two significant outages in the year – a control system issue on the Calder platform in the first half of the year, followed by a compressor issue at the North Morecombe Terminal. Combined, these issues led to a production efficiency of less than 40% for 2020. Chrysaor is evaluating a variety of potential developments in the East Irish Sea in conjunction with Spirit Energy along with asset integrity projects to improve reliability.

Production from the BP-operated Clair Phase 1 and Clair Ridge fields averaged 5 kboepd (net) to the end of November 2020 with high Phase 1 Clair production efficiency offset by delayed drilling and poorer performance on Clair Ridge. On the Ridge development, to date 8 wells have been executed of the 36 well programme. A ninth well has been drilled and is currently being completed. These early wells are producing lower than initial pre-drill expectations and three have seen water breakthrough, albeit expected given the nature of the reservoir. Near-term production from Clair Ridge is lower than was prognosed at project sanction in 2011. Optional infill campaigns, beyond the sanctioned 36 wells, are now under consideration.

The Schiehallion field produced 6 kboepd (net) to the end of November 2020. The Glen Lyon FPSO has improved its production efficiency in 2020 compared to 2019 and has now gone over 200 days without a trip. However, the production performance has recently been impaired by sand management issues. The pausing of the infill drilling programme has also impacted production rates; as a result, production is expected to show normal decline in 2021-2022 until the expected re-start of infill drilling in 2023.

The Total-operated Elgin Franklin area averaged 19 kboepd (net) for the first 11 months of the year. This was ahead of expectations with the fields benefitting from very high production efficiency and an ongoing infill drilling and well intervention programme. The operator is currently planning facilities and integrity work towards a potential extension of field life.

Financials

Chrysaor's operating costs (including net tariff costs) to the end of November 2020 averaged US$11.4/boe. Chrysaor's total capital expenditure (including exploration and decommissioning) to the end of November 2020 was US$651 million. Chrysaor expects total capital expenditure for the full year 2020 to be around US$718 million. This is approximately US$575 million lower than forecast at the outset of the year, reflecting the pause in non-essential platform activity and the suspension of operated drilling activities for nearly six months.

Given lower levels of production and increased maintenance expense in 2021, Chrysaor expects unit operating costs to be higher than the 2020 outturn but below its long-term target of US$15/boe (including net tariff costs). Chrysaor expects its total 2021 capital expenditure to be US$750-850 million, principally relating to drilling and development activities at J-Area, AELE, Beryl and Buzzard, and including approximately US$170 million for decommissioning (pre-tax relief).

Chrysaor benefits from a significant hedging programme with approximately 67 per cent of its 2021 1H oil volumes hedged at an average price of US$60/bbl, and 73 per cent of its 2021 1H gas volumes hedged at an average price of 42 pence/therm.

8. Dividend policy

Premier did not pay a dividend for the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019. Under the terms of the Existing Debt Facilities, the Premier Group is subject to restrictive covenants such that it shall not declare, make or pay any dividend or other distribution or redeem or repay any of its share capital. Premier at present has no plans to pay a dividend prior to completion of the Merger and Debt Restructuring.

As described above, going forward, the Directors and Proposed Directors believe the combination of Premier and Chrysaor will create a business with the potential to offer a meaningful dividend for shareholders over time. The Combined Group is expected to generate sufficient free cash flow to support shareholder returns including via a sustainable dividend which, subject to market conditions and Board approval, is expected to be introduced with respect to the financial year ending December 2021.

PART II

DETAILS OF THE DEBT RESTRUCTURING

1. Introduction

Premier has been in discussions with certain of its creditors and hedge counterparties for some time regarding the refinancing of its Existing Debt Facilities and XCCY Swaps due to their upcoming maturity date of 31 May 2021.

The proposed terms of the Debt Restructuring, which will be implemented through three Court-sanctioned Restructuring Plans, were agreed with a sub-set of Premier's creditors on 6 October 2020. Given the level of Super Senior XCCY Restructuring Plan Creditors, Super Senior RCF/LC Restructuring Plan Creditors and Senior Restructuring Plan Creditors which have entered into the Support Letter, the Directors confirm that Premier has secured sufficient commitments from the requisite majorities to obtain the creditor approvals required for the Debt Restructuring.

It is anticipated that the Restructuring Plan Creditor Meetings will be convened following a hearing at the English Court scheduled to be held on 19 January 2021 and a hearing at the Scottish Court scheduled to be held on 25 January 2021. If the Restructuring Plan Creditor Meetings are convened by the relevant Courts as expected, it is anticipated that the Restructuring Plan Creditor Meetings will be held on 22 February 2021.

If the Debt Restructuring completes, Restructuring Plan Creditors will receive the following in satisfaction of their drawn commitments or exposure (as applicable) under the Existing Debt Facilities and XCCY Swaps:

– an upfront cash payment (funded through a combination of the New RBL Facility and Premier's and Chrysaor's existing cash resources) of US$1.23 billion (subject to certain adjustments);

– Creditor Shares or, subject to meeting eligibility requirements, New Equity Warrants, or, for Senior Creditors and Senior XCCY Hedge Counterparties which so elect, a further cash payment pursuant to the Partial Cash Alternative (capped at approximately US$175 million).

As announced on 6 October 2020, the Upfront Cash Consideration and the refinancing of the Premier Group's outstanding letters of credit of approximately US$400 million together represent approximately 61 cents on the dollar for Restructuring Plan Creditors (on average across all Restructuring Plan Creditors). If a Senior Creditor elects for the Partial Cash Alternative, they will receive an additional payment of up to 14 cents on the dollar, approximately, instead of receiving Creditor Shares.

In addition, the Debt Restructuring will involve:

– the cancellation of all undrawn commitments under the Super Senior Secured RCF/LC Facility Agreement, the Senior RCF/LC Facility Agreement and the Nelson Bilateral LC Facility Agreement;

– the replacement of all outstanding letters of credit under the Super Senior Secured RCF/LC Facility Agreement, the Senior RCF/LC Facility Agreement and the Nelson Bilateral LC Facility Agreement with the cancellation of all commitments in relation to such letters of credit;

– Senior Creditors and Senior XCCY Hedge Counterparties will be able to subscribe for unallocated Creditor Shares through the Top-Up Election; and

– in order to allow time for the Merger to complete, or alternatively in the event the Merger and Debt Restructuring Resolutions are not passed to agree and implement an alternative plan for implementation of the Merger and the Debt Restructuring or, if that is not possible, an alternative transaction to address the Existing Debt Facilities, the Interim Maturity Extension.

Furthermore, as part of the Debt Restructuring, certain creditors of the Premier Group will enter into the Creditor Lock-Up Agreement, conditional on Admission and Readmission occurring. Under the terms of the Creditor Lock-Up Agreement, Creditor Shares (which shall include the New Equity Warrants and the New Warrant Shares but shall exclude any Creditor Shares issued pursuant to the Top-Up Election) held by Restructuring Plan Creditors and their designated nominees whose holdings represent more than 2.7 per cent. of the enlarged share capital of the Company on Admission will be subject to a lock-up period of three months in respect of fifty per cent. of their Creditor Shares and a further three-month lock-up period in respect of their remaining Creditor

Shares. For further details on the Creditor Lock-Up Agreement, please see section 8.1 of Part XIII (*Additional Information*).

2. Overview of the Premier Group's capital structure

The Premier Group completed the 2017 Refinancing in July 2017. The key terms of the 2017 Refinancing involved:

(A) the amendment of the maturity dates under each of the Existing Debt Facilities and the XCCY Swaps to 31 May 2021;

(B) amending the Premier Group's financial covenants to give the Premier Group greater financial flexibility in the medium term;

(C) improved creditor economics, including an amendment fee, an interest rate uplift and the issue of equity warrants and/or synthetic warrants to creditors under the Premier Group's existing debt facilities;

(D) increased guarantor coverage and the grant of security over substantially all the Premier Group's assets;

(E) priority being granted to the Super Senior Secured RCF/LC Facilities, being the portion of the Premier Group's existing revolving credit and letter of credit facility that was undrawn as at a reference date of 15 March 2016, as well as any increase in hedging exposure of the Hedge Counterparties since that date;

(F) milestones and covenants aimed at facilitating the deleveraging of the Premier Group; and

(G) a common set of creditor reserved matters and covenants, including annual approval of the Premier Group's expenditure budget, final sanction of capital expenditure in excess of certain thresholds and certain approval rights in respect of acquisitions and disposals.

As part of the 2017 Refinancing, the documents constituting the Existing Debt Facilities and the XCCY Swaps (as in effect at the time) were amended, and their key terms overridden, by the Override Agreement and the Intercreditor Agreement. The Override Agreement includes a common set of representations and warrants, information undertakings, financial and non-financial covenants and events of default, which apply to each of the Existing Debt Facilities (other than the Retail Bonds). Further details of the Override Agreement and the Intercreditor Agreement are set out at paragraph 8 of Part XIII (*Additional Information*) of this document.

Following the 2017 Refinancing, amounts owed under the Existing Debt Facilities and the XCCY Swaps are guaranteed by certain members of the Premier Group and are secured by a comprehensive security package. The security package consists of, subject to certain limited exceptions in each case: (i) security over the shares in certain members of the Premier Group; and (ii) fixed and floating charges over the assets of certain members of the Premier Group incorporated in England and equivalent security over the assets of certain other members of the Premier Group to the extent possible.

Under the Intercreditor Agreement, the Super Senior Secured RCF/LC Facilities and the Super Senior XCCY Exposures are first-ranking, rank *pari passu* with each other, and have the benefit of priority over all the other Existing Debt Facilities and the Senior XCCY Exposures. Those other Existing Debt Facilities and Senior XCCY Exposures are, in turn, senior to other debt ranked under the Intercreditor Agreement and rank *pari passu* with one another.

After the 2017 Refinancing, the Premier Group returned to positive free cash flow and took a number of measures to deleverage its balance sheet. These have included the conversion of its convertible bonds into Ordinary Shares and the realisation of more than US$300 million of proceeds from non-core disposals.

Following the conversion of the convertible bonds and the application of disposal proceeds and excess cash in mandatory prepayment of its existing debt facilities, as at the Latest Practicable Date the Premier Group has the following debt facilities, namely the Existing Debt Facilities:

– the Super Senior Secured RCF/LC Facilities, comprising a US$25.84 million cash loan facility and a US$15.15 million letter of credit facility;

- the Senior RCF Facilities, comprising a US$1,346 million cash loan facility and a US$434.85 million letter of credit facility;
- the Term Loan Facilities, comprising a £100 million Facility A and a US$150 million Facility B;
- the USPP Notes, comprising the €35 million Series A 2011 notes, the US$13 million Series B 2011 notes, the US$128 million Series C 2011 notes, Series C 2011 notes, the €25 million Series A 2012 notes, the US$35 million Series B 2012 notes, the US$84 million Series C 2012 notes, the US$38 million Series D 2012 notes and the make-whole notes issued as part of the 2017 Refinancing;
- the Converted Facility, comprising a US$60 million Facility A, a US$50 million Facility B and a US$20 million Facility C;
- the Nelson Bilateral LC Facility (£4.4 million); and
- the Retail Bonds (£150 million).

In addition to the Existing Debt Facilities, the Premier Group has various hedging transactions in place, including cross-currency swaps (the "**XCCY Swaps**"), commodity swaps and options and interest rate swaps. Where hedging transactions are entered into with institutions which are party to the Override Agreement and the Intercreditor Agreement in their capacity as hedge counterparties, the relevant hedging transactions benefit from the same guarantee and security package as the Existing Debt Facilities (as described above). Under the Intercreditor Agreement, the guaranteed and secured hedging transactions rank senior save that any increase in a Hedge Counterparty's hedging exposure since 15 March 2016 ranks super senior.

The hedge counterparties to the XCCY Swaps are referred to as the "XCCY Hedge Counterparties". The exposure of the XCCY Hedge Counterparties up to a maximum of its exposure as at 15 March 2016 is referred to as the "Senior XCCY Exposure", and any increase in a XCCY Hedge Counterparty's exposure since 15 March 2016 is referred to as the "**Super Senior XCCY Exposure**"). As at 30 November 2020, the XCCY Swaps represented a liability of the Premier Group of US$109.0 million, of which US$49.1 million ranked super senior (the "**Super Senior XCCY Swaps**") and US$59.9 million ranked senior (the "**Senior XCCY Swaps**").

3. Background to and reasons for the Debt Restructuring

3.1 Deleveraging since the 2017 Refinancing and upcoming maturity

As a result of the Premier Group's return to positive free cash flow following completion of the 2017 Refinancing, and the other measures taken to deleverage its balance sheet, the Premier Group delivered significant debt reduction of US$393.5 million during 2018 and in excess of US$340 million more during 2019. Despite the significant commodity price weakness and volatility driven by the collapse in global oil demand due to COVID-19, the Premier Group's net debt reduced slightly in the half year ending 30 June 2020. Notwithstanding this significant debt reduction since the 2017 Refinancing, the Premier Group's net debt at the half year ended 30 June 2020 was US$1.97 billion. In addition, the Premier Group's aggregate mark-to-market liability under the XCCY Swaps owing to the XCCY Hedge Counterparties was approximately US$145 million as at that date. The Directors are of the view that it will not be possible to repay this amount of debt on 31 May 2021 (the "**Existing Maturity Date**"), being when the Existing Debt Facilities and XCCY Swaps mature.

3.2 Feasibility of a future refinancing

As noted above, the Combined Group will be primarily financed by the New RBL Facility. Prior to the announcement of the Debt Restructuring, the Premier Group's medium-term objective was to migrate its current capital structure to a more conventional funding position for E&P companies similar to Premier, such as Chrysaor, which was likely to involve a secured reserve based lending ("**RBL**") facility combined with a subordinated public debt instrument (for example, a New York law governed high yield bond). An RBL facility is a type of asset-based lending commonly used in the upstream oil and gas sector, under which loans are made against, and secured by, an oil and gas field or a portfolio of undeveloped and/or developed and producing oil and gas assets. The amount of the RBL facility available to the borrower is based on the value of the borrower's oil and gas reserves, as adjusted from time to time.

The Premier Group carried out extensive discussions with lenders who frequently arrange and participate in RBL facilities about the possibility of putting in place an RBL facility prior to 31 May 2021. Based on these discussions the Directors concluded that the Premier Group's current debt capacity under an RBL facility, without the reserves provided by the Chrysaor Group, is far lower than the Premier Group's current debt levels, and that the Premier Group's current credit profile would not support a high yield bond issue of sufficient size to cover the resulting shortfall. Accordingly, the conclusion was reached that it was not possible to achieve a refinancing based on an RBL facility with the Premier Group's existing assets and a high yield bond issue until the Premier Group had deleveraged further.

As an alternative, the Directors explored whether it would be possible to refinance part of the Existing Debt Facilities and XCCY Swaps through third party facilities prior to 31 May 2021. However, given the fully secured nature of the Premier Group's existing capital structure and the complex intercreditor arrangements that were put in place as part of the 2017 Refinancing, the Directors considered that it would not be possible to introduce new debt facilities into, or to restructure, the Premier Group's capital structure while the Existing Debt Facilities and XCCY Swaps remain outstanding. In the absence of other options to refinance the Existing Debt Facilities and the XCCY Swaps in part or in full, the Directors concluded that the appropriate course was to seek an extension of the Existing Maturity Date, which it attempted to do through the schemes of arrangement proposed by the Company and POUK with certain of its creditors earlier this year (the "**2020 Schemes**").

3.3 2020 Schemes

Under the 2020 Schemes the Premier Group sought to implement a transaction which, had it gone ahead, would have involved the acquisition of BP's interests in the Andrew Area and the Shearwater Field in the North Sea and an additional 25 per cent. interest in the Tolmount field from Dana Petroleum, the funding of those acquisitions through a US$500 million equity raise, and an extension of the Existing Maturity Date to 30 November 2023. The intention had been that successful implementation of this transaction (each element of which was interconditional on the others) would have created a period in which the Premier Group could continue to deleverage its balance sheet and seek to increase its debt capacity, with a view to being able to refinance through new third party debt facilities on or before 30 November 2023.

Although the 2020 Schemes were actively opposed by ARCM, they were approved by the requisite majorities of creditors (86.81 per cent. of super senior secured commitments by value and 83.86 per cent of the senior commitments by value) on 12 February 2020 and were sanctioned by the Scottish Court on 29 April 2020. However, as a result of the collapse in commodity prices due to COVID-19, implementation of the acquisitions and equity raise contemplated by the 2020 Schemes ceased to be commercially viable. That in turn meant, due to the inter-conditional terms of the transaction, that the extension of the Existing Maturity Date to 30 November 2023 did not take place.

Premier reached a settlement agreement with ARCM in respect of the 2020 Schemes on 5 June 2020, whereby ARCM withdrew its appeal of the Scottish Court's judgment approving the 2020 Schemes, undertook to support the Stable Platform Agreement and the acquisition of the Andrew and Shearwater assets on amended terms, and undertook to provide its consent to any proposed solution to the Existing Maturity Date which had the agreement of each member of the IWG (other than any proposal which unfairly prejudiced ARCM relative to other creditors). Pursuant to the ARCM Settlement Agreement, Premier issued new shares representing 8.91 per cent. of the Company's enlarged share capital to ARCM, and paid certain of ARCM's costs in relation to the 2020 Schemes.

3.4 Deferral of covenants under the Stable Platform Agreement

As a result of the impact of lower oil prices and the COVID-19 pandemic on the Premier Group's financial performance, and despite actions taken by the Premier Group to reduce costs, the leverage of the Premier Group has increased since 31 December 2019.

The Override Agreement contains a net debt to EBITDA financial covenant (the "**Net Leverage Ratio**") and an EBITDA to net interest payable financial covenant (the "**Interest Cover Ratio**"), each of which is assessed in respect of 12 month testing periods ending on 31 March, 30 June, 30 September and 31 December of each year. In the second quarter of 2020, forecasts showed a possibility that the Premier Group would not comply with the Net Leverage Ratio or the Interest Cover Ratio in respect of the 12 month testing period ended 30 June 2020.

Accordingly, Premier agreed a range of measures under the Stable Platform Agreement which became effective on 8 July 2020 in order to create a period of stability until 30 September 2020 during which Premier could finalise the terms of and implement a refinancing of its Existing Debt Facilities and XCCY Swaps ahead of the Existing Maturity Date. This included the temporary waiver of the Net Leverage Ratio and the Interest Cover Ratio until 30 September 2020.

The Premier Group's financial statements for the testing period ended 30 June 2020 subsequently showed that the Premier Group would have breached the financial covenants under the Override Agreement if they had not been temporarily waived pursuant to the Stable Platform Agreement. Pursuant to a consent letter dated 29 September 2020, the Stable Platform Agreement (including the financial covenant waivers thereunder) was extended to 5 November 2020, such that it covered the testing period ended on 30 September 2020 as well as the one ended on 30 June 2020. The Stable Platform Agreement was subsequently terminated by the Support Letter, which waives the Premier Group's financial covenants through to the earlier of: (a) the date on which the Debt Restructuring becomes effective or (where the Merger Agreement has terminated) the Interim Maturity Extension becomes effective; and (b) the date that is 45 days following the termination of the Support Letter.

Further details in respect of the termination rights under the Support Letter are set out under the Risk Factor entitled *"The Support Letter may be terminated in accordance with its terms on the occurrence of certain specified events."*.

3.5 Development of the Merger and the Debt Restructuring

In parallel with negotiating and signing the Stable Platform Agreement, the Premier Group continued to engage with creditors on options to address the Existing Maturity Date. These negotiations were led on the creditor side by a subset of Private Creditors, being the IWG and ARCM.

As part of the discussions that took place, a range of possible options was considered. One option which emerged (the "**Standalone Transaction**") was an extension of the Existing Maturity Date until 31 March 2025, which would be supported by an equity raise of up to US$530 million and the acquisition from BP of the Andrew or Andrew and Shearwater assets on amended terms. Up to a maximum of US$205 million of the equity raise would be underwritten by the creditors under the Existing Debt Facilities and the XCCY Swaps, who would convert their debt claims into new ordinary shares in the Company to the extent that the equity raise was not fully subscribed. Certain other amendments would also be made to the documents governing the Existing Debt Facilities and the XCCY Swaps, including a reset of the financial covenants under the Override Agreement and the repricing of the Existing Debt Facilities.

On 20 August 2020 the Company announced that it had agreed heads of terms for the Standalone Transaction with a sub-set of its creditors, being the IWG and ARCM. The announcement stated that the Standalone Transaction remained subject to a number of matters, including shareholder approvals, finalisation of a detailed term sheet for credit approval processes, long-form documentation, implementation of the transaction through restructuring plans under Part 26A of the Companies Act 2006 and total take-up under the equity raise being not less than US$325 million. A detailed term sheet for the Standalone Transaction was subsequently finalised and posted to the Private Creditors and the XCCY Hedge Counterparties, who were invited to enter into a support letter whereby they would undertake to support the Standalone Transaction and vote in favour of the restructuring plans.

In parallel to developing and progressing the Standalone Transaction, and as required by the terms of the Stable Platform Agreement, the Company ran a process to determine whether a strategic investor might be interested in investing in the Premier Group. As part of this process, the Company invited six potential strategic investors, including Chrysaor, to submit an expression of interest regarding the subscription for a significant minority stake in the Company. Two potential strategic investors (including Chrysaor) submitted an expression of interest; however, instead of indicating an interest in subscribing for a minority stake, Chrysaor proposed a merger of the Premier Group and the Chrysaor Group and a reorganisation of the Existing Debt Facilities. The Company entered into discussions regarding alternatives to the Standalone Transaction with both of the parties which had submitted expressions of interest, as was confirmed by the Company's announcement on

15 September 2020 following press speculation that the Company was in discussions with Chrysaor. Whereas discussions with the second party were not successful, discussions with Chrysaor developed into the Debt Restructuring and the Merger.

On 6 October 2020 the IWG and ARCM confirmed to the Company in writing that they had decided to support the Merger and the Debt Restructuring over the Standalone Transaction on the basis that, in their view, the Merger and the Debt Restructuring was likely to offer a better outcome to creditors than the Standalone Transaction. Following this feedback, and in light of the challenging macroeconomic conditions, the Board concluded that the Standalone Transaction was no longer capable of gaining the requisite creditor support required for implementation in accordance with its terms and that the Proposed Transaction had greater execution certainty than the Standalone Transaction. All further work on the Standalone Transaction ceased accordingly.

In the days leading up to the announcement of the Merger and Debt Restructuring on 6 October 2020, the Company negotiated the final terms of the Merger with representatives of Chrysaor and Chrysaor's shareholders and agreed an increase in the proportion of equity in the Combined Group that will be retained by the Company's existing shareholders.

Having carefully developed and reviewed the terms of the Debt Restructuring and the Merger, and having considered the feedback from the IWG and ARCM, the Directors concluded that the Debt Restructuring and the Merger was in the best interests of, and would promote the success of, the Premier Group for the benefit of its shareholders and creditors and other stakeholders.

3.6 Support Letter

Super Senior XCCY Restructuring Plan Creditors representing 100 per cent. of the aggregate of the estimated Super Senior XCCY Exposures as at 30 November 2020, Super Senior RCF/LC Restructuring Plan Creditors representing 92 per cent. of the aggregate outstanding commitments under the Super Senior Secured RCF/LC Facilities and Senior Restructuring Plan Creditors representing 86 per cent. of the aggregate of (i) outstanding commitments under the Senior Secured Debt Facilities, and (ii) the aggregate of the Senior XCCY Exposures, have entered into the Support Letter whereby they have undertaken to support the Debt Restructuring, including by voting in favour of the Restructuring Plans. The Non-XCCY Hedge Counterparties have undertaken to consent to the aspects of the Debt Restructuring which require their consent, having respectively entered into separate support letters.

For further information regarding the Support Letter and the Non-XCCY Hedging Support Letter, see paragraph 8 of Part XIII (*Additional Information*).

4. Terms of the Debt Restructuring

If the Debt Restructuring and Merger complete, Restructuring Plan Creditors will receive the following in satisfaction of their drawn commitments or exposure (as applicable) under the Existing Debt Facilities and XCCY Swaps:

- an upfront cash payment (funded through a combination of the New RBL Facility and Premier's and Chrysaor's existing cash resources) of US$1.23 billion (subject to certain adjustments);
- Creditor Shares or, subject to meeting eligibility requirements, New Equity Warrants, or, for Senior Creditors and Senior XCCY Hedge Counterparties which so elect, a further cash payment pursuant to the Partial Cash Alternative (capped at approximately US$175 million).

In addition, the Debt Restructuring will involve:

- the cancellation of all undrawn commitments under the Super Senior Secured RCF/LC Facility Agreement, the Senior RCF/LC Facility Agreement and the Nelson Bilateral LC Facility Agreement;
- the replacement of all outstanding letters of credit under the Super Senior Secured RCF/LC Facility Agreement, the Senior RCF/LC Facility Agreement and the Nelson Bilateral LC Facility Agreement with the cancellation of all commitments in relation to such letters of credit
- Senior Creditors and Senior XCCY Hedge Counterparties will be able to subscribe for unallocated Creditor Shares through the Top-Up Election; and

– in order to allow time for the Merger to complete, or alternatively in the event the Merger and Debt Restructuring Resolutions are not passed to agree and implement an alternative plan for implementation of the Merger and the Debt Restructuring or, if that is not possible, an alternative transaction to address the Existing Debt Facilities, the Interim Maturity Extension.

The Upfront Cash Consideration will be applied first in *pro rata* and *pari passu* repayment of: (i) the Super Senior XCCY Exposure; and (ii) drawn commitments (excluding letters of credit) under the Super Senior Secured RCF/LC Facility Agreement. As at 30 November 2020, the mark-to-market of the Super Senior XCCY Exposures was around US$49.0 million, and there were no drawn amounts outstanding under the Super Senior Secured RCF/LC Facility Agreement. As a result, it is expected that the Super Senior XCCY Hedge Counterparties and Super Senior Secured RCF/LC Facility creditors will be repaid in full in respect of their Super Senior XCCY Exposures and drawn commitments under the Super Senior Secured RCF/LC Facility Agreement (respectively).

The remaining Upfront Cash Consideration available after distribution to the Super Senior Creditors will be distributed among the Senior Creditors. In addition, Senior Creditors and Senior XCCY Hedge Counterparties will be offered the opportunity to elect to receive additional value in the form of Creditor Shares or by participating in the Partial Cash Alternative (the aggregate amount of which is capped). The deadline for making an election to participate in the Partial Cash Alternative (or, if the Partial Cash Alternative is oversubscribed, to receive Creditor Shares or subject to certain eligibility criteria, to receive New Equity Warrants) will be the date falling two business days prior to the Restructuring Plan Creditor Meetings and any Restructuring Plan Creditor who does not make an election prior to the deadline will be deemed to have elected to receive Creditor Shares. Senior Creditors and Senior XCCY Hedge Counterparties may, after the date falling two business days prior to the Restructuring Plan Creditor Meetings but before the Restructuring Plan Creditor Meetings, make new elections which will override any previous elections made by that Senior Creditor or Senior XCCY Hedge Counterparty (as applicable) (including its deemed elections, if applicable). Eligible Restructuring Plan Creditors who are entitled to Creditor Shares and/or New Equity Warrants shall not be obliged to receive such Creditor Shares or New Equity Warrants.

The maximum number of Creditor Shares that will be issued to Restructuring Plan Creditors in connection with the Debt Restructuring is 3,331,917,634, the maximum amount available to be distributed among Senior Creditors and Senior XCCY Hedge Counterparties under the Partial Cash Alternative is approximately US$175 million and the maximum number of New Equity Warrants that will be issued to eligible Restructuring Plan Creditors is 148,085,228.

To the extent that the Senior Creditors' and Senior XCCY Hedge Counterparties elections cannot be satisfied in full, they will be scaled down on a *pro rata* basis. If the Partial Cash Alternative is oversubscribed, Senior Creditors and Senior XCCY Hedge Counterparties choosing this option will be entitled to receive the default consideration of Creditor Shares or (if they meet certain eligibility requirements) New Equity Warrants, which are intended to be as economically equivalent to the Creditor Shares as possible subject to the constraints of Scottish company law and will be issued in substitution for Creditor Shares. If the New Equity Warrants are oversubscribed, the Restructuring Plan Creditors will be entitled to receive the default consideration of Creditor Shares. While Restructuring Plan Creditors may be entitled to receive Creditor Shares or New Equity Warrants, they also have the right to refuse receipt of Creditor Shares or New Equity Warrants.

The terms and conditions of the Top-Up Election will be set out in the Explanatory Statement to be published by the Company and the relevant members of the Premier Group.

If and to the extent that the maximum number of Creditor Shares (including, for these purposes, New Equity Warrants) that may be issued to Restructuring Plan Creditors in connection with the Debt Restructuring is not allocated to Restructuring Plan Creditors, as a result of Senior Creditors and Senior XCCY Hedge Counterparties electing to participate in the Partial Cash Alternative or Restructuring Plan Creditors electing not to receive Creditor Shares at all, these unallocated shares will be available to Restructuring Plan Creditors who wish to participate in the Top-Up Election.

The Directors believe that the implementation of the Merger and the Debt Restructuring is critical to the future success of Premier. In particular, this is because, had Premier not entered into the Support Letter (and, prior to that, the Stable Platform Agreement) which served to defer the testing of the Premier Group's leverage and interest cover financial covenants for the testing periods ended on 30 June 2020 and 30 September 2020, the Premier Group would have been in breach of the financial covenants contained in the

Override Agreement for those periods. As a result, if such financial covenant deferrals were to lapse and the Premier Group was unable to secure further deferrals of a similar nature, there would be an event of default under the Override Agreement. The consequences of an event of default in these circumstances are very severe and would mean the Private Creditors would have the right to declare the Private Debt Facilities (which totalled US$2.2 billion as at 31 October 2020) immediately due and payable, which if exercised, would in turn trigger an event of default under the XCCY Swaps and cross-default under the Retail Bonds.

As a result, if the Debt Restructuring does not proceed, the Interim Maturity Extension proceeds and the Premier Group does not secure future financial covenant deferrals, it is expected that the Premier Group's outstanding commitments and exposures under the Existing Debt Facilities and XCCY Swaps respectively will become payable before the extended maturity date of 31 March 2022 as a consequence of the events of default and acceleration of the Premier Group's debt described above. Premier considers that the Premier Group would not be able to repay the outstanding commitments and exposures under the Existing Debt Facilities and XCCY Swaps respectively in these circumstances. Even if Premier is able to secure future financial covenant deferrals for the period until 31 March 2022, Premier does not consider that the Premier Group will be able to repay the outstanding commitments and exposures under the Existing Debt Facilities and XCCY Swaps respectively when they mature, or crystallise (as relevant) on that date in which case the events of default, acceleration and enforcement of security described in paragraph 5.2 of Part I (*Background to and reasons for the Merger and the Debt Restructuring*) could occur.

5. Terms of the Top-Up Election

Under the terms of the Debt Restructuring, Restructuring Plan Creditors will be offered the opportunity to elect to receive additional value in the form of Creditor Shares or by participating in the Partial Cash Alternative, in addition to the Upfront Cash Consideration payable in connection with the Debt Restructuring. As described in section 4 above, the maximum number of Creditor Shares that will be issued to Restructuring Plan Creditors in connection with the Debt Restructuring is 3,331,917,634, the aggregate maximum amount payable to Senior Creditors and Senior XCCY Hedge Counterparties under the Partial Cash Alternative is approximately US$175 million and the maximum number of New Equity Warrants that will be issued to eligible Restructuring Plan Creditors is 148,085,228.

If and to the extent that the maximum number of Creditor Shares (including, for these purposes, New Equity Warrants) that may be issued to Restructuring Plan Creditors in connection with the Debt Restructuring is not allocated to Restructuring Plan Creditors as a whole, as a result of Senior Creditors and Senior XCCY Hedge Counterparties electing to participate in the Partial Cash Alternative or electing not to receive Creditor Shares at all, these unallocated shares (the "**Unallocated Creditor Shares**") will be made available to eligible Restructuring Plan Creditors who apply to participate in the Top-Up Election.

Senior Creditors and Senior XCCY Hedge Counterparties who do apply to participate in the Top-Up Election shall be offered the opportunity to apply to subscribe in cash for a whole number of Unallocated Creditor Shares at a price of 11.44 cents per share (8.57 pence per share as at the Latest Practicable Date). As described further in paragraph 5.4 of Part I (*Background to and reasons for the Merger and the Debt Restructuring*), the nominal value of each Ordinary Share will be reduced to 0.0001 pence prior to the issue and allotment of any Unallocated Creditor Shares in connection with the Subdivision.

The issue and allotment of Unallocated Creditor Shares pursuant to the terms of the Top-Up Election is conditional upon the Merger and the Debt Restructuring becoming effective.

The Company intends to apply for the admission of the New Ordinary Shares in connection with the Merger and Debt Restructuring (including Unallocated Creditor Shares subscribed for under the terms of the Top-up Election) for listing on the premium listing segment of the FCA's Official List and admission to trading on the main market of the London Stock Exchange, as soon as reasonably practicable once: (i) each of the Restructuring Plans has been sanctioned by the relevant Courts and delivered to Companies House; and (ii) all of the other conditions to the completion of the Merger have been satisfied (save for those relating to Admission).

As noted above, the terms and conditions of the Top-Up Election, through which Senior Creditors and Senior XCCY Hedge Counterparties may elect to receive Unallocated Creditor Shares, will be set out in the Explanatory Statement to be published by the Company and the relevant members of the Premier Group.

6. Terms of the New Equity Warrants

Introduction

In the event that the Partial Cash Alternative is oversubscribed, Restructuring Plan Creditors who have elected to participate in the Partial Cash Alternative and are able to provide Premier and Chrysaor with evidence (to the reasonable satisfaction of Premier and Chrysaor) that the subscription by it for New Ordinary Shares: (i) is prohibited by laws or regulations to which it is subject (and provides appropriate detail of the laws or regulations); or (ii) could give rise to liability for it or any of its affiliates to any governmental, banking, taxing, municipal or other regulatory authority or similar body (and provides appropriate detail of the potential liability) may elect to be issued New Equity Warrants rather than receiving an allocation of New Ordinary Shares pursuant to the Debt Restructuring. Such New Equity Warrants will represent a number of New Ordinary Shares equal to the number of Creditor Shares such a Restructuring Plan Creditor would otherwise have been allocated pursuant to the Debt Restructuring. The maximum number of New Equity Warrants that will be issued on completion of the Debt Restructuring is 148,085,228.

The New Equity Warrants will be constituted by the New Equity Warrant Deed Poll and will be issued subject to, and with the benefit of, the terms and conditions which are summarised below. The ISIN of the New Equity Warrants will be GB00BM9GMR34.

The number of New Equity Warrants to be issued by the Company upon the completion of the Merger and the Debt Restructuring will be determined by the extent to which eligible Restructuring Plan Creditors elect to take up entitlements in respect of the Partial Cash Alternative. If the maximum number of New Equity Warrants are issued pursuant to the Debt Restructuring, the Company will issue New Equity Warrants equivalent to up to 0.80 per cent. of the enlarged issued share capital of the Company following completion of the Merger and the Debt Restructuring (assuming maximum take-up of the Partial Cash Alternative).

The New Equity Warrants will be afforded certain anti-dilution protections as described below.

(A) Subscription rights

Each New Equity Warrant Holder will have the right to subscribe at any time during the Exercise Period for New Warrant Shares at the New Equity Warrant Exercise Price, on the basis of one New Warrant Share for every New Equity Warrant held (although the number of New Warrant Shares to be issued per New Equity Warrant may be adjusted on the occurrence of an Equity Adjustment Event as described in paragraph (J) below).

(B) New Equity Warrant Exercise Price

Subject to the occurrence of any Equity Adjustment Event, the New Equity Warrants will have an exercise price equal to 0.001 pence.

(C) Currency

The New Equity Warrant Exercise Price is denominated in pounds sterling.

(D) Fractions of shares

No fraction of a New Warrant Share will be issued on the exercise of a New Equity Warrant and any fractional entitlement will accordingly be rounded down to the nearest whole New Warrant Share, but if more than one New Equity Warrant is exercised at the same time by the same New Equity Warrant Holder, then, for the purposes of determining the number of New Warrant Shares to be issued and whether any (and, if so, what) fraction a of New Warrant Share would arise, the number of New Warrant Shares arising on the exercise of each New Equity Warrant (including, for this purpose, fractions) will first be aggregated.

(E) Exercise procedure

New Equity Warrants represented by Global Warrant Certificates may only be exercised by the delivery, or the sending by authenticated SWIFT message (or such other method acceptable to CREST) (confirmed in writing), of both a duly completed Exercise Notice and a duly completed Investor Letter (copies of which may be obtained from CREST and the Warrant Agent during normal business hours) to CREST, with a copy to the Warrant Agent and the Company immediately after such Exercise Notice and Investor Letter have been delivered or sent to CREST.

To exercise one or more New Equity Warrants represented by Individual Warrant Certificates, the New Equity Warrant Holder must: (i) execute and deposit, at such New Equity Warrant Holder's own expense, both a duly completed Exercise Notice and a duly completed Investor Letter at the specified office of the Warrant Agent during the Exercise Period, with a copy to the Company immediately after such Exercise Notice and Investor Letter have been so deposited; (b) at the same time as it delivers an Exercise Notice and an Investor Letter in accordance with (a) above, deposit the relevant Individual Warrant Certificates at the specified office of the Warrant Agent; and (c) pay to the Warrant Agent the aggregate amount of the New Equity Warrant Exercise Price due in respect of the Equity Warrants specified in the Exercise Notice.

(F) Allotment and partial exercise

New Warrant Shares will be issued in uncertificated form through CREST, unless the relevant New Equity Warrant Holder elects to receive the New Warrant Shares in certificated form or, at the time of issue, the Ordinary Shares are not a participating security in CREST.

Where New Warrant Shares are to be issued through CREST, they will be delivered to the account specified by the relevant New Equity Warrant Holder in the relevant Exercise Notice within two business days following the relevant exercise date of the New Equity Warrants (or as soon as practicable thereafter but not later than seven business days from the relevant exercise date of the New Equity Warrants). Where New Warrant Shares are to be issued in certificated form, a certificate in respect thereof will be dispatched by mail free of charge (but uninsured and at the risk of the person entitled thereto) to the relevant New Equity Warrant Holder, or as it may direct in the relevant Exercise Notice, within 21 days following the relevant exercise date of the New Equity Warrants. If a New Equity Warrant Holder exercises only some of the New Equity Warrants represented by his Individual Warrant Certificate, the Company will procure that a new Individual Warrant Certificate is issued to him for the balance.

(G) Dividends

If the Company declares a dividend during the Exercise Period but before a New Equity Warrant Holder has elected to receive its corresponding New Warrant Shares, the New Equity Warrant Exercise Price shall be adjusted accordingly (see paragraph (J) below for further details). However, if such Equity Adjustment Event would result in the New Equity Warrant Exercise Price of the New Warrant Share(s) to be issued on exercise of a New Equity Warrant being adjusted to an amount less than the nominal value of such New Warrant Shares (i.e. 0.0001 pence), pursuant to the New Equity Warrant Deed Poll, New Equity Warrant Holders shall rank for any dividends and distributions paid to Shareholders, notwithstanding that they are yet to exercise their New Equity Warrants (as if those New Equity Warrants had been exercised and the Warrant Shares issued prior to dividend or distribution record date).

(H) Applicable laws and regulation

Exercise of the New Equity Warrants will be subject to all applicable laws and regulations, including U.S federal and state (to the extent relevant) policies and practices of CREST, in force on the relevant date of exercise. Without prejudice to Premier's warranties and undertakings under the New Equity Warrant Deed Poll or any obligation to issue and deliver the certificates in respect of the New Equity Warrants issued in certificated form, neither the Company nor the Warrant Agent will incur any liability whatsoever if it is unable to effect the transactions contemplated as a result of any such laws, regulations or policies or practices. The New Equity Warrants may only be exercised by holders who are either: (i) not located in the United States (within the meaning of Regulation S); (ii) located in the United States (within the meaning of Regulation S) but are either qualified institutional buyers or institutional accredited investors under the US Securities Act; or (iii) if located in the European Economic Area or the United Kingdom, a Qualified Investor within the meaning of Article 2(1)(e) of Regulation (EU) 2017/1129.

(I) Ranking

The New Equity Warrants will not be secured and will not have any priority ranking as debt.

(J) Equity Adjustment Events

The New Equity Warrant Exercise Price and/or number of New Warrant Shares issuable upon exercise of a New Equity Warrant shall be adjusted on the occurrence of an Equity Adjustment Event. The New Equity Warrant Deed Poll includes the following Equity Adjustment Events:

(i) any allotment or issue of Ordinary Shares (or any increase in the nominal value of Ordinary Shares) by way of capitalisation of profits or reserves (including share premium account and any capital redemption reserve fund) but other than Ordinary Shares paid up out of distributable profits or reserves and issued in lieu of a cash dividend;

(ii) any dividend or distribution (whether in cash or in specie and including, without limitation, Ordinary Shares paid up out of distributable profits or reserves and issued in lieu of a cash dividend) made by the Company in respect of any record date which is on or after the date on which the New Equity Warrants are issued, provided that such Equity Adjustment Event will not result in the New Equity Warrant Exercise Price of the New Warrant Shares to be issued on exercise of a New Equity Warrant being adjusted to less than the nominal value of such New Warrant Shares, in which case the New Equity Warrant Deed Poll provides that New Equity Warrant Holders shall rank for any dividends and distributions paid in respect of any record date which is on or after the date on which the relevant New Equity Warrants are issued;

(iii) any sub-division or consolidation or reclassification of Ordinary Shares; or

(iv) any cancellation or reduction of the share capital, share premium account or capital redemption reserve of the Company, involving a repayment of capital.

(K) Information and other rights of New Equity Warrant Holders

Premier will make available to each New Equity Warrant Holder through its website (and shall, upon written request by any New Equity Warrant Holder, send (or procure the sending of) to such New Equity Warrant Holder):

(i) a copy of the Company's audited financial statements and interim accounts, in each case, no later than the time they are issued to holders of Ordinary Shares or announced via a regulatory news service; and

(ii) a copy of every notice, circular or other document issued to the holders of Ordinary Shares concurrently with the issue of the same items to those holders.

Upon the written request of any New Equity Warrant Holder, Premier will promptly inform such New Equity Warrant Holder of the New Equity Warrant Exercise Price and the specified number of Ordinary Shares which would fall to be issued at that time in respect of one New Equity Warrant.

(L) Restrictions on transfer

The New Equity Warrants will be freely transferable except that:

(i) transfer of the New Equity Warrants may not be effected after the Exercise Period;

(ii) transfers of the New Equity Warrants will be subject to all applicable laws and regulations, including US federal and state securities laws. Any purported transfer in violation of those laws or regulations shall be void and ineffective, and shall not operate to transfer any interest in the applicable New Equity Warrants to the purported transferee;

(iii) for so long as any New Equity Warrants are represented by either of the Global Warrant Certificates, such New Equity Warrants will be transferable through an account at CREST, subject to and in accordance with the rules and procedures of CREST. Title will pass upon registration of the transfer in the records of CREST;

(iv) if and for so long as any New Equity Warrants are represented by Individual Warrant Certificates, a New Equity Warrant may be transferred upon surrender of the related Individual Warrant Certificate (or, if no Individual Warrant Certificate is surrendered, upon evidence reasonably satisfactory to the Warrant Agent and the Company of a person's interest in the New Equity Warrant), with a duly completed and endorsed form of transfer in specified form at the specified office of the Warrant Agent, together with such other evidence as the Warrant Agent may reasonably require to prove the title of the transferor and the authority of the individuals who have executed the form of transfer. In the case of a transfer where not all of the New Equity Warrants evidenced by the surrendered Individual Warrant Certificate are the subject of the transfer, a new Individual Warrant Certificate in respect of the balance not transferred will be issued to the transferor. No transfer of any New Equity Warrant which is represented by an Individual Warrant Certificate will be valid unless and until entered on the warrant register. Within five Business Days of the surrender of an Individual Warrant Certificate, the Warrant Agent will register the transfer in question and deliver a new Individual Warrant Certificate to the New Equity Warrant Holder or (at the request and risk of any such relevant New Equity Warrant Holder) by uninsured first class mail (airmail if overseas) to the address specified for the purpose by such New Equity Warrant Holder;

(v) the transfer of any New Equity Warrant which is represented by an Individual Warrant Certificate will be effected without charge by or on behalf of the Company or the Warrant Agent. Neither the Company nor the Warrant Agent will be responsible for the payment of tax or other duty of whatsoever nature which may be levied or imposed in connection with such transfer; and

(vi) all transfers of New Equity Warrants and entries on the warrant register will be subject to the detailed regulations and all applicable laws concerning the transfer of New Equity Warrants, as set out in the New Equity Warrant Deed Poll.

(M) Authority

In order to issue the New Equity Warrants, the Shareholders will need to grant the Directors authority to grant rights to subscribe for and to allot New Warrant Shares on exercise of the New Equity Warrants at the General Meeting. Such authority shall, if necessary, be granted pursuant to the Merger and Debt Restructuring Resolutions, further details of which can be found in paragraph 9 of Part I (*Letter from the Chairman of Premier*) in the Circular.

(N) Admission to trading

The New Equity Warrants will not be admitted to trading on any market or exchange.

(O) The Exercise Period

The New Equity Warrants will expire and be of no further force and effect from the second anniversary of the date on which the New Equity Warrant Deed Poll comes into effect.

7. Conditions to the Debt Restructuring

The Debt Restructuring is subject to certain conditions which must be satisfied or waived, including:

(A) the Merger and Debt Restructuring Resolutions having been passed by Shareholders at the General Meeting;

(B) the Restructuring Plans (which are inter-conditional) having been approved by the requisite majorities at the Restructuring Plan Creditor Meetings, sanctioned by the relevant Courts and a copy of the sanction orders delivered to the Registrar of Companies for Scotland or the Registrar of Companies for England and Wales (as applicable);

(C) each of the Non-XCCY Hedge Counterparties having given any consents required in connection with the Debt Restructuring, which the Non-XCCY Hedge Counterparties have undertaken to do pursuant to the Non-XCCY Hedging Support Letters;

(D) satisfaction of certain documentary conditions in respect of conditions precedent that are customary for a secured financing transaction and/or are within the control of the Premier Group;

(E) the FCA and the London Stock Exchange each having approved the applications for Admission to take place (by not later than the Long Stop Date); and

(F) payment of certain costs associated with the Debt Restructuring.

As at the date of this document, each of the conditions listed above remain outstanding. In order to satisfy each of these outstanding conditions Premier intends to:

(A) pass the Merger and Debt Restructuring Resolutions at a General Meeting to be held on 12 January 2021;

(B) obtain approval of the Restructuring Plans from Restructuring Plan Creditors at the Restructuring Plan Creditor Meetings to be held on 22 February 2021 as part of the Restructuring Plans process and present the Restructuring Plans for sanction by the relevant Courts;

(C) facilitate and arrange the delivery of the relevant conditions precedent;

(D) make the applications to the FCA and the London Stock Exchange required for Admission; and

(E) arrange that the relevant costs associated with the Debt Restructuring are paid prior to or at completion of the Merger and Debt Restructuring.

If any of the conditions to the Debt Restructuring are not satisfied or waived (to the extent applicable) the Debt Restructuring will not complete. As a result, if the Debt Restructuring does not proceed and the Premier Group does not secure future financial covenant deferrals, it is expected that the Premier Group's Existing Debt Facilities and the XCCY Swaps will become payable before 31 May 2021. In such circumstances, Premier considers that the Premier Group would not be able to repay, or otherwise refinance, the facilities which would become payable in these circumstances and, as a result, it is likely, that members of the Premier Group would be unable to continue trading. It is therefore critical that Premier moves to implement the Merger and the Debt Restructuring in order to avoid the aforementioned risks.

For further details on the consequences of the Debt Restructuring not proceeding, please refer to the Risk Factors entitled "*If the Interim Maturity Extension becomes effective but the Merger and the Debt Restructuring do not proceed, the ability of members of the Premier Group to continue trading will depend on ongoing support from the Premier Group's creditors*" and "*If the Interim Maturity Extension does not become effective and the Merger and the Debt Restructuring do not proceed, the Premier Group's financial position would be materially adversely affected and it is likely that companies within the Premier Group would be placed into insolvency procedures on or before 31 May 2021*" above.

8. Overview of the New RBL Facility

8.1 Overview

On 23 November 2020, certain members of the Chrysaor Group entered into an amendment and restatement agreement with, among others, Bank of Montreal, London Branch, BNP Paribas, DNB (UK) Limited, and Lloyds Bank plc, which will amend and restate the Chrysaor Existing RBL Facility (which was originally entered into on 30 January 2017 and as amended and restated from time to time, including most recently on 3 June 2020) and pursuant to which an up to US$4.5 billion reserve-based lending facility (referred to in this document as the New RBL Facility) will be provided in connection with the Merger and the Debt Restructuring. The New RBL Facility will include a letter of credit sub-limit of up to US$1,250 million and a separate accordion facility of up to US$750 million (which would increase the total aggregate commitments up to US$5.25 billion) subject to satisfaction of certain conditions set out in the applicable accordion provisions contained in the New RBL Facility. The amendment and restatement of the Chrysaor Existing RBL Facility will become effective upon the satisfaction of certain conditions precedent, including, among other things, agreed forms of new security documentation and deeds of release, a revised CPR and projection and customary documentary conditions precedent. In addition, certain conditions precedent need to be satisfied prior to any utilisation of the New RBL Facility to fund repayment of the Premier Group's existing creditors and the replacement of letters of credit pursuant to the Merger and the Debt Restructuring.

The maximum available amount under the New RBL Facility will be an amount equal to the lower of the aggregate total commitments under the facility (being US$4.5 billion as at the effective date of the New RBL Facility) and the borrowing base amount. The borrowing base amount of the New RBL Facility will be based on the reserves of the Combined Group, in particular the reserves of specific nominated borrowing base assets. The New RBL Facility is what is known as a net present value facility, with the borrowing base amount based on the expected net present value of future cash flows from the borrowing base assets, taking into account, among other things, the P50 and P90 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 by reference to an up to date CPR commissioned by the borrower.

8.2 Security

As with the Chrysaor Existing RBL Facility, the New RBL Facility will be secured by English law share charges, English law debentures, English law charges over certain bank accounts and English law assignment agreements. As part of the completion steps for the Debt Restructuring and conditions precedent to the utilisation of the New RBL Facility, supplemental security will be provided in respect of the existing security package and new security will be provided by the new Premier obligors that hold a direct interest in the new borrowing base assets as well as share security over such obligors and key holding companies in the Combined Group.

8.3 Repayment and maturity

The final maturity date of the New RBL Facility is 23 November 2027. If, however, the remaining reserves attributable to the Combined Group's borrowing base assets are forecast to amount to 25 per cent. or less than the Combined Group's revised approved reserves (as may be subsequently revised), the New RBL Facility will mature on 30 June of the relevant calculation period.

Total aggregate commitments under the New RBL Facility will reduce to approximately US$4,091 million on 1 January 2023, to approximately US$3,682 million on 1 July 2023, to approximately US$3,273 million on 1 January 2024, to approximately US$2,864 million on 1 July 2024, to approximately US$2,455 million on 1 January 2025, to approximately US$2,045 million on 1 July 2025, to approximately US$1,636 million on 1 January 2026, to approximately US$1,227 million on 1 July 2026, to approximately US$818 million on 1 January 2027 and to approximately US$409 million on 1 July 2027.

8.4 Interest and fees

The rate of interest payable on loans under the New RBL Facility is the rate per annum equal to the aggregate of the applicable margin plus LIBOR. The applicable margin is 3.25 per cent. for the period commencing on the effective date of the New RBL Facility to the date falling four years from such effective date and thereafter 3.5 per cent., subject to certain adjustments relating to the carbon emissions associated with the operated borrowing base assets of the Combined 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 New RBL Facility.

Certain fees are payable to the lenders under the New 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 Chrysaor Group, and following completion of the Merger, the Combined Group shall pay commitment fees on a quarterly basis as follows: a) 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 b) 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.

The amendment and restatement agreement relating to the New RBL Facility also contains a "ticking fee" payable to the agent in the amounts of: (i) 0 per cent. of the applicable margin for the period on and from the date of the amendment and restatement agreement to the date falling 90 days after such date; (ii) 10 per cent. of the applicable margin for the period commencing 90 days from the date of the amendment and restatement agreement to the date falling 120 days from such date; and (iii) 20 per cent. of the applicable margin thereafter. The "ticking fee" is payable until the date on which the agent notifies Chrysaor E&P Finance Limited and the lenders that the conditions precedent to the effectiveness of the New RBL Facility have been satisfied.

8.5 Representations, warranties, covenants and events of default

Representations

The New RBL Facility contains customary representations, including 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 materiality qualifications.

Financial covenants

The New 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 and the forward-looking ratio of consolidated total net debt to consolidated EBITDAX for the relevant period is less than 3:1. These financial terms are defined in the New RBL Facility and may not correspond to similarly titled metrics in the Premier Group's or the Chrysaor Group's consolidated historical financial information or this document. In the event of non-compliance with the applicable ratio, an event of default will occur under the New RBL Facility unless waived in accordance with the New RBL Facility.

General covenants

The New RBL Facility contains customary undertakings which are subject to certain exceptions and 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, performance of and amendments to the merger documents, the sale of petroleum from borrowing base assets on the best terms reasonably available, and *pari passu* ranking. The New RBL Facility also contains customary covenants relating to the provision of information to the lenders.

Events of default

The New RBL Facility contains customary events of default including 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.

Premier Certain Funds

The New RBL Facility contains certain funds provisions relating to the Merger pursuant to which the lenders are obliged to make available utilisations in connection with the Merger provided that: (i) specified conditions precedent have been satisfied; (ii) no major default is continuing or would result from the proposed utilisation; (iii) all the major representations are true in all material respects; and (iv) no change of control (other than as contemplated by the Merger) has occurred.

8.6 Mandatory prepayment event

The New RBL Facility is to be prepaid in full immediately upon the occurrence of certain events, including on a flotation of a member of the Chrysaor Group prior to completion of the Merger (excluding the Merger itself) 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 acquisition documents.

PART III

INFORMATION ON THE PREMIER GROUP

1. Introduction

Premier is a leading independent exploration and production company with significant oil and gas interests in the UK, Indonesia, Vietnam, the Falkland Islands and Mexico. The Premier Group also has exploration interests in Brazil. The portfolio consists of: (i) oil and gas fields which are already producing; (ii) discovered fields not yet producing but which are undergoing development planning or execution; and (iii) licences to explore for new oil and gas fields in prospective areas. Premier aims to continue its growth through successful exploration and appraisal, astute commercial transactions and optimal asset management as well as the development of high quality oil and gas projects.

As at 31 December 2019, the Premier Group had 2P reserves of 174.7 mmboe and 2C resources of 672.1 mmboe, giving rise to a reserves and resource base of 846.8 mmboe. Production for the 10 month period ended 31 October 2020 averaged 62.5 kboepd and is forecast by Premier to average between 61-64 kboepd for the year ended 31 December 2020.

2. History and development

The Premier Group was founded in 1934 in Scotland to pursue oil and gas exploration and production activities in Trinidad. The Premier Group acquired its first interest in the North Sea in 1971. It has since expanded its presence on the UKCS through a series of value accretive acquisitions and successful exploration.

In 1984, the Premier Group purchased a 12.38 per cent. interest in Wytch Farm. This acquisition had a significant impact on the Premier Group's reserve base and made an important contribution to the Premier Group's cash flow. In December 2011, the Premier Group acquired an additional 17.715 per cent. interest in Wytch Farm, taking its total interest to 30.1 per cent. The Premier Group subsequently disposed of its entire holding in Wytch Farm, with the sale completing in December 2017.

In the late 1980s and early 1990s, the Premier Group enjoyed a series of exploration successes, notably the discovery of the Qadirpur gas field in Pakistan in 1990, the Angus and Fife fields in the UKCS in 1983 and 1991 respectively and the Yetagun gas field in Myanmar ("**Yetagun**") in 1992.

In 1995, as a result of the Pict Acquisition, the Premier Group participated in numerous further North Sea oil and gas fields (including the Fife, Fergus, Galahad and Scott fields). Supported by production revenue from the UKCS, the Premier Group turned its attention to South East Asia with a view to developing energy resources to serve the region's rapidly expanding economies.

In 1996, the Sumatra Acquisition gave Premier an operated interest in Natuna Sea Block A offshore Indonesia, comprising the Anoa oil field and substantial undeveloped gas fields, as well as exploration prospects ("**Natuna Sea Block A**"). Premier commenced gas deliveries from Natuna Sea Block A to Singapore under long term gas contracts in 2001.

To consolidate its position as a leading independent production company in the South East Asian energy markets, the Premier Group formed a strategic alliance with Petronas and Hess Corporation in 1999. The strategic alliance was subsequently reorganised and, in 2003, Premier acquired Premier Oil Group Limited which then became the holding company of the Premier Group.

In 2005, the Premier Group reorganised into four regional units: Asia, Middle East-Pakistan, North Sea and West Africa. This reorganisation took into account the successful entry into a number of new countries including Vietnam (where, in 2006, Premier made two discoveries on Block 12W at Chim Sáo and Dua), Norway and Mauritania.

In 2009, the Oilexco Acquisition provided the Premier Group with a greater presence in the North Sea and strengthened its existing operations in the area by adding a material package of assets comprising producing fields, development projects and exploration acreage, together with UK operatorship capabilities.

In 2010 and early 2011, the Premier Group made a series of discoveries in the Catcher area of the UK North Sea (the "**Catcher Area**"). In October 2011, the Premier Group announced the EnCore Acquisition, which increased the Premier Group's interest in the Catcher Area to 50 per cent., providing the Premier Group with the operatorship of the Catcher pre-development project and adding to the Premier Group's exploration position in the Central North Sea.

Premier received approval of its Catcher Area field development plan from the UK Government in June 2014 and, in December 2017, Premier delivered first oil from its operated Catcher Area, on schedule and under budget.

In May 2011, Premier acquired 60 per cent. of the Solan field 150 kilometres west of the Shetland Islands ("**Solan**"). The remaining 40 per cent. was acquired in June 2015. Solan started producing in April 2016.

In October 2011, Premier brought on-stream two significant operated Asian developments: the Chim Sáo oil field in Vietnam and the Gajah Baru gas field in Natuna Sea Block A in Indonesia. Premier has subsequently brought on-stream further gas fields in its Natuna Sea Block A (Naga in 2014, Pelikan in 2015 and the Bison, Iguana and Gajah Puteri (BIG-P) fields in 2019) to further support Premier's long term gas contracts into Singapore.

In 2012, Premier acquired 60 per cent. of Rockhopper's licence interests in the Falkland Islands, including the Sea Lion pre-development project ("**Sea Lion**"), and significantly enhanced the Premier Group's resource base and future growth potential. Premier executed a successful drilling campaign in the Falkland Islands in 2015 and 2016, substantially increasing the discovered resource there.

Since 2015, Premier has continued to focus the business on its core operated assets in Indonesia and Vietnam, the United Kingdom and the Falkland Islands, where it believes it has competitive advantage.

Non-core assets have been disposed of in Norway, the UK, Vietnam and Indonesia and exploration acreage relinquished in Kenya and Iraq. Premier completed the sale of its Norway business unit in December 2017 and, most recently, the sale of its Pakistan business unit in March 2019.

In 2016, the E.ON North Sea Acquisition significantly enhanced Premier's core UK business at a compelling valuation, adding stable UK gas revenues to the portfolio as well as an operated interest in the wider Tolmount Area, which included the Tolmount gas pre-development project. It also offered the potential to generate significant operating and cost synergies across the combined UK North Sea business. In August 2018, Premier sanctioned the development of its operated Tolmount field. Premier expects to achieve first gas from Tolmount in the second quarter of 2021.

In recent years, Premier has refocused its exploration portfolio on under-explored, emerging plays in proven hydrocarbon provinces. The Premier Group entered Brazil and Mexico in 2013 and 2015 respectively. In July 2017, Premier announced that its first exploration well offshore Mexico, Zama-1, had discovered a new world-class oil field. This material discovery was successfully appraised with a three well programme that completed in July 2019 and resulted in Premier significantly increasing its resource estimates of the Zama field.

Premier continued to add to its exploration acreage in 2018 with the award of three new blocks in Mexico and the Andaman II licence ("**Andaman II**") in the emerging South Andaman Sea gas play in Indonesia. During 2019, Premier expanded its position in the South Andaman Sea gas play, farming in for a 20 per cent. interest in the South Andaman and Andaman I licences.

Following a prolonged period of depressed commodity prices, Premier reached agreement with its lending group to undertake the 2017 Refinancing, under which the Premier Group's existing facilities were maintained and maturities were extended to 2021. Premier continues to focus on reducing absolute levels of net debt, but the 2017 Refinancing also provided the headroom and flexibility to invest selectively in the business. Premier has substantially outperformed the refinancing plan agreed with its lenders. Further information on the key terms of the material arrangements that relate to the 2017 Refinancing are included in paragraph 8 of Part XIII (*Additional Information*).

In January 2020, Premier announced its proposed acquisitions of BP's interests in the Andrew Area and Shearwater field (the "BP Acquisitions") in the UK North Sea. The BP Acquisitions, which were expected to be fully funded by equity, were in line with the Premier's stated strategy of acquiring cash generative assets in the UK North Sea, where Premier has strong operating capability and considerable tax losses. In June 2020, Premier and BP agreed in principle amended terms for the BP Acquisitions to reflect the material changes in the global commodity markets. In August 2020, Premier announced the proposed terms of the refinancing of the Premier Group's credit maturities from May 2021 to March 2025, which included an equity raise of up to $530 million (the "proposed refinancing"), including $230 million to fund the BP Acquisitions. The proposed refinancing remained subject to Premier's creditors and shareholder approval as well as to total take-up under the equity raise being not less than US$325 million.

In September 2020, Premier confirmed that, in parallel to seeking creditor consent for the proposed refinancing, it was in discussions with a number of third parties, including Chrysaor, regarding alternative long term refinancing solutions. Premier subsequently announced on 6 October 2020 the proposed all share merger with Chrysaor and the reorganisation of the Premier's existing debt and cross-currency swaps. Premier's Board believed that the Merger was of broadly comparable value to shareholders as compared to the proposed refinancing but taking into account the challenging macroeconomic conditions at the time, had greater execution certainty.

3. Purpose and Strategy

Premier's purpose is to play its role in meeting the world's energy needs through the safe, reliable and sustainable development of hydrocarbons whilst meeting the needs of society for effective governance and delivering value for our shareholders.

The Premier Group's strategy comprises four pillars, all of which contribute towards delivering Premier's purpose:

(A) *To operate in a safe and responsible manner*. Premier will never knowingly compromise its health, safety or environmental standards in pursuit of its operational objectives. The Premier Group will seek to ensure the safety of everyone in its operations and to minimise its environmental impact. Premier will act with integrity and honesty, striving for continuous improvement across all aspects of its business, assured by rigorous risk management processes.

(B) *To focus on high quality assets with commercially advantaged positions*. Premier is a full cycle exploration and production company maintaining a robust and diverse portfolio of material operated assets across multiple geographies, and hydrocarbon types, to provide scale and to diversify risk. The Premier Group seeks to grow our portfolio both through impactful exploration and appraisal in proven hydrocarbon basins and selective M&A.

(C) *To secure access to capital and financial liquidity*. Premier seeks to balance the use of available cash between debt reduction, investment in existing assets and growth. The Premier Group seeks to deliver returns for shareholders through share price appreciation. Premier will actively manage its investment programmes, employ hedging and use lease and infrastructure models to free up capital in order to maintain acceptable financial ratios and liquidity.

(D) *To maintain an effective organisation sustained by the right people*. Premier will seek to attract and retain high quality employees through challenging and satisfying employment, and through effective reward, retention, and development policies. Each business unit will have the necessary skills and competencies to stand alone but with functional support provided by corporate specialists.

4. Key strengths

4.1 Long-life production profile supported by substantial reserves and discovered resources

The Premier Group's current producing portfolio generated an average production rate of 67.3 kboepd for the half year ended 30 June 2020 (2019: 78.4 kboepd) from a spread of high quality assets. The Premier Group has a strong reserve base with approximately 174.7 mmboe of 2P reserves (as at the year ended 31 December 2019), and a portfolio of discovered resources which once developed will extend and prolong Premier's future production profile. Premier has also identified numerous opportunities to increase the reserves and field life of its producing assets through incremental investment in infill drilling and well intervention programmes, plant modifications, satellite developments and near field exploration. These projects, which are at various stages of maturity, are typically low cost with high rates of return and a rapid payback period.

4.2 Good quality long-term gas contracts

A majority of the Premier Group's gas production is sold under profitable long-term contracts to government-backed customers in Singapore. Revenues are denominated in US Dollars and funds are remitted directly to London bank accounts.

4.3 Large, operated equity stakes in high quality projects with the potential to deliver significant value

The Premier Group's current level of production is expected to increase in the medium term as a result of bringing on stream new projects. The Premier Group operates and holds material equity interests in several development and pre-development projects which are expected to deliver growth over the medium term. This includes Tolmount, where development drilling is underway through the recently installed platform, and two pre-development projects, Tuna and Sea Lion. Operatorships allow the Premier Group to exert significant influence over the planning and execution of development and pre-development projects.

4.4 Experienced production and development operator of medium-sized oil and gas projects

The Premier Group has a good track record of operating high quality assets which can be traced back to 1998 when it operated the Yetagun gas development, offshore Myanmar. Subsequently, the Premier Group has brought on stream numerous other operated development projects, including Anoa Gas Export (Indonesia) in 2001, Anoa West Lobe (Indonesia) in 2006, Chim Sáo (Vietnam) and Gajah Baru (Indonesia) in 2011, Dua (Vietnam) and Naga (Indonesia) in 2014, Pelikan (Indonesia) in 2015, Solan (UK) in 2016, Catcher (UK) in 2017 and, most recently, Bison, Iguana and Gajah Puteri (Indonesia) in 2019.

4.5 Liquidity

The Premier Group had cash and undrawn bank facilities of approximately US$435.8 million as at 30 June 2020, when excluding cash of US$33.2 million held on behalf of joint venture partners or held as security for performance related letters of credit. This is subject to the Premier Group's continued compliance with the terms of the Support Letter and the financial covenant deferrals contained therein. Combined with current cash flows, this effectively pre-finances the Premier Group's committed investment programme. The Premier Group seeks to maintain a disciplined spending target each year and where necessary will seek farm-in partners for drilling programmes and development projects to maintain this discipline.

5. Organisational structure

Premier has two principal wholly owned subsidiaries, namely Premier Oil Group Holdings Limited ("**POGHL**") and Premier Oil Finance (Jersey) Limited ("**POFJL**"). POGHL holds the majority of the Premier Group's licence interests through its subsidiaries and is registered in England and Wales. POFJL is a Jersey-registered company incorporated for the purpose of issuing convertible bonds. As at the Latest Practicable date, no convertible bonds were in issue.

A list of Premier's principal subsidiary undertakings, which are considered by Premier to be likely to have a significant effect on the assessment of the assets and liabilities, the financial position and the profits and losses of the Premier Group is set out in paragraph 7.1 of Part XIII (*Additional Information*) of this document.

Following completion of the Merger, Chrysaor will be a wholly-owned indirect subsidiary of Premier. Further information on Chrysaor is set out in Part IV (*Information on the Chrysaor Group*) of this document.

6. Premier's principal activities and investments

6.1 Overview

The Premier Group has current interests in several countries around the world, with significant assets in the UK, Indonesia, Vietnam, the Falkland Islands and Mexico. The Premier Group also has exploration interests in Brazil. The portfolio consists of: (i) oil and gas fields which are already producing; (ii) discovered fields not yet producing but which are undergoing development planning or execution; and (iii) licences to explore for new oil and gas fields in prospective areas. Fields which are already producing or for which the decision to invest in the development has already been made are classified as "**2P reserves**". Contingent resources, classified as "**2C resources**", are less certain than reserves and are potentially recoverable. This includes resources which are not yet considered mature enough for commercial development due to technological or business hurdles. As at 31 December 2019, the Premier Group had 2P reserves of 174.7 mmboe and 2C resources of 672.1 mmboe, giving rise to a reserves and resource base of 846.8 mmboe. Production for the half year ended 30 June 2020 averaged 67.3 kboepd (2019: 78.4 kboepd).

A breakdown of total revenues by category of activity and geographic market for the years ended 31 December 2017, 31 December 2018 and 31 December 2019, is given in the statutory accounts of Premier for those years, which are incorporated into this document by reference.

6.2 The Premier Group's reserves and production by country

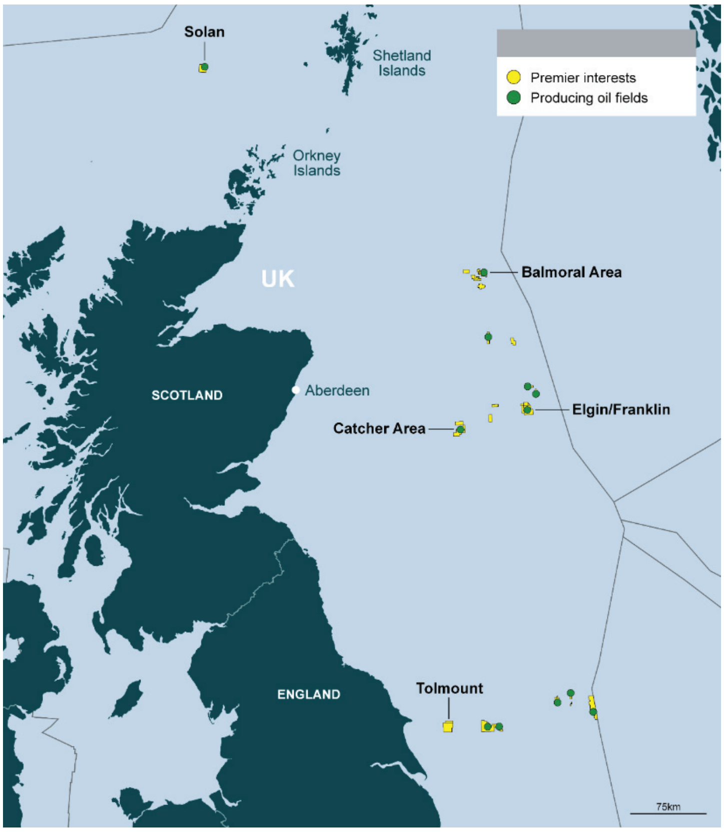
Set out in the table below are the Premier Group's production for the half year ended 30 June 2020 and 2P reserves as at 31 December 2019:

	UK	*Indonesia*	*Vietnam*	*Total*
Production (kboepd)	45.0	13.2	9.1	67.3
% of total	*66.9%*	*19.6%*	*13.5%*	*100%*
2P reserves (mmboe)	124.7	30.8	19.2	174.7
% of total	*71.4%*	*17.6%*	*11.0%*	*100%*

The Premier Group is organised into four business units: the UK, the Falkland Islands, Indonesia and Vietnam, with the exploration teams reporting directly to a central exploration function.

6.3 United Kingdom

The Premier Group's licence interests in the UK North Sea:



Headquarters: Aberdeen.

The Premier Group has a portfolio of licences in the UK which comprises a mixture of producing assets, development and pre-development assets and exploration acreage.

Net to Premier, 2P reserves and 2C resources in the UK were estimated at 191.5 mmboe as at 31 December 2019, representing 22.6 per cent. of the Premier Group's global total reserves and resources. UK production for the half year ended 30 June 2020 averaged 45.0 kboepd and accounted for 66.9 per cent. of the Premier Group's total production. Staff in this business unit also manage the Premier Group's sole (non-operated) interest in Mauritania, namely the Chinguetti oil field, which ceased production on 30 December 2017 and in relation to which a field abandonment and decommissioning programme is under way.

(A) Balmoral Area Fields—producing assets, various operated interests

The Balmoral, Glamis, Stirling, Brenda and Nicol fields are located in blocks 16/21a-c, 16/21d and 15/25a in the UK Central North Sea (the "**Balmoral Area Fields**"). The Premier Group acquired its interest in the Balmoral Area Fields through the Oilexco Acquisition. The Balmoral Area Fields were Premier's first operated UK North Sea producing asset and have been instrumental in enabling the Company to build and develop its operatorship capability in the UK North Sea.

The Balmoral Area Fields produce via a floating production facility located on the Balmoral field. Oil is transported via the Brae-Forties link to Cruden Bay and overland to Hound Point. Over 190 million barrels of oil equivalent has been produced over the Balmoral floating production facility since first production in 1986.

In June 2020, as a result of the low oil price environment, Premier took the decision to bring forward final production from its operated Balmoral Area Fields to November 2020 from 2021. This is three years later than the 2017 cessation of production anticipated when the Premier Group acquired the asset in 2009. Abandonment expenditure for the Balmoral Area Fields which comprises to a floating production vessel is not expected to be material in the near term with related well abandonment expenditure spread over a number of future years.

Net to Premier, 2P reserves in the Balmoral Area Fields are estimated at 1.1 mmboe as at 31 December 2019. Production from the Balmoral Area Fields for the half year ended 30 June 2020 averaged 2.0 kboepd, net to Premier.

(B) Catcher Area—producing and development assets, 50 per cent. operated interest

The Catcher discovery was made by an exploration well drilled in May 2010. The Catcher East side-track well, drilled in June 2010, encountered excellent quality oil bearing sandstones and established a common pressure regime. The second phase of the Catcher Area exploration campaign was completed in early 2011 with successful discoveries at Varadero and Burgman.

The development concept for the Catcher Area was formally agreed by partners in December 2013 and government approval was received in June 2014. The Catcher Area produces from 18 subsea wells on Catcher, Varadero and Burgman. These are a combination of production and water injection wells which are tied back to a newly built leased FPSO. The oil is offloaded by tankers and the gas is being reinjected into the reservoir. Total gross reserves at project sanction were estimated to be 96 mmboe.

First oil was delivered on schedule and 30 per cent. below budget on 23 December 2017 initially from Catcher with first oil from Varadero in January 2018 and Burgman coming on stream in May 2018. The Catcher Area reached plateau production oil rates of 60,000 boepd (gross) in May 2018. Day rates of up to 66,000 boepd (gross) have been consistently achieved subsequently, considerably in excess of the 50,000 (gross) envisaged at sanction, and reflects very high operating efficiency and strong reservoir performance.

Production data from the Catcher Area continues to demonstrate good pressure support provided by the aquifer and injector wells and generally excellent lateral reservoir connectivity. Well productivity, supported by better than expected permeability, remains constrained by the FPSO design capacity and the well stock is being managed to optimise production and ultimate oil recovery.

The Catcher Area reached cash payback by the end of October 2019, less than two years after first oil. The Catcher Area also achieved a low GHG intensity during 2019, benefiting from high plant uptime and a new build FPSO with modern gas recovery and treatment systems.

During the third quarter of 2020, Catcher Area production was constrained due to the produced water plant being offline while a build-up of calcium naphthenate was removed. The produced water plant was subsequently reinstated in early November. Premier, together with its joint venture partners and BW Offshore, the operator of the Catcher FPSO, are proactively working on plans to mitigate against this happening again in the future.

Premier has identified a programme of infill drilling to increase recovery from the Catcher Area. In particular, the Premier Group brought the Vardero infill well online in September 2020 and the subsea infrastructure was installed for the Catcher North and Laverda tiebacks via the Varadero manifold in the second half of 2020.

In addition to the Catcher North and Laverda development wells, Premier has identified an additional infill target on the Burgman field and expects further targets to be confirmed post the acquisition of the 4D seismic survey across the Catcher Area, planned for 2021. This survey will further calibrate existing reservoir models, help high grade future opportunities and provide better imaging of potential oil-bearing reservoirs to evaluate new tie back opportunities.

The Premier Group first acquired an interest in the Catcher Area as part of the Oilexco Acquisition. Premier increased its interest in the Catcher Area by 15 per cent. to 50 per cent. in 2012 as a result of the EnCore Acquisition and acquired operatorship.

Net to Premier, 2P reserves for the Catcher Area as at 31 December 2019 were 18 mmboe. This reflects an increase in reserves compared to the 96 mmboe of reserves estimated at sanction. Premier continues to see significant upside in the recovery from the field supported by more production history to calibrate the Premier Group's dynamic models, successful infill drilling programmes and well sequencing optimisation.

Catcher Area production for the half year ended 30 June 2020 averaged 28.4 kboepd. Production is forecast to continue until at least 2029.

The partners in the Catcher Area are Premier (50 per cent., operator), Cairn (20 per cent.), MOL (20 per cent.) and ONE-Dyas (10 per cent.).

(C) Huntington—producing asset, 100 per cent. operated interest

The Huntington oil field is in the Central North Sea, 230 kilometres north-east of Aberdeen ("**Huntington**"). It was discovered by Oilexco in 2007. Premier acquired Oilexco and its 40 per cent. non-operated interest in Huntington as part of the Oilexco Acquisition and subsequently acquired the interests of all the remaining partners between November 2015 and April 2016, resulting in Premier having a 100 per cent. operated interest in Huntington.

A field development plan ("**FDP**") was sanctioned in November 2010, utilising the Sevan Marine-owned Voyageur FPSO which Teekay agreed to acquire in 2011 (the "**Voyageur FPSO**"). Teekay subsequently financed the completion of the upgrade of the Voyageur FPSO and first oil from Huntington was achieved in April 2013.

During 2018, the offshore plant was successfully modified to facilitate gas import which, together with conversion of a former production well to a water injector, improved plant stability and reservoir deliverability.

The continued strong reservoir performance from Huntington and markedly improved uptime of the FPSO has meant that the field has produced for longer than envisaged when Premier acquired operatorship of Huntington in April 2016. As a result, Premier extended its FPSO lease agreement with Teekay for a year in April 2018 and again for another year in April 2019.

At the start of 2020 water cut in the highest producing well increased prompting Premier to submit a draft decommissioning programme for the removal of the Huntington FPSO from the field to the Secretary of State for Business, Energy and Industrial Strategy in February 2020. The last Huntington cargo was lifted from the field in April 2020. The first phase of the decommissioning programme was substantially completed during 2020 with the sailaway of the FPSO and recovery of the riser systems. The second phase, which will entail recovery of the subsea equipment and remaining mooring system, is scheduled for 2022.

Net to Premier, 2P reserves for Huntington are estimated at 0.6 mmboe as at 31 December 2019. Huntington production for the half year ended 30 June 2020 averaged 1.5 kboepd.

(D) Johnston—producing asset, 50.1 per cent. operated interest

The Johnston field is a dry gas accumulation and was discovered in 1990 and is located within blocks 43/26a and 43/27a in the UK Southern North Sea ("**Johnston**"). Premier acquired its 50.1 per cent. operated interest in Johnston through the E.ON North Sea Acquisition.

Johnston was developed with two horizontal development wells drilled from a four slot subsea template, tied back to Ravenspurn North. Production commenced in 1994. An additional four wells have since been drilled, with two tied back to the subsea template. After processing at Ravenspurn North, gas is exported to the Perenco-operated terminal at Dimlington.

Net to Premier, 2P reserves for Johnston are estimated at 0.6 mmboe as at 31 December 2019. Johnston production for the half year ended 30 June 2020 averaged 0.6 kboepd, net to Premier. Production is forecast to continue until 2021.

Premier's partner in Johnston is Dana Petroleum (49.9 per cent.)

(E) Solan—producing asset, 100 per cent. operated interest

Solan was discovered in 1991 and was appraised by Chrysaor, with two wells drilled in 2008 and 2009. In May 2011, Premier signed a sale and purchase agreement with Chrysaor to acquire a 60 per cent. equity interest in Solan. In June 2015, Premier acquired Chrysaor's remaining 40 per cent. interest in the field for nil upfront consideration. At the same time, Premier entered into an agreement with FlowStream whereby a US$100 million payment was received in return for the proceeds from 15 per cent. of future production from the field for a period of time.

Approval of an FDP for Solan (the "**Solan FDP**") was granted by the Department of Energy and Climate Change ("**DECC**") in April 2012. The Solan FDP consisted of two producers and two injectors tied back to a platform with oil produced into a subsea storage tank and offloaded by shuttle tanker. The facilities were installed during 2014, with first oil achieved in April 2016.

During the second quarter of 2020, the Transocean Leader successfully drilled a new Solan production well (P3) with the horizontal well encountering more than 2,300 feet of net sand with reservoir properties at the higher end of expectations. First oil from the well was achieved in September 2020 and production from the P3 well, with the ESP online, is expected to reach rates in excess of 10 kboepd.

Premier is considering side-tracking an existing Solan water injection well in 2022 to enhance recovery from the P3 well and further extending field life.

Net to Premier, 2P reserves for Solan are estimated at 9.4 mmboe as at 31 December 2019. Solan production for the half year ended 30 June 2020 averaged 1.7 kboepd. Production was impacted by a planned shut down for P3 platform modifications and the second production well (P2) being on free flow since March. Production is forecast to continue until 2025.

(F) Elgin-Franklin Area—producing asset, 5.2 per cent. non-operated interest

The Elgin-Franklin area (including Elgin, Franklin and West Franklin) is located in the Central North Sea (the "**Elgin-Franklin Area**"). Premier acquired its 5.2 per cent. non-operated interest in the Elgin-Franklin Area through the E.ON North Sea Acquisition.

The Elgin-Franklin Area started production in 2001. The development utilises a TGP-500 jack-up design production, utilities and quarters platform located on Elgin (the "**Elgin PUQ**"). The Elgin PUQ is bridgelinked to a satellite wellhead platform ("**WHP**"). A NUI WHP is located on Franklin, with production transported via subsea flow lines to the Elgin PUQ. West Franklin was developed via an extended reach well drilled from the Franklin WHP, with first production in 2007. The West Franklin phase two development started production in January 2015 and includes the West Franklin A WHP and the Elgin B WHP. The Elgin B WHP is bridge-linked to the Elgin A WHP. Once processed on the Elgin PUQ, liquids are transported via a spur line to the FPS. Sales gas is exported via a dry gas pipeline to the Shell-operated Bacton terminal ("**Bacton**").

The Elgin-Franklin Area is a mid-life asset with low operating costs. Ongoing well intervention campaigns and infill drilling continues to help maintain production from the area and result in incremental reserve upgrades in the near term.

Net to Premier, 2P reserves for the Elgin-Franklin Area are estimated at 21.5 mmboe as at 31 December 2019. Elgin-Franklin Area production for the half year ended 30 June 2020 averaged 7.3 kboepd, net to Premier. This was ahead of forecast as the field benefitted from very high operating efficiency and an ongoing infill drilling programme. Production is forecast to continue until 2040.

Premier's partners in the Elgin-Franklin Area are Total (operator, 46.17 per cent.), Eni (21.87 per cent.), Chrysaor (14.11 per cent.), ExxonMobil (4.38 per cent.), Ithaca (3.90 per cent.), ONE-Dyas (2.19 per cent.) and Sumitomo Corporation (2.19 per cent.).

(G) Glenelg—producing asset, 18.57 per cent. non-operated interest

The Glenelg gas condensate field is located in blocks 29/4D and 29/5B in the Central North Sea, four kilometres to the west of the Elgin-Franklin Area ("**Glenelg**"). Glenelg was discovered in 1999 and began producing in 2006. Premier acquired its 18.57 per cent. non-operated interest in Glenelg through the E.ON North Sea Acquisition.

Glenelg has been developed as a satellite to the Elgin-Franklin Area and is produced via a single well from the Elgin A WHP. Condensate from Glenelg is exported from Elgin via a spur line to Marnock and onwards through the FPS. Following processing offshore on facilities at Elgin-Franklin, gas is exported via the SEAL to Bacton. Glenelg is currently on cyclical production due to downhole scaling in the single well.

Net to Premier, 2P reserves for Glenelg are estimated at 0.2 mmboe as at 31 December 2019. Glenelg production for the half year ended 30 June 2020 averaged 0.4 kboepd, net to Premier.

Production is forecast to continue until 2030. Premier's partners in Glenelg are Total (58.73 per cent.), Chrysaor (14.70 per cent.) and Eni (8 per cent.).

(H) Kyle—producing field, 40 per cent. non-operated interest

In 1995, Premier acquired a 20 per cent. interest in the P748 licence, which contains the Kyle oil field ("**Kyle**"), through the Pict Acquisition. Between 1997 and 2002, Premier acquired additional equity interests in Kyle, taking its total interest to 40 per cent. Kyle was developed via sub-sea wells connected to two manifolds (North and South) tied back 18 kilometres to the Maersk-operated Maersk Curlew FPSO. Oil and gas production via the Maersk Curlew FPSO began in 2001 before being diverted in 2005 to the Petrojarl Banff FPSO operated by Teekay. In December 2011, a severe storm resulted in damage to the subsea infrastructure and the Petrojarl Banff FPSO. The vessel was subsequently removed from Kyle and towed to Scapa Flow, in Orkney, to facilitate repairs. Production from Kyle resumed in mid-2014 following a two and a half year reinstatement project.

Production from the Kyle field ceased in June 2020 and the Kyle joint venture partners are working closely with the Banff owners towards the safe and cost efficient decommissioning of the Kyle facilities. Sail-away of the FPSO occurred during September 2020.

Net to Premier, 2P reserves are estimated at 0.3 mmboe as at 31 December 2019. Kyle production for the half year ended 30 June 2020 averaged 1.1 kboepd, net to Premier. Premier's partners in Kyle are CNR (operator, 45.71 per cent.) and Dana Petroleum (14.29 per cent.).

(I) Merganser—producing asset, 7.9 per cent. non-operated interest

The Merganser gas and condensate field is located in blocks 22/30a and 22/25a in the Central North Sea ("**Merganser**"). Premier acquired its interest in Merganser through the E.ON North Sea Acquisition. Merganser was discovered in 1995 and began producing in 2006. It produces from the Forties and Andrew reservoirs and consists of two subsea wells tied into the pipeline at the Scoter field. The commingled production is transported to the Shearwater Field for processing. Gas is exported from the Shearwater Field via the SEAL to Bacton. Liquids production is exported to Cruden Bay via the Marnock Central Processing Facility, the Forties Unity Platform and the FPS.

Net to Premier, 2P reserves for Merganser are estimated at 0.1 mmboe as at 31 December 2019. Merganser production for the half year ended 30 June 2020 averaged 0.3 kboepd, net to Premier. Production is forecast to continue until Q1 2021. Premier's partners in Merganser are Esso (44 per cent.) and Shell (48.08 per cent.).

(J) Nelson—producing asset, 1.66 per cent. non-operated interest

The Nelson oil and gas field, discovered in 1988, is located to the south east of the Forties field ("**Nelson**"). Following an extensive appraisal drilling programme in the late 1980s, Nelson was subsequently developed using a conventional stand-alone fixed steel platform with one subsea template located six kilometres to the south. First oil was achieved in February 1994. Oil is exported via a spur line to the FPS and onwards to Cruden Bay. Gas export is via the Fulmar Pipeline to the Shell-operated terminal facilities at St Fergus on the north east coast of Scotland ("**St Fergus**"). The Premier Group acquired its 1.66 per cent. interest in Nelson through the Oilexco Acquisition.

Net to Premier, 2P reserves are estimated at 0.6 mmboe as at 31 December 2019. Nelson production for the half year ended 30 June 2020 averaged 0.2 kboepd, net to Premier. Production is forecast to continue until 2033.

Premier's partners in Nelson are Shell (operator, 58.11 per cent.), Exxon Mobil (21.23 per cent.), Apache (11.52 per cent.), and Rockrose (7.48 per cent.).

(K) Ravenspurn North—producing asset, 28.75 per cent. non-operated interest

Ravenspurn North is a dry gas field discovered in 1984 within blocks 42/30a and 43/26a in the Southern North Sea ("**Ravenspurn North**"). It came on-stream in 1990, had a peak rate of 450 MMSCFD in 1997 and is currently producing 25 MMSCFD (gross). Premier acquired its 28.75 per cent. interest in Ravenspurn North through the E.ON North Sea Acquisition.

The Ravenspurn North field development consists of a gravity based concrete platform with accommodation, process facilities and compression linked to a steel WHP. Two additional WHPs were subsequently installed.

Gas is exported to the facilities at Cleeton and then onward via the Cleeton/Ravenspurn South pipeline to Dimlington. 42 development wells have been drilled although three were not completed. Wells are largely deviated and hydraulically fractured.

Net to Premier, 2P reserves for Ravenspurn North are estimated at 3.0 mmboe as at 31 December 2019. Ravenspurn North production for the half year ended 30 June 2020 averaged 1.2 kboepd, net to Premier. Production is forecast to continue until 2028. Premier's partner in Ravenspurn North is Perenco (operator, 71.25 per cent.).

(L) Scoter – producing asset, 12 per cent. non-operated interest

The Scoter field is located in blocks 23/26d and 22/30a in the Central North Sea ("**Scoter**"). Premier acquired its interests in Scoter through the E.ON North Sea Acquisition. Scoter was developed as a three well subsea tie-back to the Shearwater Field. Gas sales from the field commenced in 2004. After processing, gas is exported from the Shearwater platform via the SEAL to Bacton. Liquid production is exported to Cruden Bay via the Marnock Central Processing Facility, the Forties Unity Platform and the FPS.

Net to Premier, 2P reserves for Scoter are estimated at 0.1 mmboe as at 31 December 2019. Scoter production for the half year ended 30 June 2020 averaged 0.3 kboepd, net to Premier. Production is forecast to continue until Q2 2021. Premier's partners in Scoter are Esso (44 per cent.) and Shell (44 per cent).

(M) Tolmount—development project, 50 per cent. operated interest

The Tolmount gas field is situated in block 42/28d, in the UK Southern North Sea. It was discovered in 2011 with further appraisal drilling in 2013. Tolmount is one of the largest discoveries in the Southern Gas Basin in recent years. Premier acquired its interest in the wider Tolmount Area, which includes Tolmount, the Tolmount East and Mongour discoveries and exploration prospect Tolmount Far East as a result of the E.ON North Sea Acquisition.

In February 2017, a development concept comprising a standalone normally unmanned installation ("**NUI**") unit and a new gas export pipeline to the shore was selected to develop Tolmount. Front end engineering and design ("**FEED**") work was completed over the course of 2017 and the first half of 2018. The project was sanctioned by the joint venture and the infrastructure partners in August 2018. As at the date of this document, Premier's share of the capital expenditure to develop Tolmount is approximately US$120 million, comprising project management and development drilling costs. The Humber Gathering System, an infrastructure joint venture, will own and pay for the platform and pipeline capital expenditure as well as pay for upgrades to the onshore terminal. In return, Premier will pay a tariff for the use of the infrastructure.

The Tolmount development is scheduled for first gas in Q2 2021. The Tolmount platform, which was built in the Rosetti yard in Italy, was successfully installed over the Tolmount field in the UK Southern Gas Basin during October 2020. The drilling rig was subsequently mobilised and the first of the four firm development wells was spudded in November 2020. The pipe lay was successfully completed during the summer of 2020 and works on the onshore terminal modifications are progressing. Initial peak production rates of over 50 kboepd (gross) are expected from the field once production has ramped up. Production from Tolmount is expected to continue until at least 2035.

Net to Premier, 2P reserves for Tolmount are estimated at 50.0 mmboe as at 31 December 2019. Premier is considering drilling further wells on Tolmount post first gas to deliver incremental recovery from the field.

On 17 October 2019, Premier announced the success of the Tolmount East well in an undrilled area four kilometres east of the 500 bcf Tolmount gas field. The well penetrated 241 feet of gas bearing high quality Leman sands with a net-to-gross ratio of 71 per cent., porosity of 16 per cent. and gas saturation of 82 per cent.

On the proposed Tolmount East development, Premier is now in final negotiations with its selected contractors ahead of making a final investment decision on the project. Once on-stream, Tolmount

East (and potentially Mongour which could also be developed as a subsea tieback to the Tolmount infrastructure) will help extend plateau production from Tolmount.

There is considerable upside within the Greater Tolmount Area. In September 2020, Premier was awarded two licences directly adjacent to its Tolmount Field Development Area and is in the process of maturing a number of leads and prospects which, in the success case, could be developed via the Tolmount infrastructure.

Premier's partner in Tolmount is Dana Petroleum (50 per cent.).

(N) UK exploration assets

Premier's exploration activities in the UK focus on near-field prospects close to existing infrastructure. In particular, Premier will look to evaluate and mature its exploration acreage in the Tolmount Area in the Southern Gas Basin. Premier actively manages its exploration portfolio, exiting a number of licences including those with commitment well obligations at Ekland and Artemis.

Summary of regulatory regime and licence terms in the UK

The Petroleum Act 1998 (the "**Petroleum Act**") governs oil and gas exploration and production activities in the UK. The Petroleum Act provides for a licensing regime, whereby 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 the Premier Group 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 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 completed the work programme. At this stage, the licensee must also relinquish a fixed amount of acreage.

The appraisal and development period is four years for Seaward Production Licences. The licence expires at the end of the second term unless 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 it was granted. 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 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. When an interest in a licence changes hands, the Secretary of State typically releases a former licensee from its decommissioning obligations once the Secretary of State is satisfied that adequate arrangements are in place in relation to the decommissioning liabilities. These arrangements typically require the provision of financial security to ensure that existing and incoming licensees can discharge their decommissioning liabilities.

From 1 April 2016, the OGA replaced the DECC as the entity responsible for petroleum licensing and regulation of the upstream oil and gas sector in the UK. On 14 July 2016, 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.

Summary of the economic and fiscal regime in the UK

The primary amounts which the Premier Group must pay to the UK government comprise taxation arising from the production of oil and gas. There are currently three 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**"); and (iii) a supplementary charge (the "**Supplementary Charge**"). 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 five of the Premier Group'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 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.

As part of the Oilexco Acquisition, the Premier Group acquired US$1.2 billion of UK ring fence tax allowances. At 31 December 2019, the Premier Group's ring fence tax losses and allowances had increased to an estimated US$4.1 billion due to investment in the UKCS and the availability of the ring fence expenditure supplement. These UK tax losses and allowances are available indefinitely for offset against future ring fence profits. The Premier Group currently does not pay UK ring fence corporation tax or Supplementary Charge due to the ability to set these tax losses and allowances against future taxable profits. The Premier Group will continue to benefit from the ring fence expenditure supplement, which, under current legislation, will uplift a small proportion of the tax losses by 10 per cent.

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 losses for oil and gas companies to the extent the costs exceed current year profits.

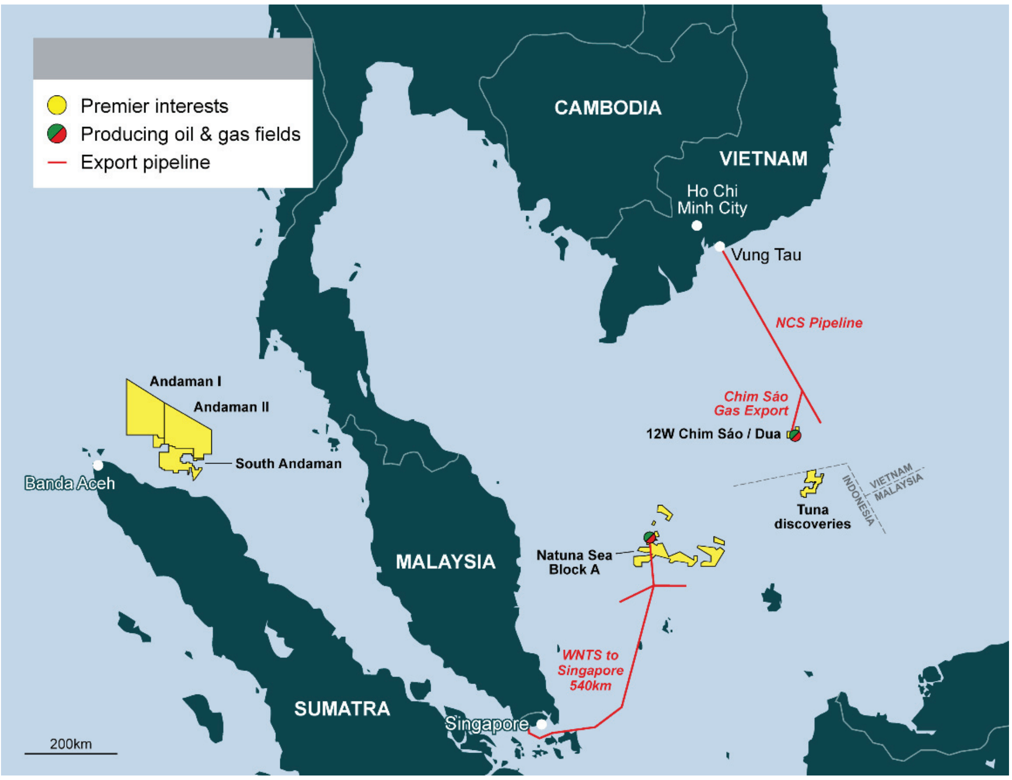
These losses can be carried forward if the company is still trading or carried back and set off against past profits as far back as 2002 (or indefinitely for PRT purposes). The carry back of losses can generate valuable tax refunds to the extent the company incurring the losses has paid tax historically. 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 ("**DSAs**") to be posted on a "net of tax" basis, the Finance Act 2013 introduced the decommissioning relief deed ("**DRD**").

This 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 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.

More recently, the Finance Act 2019 introduced the concept of transferable tax history which enables the seller of an interest in an oil field in the UK and UKCS to transfer tax history (i.e., a portion of its historic taxable profits) to the buyer, who can then use it to potentially generate tax refunds on incurring decommissioning costs. The transferred tax history is only accessed to the extent the transferred asset becomes net loss making from the date of transfer. This measure facilitates acquisitions by participators who may not otherwise have tax capacity against which decommissioning expenditure could be carried back and offset. The mechanism requires a joint election between the buyer and the seller.

6.4 Asia

The Premier Group's licence interests in South East Asia:



(A) Indonesia

Headquarters: Jakarta

Net to Premier, 2P reserves in Indonesia are estimated at 30.8 mmboe as at 31 December 2019, representing 17.6 per cent. of the Premier Group's global total reserve base. With 13.2 kboepd produced in the region for the half year ended 30 June 2020, Indonesia accounted for 19.6 per cent. of the Premier Group's total production.

Natuna Sea Block A—producing asset and exploration, 28.67 per cent. operated interest

Natuna Sea Block A lies near the maritime borders between Malaysia, Indonesia and Vietnam and is a major supplier of gas to Singapore. Premier acquired its 28.67 per cent. operated interest in Natuna Sea Block A through the Sumatra Acquisition.

Natuna Sea Block A consists of seven separate producing fields (Anoa, Gajah Baru, Pelikan, Naga, Bison, Iguana and Gajah Puteri), which have each been developed through a combination of platforms and subsea tie-backs.

Premier delivers gas from Natuna Sea Block A to Singapore through the West Natuna Transportation System ("**WNTS**") under two gas sales agreements, "GSA1" and "GSA2". GSA1 was signed in 1999 with SembCorp, a government-controlled Singaporean utility, to deliver gas into Singapore from three PSCs (Natuna Sea Block A PSC, Kakap PSC and B Block PSC). Deliveries under GSA1 commenced in January 2001 and GSA 1 is a 90 per cent. take or pay contract (which shall reduce to 70% in March 2023). Anoa, which came on-stream in January 2001, Pelikan, which came on-stream in 2015, and Bison and Gajah Puteri, which came on-stream in 2019, deliver gas under GSA1 from Natuna Sea Block A to Singapore.

In 2008, Premier signed GSA2 with SembCorp for additional gas sales into the Singapore market. GSA2 is also a 90 per cent. take or pay contract. Gajah Baru, which was discovered by Premier in 2000 and brought on-stream in October 2011, Naga, which came on-stream in November 2014, and Iguana, which came on-stream in 2019, supply gas to Singapore from Natuna Sea Block A under GSA2.

Preparations are underway for a 2021 rig programme which will seek to recover further incremental reserves from the Anoa and Gajah Baru fields. Premier sees incremental investment opportunities beyond that including a potential well to test the northern flank of Anoa in 2023.

The pricing of Premier's gas delivered under GSA1 and GSA2 is directly related to HSFO pricing. Net to Premier, 2P reserves for Natuna Sea Block A are estimated at 30.8 mmboe as at 31 December 2019. Natuna Sea Block A production for the half year ended 30 June 2020 averaged 13.2 kboepd, net to Premier. Production is forecast to continue until 2029, with GSA1 expiring in 2029 and GSA2 expiring in 2028.

Premier's partners in Natuna Sea Block A are KUFPEC (33.33 per cent.), Pertamina and PTTEP (23 per cent.) and Petronas (15 per cent.).

Tuna Block—pre-development asset, 100 per cent. operated interest

In March 2007, Premier was awarded a 65 per cent. operated interest in the Tuna offshore block (the "**Tuna Block**") by the Indonesian Government. In April 2014, Premier drilled the Kuda Laut-1 exploration well which discovered 183 feet of net oil-bearing reservoir and 327 feet of net gas-bearing reservoir. Oil and gas samples were also recovered to surface. The well was then sidetracked to drill a prospect at Singa Laut in an adjacent fault block where 177 feet of net gas-bearing reservoir quality sands were penetrated.

In November 2017, a memorandum of understanding between PetroVietnam, SKKMIGAS (on behalf of the Indonesian Government) and Premier for future gas sales from the Tuna Block into Vietnam was signed and represented a significant step forward in the potential development.

In December 2019, Premier signed a Heads of Terms with Zarubezhneft, a Russian company with upstream interests primarily in Vietnam, to farm in for 50 per cent. non-operated interest in the Tuna PSC. Under the fully termed farm down agreement, which was signed in September 2020, Zarubezhneft will carry Premier for its share of a two well appraisal campaign, with such carry capped at US$32.5 million. The campaign is planned for 2021 with the rig procurement process well-advanced. Premier's former partners in the Tuna Block, Mitsui Oil Exploration (20 per cent.) and GS Energy Corporation (15 per cent.) have both exited the Tuna PSC. It is anticipated that, post completion and receipt of government approval for the farm down, Premier will retain operatorship and a 50 per cent. interest in the Tuna PSC. Premier and Zarubezhneft are now in the process of securing Indonesian government approval for the farm out agreement and a one year extension to the Tuna PSC to March 2022.

Andaman Sea – exploration assets, Andaman II (40.00 per cent. operated interest); South Andaman and Andaman I (20.00 per cent. non-operated interest)

In January 2018, Premier was awarded a 40 per cent. operated interest in Andaman II in the Indonesian Licence Round. Andaman II is located in the emerging South Andaman Sea gas play offshore Aceh, Indonesia.

In July 2019, Premier increased its position in the emerging South Andaman Sea gas play by farming in for a 20 per cent. interest in the South Andaman and Andaman I blocks located adjacent to Premier's Andaman II acreage. This expands Premier's collaboration with Mubadala Petroleum who are the operator of the South Andaman and Andaman I blocks and also Premier Group's joint venture partner in Andaman II.

A 3D seismic acquisition programme across Andaman I, Andaman II and South Andaman was completed in 2019 with highly encouraging initial results and will be used to mature the prospects identified on the existing 2D data, many of which exhibit direct hydrocarbon indicators. Premier plans to drill its first well in the Andaman Sea on its operated Andaman II licence in 2022. Premier's Andaman Sea position has the potential to deliver multi-tcf of gas and adds a potentially material gas play to Premier's Indonesian portfolio.

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, Law No.22 of 2001, and its subordinate legislation and regulations. In addition, various environmental and health and safety laws and regulations apply. Furthermore, on 24 April 2014 a new negative investment list was issued through Presidential Decree No. 39/2014, which prohibits foreign investment companies from engaging in onshore drilling and limits the maximum foreign shareholding for offshore drilling to 75 per cent.

The Premier Group's activities in Indonesia are governed by the production sharing contract regime. The Premier Group is party to three 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). The exploration period is six years (subject to possible extensions approved by the Special Task Force for Upstream Oil and Gas Business Activities Republic of Indonesia ("**SKKMIGAS**")). The development and production period begins after the declaration of commercial discovery with no specific duration stipulated for this period.

The PSCs deal with matters such as: (i) the exploration, development and production periods; (ii) obligations to carry out the work programme during the initial term and to obtain approval for its development and production programme; (iii) the automatic transfer of assets acquired by the contractor in connection with the PSC to SKKMIGAS if charged as petroleum costs upon import into Indonesia; (iv) the requirement to offer a regionally owned business a 10 per cent. participating interest in the PSC upon the declaration of commercial discovery; (v) restrictions on, and government consent for, assignment of the PSC or change of control of a contractor; and (vi) the power of the contractor and SKKMIGAS to revoke the PSC where a party fails to remedy a major breach of the PSC.

Minister of Energy and Mineral Resources Regulation 23/2018 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 Pertamina; or (iii) joint operations between Pertamina and one or more of the existing PSC contractors. If the Minister of Energy and Mineral Resources 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 right to manage a contract area can be made by both Pertamina or the current PSC contractors at the earliest 10 years before the expiry of the PSC, and no later than two years before the expiry. 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 with final approval given by the Minister of Energy and Mineral Resources. 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 Minister of Energy and Mineral Resources 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. Furthermore, the Minister of Energy and Mineral Resources 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 (Pertamina 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 Pertamina and/or 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 structure in Indonesia is one of production-sharing, so each asset is the subject of an individual contract with a unique formula for calculating the production split between the Indonesian Government and the PSC contractor.

Some PSCs require first tranche petroleum, 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 the PSCs, a share of net petroleum production in each year up to a maximum percentage of net production ("**Cost Recovery Petroleum**") 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 79/2010 (and its amendment Government Regulation 27/2017) are eligible for cost recovery. Profit petroleum (being net production after the deduction of Cost Recovery Petroleum) is allocated between the Government of Indonesia and contractors in accordance with production on a sliding scale 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.

The income tax rate applicable to a PSC is 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. The PSCs include tax stabilisation clauses. A contractor is required to supply a specific portion of profit petroleum allocation to the domestic market at a defined percentage market price, with current ranges varying between 10 and 25 per cent. depending on the contract. Contractors are required to give preference to Indonesian goods and services in accordance with competitive standards. No specific percentage of local content is prescribed.

(B) Vietnam

Headquarters: Ho Chi Minh City

Block 12W is Premier's sole asset in Vietnam. Net to Premier, estimated 2P reserves for Block 12W are estimated at 19.2 mmboe as at 31 December 2019, representing 11.0 per cent. of the Premier Group's global total reserve base. With 9.1 kboepd produced in the region for the half year ended 30 June 2020, Block 12W accounted for 13.5 per cent. of the Premier Group's total production.

Block 12W—producing asset, 53.13 per cent. operated interest

The Premier Group acquired a 75 per cent. interest in Block 12W from Delek Energy Systems Limited in 2004 and currently holds a 53.13 per cent. interest in Block 12W.

The area has similar geology to the West Natuna Sea area in Indonesia, approximately 300 kilometres to the south west. The Premier Group announced two discoveries (Chim Sáo and Dua) on Block 12W in 2006. Chim Sáo was appraised and an FDP was approved by the Vietnamese Government in 2008. Chim Sáo was successfully brought on stream in October 2011. The development of Dua as a near field subsea tie-back to the processing facilities at Chim Sáo received approval from the Vietnamese Government in August 2012. First oil from Dua was achieved in July 2014.

In recent years, successful well intervention programmes, infill wells and increasing the use of gas lift in the wells have supported production levels from Block 12W. This, together with high operating efficiency, has helped to mitigate natural decline from the field. Further well intervention work is underway to help slow natural decline and optimise offtake from the Chim Sáo field. A four well infill drilling programme aimed at further maximizing recovery from the Chim Sáo field was completed in October 2020.

At the end of 2018, Premier again increased its total recoverable reserves estimates for Block 12W to over 120 mmboe (gross), a third increase since 2011 and significantly above the 55 mmboe (gross) total recoverable reserves estimated at sanction.

In 2016, Premier completed a revised agreement with the FPSO provider for Chim Sáo. This lowered the lease rate and extended the life of the field out to 2030. Premier's partners in Block 12W are Medco Energi (31.88 per cent.) and PetroVietnam (15 per cent.).

Summary of regulatory regime and licence terms in Vietnam

Oil and gas exploration and production activities in Vietnam are mainly regulated by the Law on Petroleum No. 18-L/CTN dated 6 July 1993, as amended and supplemented in 2000 and 2008 and its subordinate legislation and regulations.

The Premier Group is party to one PSC in Vietnam. Under the PSC, the maximum total term is between 25 and 30 years. The exploration period is five to seven years. The development and production period begins after the declaration of commercial discovery with no specific time period stipulated for such period. The PSC includes provision for the PSC to be extended by agreement with the national oil company, PetroVietnam.

The PSC deals with matters such as: (i) the exploration, development and production periods; (ii) extension of the PSC by agreement with PetroVietnam; the contractor's 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 a well; (iii) the automatic transfer of assets acquired and/or provided by the contractor in connection with the PSC to PetroVietnam if charged as petroleum costs upon full cost recovery or upon termination of the PSC; (iv) an option for PetroVietnam to hold a participating interest in a PSC upon the declaration of commercial discovery; (v) joint and several liability of the contractors; an indemnity by the contractors for the benefit of PetroVietnam for any third party claims arising in relation to the PSC or anything done pursuant to it; (vi) restrictions on and government consent for assignment of the PSC or change of control of a contractor; and (vii) the power of the contractor and PetroVietnam to terminate the PSC where a party fails to remedy a material breach of the PSC. Within 12 months from first oil production, contractors are required to prepare a decommissioning plan which also includes a decommissioning work programme and budget for PetroVietnam's endorsement and approval by the Ministry of Industry and Trade (the "**MOIT**"). Contractors are required to establish a decommissioning fund and start contributing to it once the Decommissioning plan is approved by the MOIT. Such financial funding is made annually in accordance with petroleum production and the funding costs are recoverable as petroleum costs. Contractors remain liable for decommissioning all facilities and assets used for petroleum operations under the PSC until decommissioning is completed to the MOIT's satisfaction.

A new form of model PSC was issued by the Vietnamese Government in 2013 which applies to all PSCs signed after 8 June 2013 (the "**new model PSC**"). Export tax and corporate income tax rates are now specified in the model, and contractors are subject to new compulsory payments which include a signing bonus and incremental production bonuses. The stabilisation clause has been narrowed and now only covers royalties, corporate income tax, and export tax. The new model PSC also sets out the procedures for PetroVietnam to exercise its pre-emption rights in the event that a contractor assigns all or part of its participating interest to a third party, or where a contractor experiences a change of control. Furthermore, PetroVietnam has been granted additional termination rights under the new model PSC. The new model PSC sets out more detailed abandonment requirements and procedures, including the requirement for the contractor to pay a security deposit into reserved funds for abandonment purposes. The new model PSC also increases the domestic supply obligations of a contractor and includes a requirement to prioritise the sale of all crude oil within the Vietnam market on prescribed terms at the Vietnamese Government's request.

Premier signed the PSC before 2013, but the new model PSC will apply to any further PSC or on renewal of the existing PSC. Summary of economic and fiscal regime in Vietnam. The contractual regime in Vietnam is one of production-sharing, so each asset is the subject of an individual contract with a unique formula for calculating the production split between the Vietnamese Government and the contractor based on subtracting a resource tax and Cost Recovery Petroleum from actual petroleum output.

Under the PSC, Cost Recovery Petroleum 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 quarter may be carried forward to the next succeeding quarters without interest until fully recovered. Contractors are required to pay a resource tax to PetroVietnam progressively in accordance with production on a sliding scale, with concessional rates for encouraged projects. Contractors are charged income tax at a rate from 32 per cent. to 50 per cent. on their taxable income. The specific rate is determined by the Prime Minister of Vietnam and is subject to stabilisation clauses contained within the PSC. Profit petroleum (being net production after the deduction of Cost Recovery Petroleum) is allocated between PetroVietnam and contractors after deductions for resource tax and income tax in accordance with production on a sliding scale as prescribed in the PSC. Furthermore, a bonus or commission is paid as a lump-sum by the contractor on signing the PSC, on commercial discovery and upon first production and commercial production reaching certain targets.

Contractors must prioritise the sale of all petroleum within the Vietnam market on prescribed terms at the Vietnamese Government's request. Contractors are required to give preference to Vietnamese goods and services in accordance with competitive standards. No specific percentage of local content is prescribed.

6.5 Falkland Islands

The Falkland Islands is a British Overseas Territory with formal British diplomatic representation provided by the Governor of the Falklands. The Falkland Islands is internally self-governing except in the areas of foreign affairs and defence for which the UK Government retains responsibility.

In July 2012, Premier farmed in for 60 per cent. of Rockhopper's exploration licence interests in the North Falkland Basin, including Sea Lion. The Rockhopper Acquisition was completed in October 2012 and Premier assumed operatorship of Sea Lion in November 2012. In January 2016, Premier and Rockhopper executed an amendment to the original sales and purchase agreement for the Rockhopper Acquisition, whereby the development carry of US$674 million would be split equally between the Sea Lion Phase 1 project and the next development phase.

During 2019, Premier launched a farm down process to bring in an additional equity partner into the Sea Lion project to optimise the Premier Group's level of participation in the development. In January 2020, Premier and Rockhopper agreed a detailed heads of terms with Navitas Petroleum to farm in for a 30 per cent. interest in Sea Lion and these terms were finalised during 2020. The proposed farm-out of the Sea Lion licences to Navitas is subject to Falkland Islands government and, pursuant to the Merger Agreement, Chrysaor approval.

The overall strategy to develop the discovered reserves and resources in the North Falkland Basin remains a phased development solution. The 530 mmbbls (gross) Sea Lion project is a material opportunity for the Premier Group and its partner. The Sea Lion Phase 1 project will develop 250 mmbbls (gross) from the reservoirs in the PL032 licence. A subsequent Sea Lion Phase 2 project will develop a further 300 mmbbls (gross) of contingent resource mainly in the north of the adjacent PL004 licence. There is a further 300 mmbbls (gross) of near field exploration potential which could be included in the Sea Lion Phase 1 and Sea Lion Phase 2 projects. Phase 3 of the Sea Lion development will target the Isobel/Elaine fan complex in the south of the PL004 licence, subject to further appraisal drilling.

In November 2019, the Falkland Islands government extended the PLO32 licence until 1 May 2021, with no additional licence commitments. The licensee was previously due to expire in April 2020. Net to Premier, 2C resources for the region are estimated at 392 mmboe as at 31 December 2019, which represents 46.3 per cent. of the Premier Group's total reserve and resource base.

(A) Sea Lion Phase 1—development asset, 60 per cent. operated asset

Sea Lion is located 220 kilometres north of the Falkland Islands, and lies in 450 metres of water. The geological setting is a north-south Atlantic failed rift with primarily early cretaceous to tertiary fill in a typical half graben structure with a large bounding fault in the east. Sea Lion is close to the eastern margin and is fully appraised.

Sea Lion Phase 1, in which Premier has a 60 per cent. operated interest, will recover 250 mmbbls (gross) of resources in the PL032 licence over 20 years. It will be developed utilising a conventional FPSO base scheme, similar to the Catcher development.

During FEED, which is now completed, Premier worked collaboratively with its contractors to optimise the facilities design and installation methodology of the development. The project is at a mature stage of definition and has been substantially de-risked from a technical, cost and schedule perspective.

Premier completed a Preliminary Information Memorandum in 2019 supported by a comprehensive set of independent expert reports on the project. These formed the basis upon which Premier sought financing guarantees for the senior debt component of the project financing which were submitted to export credit agencies in July 2019. The proposed farm out with Navitas Petroleum, together with the vendor funding for the project by the contractors and the senior debt financing component, would reduce Premier's share of pre first-oil capex from US$500m to below US$300m.

In 2020, Premier took the decision to suspend Sea Lion Phase 1 to minimise ongoing spend in light of the current market conditions. Sea Lion Phase 1 is complete from a technical aspect and all of the work which has been done to date has been fully documented such that the project can be reactivated once the macroeconomic outlook improves and Premier's creditor position better supports the funding of the project. In the meantime, a reduced team continues to work with the Falkland Islands government on licensing, fiscal and regulatory matters.

Premier's partner in Sea Lion Phase 1 is Rockhopper (40 per cent.). Production from Sea Lion Phase 1, once on-stream, is forecast to continue for 20 years.

(B) Falkland Island exploration assets

Commencing in March 2015, Premier carried out a Falkland Islands exploration campaign, which targeted multiple stacked fans in PL004. The Zebedee well was declared a discovery, having penetrated multiple targets in the cretaceous F2 and F3 formations with a total hydrocarbon net pay of 136 feet, adding around 100 mmbbls of resource to a potential Phase 2 development.

The Isobel Deep well, which was the first test of the Isobel/Elaine fan complex, encountered oil-bearing sandstones at the prognosed depth and opened up a new play in the previously unexplored southern part of PL004. Following operational difficulties the Isobel Deep well was suspended. Premier completed its exploration programme in the North Falkland Basin with the successful re-drill of the Isobel Deep well, which confirmed the results of the original well and, in addition, discovered hydrocarbons in shallower sandstone horizons.

Summary of regulatory regime and licence terms in the Falkland Islands

The Offshore Mineral Ordinance 1994, as amended (the "**Mineral Oil Ordinance**") governs oil and gas exploration and production activities in the Falkland Islands. The Mineral Oil Ordinance provides for a licensing regime, whereby exploration and production licences are granted to oil and gas companies. The Mineral Oil Ordinance is supplemented by various environmental and health and safety laws and regulations. Licences are valid for a sequence of terms. Each licence expires automatically at the end of each term, unless the licensee can demonstrate that sufficient progress has been made under the licence to warrant moving into the next term. The first phase of the exploration period is set between three to eight years.

Licensees may enter additional phases of varying durations, but the licence expires at the end of a first phase if the relevant work programme is not completed or the Governor of the Falkland Islands has not approved a development plan. The production period is 35 years, or longer if needed to complete production.

The terms and conditions of every licence are prescribed in a series of model clauses, which are set out in statutory instruments deriving from the Mineral Oil Ordinance (the "**Minerals Ordinance**

Model Clauses"). The Minerals Ordinance Model Clauses applicable to a particular licence are those which are in force at the time it was granted. For the purposes of the following summary, the Model Clauses applicable to the Premier Group's licences are materially the same. The Minerals Ordinance Model Clauses govern the operation of the licence and deal with matters such as: (i) the exploration, appraisal 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 Governor of the Falklands 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 without approval, change of control, or breach of any of the licence terms. Licensees are responsible for preparing, submitting and (once approved) carrying out a decommissioning programme in relation to offshore oil and gas installations and pipelines in the licence area.

Summary of economic and fiscal regime in the Falkland Islands

A 9 per cent. royalty is payable under the licences. Each licence carries an annual rental charge which is calculated at an escalating rate on each square kilometre the licence covers at that date. The rental charge is not payable for any field that is paying royalty.

Corporation tax is currently 26 per cent. on all profits from exploration and extraction activities. 100 per cent. tax depreciation allowance will be available in the amount of US$231 million relating to consideration paid by the Premier Group when farming-in to Rockhopper's licence interests. In addition, Premier has further allowances and pre-trading losses totalling US$467 million available to offset future Sea Lion profits.

A 100 per cent. depreciation allowance is available on intangible expenditures. Tangible expenditure attracts 25 per cent. declining balance allowance.

Premier has engaged and continues to engage collaboratively with the Falkland Islands Government to ensure that the fiscal regime is well defined and stable to project sanction.

6.6 Exploration unit

Premier's exploration strategy is to focus on under-explored, emerging plays in proven hydrocarbon basins with priority given to lower cost operating environments. In these new countries, Premier has a disciplined approach to investment ensuring that cost exposure in the exploration phase is minimised and only the best opportunities are matured to drill-ready status.

(A) **Brazil**

In May 2013, Premier was awarded two blocks, CE-M-665 and CE-M-717, in the Ceará Basin, a Cretaceous rift basin with world-class oil-prone source rocks, in Brazil's 11th round. In April 2015, Premier grew its position in the Ceará Basin by farming into block CE-M-661, for a 30 per cent. non-operated interest at zero upfront cost.

Having fully evaluated the prospectivity on CE-M-665, Premier and its joint venture partner unanimously decided to relinquish the licence in April 2019.

CE-M-717 (50 per cent. operated interest); CE-M-661 (30 per cent. non-operated interest)

Multi-client 3D seismic data across all of Premier's blocks in the Ceará Basin was received in 2016 and 4,000 km2 of final processed broadband seismic data was received in April 2017.

During the first half of 2020, Premier has taken action to defer activity across its exploration portfolio to reduce expenditure, given the prevailing market conditions. This included the deferral of drilling on Block 717 (originally scheduled for July 2020). The well will target the stacked Berimbau and Maraca prospects. Berimbau is a higher risk, high value prospect with a Pmean-P10 gross unrisked resource estimate of 230-450 mmbls. Maraca is a lower risk prospect and is estimated to contain 85-165 mmbbls (Pmean-P10) of gross unrisked resource.

On CE-M-661, the joint venture successfully obtained an initial licence extension through to November 2021.

Premier's partner in CE-M-717 is CEPSA (50 per cent.). Premier's partners in CE-M-661 are Total (operator, 45 per cent.) and Quieroz Galvão E&P (25 per cent.).

Summary of regulatory regime and licence terms in Brazil

Oil and gas exploration and production activities in Brazil are regulated by the Brazilian Federal Constitution, Federal Laws Nos. 9,478/1997 (the "**Petroleum Law**"), 11,909/2009 and 12,351/2010. In addition, various environmental and health and safety laws and regulations apply. In 2018, Brazil's Congress voted to remove the obligation on the national oil company, Petrobras, to own a minimum 30 per cent. stake in and be the sole operator for Brazil's pre-salt offshore fields.

The Premier Group's concession contracts are in the form of the model contract prescribed by the ANP for the eleventh bidding round and are regulated by the wider concession contract regime under the Petroleum Law.

Under the concession contracts, the exploration period is set at five years. In general terms, the concession expires at the end of the initial term unless the concessionaire has completed the work programme and there has been a discovery. The production period begins on the date of the declaration of commerciality by the concessionaire and may last up to 27 years from the declaration of commerciality. The concession contracts include provision for the concession to be extended by agreement between the concessionaire and the ANP.

The concession contracts deal with matters such as: (i) the exploration, development and production periods; (ii) extension of the concession by agreement with the ANP; (iii) the concessionaire's 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 a well; (iv) a requirement for the appointment of the operator to be approved by the ANP; (v) local content requirements; (vi) joint and several liability of concessionaires; (vii) an indemnity by concessionaires for the benefit of the Brazilian federal government for any third party claims arising in relation to the concession or anything done pursuant to it; (viii) restrictions on and government consent for assignment of a concession or change of control of a concessionaire; and (ix) a power of revocation of the concession in circumstances including insolvency of the concessionaire or failure to remedy a breach of any of the concession terms within a period of no less than ninety days following notice from the ANP.

Concessionaires are required to submit a decommissioning plan and decommissioning work programme and budget to the ANP together with the development plan for a field. Upon request by the ANP, the concessionaire must present security for decommissioning costs which can take the form of insurance, letter of credit, contingency fund or other security acceptable to the ANP. The amount of the security is based on the field's development plan.

Summary of economic and fiscal regime in Brazil

Under the Premier Group's concession contracts, the concessionaire is required to pay royalties to the ANP monthly in an amount equal to 10.0 per cent. of sales revenue calculated on the basis of the ANP price reference. This rate can be potentially reduced to 7.5 per cent. subject to agreement from the ANP.

Extraordinary financial compensation may be payable by concessionaires in the event that high volumes of oil or natural gas are produced or a certain field is highly profitable in other ways. This compensation is known as the 'special participation percentage' and varies from 10 per cent. to 40 per cent. It is applied on sales revenue calculated on the basis of the ANP reference price and adjusted by deductions allowed by the law. Concessionaires must also pay an annual fee for the occupation or retention of the concession area throughout the exploration, development and production periods. Additionally, concessionaires must pay to the owners of the land of participation a fee of 1 per cent. applied on sales revenue calculated on the basis of the ANP reference price. The current combined corporate income tax rate is approximately 34 per cent. Brazil does not apply ring-fencing in the determination of the corporate income tax liability. There are no tax stabilisation measures in place. As at 31 December 2019, Premier has tax losses of US$48.4 million.

In the event of an emergency, the ANP may require concessionaires to restrict exports and supply oil to the Brazilian market or a national strategic inventory on a *pro rata* basis with other producers in Brazil in order to meet the needs of domestic consumption in the country. Under Brazilian national content rules, a certain percentage of goods, equipment and services must be purchased from Brazilian suppliers. The minimum national content for the Premier Group's blocks is 37 per cent. for the exploration period and between 55 per cent. and 65 per cent. for the production period.

(B) **Mexico**

In July 2015, Premier successfully entered Mexico with the award of Blocks 2 and 7 in Mexico's licence round 1.0. Blocks 2 and 7 are located in the Sureste Basin, one of the world's most prolific hydrocarbon provinces. The award of Blocks 2 and 7 represented the first time in 75 years that Mexico's upstream sector has been open to private investment. Subsequent licensing rounds have taken place and, in March 2018, Premier was awarded three further blocks (Block 30 in the Sureste Basin and Blocks 11 and 13 in the Burgos Basin) in Mexico's licence round 3.1. Having fully evaluated the prospectivity on Block 2, Premier formally relinquished its interest in the licence in February 2019.

Block 7 (25 per cent. non-operated interest), Sureste Basin

Large parts of the Sureste Basin remain under-explored, particularly in comparison to the US Gulf of Mexico. One such area is the Salinas sub-basin where block 7 is located. Premier was awarded a non-operated 10 per cent. interest in block 7 at no upfront cost in 2015.

In 2016, Premier and its joint venture partners reprocessed the existing 3D seismic data and matured a number of prospects across its Block 7 as future drilling candidates. Premier elected to exercise its option to increase its equity interest in Block 7 to 25 per cent. in December 2016.

In 2017 Premier drilled its first exploration well offshore Mexico, Zama-1. The Zama-1 exploration well drilled the Zama prospect in Block 7 and resulted in a world class oil discovery, encountering a gross oil bearing interval in Zama-1 of over 335 metres (1,100 feet).

The overall Zama structure extends into the neighbouring block operated by Petróleos Mexicanos ("**Pemex**"). Initial estimates of the gross oil-in place volumes for the overall Zama structure were between 1.2 and 1.8 billion barrels with estimated recoverable P90-P10 gross unrisked resources in the range of 400- 800 mmbbls.

The three-well Zama appraisal programme began in November 2018 when the first appraisal well, Zama-2, spudded. The Zama-2 well confirmed the oil-water contact, which was in line with the flat spot observed on seismic data; encountered 152 metres of net pay above the oil-water contact, in line with pre-drill estimates; and encountered a higher net-to-gross ratio of 73 per cent. than at the original Zama-1 exploration well. The rig then moved to drill the vertical Zama-2 well side-track ("**Zama-ST1**") up dip and included a comprehensive coring programme as well as a drill stem test of the Zama reservoir. The third appraisal well, Zama-3, evaluated the southern part of the Zama oil field and completed the block 7 appraisal programme in July 2019. A comprehensive set of data was acquired during the appraisal campaign and demonstrated reservoir properties at the upper end of expectation. This resulted in Premier increasing its gross resource estimate of the Zama structure to 670-810-970 mmboe (P90-P50-P10).

In June 2019, the Block 7 joint venture partnership agreed the main elements of a development programme to maximise overall recovery form the Zama field. The Zama field will be developed using two offshore processing, drilling and accommodation platforms together with a floating storage and offloading vessel and oil export by tankers. FEED on the Zama project scheme is reaching a conclusion and pending progress on the unitisation and other approvals a final investment decision would be made later in 2021.

Unitisation discussions around the Zama field resource split between Block 7 and the adjacent block, are progressing as per the Mexican regulatory process, which is in line with international best practice. The National Hydrocarbon Commission (the "**CNH**") declared Zama a shared reservoir in May 2020 and, in July 2020, the Mexican Ministry of Energy ("**SENER**") issued the instruction to unitise the Zama field, triggering 120 working days within which the Block 7 partners and Pemex are required to deliver a Unitisation and Unit Operating Agreement ("**UUOA**") to SENER for approval.

Following the successful appraisal of the Zama field, Premier initiated a sales process for its interest in Block 7 at the end of 2019. However the subsequent collapse in oil price, together with the ongoing unitisation process with the neighbouring block resulted in Premier suspending the sales process. Premier retains exposure to exploration upside in Mexico through its other offshore licence interests, each of which has the potential to deliver material future value for Premier.

Premier's partners in Block 7 are Talos Energy (35 per cent. operated interest) and DEA (40 per cent. interest).

Block 30 (30 per cent., non-operated interest), Sureste Basin

Block 30, which Premier and its joint venture partners were awarded in March 2018, is located directly to the south west of Block 7, which contains the Zama oil field. Premier has identified numerous material leads and prospects in the tertiary clastic plays, typical of the Sureste Basin. A 3D seismic survey acquisition across Block 30 was completed in July 2019. The data is being processed to delineate the full extent of the Wahoo prospect, which exhibits direct hydrocarbon indicators analogous to Zama, as well as to mature other prospectivity on the Block, including the Cabrilla prospect. Drilling is targeted for 2022.

Premier's partners in block 30 are DEA (40 per cent. operated interest) and Sapura Energy (30 per cent. interest).

Blocks 11 and 13 (100 per cent. operated interests), Burgos Basin

Premier was awarded 100 per cent. operated interests in blocks 11 and 13 in March 2018. Premier leveraged its growing understanding of the Mexican shelf to gain early access to the highly prospective Burgos Basin inboard of the proven deep water Peridido fold belt. Several structures have been identified in analogous plays to those proven in the Burgos Basin and offshore the US Gulf of Mexico. The exploration targets are Pliocene to Miocene in age. Premier's exploration plan were approved by CNH in July triggering the start of the four year initial term for these licences.

Summary of regulatory regime and licence terms in Mexico

The Mexican oil and gas industry only opened to private investors in 2013. Exploration and extraction contracts are tendered and entered into with contractors by CNH. The Ministry of Energy determines the type of contract offered in each bid round, with contractual forms including profit-sharing contracts, licences, services and PSCs. The Premier Group is party to two PSCs.

Under each PSC, a percentage of production is allocated to a contractor who assumes all costs and risks related to the activities. The initial term of a PSC is thirty years (based on executed PSCs) from the effective date which is extendable, at the request of Contractor, for two additional five-year periods, subject to the approval of the CNH. The initial exploration period is four years from the effective date, with the possibility of two additional contractual years following the termination of the initial exploration period. The development and production period begins after the declaration of commercial discovery with no specified time period stipulated for such period.

The PSCs deal with matters such as: (i) the exploration, development and production periods; (ii) extension of the PSC; (iii) the contractor's obligation to carry out the work programme during the initial term; (iv) the procedure to obtain approval for its production programme; (v) the submission of annual work programs to the CNH; (vi) the submission of budgets to the CNH 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 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 contact area. The development plan and each work program submitted to the CNH must provide for provisions related to abandonment. Upon making a commercial discovery, contractors are obliged to set up an investment trust as an abandonment fund under joint control of the contractor and the CNH at a Mexican financial institution authorised by 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 35 per cent. For these purposes, local content refers to the amount of locally produced materials, personnel, financing, 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 will compute and pay the considerations to the Mexican State and the contractor when regular commercial production starts and delivery of hydrocarbon exists at the measurement points.

The PSCs use a unique formula for calculating the production split between the Mexican Government and the contractor based on subtracting royalties and Cost Recovery Oil (as defined below) from the actual crude oil output. Under the PSCs, a share of net oil 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. Petroleum costs which are not recovered from the allocation of Cost Recovery Oil in a quarter may be carried forward to succeeding months without interest and will exist as long as the contract exists.

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 will be adjusted each year in the month of January in accordance with the United States Consumer Price Index consumer price indices 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 based on the monthly internal rate of return of contractors, which is designed to capture additional profits for the Mexican Government. 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. As at 31 December 2019,

Premier had tax losses of US$53.4 million. Employers in Mexico must pay profit sharing to employees each year equal to 10 per cent. of the taxable income of the business.

7. Premier licence interests

Premier's business is dependent on the holding of licences and approvals from government authorities, which entitle the Premier Group, *inter alia*, to extract oil and gas. Details of the Premier Group's key licences are set out below (as at November 2020).

Licence	*Blocks*	*Operator*	*Premier equity*	*Unit interest (if applicable)*	*Associated fields /discoveries*
Brazil					
CE-M-661	CE-M-661	Total	30.00		
CE-M-717_R11	CE-M-717	Premier	50.00		Pecem
Falkland Islands					
PL003a	14/14 (part) & 14/19 (part)	Rockhopper	4.50		
PL003b	14/14 (part) & 14/19 (part)	Rockhopper	4.50		
PL004a	14/15 (part), 14/20, 15/11 (part) & 15/16 (part)	Premier	36.00		Isobel Deep
PL004b	14/15 (part)	Premier	36.00		Beverley; Casper South; Zebedee
PL004c	14/15 (part)	Premier	36.00		
PL032	14/5, 14/10	Premier	60.00		Casper North; Sea Lion
PL033	15/1 (part) & 15/6 (part)	Premier	60.00		
Indonesia					
South Andaman	South Andaman	Mubadala Petroleum	20.00		
Andaman I	Andaman I	Mubadala Petroleum	20.00		
Andaman II	Andaman II	Premier	40.00		
Natuna Sea Block A	Natuna Sea Block A	Premier	28.67		Anoa; Gajah Baru; Naga; Pelikan; Bison, Iguana & Gajah Puteri
Tuna Block	Tuna Block	Premier	100.00		Kuda Laut; Singa Laut
Mauritania					
PSC-B (Chinguetti)	Deepwater Blocks 4 & 5	Petronas	8.12		Chinguetti

Licence	Blocks	Operator	Premier equity	Unit interest (if applicable)	Associated fields /discoveries
Mexico					
Mexico Block 7	7	Talos	25.00		Zama
Mexico Block 11	11	Premier	100.00		
Mexico Block 13	13	Premier	100.00		
Mexico Block 30	30	WDEA	30.00		
United Kingdom					
P077	22/12a (Nelson Field (NELS))	Enterprise	50.00	1.66	Nelson
P087	22/7a (Nelson Field (NELS))	Premier (Shell for field)	46.50	1.66	Nelson
P111	22/25a (Merganser down to 3300 metres (MERG))	Premier (Shell for field)	65.99	7.92	Merganser
P164	205/26a (ALL)	Premier	100.00		Solan
P185	15/22 (Rest of Block (Non-Palaeocene Formation) (A))	CNOOC	50.00		Blackhorse
P188	22/30b (Area A – Elgin Field (ELGN))	Total	5.20	5.20	Elgin; Franklin
P201	16/21a Balmoral & Glamis Field Areas (BALMO), Rest of Block (Exploration Area) (REST), Stirling Field Area (STIRL); and 16/21d Balmoral & Glamis Field Areas (BALMO), Rest of Block (Exploration Area) (REST)	Premier	85.00	Balmoral: 78.12 Stirling: 68.68	Balmoral; Glamis; Stirling
P201	16/21d (Brenda Field Area (above 7500 feet) (A))	Premier	100.00		Brenda
P213	16/26a (Area P – Caledonia Field Area (P-CAL))	Premier	100.00		Caledonia
P233	15/25a (ALL)	Premier	70.00		Nicol
P264	23/26d (Scoter Field Area (A))	Premier (Shell for field)	100.00	12.00	Scoter
P344	16/21b (Balmoral Field Area (BALM)) and 16/21c (Stirling Field (STIR))	Premier	44.20	Balmoral: 78.12 Stirling: 68.68	Balmoral; Stirling
P362	29/5b (ALL)	Total	5.20	5.20	Elgin; Franklin
P380	43/26a (Rave (RAVE A)) and (Rave (Rave B))	Perenco	35.94	28.75	Ravenspurn North
P380	43/26a (Residual Area excluding Ravenspurn North (RESID)	Premier	72.22	50.11	Johnston
P454	44/29b (Orca Field Area (B))	Neptune	42.67	19.5	Orca
P611	44/24a (ALL) and 44/30a (ALL)	Neptune	42.67	Orca: 19.5	Minke; Orca
P666	22/30c (ALL) and 29/5c (ALL)	Total	5.20	5.20	Elgin; Franklin; West Franklin
P686	43/27a (ALL)	Premier	42.22	50.11	Johnston
P748	29/2c (ALL)	CNR	40.00		Kyle
P752	29/4d (ALL)	Total	18.57		Glenelg
P1042	15/25b (ALL)	Premier	100.00		Brenda
P1114	22/14b (ALL)	Premier	100.00		Huntington
P1330	42/28d (ALL)	Premier	50.00		Tolmount
P1430	28/9a (ALL)	Premier	50.00		Burgman; Carnaby; Catcher; Varadero
P2070	28/4a (ALL)	Premier	50.00		Laverda
P2305	42/28c (ALL)	Premier	50.00		Greater Tolmount
P2453	28/9c (ALL)	Premier	50.00		Bonneville
P2454	28/9d (ALL)	Premier	50.00		Laverda
Vietnam					
Block 12W	12W	Premier	53.13		Chim Sáo; Dua

PART IV

INFORMATION ON THE CHRYSAOR GROUP

1. Introduction

Chrysaor is an independent UK North Sea oil and gas exploration and production company with assets located primarily on the UKCS. Since its inception in 2007, it has grown organically and through acquisitions. This includes the acquisition of certain UK oil and gas assets from Shell for US$3 billion in 2017 and ConocoPhillips for US$2.675 billion in 2019. Chrysaor's portfolio consists of generally high quality, mid-life oil and gas assets. It is operator of the Greater Britannia Area, the J-Area and the Armada, Everest and Lomond production hubs and also has non-operated interests in some of the UK's largest producing fields, including Elgin-Franklin (where Premier is also a partner), Buzzard and Clair.

As at 30 June 2020, Chrysaor had 2P reserves of 490.7 mmboe. Production for the half year ended 30 June 2020 averaged 187 kboepd (2019: 123 kboepd) and is forecast by Chrysaor to average between 170 and 180 kboepd for the year ending 31 December 2020.

2. History and development

Chrysaor was founded in 2007 by Phil Kirk with a £96.5 million investment commitment from Barclays and a US private equity fund managed by NGP ("Natural Gas Partners'"). Phil Kirk, together with some of the CH4 Energy Limited management team, founded the new start-up to focus on UK oil and natural gas development opportunities. The founding strategy was to add material value by acquiring oil and gas discoveries, applying development and commercial skills to de-risk and move the assets further towards commercialisation.

Between 2007 and 2016, Chrysaor owned certain exploration and appraisal licence interests and a single development asset. In 2008, Chrysaor agreed a farm-in to an exploration licence in the Republic of Ireland with Providence Resources and Sosina Exploration Ltd covering the Spanish Point gas condensate discovery (subsequently exited undrilled). Chrysaor was also awarded Phoenix (Block 13/22c) in the 25th UK licensing round but this was subsequently relinquished after the development proved unviable. In 2009, Chrysaor successfully drilled two appraisal wells on the Solan discovery Block 205/26a and in 2011 signed a farm-out deal for the Solan Field with Premier. In 2015, the Mustard oil discovery was drilled. In 2015, Chrysaor completed the disposal of its equity in Solan to Premier retaining a royalty interest in the field.

On 1 November 2017, Chrysaor completed the acquisition of a collection of oil and gas assets in the UK North Sea from Shell for a price of US$3.0 billion (the "**Shell Acquisition**"). The package consisted of interests in Beryl, Bressay, Buzzard, Elgin-Franklin, Erskine, Everest, the Greater Armada cluster, J-Area, Lomond and Schiehallion and Chrysaor became the operator of the Armada, Lomond and Everest hubs. The funding for the Shell Acquisition was a combination of equity and debt. The majority of the equity was contributed from Harbour Chrysaor Equity Holdings Limited who, as a result of the investment, became owner of an approximate 90 per cent. economic interest in Chrysaor.

On 30 September 2019, Chrysaor completed the acquisition of ConocoPhillips' UK oil and gas business for a price of US$2.675 billion (the "**COP Acquisition**"). Through the COP Acquisition, Chrysaor took over operatorship of two additional production hubs: the Greater Britannia Area and J-Area in the UK Central North Sea. It also acquired assets in the East Irish Sea, together with a non-operated interest in the Clair Field, West of Shetland. The COP Acquisition was funded by cash and an expansion of Chrysaor's existing debt facility.

3. Purpose and Strategy

Chrysaor's purpose or vision is: "To create a market leading North European E&P company that we and our stakeholders are proud of."

Chrysaor's strategy is to deliver safe and sustainable growth and generate superior shareholder returns by exploring, appraising, developing and commercialising oil and gas resources through organic initiatives and acquisitions across the business life cycle. This strategy consists of five pillars:

(A) Safe and Reliable Operations

Chrysaor strives to deliver safe and reliable operations through embedding its Values and Business Principles in the workplace. Chrysaor is an organisation that demonstrates integrity and cares passionately about people. Safety is fundamental to everything that we do, and everyone at Chrysaor has a critical role to play in ensuring that Chrysaor maintains a safe working environment for itself and colleagues both on and offshore. Achieving Chrysaor's goals is only possible when everyone works together in an innovative, focused and collaborative way to deliver a level of success everyone within the Chrysaor Group can be proud of. All Chrysaor Group colleagues have the authority and responsibility to stop any activity if it is believed to be unsafe or may compromise the Chrysaor Group's Values. Chrysaor's overriding and most critical objective is always to prevent a Major Accident Event on its offshore installations. Everyone has a role in achieving this.

(B) Hub-Led Growth Strategy

Chrysaor employs a hub-led growth strategy to target new, near-field acreage and to attract third parties wishing to access processing and production capacity across Chrysaor's platform and pipeline infrastructure.

(C) Maximise Economic Recovery

Chrysaor continually seeks opportunities to maximise value from its portfolio at all stages of the business lifecycle. As a long-term participant in the UK North Sea, Chrysaor follows the DBEIS principles and OGA's strategic guidance on Maximising Economic Recovery. Activities being planned are viewed through this maximum value recovery lens and can cover wide-ranging commercial, drilling and well optimisation initiatives.

(D) Build a Sustainable and Profitable Full Cycle E&P Group

Chrysaor is a leading provider of hydrocarbons to meet the UK's energy supply needs. Chrysaor invests for the long term, targeting growth and development across all asset lifecycle phases, to maximise economic recovery. Chrysaor is an early engager in transformational technologies that will deliver the carbon transition.

(E) Financial Strength

Chrysaor has strong operating cashflow from its producing assets. As a result, the Chrysaor Group is financially self-sustaining with sufficient free cashflow to cover capital reinvestment and manage its borrowings even in periods of commodity price downturns.

4. Key Strengths

4.1 Long-life balanced production portfolio supported by substantial reserves and discovered resources

The Chrysaor Group's current producing portfolio generated an average production rate of 187 kboepd for the half year ended 30 June 2020 (2019: 123 kboepd) from a spread of high-quality assets. The Chrysaor Group has a strong reserve base with approximately 490.7 mmboe of 2P reserves (as at the 30 June 2020), and a portfolio of discovered resources which when developed would extend and prolong the Chrysaor Group's future production profile. The Chrysaor Group has also identified numerous opportunities to increase the reserves and field life of its producing assets through incremental investment in infill drilling and well intervention programmes, plant modifications, satellite developments and near field exploration. These projects, which are at various stages of maturity, generally have attractive financial returns across a range of commodity prices.

4.2 Large, operated equity stakes in high quality assets with the potential to deliver significant value

The Chrysaor Group operates and holds material equity interests in several producing hubs with multiple near-field incremental opportunities which are expected to add production and offset decline over the medium term. The Chrysaor Group's material operated positions allow it to exert significant influence over the planning and execution of asset enhancement, development and exploration projects. Furthermore, the operational control and high equity positions also mean the operated hubs can be positioned favourably for third party business.

4.3 Experienced operator

The Chrysaor Group has a good operating track record back to 2017 when it acquired the Armada, Everest and Lomond assets pursuant to the Shell Acquisition. On acquisition, the Chrysaor Group acquired and recruited a highly skilled operator organisation. The Chrysaor Group materially extended life on the Armada asset which had been due to cease production through executing a drilling campaign. With the addition of the ConocoPhillips UK business, the operated J-Area and Greater Britannia Area hubs and the associated teams, the Chrysaor Group has enhanced its competence across the entire value chain. By way of example, the COP Acquisition brought significant decommissioning expertise and high temperature high pressure ('**HPHT**') field & drilling expertise. The HPHT drilling competence has led to the Chrysaor Group, following qualification as an exploration licence operator in Norway, to be invited into licence applications by the Norwegian authorities. The decommissioning expertise continues to lead to costs savings and efficiency gains on the decommissioning program.

4.4 Liquidity and Balance Sheet Strength

The Chrysaor Group had cash of US$369 million and undrawn bank facilities of US$1,030 million as at 30 June 2020. Combined with current cash flows, this finances the Chrysaor Group's investment programme. The Chrysaor Group maintains a disciplined spending target each year and where necessary will seek farm-in partners for drilling programmes and development projects.

5. Chrysaor's principal activities and investments – UK Business Unit

5.1 Overview

Chrysaor operates five complexes in the Central North Sea, which are run out of three business units or hubs; the Armada, Everest, Lomond and Erskine ("**AELE**") fields comprise one hub and the J-Area and Greater Britannia Area the other two. Chrysaor also has producing assets in the East Irish Sea. In total, Chrysaor has interests in 35 producing fields located primarily in the Central North Sea area of the UKCS and 14 undeveloped discoveries in proximity to its existing infrastructure. Chrysaor also has interests in an ongoing decommissioning project on end-of life assets in the Southern North Sea. In January 2020, Chrysaor was awarded eight additional production licences on the Norwegian Continental Shelf.

As at 30 June 2020, Chrysaor had 2P reserves of 490.7 mmboe. Production for the half year ended 30 June 2020 averaged 187 kboepd (2019: 137 kboepd).

A breakdown of total revenues by category of activity for the years ended 31 December 2017, 31 December 2018 and 31 December 2019 and the six months ended 30 June 2019 and 30 June 2020, is given in Part VIII (*Historical Financial Information relating to the Chrysaor Group*).

5.2 Chrysaor's production and reserves[1]

The following table provides a summary of Chrysaor portfolio of producing fields, all of which are located in the UKCS, as at 30 June 2020.

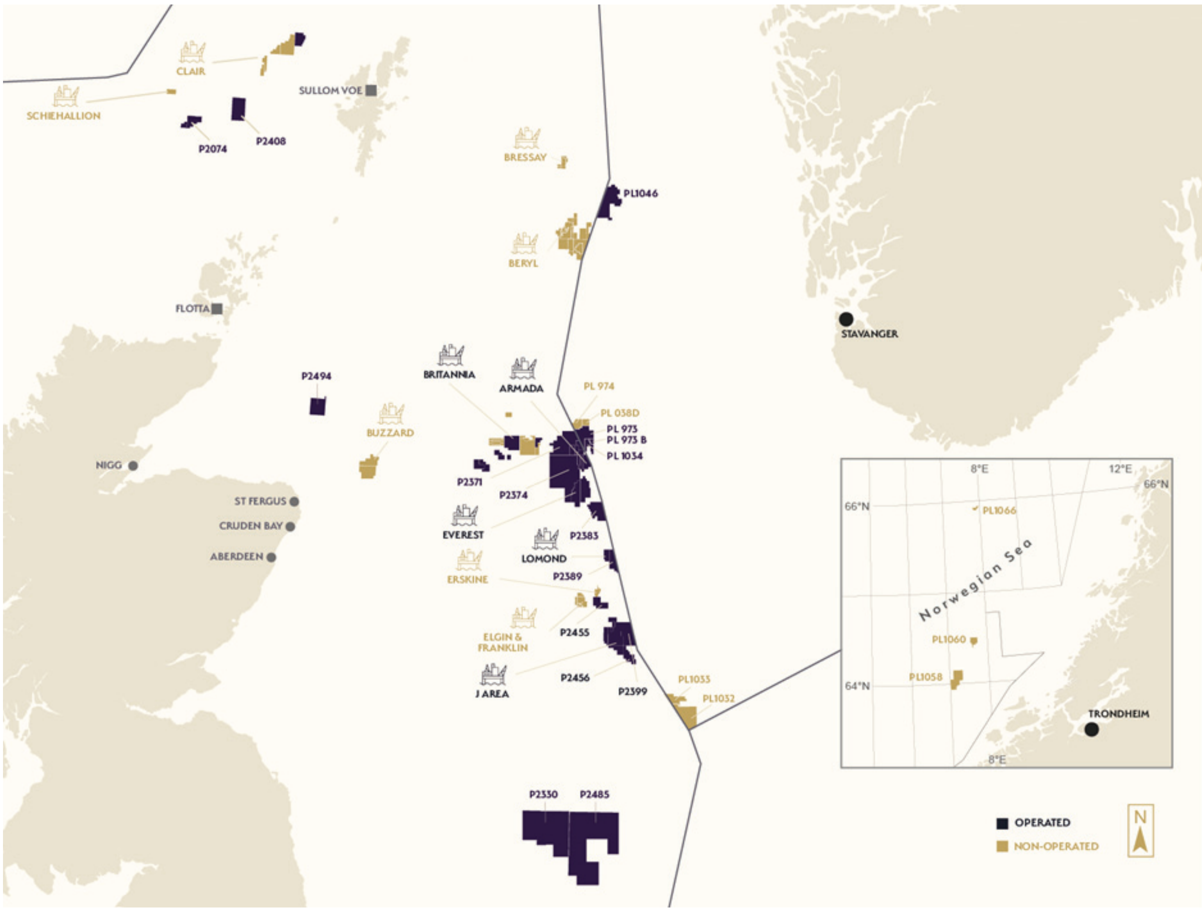
Asset	*Field*	*Operator*	*Field type*	*Working interest*
Operated assets				
AELE Hub				
Armada Area	Drake	Chrysaor	Oil/Gas	100%
	Fleming	Chrysaor	Gas	100%
	Hawkins	Chrysaor	Oil/Gas	100%
	Maria	Chrysaor	Oil	100%
	Seymour	Chrysaor	Oil/Gas	100%
Everest Area	Erskine	Ithaca Energy	Gas	32%
	Everest	Chrysaor	Gas	100%
	Lomond	Chrysaor	Gas	100%
J-Area Hub	Jade	Chrysaor	Oil/Gas	67.5%
	Jasmine	Chrysaor	Oil/Gas	67%

1 2P reserves and cessation of production dates in the asset reviews below are based on the CPR. The conversion of resources to reserves can result in a deferral of the date of cessation of production and the Directors and Proposed Directors believe that actual cessation of production dates will differ from the CPR dates as a result of this and other factors

Asset	*Field*	*Operator*	*Field type*	*Working interest*
	Joanne	Chrysaor	Oil/Gas	67%
	Judy	Chrysaor	Oil/Gas	67%
Greater Britannia Area Hub	Alder	Ithaca Energy	Oil/Gas	26.320%
	Britannia	Chrysaor	Oil/Gas	58.650%
	Brodgar	Chrysaor	Oil/Gas	87.5%[(1)]
	Callanish	Chrysaor	Oil/Gas	83.5%
	Enochdhu	Chrysaor	Oil/Gas	50%
East Irish Sea Area[(2)]	Dalton	Chrysaor	Gas	100%
	Millom	Chrysaor	Gas	100%
	Calder	Chrysaor	Gas	100%
Non-operated assets				
Beryl Area	Beryl	Apache	Oil/Gas	39.445%
	Buckland	Apache	Oil/Gas	37.472%
	Callater	Apache	Oil/Gas	45%
	Ness	Apache	Oil/Gas	39.445%
	Nevis	Apache	Oil/Gas	42.820%
	Skene	Apache	Gas	34.044%
	Storr	Apache	Oil/Gas	41%
Buzzard Field	—	CNOOC	Oil/Gas	21.733%
Clair Field	—	BP	Oil/Gas	7.503%
Elgin-Franklin Area	Elgin	Total	Oil/Gas	14.110%
	Franklin	Total	Oil/Gas	14.110%
	West Franklin	Total	Oil/Gas	14.110%
	Glenelg	Total	Gas	14.7%
Schiehallion Field	—	BP	Oil/Gas	10%
Galleon Field	—	Shell	Gas	8.4%
Nicol Field (now ceased)	—	Premier	Oil	18.0%

(1) Chrysaor's working interest in Brodgar is expected to increase to 93.75 per cent. by 31 December 2020 in accordance with the Unitisation and Unit Operating Agreement dated 10 March 2004.

(2) Operated by Chrysaor and managed under contract by Spirit Energy.



(A) AELE Area – producing assets, various operated interests

Chrysaor holds a 100 per cent. operated interest in the Armada Area, Everest field and Lomond fields and a 32 per cent. non-operated interest in the Erskine field, which is tied back to the Lomond platform.

The Armada Area is comprised of the Armada fields (Drake, Fleming and Hawkins), the Maria field and the Seymour field, with the Armada facilities acting as the production hub. Gas and condensate from the Armada Area are exported separately to the CATS Riser Platform ("CRP") which is bridge linked to the North Everest Platform. The Erskine field exports production to the Lomond platform for initial processing and separate gas and condensate streams of commingled Lomond and Erskine production are exported to the Everest facilities. Commingled AELE hub gas is then exported via the Central Area Transmission System ("CATS") pipeline to Teesside, while commingled liquids are exported via the Forties Pipeline System to the Kinneil Processing plant at Grangemouth.

Chrysaor acquired a 76.42 per cent. interest in the Drake, Fleming and Hawkins fields, a 36 per cent. interest in the Maria field and a 57 per cent. interest in the Seymour field pursuant to the Shell Acquisition in November 2017. A subsequent transaction with Spirit Energy in June 2018 saw Chrysaor increase its working interest in all of the Armada Area assets to 100 per cent..

Chrysaor acquired its 100 per cent. interest in the Everest and Lomond fields and the 32 per cent. non-operated interest in the Erskine field pursuant to the Shell Acquisition in November 2017.

Net to the Chrysaor interest, the AELE hub produced 34.0 kboepd for the six months ended 30 June 2020.

Net to the Chrysaor interest, 2P reserves for AELE are estimated at 74.6 mmboe as at 30 June 2020.

Production is forecast to continue until at least 2027 for the Armada Area fields and 2031 for the Everest, Lomond and Erskine fields.

Additional information on each field in the operating hub is provided below.

Armada Area – Producing asset, 100 per cent. operated interest

The Armada Area is a cluster of fields developed from the Armada facilities located in block 22/5b approximately 244 kilometres east of Aberdeen. Originally three fields, Fleming, Drake and Hawkins, were to be produced through the Armada facilities, but an additional two fields have been developed as subsea tie-backs, Seymour and Maria.

The Drake gas condensate field, situated in block 22/5b, was discovered in 1982 and achieved first production in 1997. The Fleming gas condensate field, situated in blocks 22/4a, 22/5a, 22/5b, 16/29g and 16/29c, was discovered in 1987 and achieved first production in 1997. The Hawkins gas condensate field, situated in blocks 22/5a, 22/5b and 16/29g, was discovered in 1980 and achieved first production in 1997. The Maria oil and gas field, situated in block 16/29a, was discovered in 1994 and achieved first production in 2008. The Seymour oil and gas field, situated in block 22/5b, was discovered in 1983 and achieved first production in 2003.

Prior to Chrysaor's ownership, a decision had been taken to apply for cessation of production in June 2018. Upon taking over operations at Armada in November 2017, Chrysaor took the decision to extend the life of the Armada hub fields and executed plans to drill on the Maria, Hawkins and Seymour fields in 2018 and 2019.

The Drake field currently has one active production well. The Fleming field is produced via one production wells and two active cyclic wells. Production at Hawkins field ceased during 2015 but re-commenced in April 2020 via a horizontal infill well, drilled as part of the life extension plan. The Maria field is producing via two infill production wells which were recently drilled. The Maria Crestal well was completed in late 2018 and came on stream in December 2018, with the Maria Terrace well drilled soon after, commencing production in February 2019. There is currently one production well in Northwest Seymour and one production well in Seymour Horst, which was brought on stream in 2020. Southwest Seymour is no longer producing.

Chrysaor's future plans for the Armada Area include Northwest Seymour, a well which is currently being matured for possible drilling in 2023.

Everest – Producing asset, 100 per cent. operated interest

The Everest field is a gas-condensate field located in block 22/10a-A in the Central North Sea area of the UKCS, approximately 240 kilometres east of Aberdeen.

The Everest field was discovered in 1982 and production began in 1993. The field comprises three separate gas-condensate accumulations, North, South and East Everest developed from the North Everest facilities, a combined wellhead, production and accommodation platform exporting gas and condensate. It is bridge-linked to the CRP which acts as a collection point for the Everest, Armada, Lomond and Erskine fields. Chrysaor operates the CRP on behalf of Kellas Midstream Limited. Two subsea templates, South Everest and the Everest East Expansion, tie back to the platform. There are currently eight producing wells, three on the North Everest accumulation, one on South Everest (although these are currently shut-in due to low productivity with well stimulation work required to bring them back online), and four on East Everest.

An infill development well, LAD, is planned for sanction in December 2020 within the Everest East Expansion area and drilling is expected to take place in 2021. Furthermore, a late life compression project has been approved to reduce the inlet pressure of the North Everest Process, increase recoverable reserves and extend field life.

Lomond – Producing asset, 100 per cent. operated interest

The Lomond field is a late-life lean gas-condensate field located in block 23/21a in the Central North Sea area of the UKCS, approximately 255 kilometres east of Aberdeen.

The Lomond field was discovered in 1972 and production commenced in 1993. The Lomond platform is a combined wellhead production and accommodation quarters platform, processing gas and condensate from the Lomond field and the Ithaca-operated Erskine field. Production from the Erskine field is processed in the Erskine Processing Module. There are currently five producing wells out of a total of ten development wells originally drilled.

The Lomond and Erskine fields were impacted by the blockage of the liquids export pipeline in January 2018, which had not been effectively pigged since 2009. The pipeline was partially replaced and production returned in October 2018 resulting in a material positive impact on production efficiency.

A late-life compression project is now underway to reduce the inlet pressure of the Lomond process, increase recoverable reserves and extend field life

Erskine – Producing asset, 32 per cent. non-operated interest

The Erskine high-pressure, high-temperature gas condensate field, operated by Ithaca Energy, is located in blocks 23/26a and 23/26b, approximately 250 kilometres east of Aberdeen, in the Central North Sea area of the UKCS.

The Erskine field was discovered in 1981, with first production achieved in 1997. The field is produced from a normally unattended satellite platform operated by Ithaca but controlled from Chrysaor's Lomond platform. Production is export via a multi-phase flowline to the Lomond platform where it is processed in the dedicated Erskine Processing Module. There are five active production wells. Performance of the Erskine field was significantly impacted during 2018 due to the blockage of the Lomond liquids export pipeline which halted production from the field from February 2018 until the restoration was completed in October 2018.

Chrysaor's partners in the Erskine field are Ithaca Energy (operator, 50 per cent.) and Serica Energy (18 per cent.).

(B) J- Area – producing and development assets, various operated interests

The J-Area lies approximately 265 kilometres east of Aberdeen in the Central North Sea area of the UKCS.

Chrysaor holds a 67 per cent. operated interest in the Judy, Joanne and Jasmine fields and a 67.5 per cent. operated interest in the Jade field.

Chrysaor acquired a non-operated 30.5 per cent. interest in the Judy, Joanne and Jasmine fields and a non-operated 35 per cent. interest in the Jade field pursuant to the Shell Acquisition in November 2017. Pursuant to the COP Acquisition in September 2019, Chrysaor became field operator and acquired ConocoPhillips' 36.5 per cent. interest in the Judy, Joanne and Jasmine fields and 32.5 per cent. in the Jade field.

The Judy platform serves as the central processing platform for the J-Area. The Judy platform is bridge-linked to the Judy Riser Platform (the "**JRP**") as well as satellite tie-backs including the Joanne subsea manifold and the Jasmine and Jade wellhead platforms. Production from the whole J-Area is exported as a commingled stream. Rich gas is exported via the CATS pipeline to Teesside, while produced liquids are exported via the Norpipe oil pipeline to Teesside.

Drilling in J-Area was suspended in March 2020 due to COVID-19, and recommenced in September. Work is continuing in preparation for drilling activity in 2021, 2022 and beyond, with development wells planned from Judy, Jasmine and Jade, and exploration and appraisal wells on the Dunnottar, Talbot and Jade South opportunities. The possibility of bringing a second drilling rig into the J-area next year is under consideration by Chrysaor, to accelerate delivery of these opportunities.

Net to the Chrysaor interest, the J-Area hub produced 33.4 kboepd in the six months ended 30 June 2020. Production is forecast to continue until at least 2041.

Net to the Chrysaor interest, 2P reserves for the J-Area hub are estimated at 137.2 mmboe as at 30 June 2020.

Additional information on each field in the operating hub is provided below.

Judy/Joanne – Producing asset, 67 per cent. operated interest

The Judy and Joanne fields are oil and gas condensate fields located in blocks 30/6a, 30/7a and 30/12a in the Central North Sea area of the UKCS.

The Judy field was discovered in 1985 and production began in 1995. The field is produced via nine production wells. Most wells in the Judy field are in late life and are cycled producers due to water loading issues.

The Joanne field was discovered in 1981 and production began in 1995. The field is produced via ten production wells, with six wells producing from the Joanne Chalk and four wells from the Joanne Paleocene. Most wells in the Joanne field are in late life and are cycled producers. The Joanne field reservoirs are connected via a subsea tieback to the Judy platform and product exported as part of the commingled stream.

Further development drilling at Judy via the JRP is being planned as well as necessary topsides modifications on the JRP to receive hydrocarbons. Shorter term production uplift opportunities are also being pursued, with a well services intervention campaign scheduled to commence in December. Potential facility modifications under consideration at Judy include further compressor re-wheel options which would reduce emissions from around 2025, and other topsides optimisation projects.

Chrysaor's partner in Judy and Joanne is Eni UK (33 per cent.).

Jasmine – Producing asset, 67 per cent. operated interest

The Jasmine field is a high-pressure, high-temperature gas condensate field located in block 30/6a and 30/7a in the Central North Sea area of the UKCS.

The Jasmine field was discovered in 2006 and production began in 2013. The Jasmine field is a dry tree platform development tied back to the Judy platform. The field is produced via nine production wells and processed hydrocarbons are exported as part of the commingled stream.

An infill drilling programme at Jasmine continued through 2019 into early 2020. J-Area drilling recommenced in September 2020 with the Jasmine S16 well, which is targeting the Joanne Chalk and is expected to commence production in the first quarter of 2021. Following S16 it is planned to drill a production well in the Jasmine West Limb, and then a workover on the S15 well.

Chrysaor's partner in Jasmine is Eni UK (33 per cent.).

Jade – Producing asset, 67.5 per cent. operated interest

The Jade field is a high-pressure, high-temperature gas condensate field located in block 30/2c in the Central North Sea area of the UKCS.

The field was discovered in 1997 and came onstream in 2002. There are currently eight wells on the Jade field. The Jade field operates as a normally unattended platform, which is run as a satellite via a 20 kilometre pipeline to the main Judy facility and processed hydrocarbons are exported as part of the commingled stream.

It is planned to drill an infill well at Jade (JM) in 2021, followed by an exploration well at Jade South, drilled from the Jade platform.

Chrysaor's partners in Jade are Ithaca Energy (19.93 per cent), Eni UK (7 per cent.) and Siccar Point Energy (5.57 per cent).

J-Area Development Opportunities

The Talbot discovery, located in UKCS block 30/13e, is a light-oil and associated gas resource opportunity located approximately 14 kilometres south-east of the Judy platform. The Talbot licence, P.2456, was acquired in October 2018 following the 30th licensing round. The joint venture partners are the same as Judy and Joanne, with Chrysaor holding 67 per cent. working interest. Preparations are ongoing for a potential appraisal well at Talbot the timing of which will depend upon the rig strategy for J-Area. Potential development scenarios for Talbot are being assessed, including possible synergies with third party fields nearby.

The Dunnottar prospect is located in UKCS block 30/8, immediately east of Judy. The licence was acquired in October 2018 following the 30th licensing round. The joint venture partners are the same as Judy and Joanne, with Chrysaor holding 67 per cent. working interest. It is currently planned to drill an exploration well at Dunnottar following the Talbot appraisal well.

(C) Greater Britannia Area ("GBA") – producing and development assets, various operated interests

GBA lies approximately 210 kilometres northeast of Aberdeen in the Central North Sea area of the UKCS.

Chrysaor holds a 58.65 per cent. operated interest in the Britannia field, an 87.5 per cent. operated interest in the Brodgar field, an 83.5 per cent. operated interest in the Callanish field, a 50 per cent. operated interest in the Enochdhu field and 26.316 per cent. non-operated interest in the Alder field.

Chrysaor acquired the GBA interests pursuant to the COP Acquisition in September 2019.

The Britannia facilities process production from the entire GBA hub and commingled liquids are exported via the Forties Pipeline System to the Kinneil processing plant at Grangemouth and commingled gas is exported via a dedicated pipeline to the SAGE gas terminal at St Fergus.

Chrysaor's future plans and outlook in the GBA hub include a focus on platform facilities modifications at the Britannia field designed to maximize reserves recovery and extend the life of the field. In particular, there are plans to "re-wheel" the Long Term Booster Compressor in the third quarter of 2021 following completion of the FPS outage in May 2021 in order to reduce the facilities back pressure on the wells and thereby enhance production rates and increase economic reserves. This is also expected to reduce carbon dioxide emissions by 10-15,000 tonnes per year. Other re-wheel options are being reviewed for the export train and medium pressure compressors.

The Zennor Petroleum-owned Finlaggan field is in development and is being tied-back via a two well subsea manifold to the Britannia platform. Production from the Finlaggan field will provide an opex sharing benefit to the Britannia JV, following first production, which is anticipated in the fourth quarter of 2021.

Net to the Chrysaor interest, the GBA hub produced 42.9 kboepd in the six months ended 30 June 2020. Production is forecast to continue until at least 2034.

Net to the Chrysaor interest, 2P reserves for the GBA hub are estimated at 60.5 mmboe as at 30 June 2020.

Summaries for each field in the operating hub are below, including contribution to hub reserves and production.

Britannia – Producing asset, 58.65 per cent. operated interest

The Britannia gas condensate field lies approximately 210 kilometres northeast of Aberdeen, Scotland, in the Central North Sea area of the UKCS in Blocks 15/29a, 15/30a, 16/26a, 16/27b and 16/27c. The Britannia gas condensate field was discovered in 1975 and first production was achieved in 1998. Britannia has been developed via a fixed steel platform, encompassing drilling, production and accommodation facilities, with the subsequent addition of a bridge-linked platform to provide reception facilities for the GBA subsea satellite fields Brodgar, Callanish, Enochdhu and Alder. The western area of the Britannia field is accessed via a subsea manifold and wells. The field is currently produced via 32 active platform wells and 4 active subsea wells.

The installed drilling rig on Britannia has been maintained in a cold stack state and there is currently ongoing work to determine the viability of reactivating the rig for infill well opportunities as well as future plug and abandon work that will be necessary. A complete subsurface model update is also underway in order to further understand and identify infill drilling opportunities in previously untapped areas of the reservoir.

Chrysaor's partners in Britannia are Ithaca Energy (32.38 per cent.) and Zennor Petroleum (8.97 per cent.).

Brodgar – Producing asset, 87.5 per cent. operated interest

The Brodgar gas condensate field is located in block 21/3a (ALL) in the Central North Sea area in the UKCS, approximately 40 kilometres west of the Britannia field.

Brodgar was discovered in 1985 and first production was achieved in 2008. The Brodgar field, has been developed as a satellite of the Britannia field and is tied back to the bridge-linked platform connected to the Britannia facility via a pipeline. The Brodgar field utilizes a three well subsea manifold tied back to the Callanish subsea manifold, and then on to the Britannia bridge-linked platform, from where gas and liquids are exported as part of the commingled stream. The field currently produces from one subsea horizontal well "H4", which came onstream in the fourth quarter of 2019 with initial production rates of approximately 18.5 kboepd net.

Chrysaor's current interest in the Brodgar field is 87.5 per cent. and, pursuant to the unitisation and unit operating agreement, this interest is forecast to revert to 93.75 per cent. early in the first quarter of 2021, once a 10 million barrels cumulative production milestone is reached. Chrysaor's partner in Brodgar is Ithaca Energy (currently 12.5 per cent., 6.25 per cent. following the forecast equity adjustment).

Callanish – Producing asset, 83.5 per cent. operated interest

The Callanish oil field is located in blocks 21/4a (ALL) and 15/29b (ALL) in the Central North Sea area in the UKCS, approximately 25 kilometres west of the Britannia field.

Callanish was discovered in 1999 and first production was achieved in 2008, along with production from the nearby Brodgar field that is also tied back to the Britannia field facilities.

The field has been developed as a satellite of the Britannia field and is tied back to the bridge-linked platform connected via a 25 kilometre pipeline to the Britannia facility from where gas and liquids are exported as part of the commingled stream. The field is produced via three subsea horizontal wells. An additional well is currently being drilled (the "**F5 well**") to target undrained oil on the east flank of the field, with first production expected in Q1 2021. If the F5 well is successful, there may be a further horizontal well production target "F6" on the north-west flank of the structure.

Chrysaor's partner in Callanish is Ithaca Energy (16.5 per cent.).

Enochdhu – Producing asset, 50 per cent. operated interest

The Enochdhu oil field is located in block 21/5a (ALL) in the Central North Sea area in the UKCS, approximately 18 kilometres west of the Britannia field.

Enochdhu was discovered in 2005 and first production was achieved in 2015. The field has been developed as a single subsea well tied back approximately 7 kilometres to the Callanish subsea manifold, which in turn is tied back to the bridge-linked platform connected to the Britannia facility from where gas and liquids are exported as part of the commingled stream.

Chrysaor's partner in Enochdhu is Ithaca Energy (50 per cent.).

Alder – Producing asset, 26.316 per cent. non-operated interest

The Alder field, operated by Ithaca Energy, is a high-pressure, high-temperature (HP/HT) gas condensate reservoir located in block 15/29a of the UKCS operated by Ithaca Energy, approximately 27 kilometres west of the Britannia facilities.

Alder was discovered in 1975 and first production was achieved in 2016. The field was developed as a single well tied back to the Britannia facility from where gas and liquids are exported as part of the commingled stream.

Chrysaor's partner in Alder is Ithaca Energy (operator, 73.684 per cent.).

(D) East Irish Sea ("EIS") Area – 100 per cent. operated interest

Chrysaor owns a 100 per cent. operated interest in the EIS assets. Chrysaor acquired the assets pursuant to the COP Acquisition in September 2019.

The EIS Area comprises of the Calder, Millom and Dalton producing fields and the Rivers terminal. The fields and associated facilities are managed by Spirit Energy under a service agreement and are treated as a non-operated asset in the Chrysaor operating model.

The Dalton field is a gas field located in block 110/2b in the East Irish Sea in the UKCS, approximately 40 kilometres from Barrow-in-Furness and approximately 10 kilometres northwest of the North Morecambe Gas field. The field was discovered in 1990 and first production was achieved in 1999.

The Millom field is a gas field located in blocks 113/26a, 113/27a and 110/2c in the East Irish Sea in the UKCS, approximately 40 kilometres from Barrow-in-Furness and approximately 10 kilometres northwest of the North Morecambe Gas field. The Millom field was discovered in 1982 and first gas was achieved in 1999.

The Millom field was developed using a normally unattended installation and a subsea template, currently producing from four platform wells and one subsea well. The Dalton field is produced via two vertical subsea wells. Both Millom and Dalton are tied back to and controlled from Spirit Energy's North Morecambe Platform, a normally unattended installation. From there, gas is transported to North Morecambe Terminal.

The Calder field is wholly located in block 110/7a of the East Irish Sea in the UKCS, approximately 10 kilometres southeast of Dalton. The Calder accumulation was discovered in 1983 and first gas was achieved in 2004. Calder produces sour gas and was developed with an unmanned platform and three development wells, exporting through a dedicated pipeline to the Rivers Terminal, which provides compression, hydrogen sulphide removal and metering. Gas is then transported to the North Morecambe Terminal for further treatment. Electrical power is imported from the Spirit Energy's South Morecambe Central Platform via a subsea power cable. The Calder platform is normally unmanned and is monitored and controlled either from the permanently manned South Morecambe Central Platform and/or from the North Morecambe Terminal control room onshore.

In 2019, operating efficiency for the EIS Area was improved significantly and base maintenance and integrity scopes for safety and production at critical facilities were carried out. Production in the first half of 2020 was below expectations due to control system issues at Calder, and unplanned compressor maintenance onshore at the North Morecambe Terminal. A field barge campaign for Calder to address maintenance and integrity scopes and helideck upgrades is anticipated in 2021. A similar campaign for Millom is being evaluated.

Chrysaor continues to work with Spirit Energy to evaluate strategic options to increase value for the overall Morecambe Bay area, including, but not limited to several Chrysaor owned satellite fields. Options for developing the Darwen sour gas field, which was discovered in 1991, are being assessed. This field would be tied back to the Calder facility and Rivers Terminal once the Calder field begins to decline.

Net to the Chrysaor interest, the EIS area produced 8.5 kboepd for the half year ended 30 June 2020. Production is forecast to continue until 2028.

Net to the Chrysaor interest, 2P reserves for the EIS Area are estimated at 18.8 mmboe as at 30 June 2020.

(E) Beryl Area – producing assets, various non-operated interests

Chrysaor has non-operated interests ranging from 34.04 to 49.09 per cent. in the Beryl, Buckland, Callater, Ness, Nevis, Skene and Storr fields, all of which are operated by Apache. The fields are located in blocks 9/12, 9.13, 9/18 and 9/19 in the Central North Sea area of the UKCS, approximately 340 kilometres north east of Aberdeen.

Chrysaor acquired its interests in the Beryl Area pursuant to the Shell Acquisition in November 2017.

The Beryl field (where Chrysaor has a 39.44 per cent. interest) has been developed in three phases. The first two phases developed the oil reserves using a large concrete platform ("**Beryl Alpha**") in the south of the field built in 1974, together with a smaller steel platform ("**Beryl Bravo**") to the north built in 1984. A separate riser platform bridge-linked to Beryl Alpha was installed in 1990 to allow gas export. This core infrastructure provides the drilling capability, fluid handling, export and storage capacity for the current and future satellite fields, which utilize the Beryl infrastructure. Oil is exported by tanker and gas is exported via the Ancala-operated SAGE pipeline to the SAGE gas plant at St. Fergus, Scotland. Chrysaor holds a 19.72 per cent. interest in the SAGE System, acquired pursuant to the Shell Acquisition.

There are currently thirty active producers in the Beryl field with fourteen wells producing from the Alpha platform and sixteen wells on the Bravo platform. Reservoir pressure support via water and gas injection is, and will continue to be, one of the principal focus areas for ongoing reservoir management in the Beryl field.

The Buckland field (where Chrysaor has a 37.47 per cent, interest) was discovered in 1978 and production began in 1999. The field is produced via two active production wells tied back to Beryl Alpha.

The Skene field (where Chrysaor has a 34.04 per cent. interest) was discovered in 1976 and production commenced in 2001. The field is produced via three production wells out of an original five wells. The Skene field is developed as a subsea tieback to Beryl Alpha, with the Callater field tied back to the Skene subsea facilities.

The Callater field (where Chrysaor has a 45 per cent. interest) was discovered in 2015 and production began in May 2017. The field is currently produced via five production wells. Two of these five wells were drilled on Callater in the second half of 2018. The Callater field is developed as a subsea tieback to the Skene subsea facilities, which in turn are tied back to the Beryl Alpha platform.

The Ness field (where Chrysaor has a 39.44 per cent. interest) was the first Beryl subsea satellite to come on stream in 1987 and is tied back to Beryl Bravo, along with Ness South. The field is produced at low rates via one production well in Ness South, which is shut-in at times for flowline capacity reasons. The Nevis field was discovered in 1974 and first production was achieved in 1996. The Nevis field currently has ten production wells across 5 accumulations (Chrysaor interests 39.44 per cent. – 49.09 per cent.). The Nevis accumulations were developed as subsea tiebacks to the Beryl platforms.

The Storr field (where ay Chrysaor has a 41 per cent. interest) was discovered in 2016. The first development phase of the Storr field was underway in 2018, with first production occurring in November 2019. The field is produced via one production well tied back to the Skene manifold, which in turn is tied back to Beryl Alpha.

Production continued to be strong in the first half of 2020 despite various production curtailments due to adverse weather causing tanker offload delays and plant-trip challenges. Five well interventions are planned for the second half of 2020, with one well intervention deferred to 2021. Drilling activity has continued in the area, both infill and exploration. In August 2019, Chrysaor and Apache completed a farm-in to equalise equity in the Tertiary play in the area to remove commercial barriers to drilling. This play has already seen two discoveries (Corona and Solar) in the acreage, with another well currently being drilled. This play is likely to extend into the Norwegian sector, where Aker BP and its partners have made a material discovery in Froskelår.

Net to the Chrysaor interest, the Beryl Area produced 17.8 kboepd in the six months ended 30 June 2020. Production is forecast to continue until 2030.

Net to the Chrysaor interest, 2P reserves for the Beryl Area are estimated at 27.8 mmboe as at 30 June 2020.

Apache is the sole partner and operator in the Beryl Area.

(F) Buzzard field – producing asset, 21.7 per cent. non-operated interest

The Buzzard field, operated by CNOOC International, is an oil and gas field located in blocks 19/5a, 19/10a, 20/6a and 20/1a in the Outer Moray Firth area of the North Sea, approximately 100 kilometres north-east of Aberdeen.

Chrysaor acquired its 21.7 per cent. interest in the Buzzard field pursuant to the Shell Acquisition.

The Buzzard field was discovered in 2001 and production began in 2007. Since 2007, it has been one of the largest producing fields in the region. The Buzzard facilities comprise four bridge-linked steel platforms which support wellhead and production facilities, utilities and living quarters, and a further hydrogen sulphide stripping platform.

The Buzzard infill platform drilling campaign was concluded in the first half of 2020, but the Buzzard Phase 2 campaign schedule was affected by the postponement of the FPS shutdown from summer 2020 to 2021, delaying first oil from March 2021 to December 2021.

Oil is exported via the FPS to the Kinneil Terminal, and gas is exported via the Frigg Pipeline System to the St. Fergus gas terminal.

Net to the Chrysaor interest, the Buzzard Field produced 19.6 kboepd in the six months ended 30 June 2020. Production is forecast to continue until 2041.

Net to the Chrysaor interest, 2P reserves for the Buzzard Field are estimated at 44.5 mmboe as at 30 June 2020.

Chrysaor's partners in Buzzard are CNOOC International (43.21 per cent.), Suncor Energy (29.89 per cent.) and ONE-Dyas (5.17 per cent.).

(G) Clair – producing and development asset, 7.5 per cent. non-operated interest

The Clair field, operated by BP, is a large oil field located in blocks 206/7, 206/8, 206/9, 206/11, 206/12 and 206/13 in the UKCS, approximately 70 kilometres north west of Shetland.

Chrysaor acquired its 7.5 per cent. interest in the Clair field pursuant to the COP Acquisition.

The Clair field was discovered in 1977. Within the Clair field, there are four accumulations: Phase 1, Ridge, South and North.

Phase 1 was developed as an integrated drilling and production platform that ties into the 20-inch West of Shetland Pipeline System ("**WoSPS**") to export gas to the Sullom Voe Terminal ("**SVT**"). Oil is exported via a 22-inch pipeline to SVT. Production in Phase I came onstream in 2005. A total of 25 wells have been drilled on Phase 1 and there are 23 currently online; 17 producers and six water injectors.

The Clair Ridge development was sanctioned in 2011 and targets the reservoir ridge area to the north-east of Phase 1. A quarters and utilities platform bridge-linked to a drilling and production platform have been installed. Oil and gas from the Clair Ridge development are exported via new pipelines which tie-in to the existing Clair Phase 1 gas export pipeline and oil pipeline to SVT. First oil was announced in November 2018. The initial development plan is to drill 36 wells from the Ridge platform, 8 of these planned wells have been drilled to date; five producers, two injectors and one cuttings reinjection well. Pending the success of these initial wells, the Clair Ridge development could also include two further tranches of infill wells.

Clair South is a proposed development. the main area of which lies 3 kilometres south of the Phase 1 core area. The Clair partners are currently assessing development options for Clair South.

At the northern end of Clair Ridge are two segments which are not part of the main Clair Ridge development, referred to as Clair North. The Clair partners are currently assessing development options for Clair North.

The Clair JV's future plans and outlook for the Clair field include Clair Phase 1 near term well activity including interventions and new wells, and continued drilling on Clair Ridge.

Net to the Chrysaor interest, Clair Phase 1 and Clair Ridge together produced 5.3 kboepd in the six months ended 30 June 2020.

Net to the Chrysaor interest, 2P reserves for Clair Phase 1 and Clair Ridge together are estimated at 49.4 mmboe as at 30 June 2020. Production is forecast to continue until beyond 2050.

Chrysaor's partners in Clair are BP (45.1 per cent.), Chevron (19.4 per cent.) and Shell (28.0 per cent.).

(H) Elgin-Franklin Area – producing assets, various non-operated interests

The Elgin-Franklin area (incorporating Elgin, Franklin, West Franklin and Glenelg), operated by Total, is located in the Central North Sea approximately 240 kilometres east of Aberdeen (the "**Elgin-Franklin Area**").

Chrysaor acquired its 14.11 per cent. non-operated interest in Elgin, Franklin and West Franklin and its 14.7 per cent. non-operated interest in Glenelg pursuant to the Shell Acquisition.

The Elgin-Franklin Area started production in 2001. The development utilises the Elgin PUQ. The Elgin PUQ is bridge-linked to a satellite WHP; the Elgin A WHP, which in turn is bridge-linked to the Elgin B WHP. A further normally unmanned WHP is located at the Franklin field, with production transported via subsea flow lines to the Elgin PUQ. West Franklin was first developed via an extended reach well drilled from the Franklin WHP, with first production in 2007. The West Franklin phase two development started production in January 2015 and includes the West Franklin A WHP and the Elgin B WHP.

The Elgin field currently has six active wells, the Franklin field has five wells and the West-Franklin field has four.

The Glenelg field is produced via a single production well from the Elgin wellhead platform. The well has historically experienced water breakthrough and scaling issues, which has led to intermittent production. A number of options are being considered that could restore the well to continuous production.

Once processed on the Elgin PUQ, liquids are transported via a spur line to the FPS. Sales gas is exported via a dry gas pipeline to the Shell-operated Bacton terminal ("**Bacton**").

The Elgin-Franklin Area is a mid-life asset with low operating costs. Ongoing well intervention campaigns and infill drilling continues to help maintain production from the area.

Net to the Chrysaor interest, 2P reserves for the Elgin-Franklin Area are estimated 52.2 mmboe as at 30 June 2020.

Net to the Chrysaor interest, Elgin-Franklin Area production for the half year ended 30 June 2020 averaged 19.7 kboepd. Production is forecast to continue until 2040.

Chrysaor's partners in the Elgin, Franklin and West Franklin fields are Total (operator, 46.17 per cent.), Eni (21.87 per cent.), Premier (5.2 per cent.), ExxonMobil (4.38 per cent.), Ithaca (3.90 per cent.), ONE-Dyas (2.19 per cent.) and Sumitomo Corporation (2.19 per cent.).

Chrysaor's partners in the Glenelg field are Total (operator, 58.73 per cent.), Eni (8.00 per cent.) and Premier (18.57 per cent.).

(I) Schiehallion field – producing asset, 10 per cent. non-operated interest

The Schiehallion field, operated by BP, is an oil and gas field located in blocks 204/20a, 205/16a, 205/21b, 204/25a and 204/25b in the UKCS, approximately 130 kilometres west of the Shetland Islands.

Chrysaor acquired its 10 per cent. interest in the Schiehallion field pursuant to the Shell Acquisition.

The Schiehallion field was originally discovered in 1993 and first oil was achieved in 1998. The field was shut-in beginning in 2013 and resumed production in May 2017 following the major "Quad 204" re-development program. This involved replacement of the old FPSO with the new 130,000 stb/d joint venture owned FPSO (the "**Glen Lyon FPSO**") delivered in 2017, the replacement and enhancement of subsea structures and the drilling of additional wells. The drilling program for phase 1 resulted in a total of 17 new wells. Phase 1 drilling is now finished, with all of the wells completed and on stream. The re-development program is expected to unlock significant reserves extending the Schiehallion field life through the 2040s. Oil from the Schiehallion field is exported by tanker, and gas is exported via the WoSPS to the SVT on the Shetland Islands.

Net to the Chrysaor interest, Schiehallion production for the half year ended 30 June 2020 averaged 5.6 kboepd. Production is forecast to continue until 2050.

Net to the Chrysaor interest, 2P reserves for the Schiehallion field are estimated at 24.3 mmboe as at 30 June 2020.

Chrysaor's partners in the Schiehallion field are BP (operator, 33.35 per cent.) and Shell (44.90 per cent.) and Siccar Point Energy (11.75 per cent.).

(J) Galleon field – producing asset, 8.4 per cent. non-operated interest

The Galleon field, operated by Shell, is a gas field located in blocks 48/14a, 48/15a, 48/19a and 48/20a in the Southern North Sea in the UKCS, approximately 75 kilometres north east of Bacton, in Norfolk.

Chrysaor acquired its 8.4 per cent. interest in the Galleon field pursuant to the COP Acquisition in September 2019.

The Galleon field has been developed in two phases, with production commencing from a minimal facilities platform ("**PN**") in the southeast part of the field in 1994. A wellhead platform ("**PG**") in the northwest area of the field was added in the second phase, with production commencing in 1998. Both platforms are tied back to the Shell-operated Clipper platform from where gas is exported to the Bacton, gas terminal via the Sole Pit gas export line. Eight wells currently produce at the PG platform, and three at PN platform. A new well PN09 was drilled during 2019, but operations were suspended due to drilling difficulties..

Net to the Chrysaor interest, 2P reserves for the Galleon field are estimated at 1.3 mmboe as at 30 June 2020.

Net to the Chrysaor interest, Galleon field production for the half year ended 30 June 2020 averaged 0.5 kboepd. Production is forecast to continue until 2034.

Chrysaor's partners in the Galleon field are Shell (operator, 41.6 per cent.), ExxonMobil (41.6 per cent) and Spirit Energy (8.4 per cent.).

(K) Nicol field – producing asset, 18 per cent. non-operated interest

The Nicol field, operated by Premier, is located in block 15/25a in the Central North Sea in the UKCS, approximately 210 kilometres north east of Aberdeen and approximately 25 kilometres north of the Britannia facilities.

Chrysaor acquired its 18 per cent. interest in the Nicol field pursuant to the COP Acquisition in September 2019.

The Nicol field commenced production in 2007 and was developed via a single horizontal subsea well tied back to the Brenda field. Commingled Nicol and Brenda oil was transported onwards to the Balmoral floating production vessel. The Balmoral area fields, including Nicol, are operated by Premier. Balmoral area oil was transported via the Forties Pipeline System. In June 2020 as a result of the low oil price environment, Premier took the decision to bring forward final production from the Balmoral area fields to October 2020 from 2021.

Net to the Chrysaor interest, 2P reserves for the Nicol Field were estimated as negligible as at 31 December 2019 and nil as at 30 June 2020.

Net to the Chrysaor interest, Nicol Field production for the half year ended 30 June 2020 averaged less than 0.1 kboepd.

Chrysaor's partners in the Nicol field are Premier (operator, 70 per cent and JX Nippon (12 per cent.).

(L) Southern North Sea – decommissioning project, various operated interests

In September 2019, pursuant to the COP Acquisition, Chrysaor assumed the responsibility for the ongoing decommissioning of ConocoPhillips' operated Southern North Sea gas fields and infrastructure, comprising the CMS, LOGGS and Viking areas and Theddlethorpe Gas Terminal. Production ceased in August 2018, and the decommissioning programme is well advanced and expected to be materially complete by 2024. Chrysaor's working interest in the area ranges from 20.0 per cent. to 61.1 per cent..

CMS Area

The Caister Murdoch System ("**CMS**") Area, consists of the Murdoch, Caister, Boulton, CMS III, Kelvin, Katy and Munro fields. In 2020 the Murdoch complex has been transitioned to cold suspension, and the Caister platform has been removed. During 2020, eight wells have been decommissioned and the nine remaining wells will be plugged and abandoned through to 2022, with platform removals continuing through to 2024.

Chrysaor's working interest in the CMS Area ranges from 39.0 per cent to 59.5 per cent, and its partners are Neptune Energy, Tullow Oil and Premier.

LOGGS Area

The LOGGS Area consists of the North Valiant, South Valiant, Vanguard, Vulcan, Vampire, Viscount, Saturn, Mimas, Tethys and Jupiter fields. The LOGGS complex has been de-manned and transitioned into cold suspension and during 2020 four field platforms have been removed. Decommissioning work to plug and abandon the wells will continue through to 2022, with removal of the remaining LOGGS area platforms continuing through to 2024.

Chrysaor's working interest in the LOGGS area ranges from 20.0 per cent to 61.1 per cent, and its partners are BP, ExxonMobil, Equinor, INEOS and Spirit Energy.

Viking Area

The Viking Area consists of the Viking, Vixen and Victor fields. Production from Viking ceased in 2016 and decommissioning is nearing completion. Platform removals began in 2019 with 8 installations being removed and transported onshore for recycling. During 2020, the remaining 5 platforms have been removed. The final two subsea wells are scheduled to be plugged and abandoned in 2021-2022.

Chrysaor's working interest in the Viking and Vixen fields is 50 per cent.; and its partner is BP. Chrysaor's working interest in Victor field is 20 per cent., with partners Spirit Energy, ExxonMobil, Dana Petroleum, INEOS and CalEnergy.

Theddlethorpe Gas Terminal

Theddlethorpe Gas Terminal was deemed hydrocarbon free in December 2019 and was transitioned into cold suspension Demolition commenced in the first quarter of 2020 and is expected to take 18 months to complete. Land remediation and restoration is currently planned to follow through to 2023.

Chrysaor's working interest in the Theddlethorpe Gas Terminal is 50 per cent. and its partner is BP.

(M) Other decommissioning projects

In September 2019, pursuant to the COP Acquisition, Chrysaor assumed responsibility for the following decommissioning projects:

MacCulloch

The MacCulloch field, operated by Chrysaor, is located in block 15/24 of the Central North Sea and ceased production in 2015. Chrysaor has a 40 per cent. interest, and its partners are Eni (40 per cent. interest), Repsol Sinopec (6 per cent. interest) and Noble Energy (14 per cent. interest). Chrysaor acquired the interest as part of the COP Acquisition.

Well abandonment operations were suspended earlier in 2020 and are due to recommence in late 2020 or early 2021, dependent upon rig scheduling. Removal of the remaining subsea infrastructure is due to take place between 2022 and 2024.

Hewett

Chrysaor has liability for 18.97 per cent. of the cost of the Eni-operated Hewett decommissioning project in the Southern North Sea. Chrysaor acquired the liability as part of the COP Acquisition.

Decommissioning operations recommenced in August 2020, following a five months suspension, and are expected to continue through to 2028. Other parties liable for costs are Eni (operator, 70.34 per cent.) and Perenco (10.69 per cent.).

Thistle

Chrysaor has liability for 18.28 per cent of the cost of decommissioning of the EnQuest-operated Thistle field in the Northern North Sea. The other partner liable for the costs in Thistle is BP. Chrysaor acquired the liability as part of the COP Acquisition.

Regulatory approval for the permanent cessation of production from Thistle was granted in September 2020. Well abandonment and topsides decommissioning are expected to take place in 2021-2026.

Miller

Chrysaor has liability for 30 per cent of the cost of the BP-operated Miller decommissioning project in the Central North Sea. The other partner in Miller is Shell. Chrysaor acquired the liability as part of the COP Acquisition.

The Miller field ceased production in 2007, and well abandonments and platform removal are complete. Remaining decommissioning works include removal of subsea infrastructure and pipework remediation which is expected to take place in 2022-2025.

(N) Infrastructure

Chrysaor owns a number of non-operated interests in pipeline and terminal assets.

Scottish Area Gas Evacuation (SAGE) System

Chrysaor owns an approximate 19.7 per cent. non-operated interest in SAGE (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 at St Fergus. Gas from the GBA hub is delivered to the SAGE Terminal for processing via a dedicated pipeline.

Central Area Transmission System (CATS)

Chrysaor owns an approximate 0.7 per cent. non-operated interest in CATS (operated by Kellas) that was acquired as part of the COP Acquisition. Gas exported from the AELE and J-Area hubs is transported through the CATS pipeline to Teesside.

Shearwater Elgin Area Line (SEAL)

Chrysaor owns an approximate 7.9 per cent. non-operated interest in SEAL (operated by Shell) that was acquired as part of the Shell Acquisition. Gas exported from the Elgin-Franklin Area is transported through SEAL to a reception facility at Bacton.

SEAL Interconnector Link Pipeline (SILK)

Chrysaor owns an approximate 16.0 per cent. non-operated interest in SILK (operated by Total) that was acquired as part of the Shell Acquisition. The pipeline connects the SEAL reception facilities at Bacton to the Interconnector.

West of Shetland Pipeline System (WoSPS)

Chrysaor owns an approximate 2.9per cent. non-operated interest in WoSPS (operated by BP) that was acquired as part of the Shell Acquisition. The pipeline connects the Glen Lyon FPSO at the Schiehallion field to onward export facilities at Sullom Voe. Gas exported from the Schiehallion and Clair field are transported through this pipeline.

Esmond Transportation System (ETS)

Chrysaor owns a 10 per cent. non-operated interest in ETS (operated by Kellas) that was acquired as part of the COP Acquisition. Chrysaor has no equity gas transported through ETS but derives income from tariffs.

Graben Area Export Line (GAEL) – Northern and Southern Spurlines

Chrysaor owns an approximate 2.9 per cent. non-operated interest in the Northern Spurline and an approximate 9.8 per cent. non-operated interest in the Southern Spurline that were acquired as part of the Shell Acquisition. GAEL is operated by BP. Liquids exported from the Elgin-Franklin Area are transported through GAEL and delivered offshore to the Forties Pipeline System.

Brent Pipeline System (BPS)

Chrysaor owns an approximate 0.8 per cent. non-operated interest in BPS (operated by Taqa) that was acquired as part of the COP Acquisition. Chrysaor has no equity production transported through BPS.

Sullom Voe Terminal (SVT)

Chrysaor owns an approximate 0.5 per cent. non-operated interest in SVT (operated by EnQuest) that was acquired as part of the COP Acquisition. Chrysaor's share of Clair oil is exported via a dedicated pipeline to dedicated storage tanks located at SVT and leased from the SVT owners.

6. UK Exploration

Chrysaor's exploration strategy is to create value through core area, infrastructure-led exploration ("**ILX**") and to build a high-graded and balanced portfolio to sustain longer term production. Chrysaor develops plans centred on operated producing hubs, identifying and maturing exploration opportunities that can be tied-in to existing infrastructure, extending hub life.

Chrysaor actively participates in UKCS offshore licensing rounds and has had considerable success in recent rounds, with eight licence awards in 2018's 30th licensing round, three in the 31st licensing round in 2019 and fourteen provisional licenses offered in the recent 32nd licensing round.

Significant investment in 3D seismic data underpins Chrysaor's commitment to exploit the remaining potential in both the mature and frontier areas of the UKCS, generating a portfolio that offers a range of opportunities.

7. Summary of regulatory regime and licence terms in the UK

For a summary of the regulatory regime and licence terms in the UK, please see the paragraph headed "Summary of regulatory regime and licence terms in the UK" in Part III *Information on the Premier Group*.

8. Summary of the economic and fiscal regime in the UK

For a summary of the economic and fiscal regime in the UK, please see the paragraph headed "Summary of the economic and fiscal regime in the UK" in Part III *Information on the Premier Group.*

9. Chrysaor's principal activities and investments – Norway Business Unit

9.1 Overview

Chrysaor's Norwegian operations are headquartered in Oslo.

Chrysaor first entered Norway in March 2018 via an acquisition of an interest in the PL038D licence holding the Grevling discovery, which lies approximately 28km north of the Armada facilities in block 15/12A. Chrysaor was prequalified as a Licensee on the NCS in 2018 and as Operator in 2019 and subsequently took over the operatorship of PL 973 marking the company's first operatorship on the NCS.

In January 2020, Chrysaor was awarded eight further production licences on the NCS by the Ministry of Petroleum and Energy ("**MPE**") in relation to the Awards in Pre-Defined Areas ("**APA**") 2019 Offshore Licensing Round. As a result, Chrysaor currently holds working interests in 11 licences over 18 blocks with an average working interest of 42 per cent., comprising gross un-risked recoverable resources of more than 1.4 billion boe and may drill the company's first operated wells in the second half of 2021 on the Jerv and Ilder prospects covered by licence PL973. All the licences are in the exploration phase.

In September 2020, Chrysaor participated in the APA 2020 Offshore licensing round with results/awards expected in January 2021.

As Chrysaor has no producing assets in Norway it pays no tax and since the licences are in the exploration phase current activities generate the basis for a tax refund which is paid out in November the year after the income year. Other tax-deductible expenditures and post exploration expenditures are added to a pool of tax losses which will be available for offset against future profits. However, for income years 2020 and 2021, Chrysaor is essentially refunded the tax value of all costs incurred, not just the exploration expenditure, due to the temporary measures introduced (see below).

10. Summary of the regulatory regime and licence terms in Norway

The Norwegian Petroleum Act (of 29 November 1996 no.72) (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 are vested in the Norwegian State. The regulatory regime for the Norwegian petroleum activities is based on a licensing system, under which companies are granted rights to explore for and produce petroleum within a specified geographical area and for a limited period (the "**Production Licences**"). The NPA is supplemented by further petroleum regulations specific to health, safety and the environment.

Production 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 MPE.

Each Production Licence is 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 30 years but in certain specific cases it may be up to 50 years.

As a condition for the award of a Production Licence the licensees will have to enter into an "Agreement for Petroleum Activities" that regulates their joint activities in the Production Licence. This Agreement is in a non-negotiable format stipulated by the MPE. By means of the Agreement, the licensees form an unincorporated joint venture. The participants in the joint venture are liable to each other principally on a pro-rata basis and alternatively joint and several.

The Production 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 by agreement with the MPE; the licensee's 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 MPE; joint and several liability of licensees; restrictions on and government consent for assignment of a Production Licence or change of control of a licensee; and a power of revocation of the Production Licence in certain circumstances including where there have been serious or repeated violations of the legislation or the terms of the Production Licence.

Under the current legislation, licensees must submit a decommissioning plan to the MPE between two and five years before a Production Licence expires or is relinquished, consent for installation and operation of a facility expires or is relinquished and use of the facility is terminated permanently. The licensees and owners of the installation, facilities and pipelines are liable for the costs related to decommissioning. If an interest in a Production Licence has, directly or indirectly, been transferred to another entity, the transferee will continue to be secondarily liable for the decommissioning obligations to the state and the other licensees.

11. Summary of the economic and fiscal regime in Norway

Special tax and ordinary tax

A company involved in exploration and production activities within the geographic area of the NCS is subject to a ring-fenced special tax regime. The marginal tax rate for these companies are 78 per cent consisting of the general corporation tax rate of 22 per cent. and the special petroleum tax rate of 56 per cent.

In calculating tax, deductions are available for costs relating to exploration, research, development, financing, operations, removal and related administrative costs. The tax basis for calculating special taxes is essentially the same as for ordinary taxes except for the treatment of interest costs and uplift allowances.

Exploration costs and Capital allowances

All exploration costs may be expensed and, for companies making a loss, the Norwegian government makes a cash refund of the tax value (i.e., 78 per cent.) of the exploration costs in November the year after the income year.

Investments in offshore production facilities, pipelines and installations (tangible assets) used in the E&P activity, are depreciated over a six-year period beginning with the year of investment.

In addition, to shield normal returns from the special petroleum tax rate, an extra deduction, called uplift, is available at 20.8 per cent. (5.2 per cent. per annum over four years). This means that 89.65 per cent (i.e., 56 per cent. + 22 per cent. + (20.8 per cent. × 56 per cent.)) of offshore investments are nominally covered by the Norwegian state.

Financial items

Only a portion of interest costs (and related foreign exchange) is deductible in the offshore tax regime at 78 per cent. The remaining interest costs and all other financial costs/income are subject to onshore taxation at the ordinary 22 per cent. tax rate.

The allocation of interest cost to the offshore regime is calculated as the ratio of the aggregate of interest costs and foreign exchange costs related to interest-bearing debt multiplied by 50 per cent.

multiplied by the remaining tax balances of offshore-related assets at year-end to the daily average interest-bearing debt.

If the company has no investments or assets, all interest costs and related foreign-exchange costs are allocated onshore. However, if the company has no other onshore income, the financial costs may be allocated back to the offshore regime for deduction against the 22 per cent. corporate tax rate. Note that the general interest limitation rule does not apply for oil and gas companies subject to petroleum taxation.

Tax losses

Offshore losses may be carried forward indefinitely and is increased with a risk-free interest rate every year. Tax losses can also be transferred in connection with the sale of the total activity or by a merger with another "upstream" company. The tax value of the losses can be refunded when the upstream activity on the NCS ceases. Thus, a company subject to the Norwegian offshore tax regime is essentially guaranteed a full tax deduction or refund of all costs incurred.

Temporary tax stimulus measures for oil and gas companies anchored in COVID-19

On 12 June 2020, the Norwegian government introduced temporary tax measures for oil and gas companies to improve liquidity and stimulate activity. The temporary measures will apply to investments made in 2020 and 2021, as well as to investments relating to projects where a development plan is submitted by the end of 2022 and sanctioned by the end of 2023. Provisions include:

(a) a 100 per cent. depreciation against special tax basis: oil and gas companies can depreciate 100 per cent. of all investments against the special tax basis (56 per cent.) in the year of investment in 2020 and 2021;

(b) interest deductions: the formula for interest deductions will be based on tax written down values in the special tax base. As there will be a 100 per cent. write down in the special tax basis, this essentially means that the companies can only claim a 22 per cent. interest cost deduction for financing of investments that fall under this temporary regime (and not partly 78 per cent., as under the current/ordinary regime).

(c) an increased uplift: the uplift is increased from 20.8 per cent. (5.2 per cent. per annum over four years) to 24 per cent. in the year of investment, or year one for the same period and projects as described above; and

(d) a tax loss refund: companies generating tax losses may receive a cash refund of tax value through the income years 2020 and 2021.

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 and explored efficiently. No royalty is charged for petroleum activities.

12. Chrysaor licence interests

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

Licence	*Blocks*	*Operator*	*Chrysaor equity*	*Unit interest (if applicable)*	*Associated fields/discoveries*
United Kingdom					
P.008	Block 48/20a (NVALT)	Chrysaor	100%		
P.011	Block 30/6a JPART	Chrysaor	67%		J-Block
P.028	Block 49/11a ALEX	Chrysaor	50%		
P.032	Blocks 30/7a ALL and 30/12a ALL	Chrysaor	67%		J-Block
P.039	Block 49/21a A	Chrysaor	25%		Viper and South Valiant
P.039	Block 49/21a REST	Chrysaor	25%		Viper and South Valiant
P.057	Block 23/26a Erskine Field Area	Ithaca	32%		Erskine
P.066	Block 22/5a Armada Fields	Chrysaor	100%		Armada
P.066	Block 22/5d	Chrysaor	100%		Everest
P.066	Block 22/10a	Chrysaor	100%		Armada
P.079	Block 30/13d A (North)	Chrysaor	85%		J-Block
P.099	Block 110/7a D	Chrysaor	100%		Calder
P.101	Block 22/9a C Rest of Bloc	Chrysaor	100%		Everest
P.101	Block 23/21a B Lomond Field Area	Chrysaor	100%		Lomond
P.103	Block 15/30a S-BRI	Chrysaor	67%	58.65%	Britannia Field
P.103	Block 21/5a ALL	Chrysaor	50%		Enochdhu
P.103	Block 15/30a L-RST	Chrysaor	49.40%		
P.103	Block 9/18a Area G, Buckland below 9500 TVDSS	Apache	37.47%		Buckland
P.103	Blocks 9/19a (as redesignated) and 9/19c (formerly part of Block 009/19a prior to its redesignation), excluding Areas N, R, Z & AA) Area O	Apache	10.21%	39.44%	Beryl
P.103	Blocks 9/19a (as redesignated) and 9/19c (formerly part of Block 009/19a prior to its redesignation), excluding Areas N, R, Z & AA) Area O	Apache	10.21%	41.00%	Storr
P.103	Block 9/18a Area Y, Triassic interval (a portion of Beryl Field)	Apache	39.44%		Beryl
P.103	Block 9/19c Area Z (Skene field)	Apache	34%		Skene
P.103	Block 9/19c Area Z (Skene field)	Apache	34%	41%	Storr
P.103	Block 9/19a (as redesignated) AA, excluding Areas AC, AD, N, O and Z which forms part of Area AA	Apache	4.08%		
P.103	Block 9/19c (formerly part of Block 9/19a prior to its redesignation) Cretaceous, excluding Areas AC, AD, N, O and Z which forms part of Area AA	Apache	4.08%		
P.103	Block 9/19c (formerly part of Block 9/19a prior to its redesignation) Post Cretaceous excluding Areas AA, O and Z Area AD	Apache	39.44%		
P.103	Block 9/18a (as redesignated) Post Cretaceous, excluding Areas W, G, Y, R and N) Area AE	Apache	39.44%		
P.110	Block 16/29g Armada Fields Area (Fleming Extension)	Chrysaor	100%		Armada
P.110	Block 16/29a Maria Area (South Part of Assigned Area)	Chrysaor	100%		Maria
P.110	Block 22/14a Everest Field Area)	Chrysaor	100%		Everest
P.118	Block 21/3a ALL	Chrysaor	75%	87.5% / 93.75%	Brodgar
P.119	Block 15/29a ALDER	Ithaca	26.32%		Alder
P.119	Block 15/29a (Area B)	Ithaca	25%	58.65%	Britannia
P.119	Block 15/29a A	Ithaca	26.32%		
P.119	Block 15/29a (Area C)	Ithaca	25%		
P.130	Block 48/15a (REST)	Chrysaor	50%	8.40%	Galleon
P.130	Block 48/25b (VULC)(1)	Chrysaor	50%		
P.130	Block 48/25b (REMAINDER)(1)	Chrysaor	50%		
P.139	Block 9/13a ALL	Apache	39.44%		Beryl
P.165	Block 206/8a ALL	BP	5.94%	7.50%	Clair
P.168	Blocks 206/7a ALL and 206/11a ALL	BP	10.42%	7.50%	Clair
P.170	Block 206/9a ALL	Chrysaor	20.84%	7.50%	Clair

Licence	*Blocks*	*Operator*	*Chrysaor equity*	*Unit interest (if applicable)*	*Associated fields/discoveries*
P.188	Block 22/30b (ELGN)	Total	14.11%		Elgin
P.213	Block 16/26a (B-BRI)	Ithaca	54.8%	58.65%	Britannia
P.213	Block 16/26a C-10K	Ithaca	22.75%		
P.225	Block 16/27c (BRIT)	Chrysaor	100%	58.65%	Britannia
P.233	Block 15/25 (ALL)	Premier	18%		Nicol
P.234	Block 3/28a	Equinor	18.38%		Bressay
P.236	Blocks 211/18c and 211/18a (North East)	Britoil	19.70%		Don
P.236	Blocks 211/18c and 211/18a (South West)	Britoil	41.60%		Don
P.251	Block 110/8c ALL	Chrysaor	100%		
P.254	Block 9/12a ALL	Apache	49.09%	42.82%	Nevis
P.264	Block 23/26b Erskine Field Area	Ithaca	32%		Erskine
P.287	Block 113/26a ALL	Chrysaor	100%		Millom
P.337	Blocks 9/13b and 9/13c	Apache	39.44%		Beryl
P.345	Block 16/27b (Area B)	Ithaca	39.49%	58.65%	Britannia
P.345	Block 16/27b (Area A) (Rest of Block excluding Britannia)	Ithaca	38.25%		
P.347	Block 21/4a ALL	Chrysaor	86.30%	83.50%	Callanish
P.355	Block 22/4a Armada Fields	Chrysaor	100%		Armada
P.356	Block 22/5b Armada Area	Chrysaor	100%		Armada
P.356	Block 22/5b Residual Area	Chrysaor	100%		Seymour
P.362	Block 29/5b (ALL)	Total	14.10%		Elgin and Franklin
P.493	Block 3/28b	Equinor	18.38%		Bressay
P.547	Block 113/27a ALL	Chrysaor	100%		Millom
P.559	Block 204/25a ALL	Shell	30%	10%	Schiehallion
P.590	Block 15/29b ALL	Chrysaor	80%	83.50%	Callanish
P.591	Block 16/29c Armada Fields Area	Chrysaor	100%		Armada
P.591	Block 16/29c Rest of Block	Chrysaor	100%		
P.666	Block 22/30c (ALL)	Total	14.11%		Elgin
P.666	Block 29/5c	Total	14.11%		Franklin and West Franklin
P.672	Block 30/2c JADE	Chrysaor	67.50%		Jade
P.672	Block 30/2c (REST)	Chrysaor	80.84%		
P.706	Block 110/2b ALL	Chrysaor	100%		Dalton
P.706	Block 110/2c ALL	Chrysaor	100%		Millom
P.741	Block 21/3b ALL	Chrysaor	100%	87.5% / 93.75%	Brodgar
P.752	Block 29/4d (ALL)	Total	14.70%		Glenelg
P.920	Block 3/27b	Equinor	18.38%		Bressay
P.928	Blocks 19/5a and 20/1 (South)	CNOOC	21.73%		Buzzard
P.977	Block 9/2a and 9/3a	Equinor	18.38%		Bressay
P.986	Blocks 19/10a and 20/6a	CNOOC	21.73%		Buzzard
P.1570	Block 206/11b ALL	BP	7.50%		Clair
P.1589	Block 30/7b ALL	Chrysaor	67.50%		Jade
P.1764	Block 9/13d	Apache	39.44%		Beryl
P.1985	Blocks 9/14b Cretaceous and below Base Cretaceous Unconformity and 9/14e Cretaceous and below Base Cretaceous Unconformity	Apache	22.80%		
P.1985	Blocks 9/14b (Post Cretaceous) and 9/14e (Post Cretaceous)	Apache	39.44%		
P.1986	Block 9/19b (Cretaceous and below Base Cretaceous)	Apache	45%		Callater
P.1986	Block 9/19b (Cretaceous and below Base Cretaceous)	Apache	45%	41%	Storr
P.1986	Block 9/19b Post Cretaceous	Apache	39.44%		
P.2074	Blocks 205/26c ALL and 205/27a ALL[(1)]	Chrysaor	40%		Mustard
P.2221	Block 30/7c ALL	Chrysaor	67%		
P.2330	Blocks 37/17, 37/18, 37/19, 37/22b, 37/23b, 37/24	Chrysaor	100%		
P.2335	Block 9/18e Post Cretaceous	Apache	39.44%		
P.2353	Blocks 9/9g, 9/13g and 9/14c	Apache	39.44%		
P.2354	Block 9/15d Post Cretaceous	Apache	39.44%		
P.2355	Block 9/18f	Apache	39.44%		
P.2371	Blocks 16/28d ALL and 16/29e ALL	Chrysaor	100%		
P.2374	Blocks 22/3, 22/4b, 22/8b and 229b	Chrysaor	100%		
P.2389	Block 23/22b	Chrysaor	100%		
P.2399	Block 30/7d ALL and 30/8 ALL	Chrysaor	67%		
P.2408	Block 205/25 ALL	Chrysaor	100%		
P.2455	Block 30/1a (ALL)	Chrysaor	100%		

Licence	Blocks	Operator	Chrysaor equity	Unit interest (if applicable)	Associated fields/discoveries
P.2456	Block 30/13e ALL	Chrysaor	67%		
P.2485	Blocks 37/20, 37/25, 37/30a, 38/16, 38/17, 38/21a, 38/22a and 38/26	Chrysaor	100%		
P.2489	Blocks 109/5, 109/10, 109/15, 110/1, 110/6, 110/7b, 110/11, 110/12c and 112/30	Chrysaor	100%		
Norway					
PL.038D	Block 15/12	OKEA	35%		Grevling
PL.973	Block 15/12	Chrysaor	50%		
PL.973B	Block 15/12	Chrysaor	50%		
PL.974	Block 15/12	OKEA	40%		Storskrymten
PL.1032	Blocks 2/7 and 2/10	Lundin	40%		
PL.1033	Blocks 1/9 and 2/7	OMV	40%		
PL.1034	Block 15/12	Chrysaor	60%		
PL.1046	Blocks 24/3, 24/6, 25/1, and 25/4	Chrysaor	40%		
PL.1058	Blocks 6307/1 and 6407/10	Equinor	40%		
PL.1060	Blocks 6407/8 and 6407/9	Equinor	20%		Galtvort
PL.1066	Block 6507/3	Aker BP	50%		

(1) In the process of being relinquished, with a relinquishment date of 31 December 2020.

13. Health, safety, environment, quality and assurance

Chrysaor places a commitment to health safety and environmental performance centrally to business success. The health, safety and security of those that work for and with Chrysaor is of paramount importance, whilst ensuring absolute adherence to all legal and regulatory requirements in the jurisdictions in which Chrysaor operates.

Chrysaor promotes and adheres to a safety culture whereby nothing is so urgent or important that it cannot be done safely, and as such neither the health and safety of people or the environment would be compromised in pursuit of commercial activity

Chrysaor manages risk and major event prevention through adherence to management systems and processes implemented to assure process safety and asset integrity.

Annual environmental objectives and plans, including the HSEQ plan, are established to monitor and measure Chrysaor's impact on nature and reduce the risk of causing environmental damage.

Chrysaor has a Business Management System (the "**BMS**") that holds all Chrysaor's mandatory policies, standards, guidelines and procedures. The BMS provides instruction and performance expectations consistent with Chrysaor's core values and business principles to ensure Chrysaor achieves its stated business objectives safely and consistently. It is the single authorized source of group instruction and guidance applicable to both onshore and offshore activities within the business. The BMS has four key policies, including the Corporate Major Accident Prevention Policy, Health, Safety and Environmental Policy, Quality Policy and Tax, Anti-Bribery and Corruption Policy. The BMS allows Chrysaor to meet the requirements of International Standard ISO9001 and ISO14001.

Chrysaor seeks to develop and implement progressive HSEQ approaches and foster a learning culture that results in continuously improved performance. HSEQ data analytics are used to identify enterprise and asset level trends to enable focused preventative action to be taken throughout all levels of the organisation. Leading and lagging process safety, occupational and environmental performance indicators are routinely reviewed by the leadership team including engagement with offshore leadership and safety representatives during frequent visits across the offshore assets. There are two independently facilitated HSEQ management reviews each year to communicate performance and meet the requirements of International Standards ISO9001 and ISO14001 as well as the UK Health & Safety Executive document HS(G)65. These reviews are chaired by the CEO and provide an opportunity for open engagement between operational leadership, offshore personnel and functional HSEQ staff to discuss performance, identify areas for improvement and agree future approaches. Organisational HSEQ performance and progress against the plan is also reviewed regularly with the board of directors. Achievement of the stated objectives is also supported by a broad ranging HSEQ audit and assurance program which is completed during the year.

14. Insurance

Chrysaor undertakes significant and appropriate insurance programs to minimize the risk to operational investment programs, including business interruption insurance.

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

Where applicable, Chrysaor procures construction all risks insurance coverage in respect of development projects. Such coverage generally applies to works executed in performance of contracts wherein Chrysaor 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.

Chrysaor 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 Chrysaor feels adequately provide for its needs and the risks that it faces. Chrysaor has not had any material claims under its insurance policies that would either make them void or materially increase their premiums.

PART V

OPERATING AND FINANCIAL REVIEW RELATING TO THE PREMIER GROUP

The following discussion of the Premier Group's financial condition and results of operations should be read in conjunction with the historical financial information on the Premier Group and the notes related thereto referred to in Part VII (*Historical Financial Information relating to the Premier Group*), which is incorporated into this Prospectus by reference and the information relating to the business of the Premier Group contained elsewhere in this Prospectus. Except as otherwise stated, the financial information included in this Part V (*Operating and Financial Review relating to the Premier Group*) has been extracted without material adjustment from the financial information referred to in Part VII (*Historical Financial Information relating to the Premier Group*), which has been incorporated into this Prospectus by reference. The historical financial information referred to in this Part V (*Operating and Financial Review relating to the Premier Group*) has been prepared in accordance with IFRS as explained in Part VII (*Historical Financial Information relating to the Premier Group*).

The following discussion contains forward looking statements. The Premier Group's actual results could differ materially from those contained in any forward looking statements as a result of factors discussed below and elsewhere in this Prospectus, particularly in the Parts of this Prospectus headed 'Risk Factors' and 'Important Information'.

1. Documents incorporated by reference

This document should be read and construed in conjunction with the following documents which have been previously published and filed with the FCA and which shall be deemed to be incorporated in, and form part of, this document:

Reference Document	*Information incorporated by reference into this document*	*Page number(s) in reference document*
Premier Group's 2020 Unaudited Interim Financial Statements (for the half year ended 30 June 2020)	Independent Review Report	27 to 28
	Condensed Consolidated Income Statement	14 to 15
	Condensed Consolidated Statement of Comprehensive Income	15 to 16
	Condensed Consolidated Balance Sheet	16
	Condensed Consolidated Statement of Changes in Equity	17
	Condensed Consolidated Cash Flow Statement	17
	Notes to the Condensed Financial Statements	18 to 29
Premier Group's 2019 Annual Report and Financial Statements	Independent Auditor's Report	117 to 126
	Consolidated Income Statement	34
	Consolidated Balance Sheet	136
	Consolidated Statement of Changes in Equity	137
	Consolidated Cash Flow Statement	138
	Notes to the Consolidated Financial Statements	139 to 171
	Business performance reconciliation table	46

Reference Document	*Information incorporated by reference into this document*	*Page number(s) in reference document*
Premier Group's 2018 Annual Report and Financial Statements	Independent Auditor's Report	112 to 120
	Consolidated Income Statement	128
	Consolidated Balance Sheet	130
	Consolidated Statement of Changes in Equity	131
	Consolidated Cash Flow Statement	132
	Notes to the Consolidated Financial Statements	133 to 165
	Business performance reconciliation table	30
Premier Group's 2017 Annual Report and Financial Statements	Independent Auditor's Report	118 to 127
	Consolidated Income Statement	134
	Consolidated Balance Sheet	136
	Consolidated Statement of Changes in Equity	137
	Consolidated Cash Flow Statement	138
	Notes to the Consolidated Financial Statements	139 to 173
	Business performance reconciliation table	39

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

Any statement contained in a document which is deemed to be incorporated by reference into this document shall be deemed to be modified or superseded for the purpose of this document to the extent that a statement contained in this document (or in a later document which is incorporated by reference into this document) 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 document.

These documents are also available on the Company's website at http://www.Premier-oil.com/ investors/ results-centre.

2. Capitalisation and indebtedness

The tables below set out the Premier Group's capitalisation and indebtedness as at 31 October 2020. This statement of capitalisation and indebtedness has been prepared on a basis consistent with the accounting policies used in preparing the Premier Group's financial information for the six months ended 30 June 2020 as incorporated by reference in this Part V of this Prospectus.

The capitalisation and indebtedness information as at 31 October 2020 has been extracted without material adjustment from the Premier Group's unaudited accounting records.

The tables below do not reflect the effect of the Merger and the Debt Restructuring, and the following tables should be read together with this Part V, Part IX (*Unaudited Pro forma Financial Information*) and Part XIII (*Additional Information*). There has been no material change to the Premier Group's total capitalisation and indebtedness since 31 October 2020.

3. Capitalisation

	As at 31 October 2020 $ million (unaudited)
Current debt	
Guaranteed[1]	2,168.4
Secured	—
Unguaranteed/ Unsecured	—
Total current debt	**2,168.4**
Non-current debt	
Guaranteed	—
Secured	—
Unguaranteed/ Unsecured	—
Total non-current debt	**—**
Shareholders' equity[2]	
Share capital	170.5
Share premium account	516.9
Other reserves	343.1
Total shareholders' equity	**1,030.5**
Total capitalisation	**3,198.9**

(1) This comprises obligations under the RCF, USPP Notes, Schuldschein Loan Agreements and Retail Bond notes. All of this debt is current due to a maturity date of 31 May 2021 for all facilities. The carrying amounts presented are gross of unamortised debt fees.

(2) Other reserves comprise a merger reserve, capital redemption reserve, translation reserve and hedge reserve.

4. Net indebtedness

The following table sets out the Premier Group's net financial indebtedness as at 31 October 2020.

	As at 31 October 2020 $ million (unaudited)
Cash	117.9
Cash equivalents	—
Trading securities	—
Liquidity	**117.9**
Current financial receivable	**—**
Current bank debt(1)	1,973.4
Bonds issued(2)	195.0
Current portion of non-current debt	—
Other current financial debt	—
Current financial debt	**2,168.4**
Net current financial indebtedness	**(2,050.5)**
Non-current bank loans	—
Bonds issued	—
Other non-current debt	—
Non-current financial indebtedness(3)	**—**
Net financial indebtedness	**(2,050.5)**

(1) This comprises the Premier Group's Super Senior RCF, Senior RCF, Term Loans, USPP Notes and Converted Facility Agreement. The debt liabilities have been classified as current due to the maturity of each facility being at 31 May 2021.

(2) This comprises the Premier Group's Retail Bonds. The bond liabilities have been classified as current due to a maturity date of 31 May 2021.

(3) The Premier Group's letter of credit facilities in respect of future decommissioning obligations are not recognised in the Premier Group's balance sheet and are excluded from the indebtedness table above. The Premier Group's lease liabilities are not included in the table above as they do not represent borrowings within the definitions of the Premier Group's Override Agreement.

The Premier Group had no indirect or contingent indebtedness at 31 October 2020.

5. Capital resources and liquidity

5.1 Liquidity

Premier seeks to have sufficient liquidity to underpin the Premier Group's capital investment programme and to access new opportunities for future growth. The Premier Group seeks to maintain a disciplined approach to spending each year and where necessary will seek farm-in partners for drilling programmes and development projects to maintain this discipline.

The Premier Group monitors its funding position and its liquidity risk throughout the year to ensure it has access to sufficient funds to meet forecast cash requirements. Cash forecasts are regularly produced based on, among other things, the Premier Group's latest life of field production and expenditure forecasts, management's best estimate of future commodity prices (based on recent forward curves, adjusted for the Premier Group's hedging programme) and the Premier Group's borrowing facilities. Sensitivities are run to reflect different scenarios including, but not limited to, changes in oil and gas production rates, possible reductions in commodity prices and delays or cost overruns on major development projects. This is done to identify risks to liquidity and covenant compliance and enable management to formulate appropriate and timely mitigation strategies.

In the second quarter of 2020, forecasts showed a possibility that the Premier Group would not comply with the Net Leverage Ratio or the Interest Cover Ratio in respect of the 12 month testing period ended 30 June 2020. The Premier Group's financial statements for the financial period ending 30 June 2020 subsequently showed that the Premier Group would have breached both financial covenants if a deferral had not been obtained under the Stable Platform Agreement. This deferral was subsequently renewed and extended to cover the 12 month testing period ended 30 September 2020 under the Support Letter.

5.2 Cash flows

Premier aims to maximise cash flow from operations in order to maintain financial strength, so as to meet its debt obligations, invest in the future of the business and deliver long-term returns to shareholders. Premier's cash flows are protected by a rolling forward hedging programme.

The following table sets forth the consolidated cash flow statements of the Premier Group for the financial years ended 31 December 2017, 2018 and 2019.

	2017	*2018*	*2019*
	US$m	*US$m*	*US$m*
Net cash from operating activities	**496.0**	**722.8**	**1,108.7**
Investing activities:			
Capital expenditure	(275.6)	(279.8)	(241.4)
Decommissioning pre-funding	(16.7)	(17.8)	(9.9)
Decommissioning expenditure	(25.7)	(72.7)	(35.3)
Receipts for sublease income	—	—	20.2
Proceeds from disposal of oil and gas properties	202.3	73.4	4.2
Net cash used in investing activities	**(115.7)**	**(296.9)**	**(262.2)**
Financing activities:			
Proceeds from issuance of Ordinary Shares	0.8	13.8	4.7
Net release/(purchase) of ESOP Trust shares	(0.2)	(1.5)	1.1
Warrant cash consideration	—	—	(13.8)
Proceeds from drawdown of long-term bank loans	45.0	105.0	—
Debt arrangement fees	(86.0)	—	—
Repayment of long-term bank loans	0	(415.3)	(399.7)
Lease liability payments	0	—	(224.7)
Interest paid	(223.7)	(228.7)	(251.9)
Net cash from financing activities	**(264.1)**	**(526.7)**	**(884.3)**
Currency translation differences relating to cash and cash equivalents	(6.7)	(20.0)	(8.7)
Net (decrease)/increase in cash and cash equivalents	**109.5**	**(120.8)**	**(46.5)**
Cash and cash equivalents at the beginning of the year	255.9	365.4	**244.6**
Cash and cash equivalents at the end of the year	**365.4**	**244.6**	**198.1**

The following table sets forth the consolidated cash flows of the Premier Group for the six-month periods ended 30 June 2019 and 30 June 2020.

	Six months ended 30 June 2019	*Six months ended 30 June 2020*
	US$m	*US$m*
Net cash from operating activities	**544.6**	**323.7**
Investing activities:		
Capital expenditure	(103.3)	(140.5)
Decommissioning pre-funding	(5.2)	(3.8)
Decommissioning expenditure	(24.3)	(21.7)
Receipts of sublease income	13.8	13.3
Proceeds from disposal of oil and gas properties	3.1	(2.6)
Net cash used in investing activities	**(115.9)**	**(155.3)**
Financing activities:		
Proceeds from issuance of Ordinary Shares	3.8	30.2
Net release/(purchase) of ESOP Trust shares	1.0	0.2
Warrant cash consideration	(11.9)	—
Repayment of long-term bank loans	(169.7)	(52.3)
Lease liability payments	(111.9)	(94.1)
Interest paid	(127.5)	(105.1)
Net cash from financing activities	**(416.2)**	**(221.1)**
Currency translation differences relating to cash and cash equivalents	(3.6)	(5.7)
Net (decrease)/increase in cash and cash equivalents	**8.9**	**(58.4)**
Cash and cash equivalents at the beginning of the period	244.6	198.1
Cash and cash equivalents at the end of the period	**253.5**	**139.7**

(A) Net cash from operating activities

The increase in operating cash flows in 2019 was driven by increased production and revenue in the period and due to US$204.5 million of lease cash costs (net) in 2019 being recorded as financing and not operating cash flows. The reduction in 1H 2020 operating cash flows was due to a reduction in average oil and gas prices realised in the period compared to the corresponding period in 1H 2019.

(B) Net cash used in investing activities

Development expenditure in 2019 primarily related to the BIG-P development in Indonesia and the Tolmount project in the UK, in addition to appraisal drilling for the Zama project in Mexico.

5.3 Funding structure

(A) Equity financing

As at the Latest Practicable Date, Premier has issued 925,532,676 Ordinary Shares (all of which are fully paid). The Ordinary Shares currently have a nominal value of 12.5 pence each (which will be reduced to 0.0001 pence each following the Subdivision).

(B) Debt financing

The Premier Group's borrowings as at 31 December 2019 amounted to US$2,187.9 million (2018: US$2,575.3 million). The Premier Group's net accounting debt position as at 31 December 2019 was US$1,989.8 million (2018: US$2,330.7 million) including cash resources of US$198.1 million (2018: US$244.6 million) as summarised below.

	2017	*2018*	*2019*
	US$m	*US$m*	*US$m*
Cash and cash equivalents	365.4	244.6	198.1
Convertible bonds	(180.5)	—	—
Other long-term debt	(2,909.1)	(2,575.3)	(2,187.9)
Net debt	(2,724.2)	(2,330.7)	(1,989.8)

Further details of the Premier Group's borrowings are set out in Part II (*Details of the Debt Restructuring*).

5.4 Funding and treasury policies

(A) Commodity price hedging

Oil and gas price commodity hedging is undertaken using swaps, options, collar options, reverse collars, collar structures, hedges embedded in long-term crude offtake agreements and selling forward using fixed price sales contracts. Oil is hedged using Dated Brent oil price swaps and options. Indonesian gas is hedged using HSFO Singapore 180cst which is the variable component of the gas price and UK gas is hedged by selling gas forward through fixed price contracts and through UK NBP gas swaps and options.

(B) Foreign exchange hedging

The Premier Group's functional and reporting currency is US dollars. However, the Premier Group's primary foreign exchange exposure is to GBP due to its large UK asset base. The Premier Group policy is to sell US dollars and purchase GBP forward up to six months based on forecast expenditure. The Premier Group currently has relatively small exposures to Euros; these are covered by selling US dollars on a spot basis.

As at 31 December 2019, the Premier Group recorded a mark-to-market gain of US$6.2 million on its outstanding foreign exchange contracts (2018: loss of US$2.1 million). The Premier Group had £150.0 million retail bonds, €60.0 million long-term senior loan notes and a £100.0 million term loan in issue which have been hedged under cross currency swaps in US dollars at average fixed rates of US$1.64:£ and US$1.37:€.

(C) Applicable interest rates

As at 31 December 2019, 73 per cent. of the Premier Group's total borrowings is fixed or has been fixed using the interest rate swap markets. On average, the cost of drawn funds for the year was 8.2 per cent. Mark-to-market charges on interest rate swaps amounted to US$0.9 million (2018: US$3.6 million), which are recorded as movements in other comprehensive income.

The Premier Group's exposure to interest rates is managed by maintaining an appropriate mix of both fixed and floating interest rate borrowings within its debt portfolio. However, given the very low level of fixed interest rates available relative to historical rates, a substantial portion of the current drawings have been converted to fixed interest rates using the interest rate swap and option markets.

5.5 Restrictions on use of capital resources

The Premier Group is subject to restrictive covenants under the Existing Debt Facilities, restricting the ability of the Premier Group, without the consent of its creditors, to, amongst other things: incur additional debt; make certain payments, including dividends and other distributions, with respect to outstanding share capital; repay or redeem subordinated debt or share capital; create or incur certain liens; make certain acquisitions and investments or loans; sell, lease or transfer certain assets, including shares of any of Premier's restricted subsidiaries; incur expenditure on exploration and appraisal activities in excess of approved levels; guarantee certain types of the Premier Group's other indebtedness; expand into unrelated businesses; merge or consolidate with other entities; or enter into certain transactions with affiliates.

5.6 Principal investments

The Premier Group's capital investment from 1 January 2017 to 31 December 2019 principally related to the development of the Catcher and Tolmount fields.

To the extent that Premier sanctions significant new development projects, it is expected that funding would come from one or more of the following sources: existing facilities; new equity raised; partner funding (i.e., a farm down in exchange for a carry) or third party funding arrangements.

PART VI

SECTION A: OPERATING AND FINANCIAL REVIEW RELATING TO THE CHRYSAOR GROUP

The following discussion and analysis is intended to assist in providing an understanding of the Chrysaor Group's financial condition and results of operations as at and for the years ended 31 December 2017, 2018 and 2019 and as at and for the six months ended 30 June 2020 and 2019.

The financial information as at and for each of the years ended 31 December 2017, 2018 and 2020 and as at and for the six months ended 30 June 2020 and 2019 has been derived from the historical financial information relating to the Chrysaor Group included in Section B of Part VIII of this Prospectus

The Chrysaor's Group's legal interest and effective working interest in the relevant fields and license areas are separately disclosed in Part IV (Information on the Chrysaor Group).

Where gross amounts are indicated, they are presented on a total project basis—i.e., the total interest of all relevant license holders in the relevant fields and license areas without deduction for the economic interest of the Chrysaor Group'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 Chrysaor's Group to differ from those expressed or implied by such forward looking statements. These risks and uncertainties are discussed in the section of this document headed "Risk Factors" and elsewhere in this document. See "forward looking statements" in the section of this document headed "Important Information".

Overview

Chrysaor is an independent UK North Sea oil and gas exploration and production company with assets located primarily on the UKCS. Since its inception in 2007, it has grown organically and through acquisitions. This includes the acquisition of certain UK oil and gas assets from Shell for US$3 billion in 2017 and ConocoPhillips for US$2.675 billion in 2019. Chrysaor's portfolio consists of generally high quality, mid-life oil and gas assets. It is operator of the Greater Britannia Area, the J-Area and the Armada, Everest and Lomond production hubs and also has non-operated interests in some of the UK's largest producing fields, including Elgin-Franklin (where Premier is also a partner), Buzzard and Clair.

As at 30 June 2020, Chrysaor had 2P reserves of 490.7 mmboe. Production for the half year ended 30 June 2020 averaged 187 kboepd (2019: 123 kboepd) and is forecast by Chrysaor to average between 170 and 180 kboepd for the year ending 31 December 2020.

For the years ended 31 December 2017, 31 December 2018 and 31 December 3019 the Chrysaor Group had revenue of US$313.5 million, US$1,965.6 million and US$2,357.8 million, respectively, gross profit of US$123.4 million, US$844.7 million and US$850.3 million, respectively, and operating profit of US$45.1 million, US$802.2 million and US$762.5 million, respectively. For the six months ended 30 June 2020, the Chrysaor Group had revenue of US$1,230.1 million, gross profit of US$225.6 million and an operating loss of US$180.5 million.

Key Factors Affecting the Chrysaor Group's Historical and Future Results of Operations

Covid-19

Chrysaor took early action to address and mitigate the effect of Covid-19 with the Chrysaor Group continuing to perform well both operationally and financially during 2020.

In February 2020, the Chrysaor Group initially mobilised its crisis management team and business continuity team with responses being managed through these in parallel with normal business operations. The priority was to ensure the ongoing safety of the workforce and continuing operations.

In March, the Chrysaor Group decided to suspend operated drilling activity for 6 months which deferred a significant level of capital expenditure into 2021. The Chrysaor Group resumed operated drilling activities across in September. The decommissioning of wells continued through the year.

During the Covid-19 period, Chrysaor's recovery team has prioritised the safety and wellbeing of our workforce ensuring adherence to both the UK and Scottish Governments' legislation and guidance. There has been a minimal level of staff in onshore offices. For offshore operations, activities testing, tracking and training procedures are in place. Onshore, same-day testing is available at the pre-mobilisation point. Offshore, testing machines have been installed at all offshore operated assets and medical staff have had the appropriate training. The Chrysaor Group continues to prioritise and manage the recovery phase to ensure all our facilities are ready to support an increase in our offshore activity

Price of oil and gas

The prevailing price of crude oil and gas significantly affects the Chrysaor Group's operations and also affects the levels of its oil and gas reserves estimates, which in turn impact its depreciation, depletion and amortization. The Chrysaor Group'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 the Chrysaor Group'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 to the Chrysaor Group's entitlement reserves estimates can 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. Production from US shale oil producers and increased production from Russia have further increased volatility in commodity prices.

The Chrysaor Group's 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. The average Brent crude oil quoted price decreased by US$25.88 per barrel, or 39 per cent., to US$40.07 per barrel for the six months ended 30 June 2020 from US$65.95 per barrel for the six months ended 30 June 2019. The average Brent crude oil quoted price decreased by US$7.10 per barrel, or 10 per cent., to US$64.21 per barrel for the year ended 31 December 2019 from US$71.31 per barrel for the year ended 31 December 2018. The average Brent crude oil price increased by US$17.12 per barrel, or 32 per cent., to US$71.31 per barrel for the year ended 31 December 2018 from US$54.19 per barrel for the year ended 31 December 2017.

	Year ended 31 December			*Six months ended 30 June*	
(in US$/bbl)	**2017**	**2018**	**2019**	**2020**	**2019**
Average price for the period	54.19	71.31	64.21	40.07	65.95
Highest price for the period	66.54	86.16	74.69	69.96	74.69
Lowest price for the period	44.28	50.21	52.34	13.24	53.24

Source: Platts Crude Oil Marketwire Dated Brent PCASS00

The Chrysaor Group's 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 average UK NBP quoted price decreased by 50 per cent. from 38.89 pence per therm for the six months ended 30 June 2019 to 18.92 per therm for the six months ended 30 June 2020. The average UK NBP quoted price decreased by 42 per cent. from 59.77 pence per therm year ended 31 December 2018 to 34.67 per therm for the year ended 31 December 2019. The average UK NBP quoted price increased by 34.2 per cent. from 44.74 pence per therm for the year ended 31 December 2017 to 59.77 per therm for the year ended 31 December 2018.

The following table sets forth information on UK NBP gas prices for the years ended 31 December 2017, 2018 and 2019 and for the six months ended 30 June 2019 and 2020.

	Year ended 31 December			*Six months ended 30 June*	
(in pence/therm)	*2017*	*2018*	*2019*	*2020*	*2019*
Average price for the period	44.74	59.77	34.67	18.92	38.89
Highest price for the period	67.25	229.50	60.90	30.55	60.91
Lowest price for the period	24.95	31.65	19.18	8.55	23.78

Source: ICIS European Spot Gas Markets Heren Day-ahead bid

Production volumes

In addition to oil and gas prices, production volumes are a primary revenue driver. The Chrysaor Group's production levels also affect the level of its reserves and depreciation, depletion and amortisation. The volume of the Chrysaor Group'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, future oil and gas prices) are beyond the Chrysaor Group's control and therefore these estimates may prove to be incorrect over time.

The following table sets forth information on the Chrysaor Group's oil and gas production and sales volumes for the years ended 31 December 2017, 2018 and 2019 and for the six months ended 30 June 2019 and 2020.

	Year ended 31 December			*Six months ended 30 June*	
(in pence/therm)	*2017*	*2018*	*2019*	*2020*	*2019*
Average price for the period	44.74	59.77	34.67	18.92	38.89
Highest price for the period	67.25	229.50	60.90	30.55	60.91
Lowest price for the period	24.95	31.65	19.18	8.55	23.78

* Figures for 2017 represent the daily production figures since the period of ownership from 1 November 2017

Reserves

The Chrysaor Group estimates its reserves using standard recognised evaluation techniques. This estimate is reviewed internally at least annually and is reviewed annually by independent consultants. The Chrysaor Group estimates future development costs by taking into account the level of development required to produce the reserves it has elected to develop and referencing it to similar operations where applicable, reviews by external engineers and the Chrysaor Group's experience. See "*Presentation of reserves and resources*" in the section of this document headed "*Important Information*".

Separately, the depletion of oil and gas assets charged within cost of sales in the Chrysaor Group'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 Chrysaor Group'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 Chrysaor Group'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 would not impact the Chrysaor Group's cash flow, nor its UK tax charges.

Exploration and appraisal success and exploration costs written off or impaired

The Chrysaor Group faces inherent risks in connection with its exploration and appraisal activities. The success or failure of the Chrysaor Group's exploration and appraisal activities will affect the level of its resources recognised and its future development plans for a particular license area. After the acquisition of an exploration license, exploration and evaluation costs (e.g. 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 Chrysaor Group's intangible assets is reviewed at least annually and, when appropriate, values are impaired or written off if the asset is not expected to make a sufficient economic return from the investment (e.g., if an exploration well is dry or has insufficient reserves to be commercial).

For the years ended 31 December 2017, 2018 and 2019 the Chrysaor Group wrote off costs totalling US$7.3 million, US$10.7 million and US$0.2 million, respectively, and for the six months ended 30 June 2019 and 2020 the Chrysaor Group wrote off costs totalling US$0.1 million and US$38.9 million, respectively, in relation to its intangible exploration and evaluation assets following unsuccessful exploration and appraisal activities.

The Chrysaor Group'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 of the Chrysaor Group's income statement. The Chrysaor Group accounts for such write offs using the successful efforts method of accounting. In line with the successful efforts method of accounting, all license acquisition, exploration and evaluation costs are initially capitalised as intangible oil and gas assets in cost centres by field or exploration area, as appropriate, pending determination of commerciality of the relevant property. Directly attributable administration costs are capitalised insofar as they relate to specific exploration activities. Pre-license costs and general exploration costs not specific to any particular license 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 once the field comes into production. 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 Chrysaor Group's depletion and amortisation accounting policy. See "*—Critical accounting estimates and judgments— Exploration and evaluation expenditure*."

Development and production success and impairment

The Chrysaor Group faces inherent risks in connection with its development and production activities. These risks include the difference between estimated and actual reserves, its cost efficiency in development, timing of production activities and its level of production. The Chrysaor Group reviews its development and production projects at least annually for indicators of impairment. In the event that such an indicator does exist, the Chrysaor Group 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, it records any impairment to its income statement.

For each of the years ended 31 December 2017, 2018 and 2019, the pre-tax impairment charges in respect of the Chrysaor Group's tangible oil and gas assets and goodwill was US$ nil and for the six months ended 30 June 2019 and 2020, the pre-tax impairment charges in respect of its tangible oil and gas assets and goodwill were US$ nil and US$306.3 million, respectively. For the six months ended 30 June 2020, the impairments were in relation to older gas assets.

Acquisitions and disposals

If the Chrysaor Group elects to divest an asset, it could impact several items in its 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 the Chrysaor Group enters the development phase of a project with a high equity stake and decides to farm-out a portion of the equity in that license 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 the Chrysaor Group's production volumes and revenues.

The Chrysaor Group's results also may 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 during the periods presented included, among others, those set forth below.

- January 2017: Entered into sale and purchase agreements with Shell to acquire (1) the vendor subsidiary company BG International (CNS) Ltd (later renamed Chrysaor North Sea Limited), which held interests in the Armada hub, Elgin-Franklin & Glenelg fields and a small interest in the Everest field; and (2) Shell's remaining interest in Everest and its interests in Lomond, Erskine, Buzzard, Beryl, J-Area, Schiehallion and Bressay fields. The transactions all completed on 1 November 2017. See "*—the Shell Acquisition*"
- March 2018: Entered into agreement with Spirit Energy to acquire its entire interests in the Armada, Maria and Seymour fields, taking the Chrysaor Group's overall equity interest in the Armada Area to 100 per cent.. The transaction completed on 1 June 2018.
- March 2018: Entered into a sale and purchase agreement with OKEA A.S. to acquire a 15 per cent. non-operated interest in License PL038D, which wholly contains the Grevling discovery located in the Norwegian North Sea. The transaction completed on 15 November 2018.
- April 2019: Entered into a put and call option agreement with ConocoPhillips to acquire its UK oil and gas business through the acquisition of its subsidiaries ConocoPhillips Holdings Limited and Burlington Resources (UK) Holdings Limited. The transaction completed on 30 September 2019. See "*–the COP Acquisition*"
- April 2019: Entered into an agreement with Apache Corporation to farm-in to five licenses in the Beryl Area.

As at 30 June 2020, the Chrysaor Group had no appraisal and or/development assets held for sale.

The Shell Acquisition

In November 2017, the Chrysaor Group completed the acquisition of interests in the Armada hub and Elgin-Franklin, Glenelg, Everest, Lomond, Erskine, Buzzard, Beryl, J-Area, Schiehallion and Bressay fields from Shell for US$3.0 billion. The effective date of the acquisition was 1 July 2016. The consideration payable was US$2,414.0 million, comprising cash consideration of US$2,175.1 million, deferred consideration of US$213.6 million payable over one year and contingent consideration of US$25.3 million payable over four years up to 31 December 2021.

Shell provided junior debt financing for the transaction (the "**Chrysaor Junior Facility**"), and entered into a hydrocarbon lifting and sales agreement with Chrysaor covering volumes produced from the licenses being acquired. Shell also retained a fixed decommissioning liability of approximately US$973 million, reducing Chrysaor's future decommissioning cost obligations.

The Chrysaor Group benefits from the value of the hydrocarbons produced from the interests it acquired in the Shell Assets as well as income generated from pipeline and processing tariffs.

The aggregate fair value of the identifiable assets and liabilities was US$1,920.6 million which was lower than the purchase consideration of the acquired assets, and so positive goodwill of US$493.5 million was recognized in the financial statements for the year ended 31 December 2017 and as finalised in the financial statements for the year ended 31 December 2018.

As at 31 December 2016, the Chrysaor Group had unutilised losses of US$1,074 million for which no associated deferred tax was recognised. Following completion of the Shell Acquisition, the Chrysaor Group's foreseeable future taxable profits increased sufficiently to allow previously unrecognised deferred tax associated with pre-acquisition losses to be recognised in full.

The Chrysaor Group has accounted for the Shell Acquisition as a business combination using the purchase method of accounting in accordance with IFRS 3, which involved measuring the cost of the Shell Acquisition and allocating it to identifiable assets acquired, equity instruments issues and identifiable liabilities assumed measured at their fair value as of the date at completion. From 1 November 2017, the date of acquisition, to 31 December 2017, the Shell Assets contributed US$313.5 million to the Chrysaor Group's revenues and US$212.8 million to its EBITDAX. The acquisition completed close to the reporting date and the historic data available to the Chrysaor Group as at the date of this report means it has not been practicable to determine a reliable estimate of what the results of the Chrysaor Group would have been had the acquisition occurred at the beginning of the accounting period. For more information on the Shell Acquisition, see paragraph 8.2 in Part XIII (*Additional Information*).

The COP Acquisition

In September 2019, the Chrysaor Group completed the acquisition of the UK upstream oil and gas assets and associated infrastructure interests owned by ConocoPhillips Holdings Limited (the "**Conoco Acquisition**") and Burlington Resources (UK) Holdings Limited (the "**Burlington Acquisition**" and together with the Conoco Acquisition, the "**COP Acquisition**") for US$2.675 billion. The effective date of the COP Acquisition was 1 January 2018. The total consideration payable of US$2,521.5 million comprised cash payments of US$2,430.0 million, plus additional completion adjustments of US$91.5 million payable in instalments over four years.

Through the COP Acquisition, Chrysaor took over operatorship of two additional production hubs: the Greater Britannia Area and J-Area in the UK Central North Sea. It also acquired assets in the East Irish Sea, together with a non-operated interest in the Clair Field, West of Shetland. Through the interests acquired pursuant to the COP Acquisition, the Chrysaor Group benefits from the value of the hydrocarbons produced from the fields comprising the acquired assets as well as income generated from pipeline and processing tariffs.

The aggregate fair value of the identifiable assets and liabilities was US$1,613.1 million which was lower than the purchase consideration of the acquired assets, and so positive goodwill of US$908.4 million was recognized in the consolidated statement of income for the year ended 31 December 2019.

The Chrysaor Group has accounted for the COP Acquisition as a business combination using the purchase method of accounting in accordance with IFRS 3, which involved measuring the cost of the acquisition and allocating it to identifiable assets acquired, equity instruments issues and identifiable liabilities assumed measured at their fair value as at the date of completion. From 30 September 2019, the date of acquisition, to 31 December 2019, the acquired assets contributed US$264.6 million to the Chrysaor Group's revenues, US$88 million loss to the Chrysaor Group's profit before tax and US$176.5 million to its EBITDAX. Had the increased equity interests from the COP Acquisition been in effect from 1 January 2019, the impact on the results for the year ended 31 December 2019 would have been an increase in revenues of US$1.0 billion, a decrease in profit before tax/EBITDAX of US$32.4 million and an increase in EBITDAX of US$766.0 million. For more information on the COP Acquisition, see paragraph 8.2 in Part XIII (*Additional Information*).

Operating costs

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 variable operating costs. The main variable operating costs that affect the Chrysaor Group'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 Chrysaor Group'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 programs 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 Chrysaor Group's results are affected by movements in commodity prices and foreign currency exchange. The Chrysaor Group's commodity hedging policy is to hedge predominantly by way of swaps and collar instruments. The Chrysaor Group's ability to hedge by way of instruments with an uncapped contingent credit exposure (i.e. swaps) is subject to the following limits (based on a percentage of the lending banks' forecast production from producing assets):

Commodity swap hedging limits	*Volume*
From the bi-annual hedging test date for a period of 12 months	70%
12 to 24 months from the bi-annual hedging test date of the relevant transaction	60%
24 to 36 months from the bi-annual hedging test date of the relevant transaction	50%
36 to 48 months from the bi-annual hedging test date of the relevant transaction	40%

Interest rates

The Chrysaor Group's exposure to the risk of changes in market interest rates relates primarily to its borrowings under the Chrysaor Existing RBL Facility which has a LIBOR-linked interest rate. Under its interest rate hedging policy, the Chrysaor Group manages this risk by monitoring its exposure to fluctuations in interest rates and may use interest rate derivatives to manage the fixed and floating composition of its borrowings. The Chrysaor Group may be affected by changes in market interest rates at the time it refinances any of its indebtedness.

Currency exchange rates

The Chrysaor Group's presentational currency is the US dollar.

Each entity in the Chrysaor Group 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 Chrysaor Group are U. S dollar, pound sterling and Norwegian krone. A significant amount of the Chrysaor Group's operating, staffing, and other administration costs are denominated in pounds sterling which will determine 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, the assets and liabilities of the Chrysaor Group's operations 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 the Chrysaor Group's translation reserve.

As a result, the Chrysaor Group's results are affected by changes in the US dollar/pounds sterling exchange rate. See "*Qualitative and quantitative disclosures about market risk—Foreign currency risk management*."

Taxation

Taxation can have a significant impact on the Chrysaor Group's results of operations.

Deferred tax assets are recognised to the extent that the future benefit from the underlying tax losses carried forward is probable. Relevant tax law is considered as to the availability of the tax losses to offset future income. To determine the future taxable income from which the losses may be deducted, reference was made to the profit forecasts for the Chrysaor Group as at 31 December 2019. These profit forecasts showed sufficient future taxable income to recognise the deferred tax asset.

As at 31 December 2019, the Chrysaor Group had tax losses, mainly from non-ring fence activities, of US$132.4 million that may potentially be available for offset against future taxable profits in the companies in which the losses arose. An associated deferred tax asset of US$27.7 million has not been recognised in respect of these losses as they may not be used to offset taxable profits elsewhere in the Chrysaor Group due to uncertainty of recovery. The Chrysaor Group has recognised a deferred tax asset of US$2.0 million in relation to tax losses only to the extent of anticipated future taxable profits. The Chrysaor Group has not recognised a deferred tax asset of US$2.8 million in relation to accelerated capital allowances on the basis that the deferred tax asset will not be recoverable in the foreseeable future.

As at 30 June 2020, the Chrysaor Group had tax losses, mainly from non-ring fence activities, of US$135.6 million (2019: US$132.4 million) a portion of which may potentially be available for offset against future taxable profits in the companies in which the losses arose. An associated deferred tax asset of US$28.0 million (2019: US$27.7 million) has not been recognised in respect of these losses as they may not be used to offset taxable profits elsewhere in the Chrysaor Group due to uncertainty of recovery. The Chrysaor Group has recognised a deferred tax asset of US$2.0 million (2019: US$2.0 million) in relation to tax losses only to the extent of anticipated future taxable profits.

The Chrysaor Group has not recognised a deferred tax asset US$5.6 million (2019: US$2.8 million) in relation to accelerated capital allowances, or a deferred tax asset of US$0.8 million (2019: nil) in relation to fair value movements on derivatives, on the basis that the deferred tax assets will not be recoverable in the foreseeable future.

The Chrysaor Group's taxation is also affected by tax incentive programs such as investment allowances. These allowances allow the Chrysaor Group to offset UK supplementary charge (10 per cent. since 1 January 2016) based on yearly allowances tied to the Chrysaor Group's production and investment expenditures.

The Chrysaor Group is subject to various tax claims which arise in the ordinary course of its business, including tax claims from tax authorities in the jurisdictions in which it operates. The Chrysaor Group 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.

The Chrysaor Group may also be affected by how taxes impact its counterparties and contracts.

Description of Key Line Items

Revenue

The Chrysaor Group'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 the Chrysaor Group 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 the Chrysaor Group occurs when title passes at the point the customer takes physical delivery. The Chrysaor Group principally satisfies its performance obligations at this point in time. Revenues from the production of oil and natural gas properties in which it 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.

Cost of sales

The Chrysaor Group's cost of sales consists of field operating costs and other operating costs such as transportation tariffs, depreciation, depletion and amortisation ("**DD&A**") and movements in over/underlift and in hydrocarbon inventories.

The Chrysaor Group's movement in hydrocarbon inventories arise due to differences between volumes produced and sold. Inventories of hydrocarbons are stated at market value. The Chrysaor Group's movement in overlift and underlift arise due to differences between the production sold and its 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 goodwill

The Chrysaor Group assesses, at each reporting date, whether there is an indication that an asset may be impaired. If any indication exists, the Chrysaor Group 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

The Chrysaor Group 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. Impairment losses relating to goodwill cannot be reversed in future periods.

Provision for onerous service contracts

A provision is recognised when the Chrysaor Group 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

The Chrysaor Group's E&E expenses include pre-license costs before the legal right to explore has been acquired, license 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.

Exploration costs written-off

Exploration costs written-off consists of write offs of costs for explorations evaluated to be uncommercial, including license 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 the Chrysaor Group'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.

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. No amortisation is charged during the exploration and evaluation phase.

Re-measurements

The Chrysaor Group re-measurements include fair value changes in potential contingent consideration and re-measurements of the future value attributed to certain royalty streams.

General and administrative expenses

The Chrysaor Group's general and administrative costs consist of costs for its head office staff and other costs net of the recharge of costs to the Chrysaor Group's asset activities, commercial partners and therefore reflects the net costs associated with corporate activities of the Chrysaor Group. With respect to certain of its operated assets, the Chrysaor Group's commercial partnership agreements allow it to charge back its expenses as operator to its partners at specified percentages and subject to certain conditions. These agreements typically allow the Chrysaor Group 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 and foreign exchange gains.

Finance expenses

Finance expenses include the Chrysaor Existing RBL Facility, the Chrysaor Junior Facility and loan notes interest payables, 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)/credit

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 the Chrysaor Group 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 sheet 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, that same tax authority permits the Chrysaor Group to make a single net payment and there is an intention to do so.

Results of Operations

The following table summarises the Chrysaor Group's results of operation for the six months ended 30 June 2020 and 2019 and the years ended 31 December 2017, 2018 and 2019.

	For the year ended 31 December			*For the six-months ended 30 June*	
	2017	*2018*	*2019*	*2020*	*2019 (unaudited)*
			(US$ millions)		
Revenue	313.5	1,965.6	2,357.8	1,230.0	1,055.0
Other income	—	—	9.0	13.6	—
Revenue and other income	313.5	1,965.6	2,366.8	1,243.6	1,055.0
Cost of sales	(190.1)	(1,120.9)	(1,516.5)	(1,018.0)	(568.4)
Gross profit	**123.4**	**844.7**	**850.3**	**225.6**	**486.6**
Impairment of property, plant and equipment	—	—	—	(250.6)	—
Impairment of goodwill	—	—	—	(55.7)	—
Provision for onerous service contracts	—	—	—	(27.9)	—
Exploration and evaluation expenses	(11.3)	(7.9)	(15.1)	(4.2)	(8.1)
Exploration costs written-off	(7.3)	(10.7)	(0.2)	(38.9)	(0.1)
Loss on disposal of exploration and evaluation asset	—	—	—	(0.1)	—
Remeasurements	(30.2)	0.8	3.0	0.5	(21.3)
General and administrative expenses	(29.5)	(24.7)	(75.5)	(29.2)	(22.2)
Operating profit /(loss)	**45.1**	**802.2**	**762.5**	**(180.5)**	**434.9**
Finance income	0.3	46.5	31.6	105.1	10.2
Finance expenses	(44.9)	(270.3)	(338.6)	(148.8)	(121.4)
Profit/(loss)before taxation	**0.5**	**578.4**	**455.5**	**(224.2)**	**323.7**
Income Tax credit/(expense)	258.5	(209.5)	(236.7)	69.7	(149.3)
Profit/(loss) for the financial period	**259.0**	**368.9**	**218.8**	**(154.5)**	**174.4**

Results of Operations for the six months ended 30 June 2020 compared to the six months ended 30 June 2019

The following table summarises the Chrysaor Group's results of operations for the six months ended 30 June 2019 and 2020.

	For the six months ended 30 June	
	2020	*2019 (unaudited)*
	(US$ millions)	
Revenue	1,230.0	1,055.0
Other income	13.6	—
Revenue and other income	1,243.6	1,055.0
Cost of sales	(1,018.0)	(568.4)
Gross Profit	**225.6**	**486.6**
Impairment of property, plant and equipment	(250.6)	—
Impairment of goodwill	(55.7)	—
Provision for onerous service contracts.	(27.9)	—
Exploration and evaluation expenses	(4.2)	(8.1)
Exploration costs written-off	(38.9)	(0.1)
Loss on disposal of exploration and evaluation asset	(0.1)	—
Remeasurements	0.5	(21.3)
General and administrative expenses	(29.2)	(22.2)
Operating (loss)/profit	**(180.5)**	**434.9**
Finance income	105.1	10.2
Finance expenses	(148.8)	(121.4)
(Loss)/profit before taxation	**(224.2)**	**323.7**
Income tax credit/(expense)	69.7	(149.3)
(Loss)/profit for the financial period	**(154.5)**	**174.4**

Revenue

Revenue for the six months ended 30 June 2020 was US$1,230.0 million, an increase of US$175.0 million, or 16.6 per cent., as compared to US$1,055.1 million for the six months ended 30 June 2019. This increase was principally as a result of increased production volumes due to the COP Acquisition, although this was offset by lower commodity prices in 2020.

Crude oil sales, including realised hedging results, increased to US$722.6 million for the six months ended 30 June 2020 from US$703.4 million for the six months ended 30 June 2019, driven by increased production partially offset by a lower average post-hedge realised oil price. Average post-hedge realised oil prices decreased to US$63.9/boe in the six months ended 30 June 2020 from US$69.1/boe in the six months ended 30 June 2019. Post-hedge realisations are significantly higher compared to the average Brent price of US$40.1/bbl for the six months ended 30 June 2020 and US$66.0/bbl for the six months ended 30 June 2019. Realised oil prices for each of the fields in the Chrysaor Group's portfolio do not strictly follow the Brent crude oil price pattern, with some fields sold at a discount or premium to Brent and under contracts with differing timescales for pricing.

Gas volumes and revenues have increased to revenue of US$413.4 million for the six months ended 30 June 2020 from US$268.2 million for the six months ended 30 June 2019, driven by increased production and offset by lower commodity prices. In the six months ended 30 June 2020, gas production averaged 100 mboepd compared to 51 mboepd in the six months ended 30 June 2019. Average realised gas price for the period decreased to 31 pence/therm for the six months ended 30 June 2020 compared to 39 pence/therm for the six months ended 30 June 2019, in line with the movement in the UK NBP spot gas price.

NGL sales decreased to revenue of US$70.4 million for the six months ended 30 June 2020 from revenue of US$74.2 million for the six months ended 30 June 2019. This decrease was caused by significantly lower prices but offset by the additional volumes from the COP Acquisition.

Tariff and other revenue increased by US$14.6 million to US$23.6 million for the six months ended 30 June 2020 from US$9.2 million for the six months ended 30 June 2019, driven by additional interests from the COP Acquisition.

Cost of sales

Cost of sales for the six months ended 30 June 2020 was US$1,018.0 million, an increase of US$449.6 million, or 79.1 per cent., as compared to US$568.4 million for the six months period ended 30 June 2019. This increase was principally as a result of a corresponding increase in total production on account of the COP Acquisition. Field operating costs less tariff income increased significantly to US$347.5 million for the six months ended 30 June 2020 from US$256.4 million for the six months ended 30 June 2019, with net unit costs decreasing to approximately US$10.2/boe for the six months ended 30 June 2020 from approximately US$11.5/boe for the six months ended 30 June 2019.

DD&A charges on oil and gas assets (including capacity rights) also increased significantly to U$710.7 million for the six months ended 30 June 2020 from US$352.3 million for the six months ended 30 June 2019, with net unit costs increasing to approximately US$20.8/boe for the six months ended 30 June 2020 from approximately US$15.8/boe for the six months ended 30 June 2019.

Gross profit or loss

Gross profit for the six months ended 30 June 2020 was US$225.6 million, a decrease of US$261.1 million, or 53.6 per cent. from US$486.7 million for the six months ended 30 June 2019.

Impairment of property, plant and equipment and goodwill

Impairment expense of property, plant and equipment for the six months ended 30 June 2020 was US$250.6 million compared to nil for the six months ended 30 June 2019. This expense represents a write-down of US$340.4 million on the Chrysaor Group's older gas assets as a result of the Chrysaor Group's revised view of long-term commodity prices, and a pre-tax impairment credit of US$89.8 million in respect of reductions to decommissioning estimates on the Chrysaor Group's non-producing assets. In addition, a goodwill impairment charge of US$55.7 million has been recorded in the period (2019: $nil), also attributable to changes in the Chrysaor Group's assessment of long-term commodity prices.

Provision for onerous service contracts

Provision for onerous service contract for the six months ended 30 June 2020 was US$27.9 million compared to nil for the six months ended 30 June 2019. This provision relates to an onerous lease contract in respect of long-term standby costs on the *Deepsea Aberdeen* rig, which has been operating within the Schiehallion field, whereby no future approved activities have resulted in the rig potentially remaining on standby until the end of the contract in April 2022.

Exploration and evaluation expenses

Exploration and evaluation expenses for the six months ended 30 June 2020 were US$4.2 million, a decrease of US$3.9 million, or 48.1 per cent. from US$8.1 million for the six months ended 30 June 2019. This decrease was principally as a result of a lower level of pre-license expenditure.

Exploration costs written-off

Exploration costs written-off for the six months ended 30 June 2020 were US$38.9 million, an increase of US$38.8 million from $0.1 million for the six months ended 30 June 2019. The increase in exploration costs written-off is primarily due to the write-off of the unsuccessful Mabel well in the Armada hub and lower expenditure related to license relinquishments.

Re-measurements

Re-measurements for the six months ended 30 June 2020 was a credit of US$0.5 million, a decrease of US$21.8 million compared to an expense of US$21.3 million for the six months ended

30 June 2019. The change in re-measurements is primarily due to a credit in respect of an interest in a royalty stream resulting from the disposal of a pre-production development in 2015.

General and administrative expenses

General and administrative expenses for the six months ended 30 June 2020 were US$29.2 million, an increase of US$7.0 million, or 31.5 per cent. compared to US$22.2 million for the six months ended 30 June 2019. This increase was principally as a result of increased business development activity and the materially larger organisation size.

Finance expenses

Finance expenses for the six months ended 30 June 2020 were US$148.8 million, an increase of US$27.4 million, or 22.6 per cent., compared to US$121.4 million for the six months ended 30 June 2019. This increase was principally attributable to no foreign exchange losses in the six months ended 30 June 2020, higher interest expense on the unwinding of discount on decommissioning provision obligations and lease interest expense as a result of the COP Acquisition and higher interest payable on the Chrysaor Existing RBL Facility due to a higher drawn balance offset by lower expense on loan notes following a partial repayment of the loan notes.

Income tax (expense)/credit

Income tax for the six months ended 30 June 2020 resulted in a credit of US$69.7 million compared to an expense of US$149.3 million for the six months ended 30 June 2019. This change was principally associated with loss before taxation driven by the impairment charge. The lower effective tax rate is predominantly due to the impacts of profits subject to tax at different rates, mainly related to the non-taxable expense of the goodwill impairment, the impact of investment allowance, and because of movements in unrecognised deferred tax.

Results of Operations for the year ended 31 December 2019 compared to the year ended 31 December 2018

The following table summarises the Chrysaor Group's results of operation for the years ended 31 December 2018 and 2019.

	For the year ended 31 December	
	2018	*2019*
	(*US$ millions*)	
Revenue	**1,965.6**	**2,357.8**
Other income	—	9.0
Revenue and other income	**1,965.6**	**2,366.8**
Cost of sales	(1,120.9)	(1,516.5)
Gross profit	**844.7**	**850.3**
Exploration and evaluation expenses	(7.9)	(15.1)
Exploration costs written-off	(10.7)	(0.2)
Remeasurements	0.8	3.0
General and administrative expenses	(24.7)	(75.5)
Operating profit	**802.2**	**762.5**
Finance income	46.5	31.6
Finance expenses	(270.3)	(338.6)
Profit before taxation	**578.4**	**455.5**
Income tax expense	(209.5)	(236.7)
Profit for the financial period	**368.9**	**218.8**

Revenue

Revenue for the year ended 31 December 2019 was US$2,357.8 million, an increase of US$392.2 million, or 20.0 per cent., compared to US$1,965.6 million for the year ended 31 December 2018. This increase was principally as a result of increased production volumes due to the COP Acquisition.

Crude oil sales revenue, including realised hedging results, increased to US$1,568.2 million for the year ended 31 December 2019 from US$1,278.6 million for the year ended 31 December 2018, driven by increased production and higher commodity prices. Average post-hedge realised oil prices increased to US$67.9/boe for the year ended 31 December 2019 from US$61.1/boe for the year ended 31 December 2018. In comparison, the Brent crude price averaged US$64/bbl for 2019 compared with US$71/bbl for 2018. Realised oil prices for each of the fields in the Chrysaor Group's portfolio do not strictly follow the Brent crude oil price pattern with some fields sold at a discount or premium to Brent and under contracts with differing timescales for pricing.

Gas volumes and revenues have increased to revenue of US$625.5 million for the year ended 31 December 2019 from US$516.8 million for the year ended 31 December 2018, driven by increased production and offset by lower commodity prices. For the year ended 31 December 2019, gas production averaged 63 mboepd compared to 40 mboepd for the year ended 31 December 2018. Average realised gas price for the year decreased to 36 pence/therm for the year ended 31 December 2019 compared to 43 pence/therm for the year ended 31 December 2018, in line with the movement in the UK NBP spot gas price.

NGL sales decreased to revenue of US$145.5 million for the year ended 31 December 2019 from revenue of US$154.8 million for the year ended 31 December 2018. This decrease was caused by significantly lower realised prices offset by the additional volumes from the COP Acquisition.

Tariff and other revenue increased by US$3.2 million, or 20.8 per cent., to US$18.6 million for the year ended 31 December 2019 from US$15.4 million for the year ended 31 December 2018, driven by additional interests from the COP Acquisition.

Cost of sales

Cost of sales for the year ended 31 December 2019 was US$1,516.5 million, an increase of US$395.6 million or 35.3 per cent. compared to US$1,120.9 million for the year ended 31 December 2018. This increase was principally as a result of a corresponding increase in total production on account of the COP Acquisition. Field operating costs less tariff income increased significantly to US$572.3 million for the year ended 31 December 2019 from US$480.2 million for the year ended 31 December 2018, with net unit costs decreasing to approximately US$11.5/boe for the year ended 31 December 2019 from approximately US$12.6/boe for the year ended 31 December 2018.

DD&A charges on oil and gas assets (including capacity rights) also increased significantly to U$899.6 million for the year ended 31 December 2019 from US$575.3 million for the year ended 31 December 2018, with net unit costs decreasing to approximately US$18.0/boe for the year ended 31 December 2019 from approximately US$15.1/boe for the year ended 31 December 2018.

Exploration and evaluation expenses

Exploration and evaluation expenses for the year ended 31 December 2019 were US$15.1 million, an increase of US$7.2 million or 91.1 per cent. compared to US$7.9 million for the year ended 31 December 2018. This increase was principally as a result of a higher level of pre-license expenditure.

Exploration costs written-off

Exploration costs written-off for the year ended 31 December 2019 were US$0.2 million, a decrease of US$10.5 million or 98.1 per cent. from US$10.7 million for the year ended 31 December 2018. The decrease in exploration costs written-off was primarily due to no unsuccessful wells and lower expenditure related to license relinquishments.

Re-measurements

Re-measurements for the year ended 31 December 2019 was a credit of US$3.0 million, an increase of US$2.2 million or 275.0 per cent. compared to a credit of US$0.8 million for the year ended 31 December 2018. The change in re-measurements was primarily due to two elements: a credit recognised in respect of fair value changes in potential contingent consideration as a result of the Shell Acquisition, linked to higher sustained future commodity prices and exploration success in Beryl and J-Area and a credit in respect of an interest in a royalty stream resulting from the disposal of a pre-production development in 2015.

General and administrative expenses

General and administrative expenses for the year ended 31 December 2019 were US$75.5 million, an increase of US$50.8 million, or 205.7 per cent. compared to US$24.7 million for the year ended 31 December 2018. This increase was principally as a result of pre-completion transition, post-completion integration costs and professional and corporate fees related to the COP Acquisition plus increased underlying corporate costs for the larger group post completion. Furthermore, as at 2019, there was a share-based payment expense of US$10.9 million.

Finance income

Finance income for the year ended 31 December 2019 was US$31.6 million, a decrease of US$14.9 million, or 32.0 per cent., compared to US$46.5 million for the year ended 31 December 2018. This decrease was principally as a result of nil foreign exchange gains partially offset by income from a specific financing agreement with Baker Hughes. This agreement was an innovative deal providing Baker Hughes exposure to risk and return on well performance for which it also provided services and materials as a service company.

Finance expenses

Finance expenses for the year ended 31 December 2019 were US$338.6 million, an increase of US$68.3 million, or 25.2 per cent., compared to US$270.3 million for the year ended 31 December 2018. This increase was principally as a result of attributable to foreign exchange losses and higher interest expense on the unwinding of discount on decommissioning provision obligations offset by lower interest payable on the Chrysaor Existing RBL Facility, the Chrysaor Junior Facility and loan notes.

Income tax expense

Income tax for the year ended 31 December 2019 resulted in an expense of US$236.7 million, an increase of US$27.2 million, or 13.0 per cent., compared to US$209.5 million in the year ended 31 December 2018. This increase was principally as a result of a higher level of unrecognised deferred tax assets and the impact of losses relieved at different rates offset by lower expenses not deductible for tax purposes. Also, in the year ended 31 December 2018 there was a credit in relation to ring fence expenditure supplement compared to nil in the year ended 31 December 2019.

Results of Operations for the year ended 31 December 2018 compared to the year ended 31 December 2017

The following table summarises the Chrysaor Group's results of operation for the years ended 31 December 2017 and 2018. The year ended 31 December 2017 included two months of performance following completion of the Shell Acquisition on 1 November 2017.

	For the year ended 31 December	
	2017	*2018*
	(*US$ millions*)	
Revenue	313.5	1,965.6
Cost of sales	(190.1)	(1,120.9)
Gross profit (loss)	**123.4**	**844.7**
Exploration and evaluation expenses	(11.3)	(7.9)
Exploration costs written-off	(7.3)	(10.7)
Remeasurements	(30.2)	0.8
General and administrative expenses	(29.5)	(24.7)
Operating profit (loss)	**45.1**	**802.2**
Finance income	0.3	46.5
Finance expenses	(44.9)	(270.3)
Profit before taxation	**0.5**	**578.4**
Income tax credit/(expense)	258.5	(209.5)
Profit for the financial period	**259.0**	**368.9**

Revenue

Revenue for the year ended 31 December 2018 was US$1,965.6 million, an increase of US$1,652.1 million, or 527.0 per cent., compared to US$313.5 million for the year ended 31 December 2017. This increase was principally as a result of substantially increased volumes due to the Shell Acquisition and higher realised commodity prices.

Crude oil sales revenue, including realised hedging results, increased to revenue of US$1,278.6 million for the year ended 31 December 2018 from revenue of US$203.6 million in the year ended 31 December 2017 with the acquisition of the Shell Assets driving the increase. Average post-hedge realised oil prices increased to US$61.1/bbl in 2018 from US$59.5/bbl in 2017. This is in line with the average Brent price movement to US$71/bbl for 2018 compared with US$54/bbl for 2017. While realised oil prices for each of the fields in the Chrysaor Group's portfolio do not strictly follow the Brent price pattern, with some fields sold at a discount or premium to Brent and under contracts with differing timescales for pricing, the average realised price for all the fields traded broadly in line with the price of Brent crude oil.

Gas and condensate volumes and revenues both increased significantly to a combined revenue of US$516.8 million for the year ended 31 December 2018 from US$86.0 million for the year ended 31 December 2017. This increase was caused by the additional volumes from the Shell Acquisition. Average realised gas prices remained unchanged, at 43 pence/therm for the years ended 31 December 2017 and 31 December 2018.

NGL sales increase to revenue of US$154.8 million for the year ended 31 December 2018 from revenue of US$23.9 million for the year ended 31 December 2017. This increase was caused by the additional volumes from the Shell Acquisition but offset by lower realised prices.

Tariff and other revenue increased to US$15.4 million for the year ended 31 December 2018 from nil for the year ended 31 December 2017, driven by the Shell Acquisition.

Cost of sales

Cost of sales for the year ended 31 December 2018 was US$1,120.9 million, an increase of US$930.8 million or 489.6 per cent. compared to US$190.1 million for the year ended 31 December 2017.

The increase in cost of sales is as a result of a corresponding increase in total production on account of the Shell Acquisition. Field operating costs less tariff income increased significantly to US$480.2 million for the year ended 31 December 2018 from US$85.8 million for the year ended 31 December 2017, with net unit costs decreasing to approximately US$12.60/boe for the year ended 31 December 2018 from approximately US$15.0/boe for the year ended 31 December 2017. DD&A charges on oil and gas assets (including capacity rights) also increased significantly to US$575.3 million for the year ended 31 December 2018 from US$99.6 million for the year ended 31 December 2017, with net unit costs decreasing to approximately US$15.1/boe for the year ended 31 December 2018 from approximately US$16.7/boe for the year ended 31 December 2017.

Exploration and evaluation expenses

Exploration and evaluation expenses for the year ended 31 December 2018 were US$7.9 million, a decrease of US$3.4 million or 30.1 per cent. compared to US$11.3 million for the year ended 31 December 2017. This decrease was principally as a result of a lower level of pre-license expenditure.

Exploration costs written-off

Exploration costs written-off for the year ended 31 December 2018 were US$10.7 million, an increase of US$3.4million or 46.6 per cent. from US$7.3 million for the year ended 31 December 2017. The increase in exploration costs written-off was primarily due to the acquisition of seismic data in unlicensed areas, particularly in Norway.

Re-measurements

Re-measurements for the year ended 31 December 2018 was a credit of US$0.8 million compared to a charge of US$30.2 million for the year ended 31 December 2017. The change in re-measurements is due to the recognition of a credit relating to the re-measurement of the future value attributed to a royalty stream resulting from the disposal of a pre-production development in 2015. This was partially offset by a lower charge in respect of fair value changes in potential contingent consideration as a result of the Shell Acquisition which was linked to higher sustained future commodity prices and exploration success in Beryl and J-Area.

General and administrative expenses

General and Administrative expenses for the year ended 31 December 2018 were US$24.7 million, a decrease of US$4.8 million, or 16.3 per cent. compared to US$29.5 million for the year ended 31 December 2017. This decrease was principally as a result of expenses incurred in connection with the Shell Acquisition in 2017.

Finance income

Finance income for the year ended 31 December 2018 was US$46.5 million an increase of US$46.2 million from US$0.3 million in the year ended 31 December 2017. This increase was principally as a result of an increase in foreign exchange gains and bank interest receivable. The foreign exchange gain was mainly generated from the movement in foreign exchange rates on a GBP intercompany loan between a pound sterling functional company and U.S. Dollar functional company.

Finance expenses

Finance expenses for the year ended 31 December 2018 were US$270.3 million, an increase of US$225.4 million, or 502.0 per cent., compared to US$44.9 million for the year ended 31 December 2017. This increase was principally as a result of an increase in interest payable on the Chrysaor Existing RBL Facility, the Chrysaor Junior Facility and loan notes for the full year. In 2017, this facility was only required for a portion of the year. In addition, the interest expense for the unwinding of the discount on decommissioning provisions obligations was for a full year in 2018 compared to only two months from acquisition in 2017.

Income tax credit/(expense)

Income tax for the year ended 31 December 2018 resulted in an expense of US$209.5 million compared to a credit US$258.5 million for the year ended 31 December 2017. This change was principally as a result of an increase in deferred UK corporation tax expense relating to the utilisation of deferred tax assets associated with losses recognised following the Shell Acquisition. In 2017, the deferred tax credit was driven by the recognition of tax losses arising from the claiming of previously unutilised capital allowances. As a result of the Shell Acquisition, the future taxable profits of the Chrysaor Group increased sufficiently to allow the previously unrecognised deferred tax asset associated with these losses to be recognised in full.

Liquidity and capital resources

The Chrysaor Group's liquidity requirements arise principally from its capital investment, working capital demands and debt servicing requirements. For the periods presented, the Chrysaor Group met its liquidity requirements primarily from ongoing cash flow generation from its producing assets and debt financing through ongoing drawings under the Chrysaor Existing RBL Facility, the Chrysaor Junior Facility and other loans.

In addition to amounts available under the Chrysaor Group's debt facilities, the Chrysaor Group also held cash and cash equivalents of US$299.5 million, US$316.3 million and US$573.2 million as at 31 December 2017, 2018 and 2019, respectively, and US$289.4 million and US$369.4 million as at 30 June 2019 and 2020, respectively.

Cash flow

The following table presents a summary of the Chrysaor Group's consolidated cash flow for the six months ended 30 June 2020 and 2019 and the years ended 31 December 2019, 2018 and 2017.

	For the year ended 31 December			*For the six months ended 30 June*	
	2017	*2018*	*2019*	*2020*	*2019 (unaudited)*
			US$ millions		
Net cash flows from operating activities	54.0	1,447.8	1,518.7	946.1	774.2
Net cash flows (used in) investing activities	(2,097.5)	(581.9)	(2,776.0)	(363.2)	(526.3)
Net cash flows from/(used in) financing activities	2,339.3	(847.4)	1,508.4	(786.2)	(275.2)
Cash and cash equivalents at the end of the period	299.5	316.3	573.2	369.4	289.4

Net cash flows from operating activities consist of:

	For the year ended 31 December			*For the six months ended 30 June*	
	2017	*2018*	*2019*	*2020*	*2019 (unaudited)*
			US$ millions		
Profit/(loss) before taxation	0.5	578.4	455.6	(224.2)	323.7
Finance cost, excluding foreign exchange	44.0	270.3	256.4	148.8	123.5
Finance income, excluding foreign exchange	(0.3)	(8.6)	(31.6)	(3.5)	(10.2)
Share based payments	—	—	10.9		
Depreciation, depletion and amortisation	100.8	629.2	917.0	723.5	359.3
Impairment of property, plant and equipment	—	—	—	250.6	—
Impairment of goodwill	—	—	—	55.7	—
Credit due to reduction in decommissioning provision	—	(44.5)	—	—	—
Taxes (paid)/received	—	—	(90.1)	6.6	—
Exploration write-off	7.3	10.7	0.2	38.9	0.1
Movement in realised cash-flow hedges not yet settled	—	(0.7)	(23.7)	(34.7)	(8.1)
Remeasurement in commodity-price-contingent consideration	21.4	0.7	7.2	—	22.5
Remeasurement on exploration contingent consideration	—	(0.2)	(7.8)	—	—
Remeasurement of acquisition-completion adjustments	—	—	—	0.4	—
Onerous contract provision	—	—	—	27.9	—
Decommissioning payments	—	(21.5)	(29.0)	(96.6)	(5.3)
Unrealised foreign-exchange loss/(gain)	1.7	(36.9)	63.8	(104.7)	(2.1)
Decrease in royalty consideration receivable	12.2	1.7	0.6	0.8	1.6
Gain on termination of IFRS16 lease	—	—	—	(0.6)	—
Remeasurement on exploration-contingent consideration	—	—	—	—	0.3
Loss on disposal of exploration and evaluation asset	—	—	—	0.1	—
Working-capital adjustments	—	—	—		
Decrease /(increase) in inventories	29.8	1.8	0.2	(9.7)	(4.7)
(Increase)/decrease in trade and other receivables	(193.9)	32.6	(6.1)	202.8	(50.4)
Increase/(decrease) in trade and other payables	30.5	34.8	(4.9)	(36.0)	24.0
Net cash inflow from operating activities	**54.0**	**1,447.8**	**1,518.7**	**946.1**	**774.2**

Net cash generated from operating activities was US$946.1 million for the six months ended 30 June 2020 compared to US$774.2 million generated for the six months ended 30 June 2019. The increase was primarily due to increased operating cashflow from production volumes due to the COP Acquisition.

Net cash generated from operating activities was US$1,518.7 million for the year ended 31 December 2019 compared to US$1,447.8 million generated for the year ended 31 December 2018. The increase was primarily due to increased operating cashflow from production volumes due to the COP Acquisition.

Net cash generated from operating activities was US$1,447.8 million for the year ended 31 December 2018 compared to US$54.0 million generated for the year ended 31 December 2017. The increase was primarily due to an increased operating cashflow from the production volumes due to the Shell Acquisition.

Net cash from/(used in) investing activities

	For the year ended 31 December			*For the six months ended 30 June*	
	2017	*2018*	*2019*	*2020*	*2019 (unaudited)*
			US$ millions		
Expenditure on exploration and evaluation assets	(8.8)	(28.8)	(82.6)	(46.5)	(43.3)
Expenditure on property, plant and equipment	(26.7)	(313.3)	(439.7)	(274.8)	(180.7)
Expenditure on non-oil and gas intangible assets	—	(8.0)	(7.9)	(32.9)	(4.4)
Proceeds from sale of exploration and evaluation asset	—	—	—	—	—
Expenditure on business combinations and acquisitions	(2,062.3)	(240.4)	(2,255.2)	(12.5)	(302.6)
Interest Income	0.3	8.6	9.4	3.5	4.7
Net cash flows used in investing activities	(2,097.5)	(581.9)	(2,776.0)	(363.2)	(526.3)

Net cash used in investing activities was US$363.2 million for the six months ended 30 June 2020, compared to US$526.3 million of net cash used in investing activities for the six months ended 30 June 2019. Cash flows for the six months ended 30 June 2020 included those for the COP Acquisition and legacy portfolio but were lower compared to the six months ended 30 June 2019 due to the impact of COVID-19 and lower commodity prices which resulted in the temporary suspension and deferral of certain drilling activities in the first half of 2020.

Net cash used in investing activities was US$2,776.0 million for the year ended 31 December 2019, compared to US$581.9 million of net cash used in investing activities for the year ended 31 December 2018. The increase was primarily due to the COP Acquisition at the end of the third quarter and capital expenditure on the legacy portfolio plus the portfolio acquired as part of the COP Acquisition.

Net cash used in investing activities was US$581.9 million for the year ended 31 December 2018, compared to US$2,097.5 million of net cash used in investing activities for the year ended 31 December 2017. The cash flows for the year ended 31 December 2018 were primarily associated with capital expenditure on property, plant and equipment mainly spent on J-Area, Beryl, Buzzard, Schiehallion and a drilling campaign in the Armada Area and final payments in full and final settlement of the two sale and purchase agreements in relation to the Shell Acquisition. Cash flows for the year ended 31 December 2017 related primarily to the Shell Acquisition plus capital field expenditure in the two-month period after this acquisition.

Net cash from financing activities

	For the year ended 31 December			*For the six months ended 30 June*	
	2017	*2018*	*2019*	*2020*	*2019 (unaudited)*
			US$ millions		
Repayment of borrowings	—	(735.0)	(200.0)	(634.0)	(200.0)
Proceeds from new financing arrangement	—	20.4	29.6	—	15.0
Proceeds from share issue	67.3	—	—	—	—
Lease payments	—	—	(20.6)	(32.6)	(0.5)
Proceeds from new borrowings	2,272.0	—	1,843.3	2.6	—
Redemption of loan notes	—	—	—	(46.9)	—
Interest paid and bank charges	—	(132.8)	(143.9)	(75.3)	(89.7)
Net cash inflow/(outflow) from financing activities	2,339.3	(847.4)	1,508.4	(786.2)	(275.2)

Net cash used in financing activities was US$786.2 million for the six months ended 30 June 2020, compared to US$275.2 million of net cash used in financing activities for the six months ended 30 June 2019. Cash flows for the year ended 31 December 2018 were primarily associated with repayments of the principle of the Chrysaor Existing RBL Facility from surplus cashflow.

Net cash from financing activities was US$1,508.4 million for the year ended 31 December 2019, compared to US$847.4 million of net cash used in financing activities for the year ended 31 December 2018. Cash flows for 2019 were primarily associated with the proceeds from the refinancing of the Chrysaor Existing RBL Facility to Fund the COP Acquisition.

Net cash used in financing activities was US$847.4 million for the year ended 31 December 2018, compared to US$2,339.3 million of net cash inflows from financing activities for the year ended 31 December 2017. Cash flows for the year ended 31 December 2018 were primarily associated with the repayment of senior debt under the Chrysaor Existing RBL Facility as well as interest paid on the Chrysaor Group's debt facilities. Cash flows for the year ended 31 December 2017 were primarily proceeds from the drawdown of borrowing facilities to be used for the acquisition from Shell.

Capital Resources

The Chrysaor Group's liquidity requirements arise principally from its capital investment, working capital demands and debt servicing requirements. For the periods presented, the Chrysaor Group's met its capital investment, working capital and debt servicing requirements primarily from cash flows from operations and the proceeds of debt financing.

Borrowings and Facilities

As at 30 June 2020, the Chrysaor Group had US$2,165.2 million in total borrowings, principally relating to the Chrysaor Existing RBL facility and the Chrysaor Junior Facility, described below.

Chrysaor Existing RBL Facility

In April 2017, the Chrysaor Group entered into a six -year RBL facility of US$1.5 billion, including a further accordion facility of US$0.5 billion to assist the financing of the Shell Acquisition. The Chrysaor Existing RBL Facility was underwritten and syndicated by five banks, with a further 12 global financial institutions joining the RBL facility during the syndication process. During 2018, the accordion option was exercised, increasing the facility to US$2.0 billion. In June 2019, the Chrysaor Group increased the syndicate to 19 global financial institutions and the facility size to US$3.0 billion (with an option for a further US$1.0 billion accordion) to assist the financing of the COP Acquisition. Subject to the maximum size of the facility, which reduces every six months on a straight-line basis from1 January 2022 to the maturity date of 31 December 2025, the amount available under the facility is determined based on a valuation of the Chrysaor Group's borrowing base assets under certain forward-looking assumptions.

In June 2020, certain other amendments were made to the Chrysaor Existing RBL facility in conjunction with the normal redetermination process. No changes were made to the existing US$3.0 billion facility size, but the debt availability grew to US$2.5 billion, to be redetermined now on an annual basis. Other amendments included the revision of certain governance requirements to be in line with peers, and the incorporation of a margin adjustment linked to carbon-emission reductions. The syndication group now stands at 18 banks.

As at the balance sheet date, the outstanding RBL balance, excluding incremental transaction costs was US$1,500 million and as at 30 June 2020, US$1,030 million remained available for drawdown under the Chrysaor Existing RBL Facility.

Chrysaor Junior Facility

In April 2017, the Chrysaor Group entered into a junior facility of US$400 million. In June 2019 the Chrysaor Junior Facility was extended and amended. As at the balance sheet date, the outstanding junior loan balances, excluding incremental transactions costs, was US$400 million and as at 30 June 2020, the Chrysaor Junior Facility remained fully drawn.

Letters of credit

The Chrysaor Group enters into letters of credit for its obligations in respect of future abandonment liabilities. At 31 December 2019, the Chrysaor Group had US$599 million and at 30 June 2020 had US$528 million in letters of credit outstanding relating to security obligations under certain decommissioning security agreements. The Chrysaor Group does not currently have surety bonds but does have a £3 million letter of credit in respect of a trading security deposit with the National Grid.

Cash and Cash equivalents

As at 30 June 2020, the Chrysaor Group held US$369.4 million, of cash and cash equivalents.

Capital investment

The primary objective of the Chrysaor Group'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. The Chrysaor Group 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.

Capital investment represents the Chrysaor Group's 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 comprises expenditures on property plant and equipment and expenditures on exploration and evaluation. The following table sets forth the Chrysaor Group's capital investments for the years ended 31 December 2017, 2018 and 2019 and for the six months ended 30 June 2020 and 2019.

	For the year ended 31 December			*For the six months ended 30 June*	
	2017	*2018*	*2019*	*2020*	*2019 (unaudited)*
			(US$ millions)		
Property plant and equipment expenditure	44.5	373.7	485.4	238.7	211.1
Non-oil and gas intangible expenditure	13.3	8.0	12.8	33.4	4.4
Exploration and evaluation expenditure.	8.8	28.2	81.8	44.7	43.3
Capital investment	66.6	409.9	580.0	316.8	258.8

The Chrysaor Group's capital investment for the six months ended 30 June 2020 was US$316.8 million. The investment program was centred on the operated assets of, Greater Britannia Area, J-Area and a drilling campaign in the Armada Area and the non-operated assets of Beryl and Buzzard.

The Chrysaor Group's capital investment for the six months ended 30 June 2019 was US$258.8 million. The investment program was centred on the operated assets of J-Area and a drilling campaign in the Armada Area and the non-operated assets of Beryl, Buzzard and Elgin Franklin.

The Chrysaor Group's capital investment in the year ended 31 December 2019 was US$580.0 million. The investment program was centred on the operated assets of, Greater Britannia Area, J-Area and a drilling campaign in the Armada Area and the non-operated assets of Clair, Beryl, Buzzard, Elgin Franklin and Schiehallion.

The Chrysaor Group's capital investment in the year ended 31 December 2018 of US$409.9 million related primarily to property, plant and equipment expenditure mainly spent on a drilling campaign in the operated Armada Area asset and non-operated assets of J-Area, Beryl, Buzzard, Elgin Franklin and Schiehallion.

The Chrysaor Group's capital investment in the year ended 31 December 2017 of US$66.6 million related primarily to property plant and equipment expenditure split between producing assets, with the majority mainly spent on J-Area, Beryl and Schiehallion, and additional amounts spent on fixtures and fittings mainly for information technology infrastructure assets and the fit-out of the Aberdeen office, which opened in October 2017.

Future capital investment

The Chrysaor Group's capital investments are driven largely by full phase expenditure on existing producing fields, new development projects and exploration and appraisal activities. As at 30 June 2020, the Chrysaor Group had commitments for future capital expenditure amounting to US$359.0 million. The key components of this relate to Buzzard Phase 2 drilling, Elgin Franklin FID drilling and further development opportunities within J-Area. As at 31 December 2019, the Chrysaor Group had commitments for future capital expenditure amounting to US$420.5 million. The majority of the planned capital expenditure is spread across all of the assets in the production portfolio as well as on certain pre-development and exploration assets at the front end of the lifecycle.

Contractual obligations and contingent liabilities

The following table sets forth the Chrysaor Group's remaining contractual maturity for its non-derivative financial liabilities with contractual repayment periods as at 30 June 2020. The table reflects the undiscounted cash flows of financial liabilities based on the earliest date on which the Chrysaor Group could be required to pay.

	Payments due by period as of 30 June 2020				
	Total	*Less than 1 year*	*1 to 2 years*	*2 to 5 years*	*Over 5 years*
			(US$ millions)		
Chrysaor Existing RBL Facility	1,738.5	55.8	57.4	1,285.7	339.6
Chrysaor Junior Facility	481.2	22.8	111.6	272.4	74.4
Loan notes(1)	561.8	—			561.8
Other loans(2)	71.2	9.2	18.4	35.8	7.8
Financial liabilities(3)	14.7	0.1	—	9.7	4.9
Lease obligations	171.3	53.6	53.6	30.1	34.0
Short-term payables(4)	780.2	733.8	27.7	18.7	—
Total	3,818.9	875.3	268.7	1,652.4	1,022.5

The following table sets forth the Chrysaor Group's remaining contractual maturity for its non-derivative financial liabilities with contractual repayment periods as at 31 December 2019. The table reflects the undiscounted cash flows of financial liabilities based on the earliest date on which the Chrysaor Group could be required to pay.

	Payments due by period as of 31 December 2019				
	Total	*Less than 1 year*	*1 to 2 years*	*2 to 5 years*	*Over 5 years*
			(US$ millions)		
Chrysaor Existing RBL Facility	2,403.8	713.4	580.8	1,030.5	79.1
Chrysaor Junior Facility	518.0	29.2	29.1	354.1	105.6
Loan notes(1)	660.1	—	—	—	660.1
Other loans(2)	62.9	25.8	13.3	23.8	—
Financial liabilities(3)	44.1	40.5	1.3	2.3	—
Lease obligations	237.5	80.0	72.2	55.0	30.3
Short-term payables(4)	645.4	593.0	32.6	19.8	—
Total	4,571.8	1,481.9	729.3	1,485.5	875.1

(1) Reflects loan notes subscribed for by legacy shareholders and key management as part of the Chrysaor Group's financial restructuring in January 2017. The loan notes incur interest of 10 per cent. per annum which, at the Chrysaor Group's election, is capitalised and added to the principal amount on 31 December in each year.

(2) Reflects a commercial financing arrangement with Baker Hughes, a GE company, covering a multi-year work program for drilling, completion and subsea tie-in of development wells on the Chrysaor Group'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.

(3) Reflects net settled commodity and interest rate derivatives.

(4) Reflects trade and other payables.

The Chrysaor Group also has certain liabilities for future decommissioning activities on some of its oil and gas assets. The Chrysaor Group calculates total future decommissioning liability based on its 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 it makes represent the present value of decommissioning costs which are expected to be incurred assuming no further development of its assets. The provisions also take into account the US$973 million decommissioning liability that was retained by Shell pursuant to the Shell acquisition. As at 30 June 2020, the Chrysaor Group used a risk-free rate between 1.8 per cent. and 2.5 per cent. and an inflation rate of 2.0 per cent. over the varying lives of the assets to calculate a present value of the Chrysaor Group's decommissioning liabilities of US$3,547.2 million. These decommissioning costs are expected to be incurred at various intervals over the next 30 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 the Chrysaor Group 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. No assurance can be given that actual decommissioning costs will not be materially greater than estimated. See "*Critical accounting estimates and judgments*."

Capitalisation and Indebtedness

The tables below set out Chrysaor Group's capitalisation as at 30 June 2020 and the indebtedness as at 30 September 2020.

The capitalisation information as at 30 June 2020 has been extracted without material adjustment from the Chrysaor Group's historical financial information included in Part VIII (Historical Financial Information relating to the Chrysaor Group) Section B of this Prospectus.

The statement of indebtedness as at 30 September 2020, which is unaudited, has been prepared under IFRS as adopted by the EU using policies which are consistent with those used in preparing the Chrysaor Group's historical financial information set out in Part VIII (Historical Financial Information relating to the Chrysaor Group) Section B of this Prospectus.

There has been no material change to the Chrysaor Group's total capitalisation since 30 June 2020.

Capitalisation

	As at 30 June 2020 (unaudited) (*US$ millions*)
Share capital	(0.1)
Share premium account	(910.0)
Other reserves[(1)]	—
Total capitalisation	910.1

Indebtedness

	As at 30 September 2020 (unaudited) (US$ millions)
Current debt	
Guaranteed	—
Secured(2)	(19.7)
Unguaranteed/ Unsecured	(2.6)
Total current debt	(22.3)
Non-current debt	
Guaranteed	—
Secured(3)	(1,769.4)
Unguaranteed/ Unsecured(4)	(321.9)
Total non-current debt	(2,091.3)
Total indebtedness	(2,113.6)

Net indebtedness

The following table sets out components of the Chrysaor Group's net financial indebtedness as at 30 September 2020.

	As at 30 September 2020 (unaudited) (US$ millions)
Cash	321.7
Cash equivalents	—
Trading securities	—
Liquidity	321.7
Current financial receivable	**—**
Current bank debt	—
Bonds issued	—
Current portion of non-current debt(2)	(22.3)
Other current financial debt	—
Current financial debt	(22.3)
Net current financial indebtedness	**299.4**
Non-current bank loans(5)	(1,373.2)
Bonds issued	—
Other non-current debt(6)	(718.1)
Non-current financial indebtedness	(2,091.3)
Net financial indebtedness	(1,791.9)

(1) Excludes the cash flow hedging reserve, costs of hedging reserve, currency translation reserve and retained earnings

(2) Includes an exploration financing facility and a commercial financing arrangement with BHGE, covering a three-year work programme for drilling, completion and subsea tie-in of development wells on Chrysaor's operated assets

(3) Includes the Chrysaor Existing RBL secured by a pledge over the Chrysaor Group's oil and gas interests in the North Sea and available until 31 December 2025 as well as the junior facility secured by the same interest as the existing RBL and repayable in semi-annual instalments between 2022 and 2026.
(4) Includes 10 per cent.unsecured C and D loan notes due in 2027, and the commercial financing arrangement with BHGE.
(5) Includes the Chrysaor Existing RBL secured by a pledge over the Chrysaor Group's oil and gas interests in the North Sea and available until 31 December 2025.
(6) Includes 10 per cent. unsecured C and D loan notes due in 2027, the junior facility repayable in semi-annual instalments between 2022 and 2026 and the commercial financing arrangement with BHGE.

The Chrysaor Group had no indirect or contingent indebtedness at 30 September 2020.

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 the Chrysaor Group. The majority of the Chrysaor Group's accounts receivable balance is with customers and commercial partners in the international oil and gas industry. The Chrysaor Group has a credit policy that governs the management of credit risk, including the establishment of counterparty credit limits and specific transaction approvals. The Chrysaor Group 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. The Chrysaor Group trades only with international oil and gas operators and as of each at 31 December 2017, 2018 and 2019, and as at 30 June 2019 and 2020, the Chrysaor Group had no trade receivables past due.

For the past three and a half years, substantially all of the Chrysaor Group's oil, gas and NGL sales have been to affiliates of Shell. In addition, the Chrysaor Group has third party contracts to sell oil stream raw and dry gas to INEOS, dry gas and NGLs from Buzzard field to Total, west of Shetland dry gas to Enquest and some additional NGLs are sold to Sabic and Teesside Gas Processing Plant. Each of these parties has historically demonstrated their ability to pay amounts owing to the Chrysaor Group. The Chrysaor Group has not experienced any material credit loss in the collection of accounts receivable to date. The maximum financial exposure due to credit risk on the Chrysaor Group's financial assets, representing the sum of cash and cash equivalents, accounts receivable, deposits, prepaid expenses and other, derivative financial instruments, long term receivables, and investment in associate, as at 31 December 2017, 2018 and 2019 was US$575.7 million, US$1,038.3 million and US$1,446.0 million, respectively, and as at 30 June 2019 and 2020 was US$758.1 million and US$1,569.6 million, respectively.

With respect to its decommissioning obligations, the Chrysaor Group does not expect material decommissioning costs in the short to medium term however it is exposed to the risk of commercial partners defaulting on their proportionate share of decommissioning costs once such costs become payable. The majority of this exposure is mitigated by having decommissioning security agreements in place whereby security for decommissioning is provided via letters of credit, or affiliate guarantees if certain criteria are satisfied. Although the fields and facilities in the Chrysaor Group's southern North Sea area do not typically have DSAs in place, decommissioning activities are ongoing and well progressed, with no instances of partner default to date.

Liquidity risk management

Liquidity and refinancing risks refer to the risk that the Chrysaor Group 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. The Chrysaor Group monitors its 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 bank facilities. Specifically, the Chrysaor Group 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. The Chrysaor Group 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 its portfolio of producing fields and potential delays in development projects. In addition to its operating cash flows, portfolio management opportunities are reviewed to potentially enhance its financial capacity and flexibility. Ultimate responsibility for liquidity risk management rests with the Chrysaor Group's board of directors, which has built a liquidity risk management framework which it believes to be appropriate for the management of all its funding and liquidity management requirements. As of 31 December 2019, and 30 June 2020, the Chrysaor Group was in compliance with all applicable financial covenant ratios.

The Chrysaor Group has total commitments of US$3.0 billion under the Chrysaor Existing RBL Facility. The Chrysaor Group held cash and cash equivalents of US$299.5 million, US$316.3 million and US$573.2 million as at 31 December 2017, 2018 and 2019, respectively, and US$289.4 million and US$369.4 million as at 30 June 2019 and 2020.

Foreign currency risk management

The Chrysaor Group has subsidiaries with functional currencies of pounds sterling, US dollars and Norwegian krone, though it generally conducts and manages its business in US dollars and pounds sterling, which are the operating currencies of the industry in the geographic areas where the majority of its 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, the Chrysaor Group has the ability to draw in US dollars and pounds sterling under the Chrysaor Existing RBL Facility, which assists in foreign currency risk management. From time to time, the Chrysaor Group undertakes 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 at 30 June 2020 the open foreign exchange contracts held by the Chrysaor Group were as follows:

Foreign exchange contracts	*Term*	*Volume*	*Average price*
Forwards Euro versus US Dollar	Dec 2020	Eur 13.8 million	1.10566
Forwards Sterling versus US Dollar	July 2020-Jan 2021	£125.0 million	1.23287

As at 30 June 2020, the Chrysaor Group's material monetary assets or liabilities that were not denominated in the functional currency of the respective subsidiaries involved were non-US dollar denominated cash, joint venture billing receivables and third-party suppliers. The carrying amounts of foreign currency denominated monetary assets and monetary liabilities as at 30 June 2020 was, net of liabilities, US$858.9 million. As at 30 June 2020, the Chrysaor Group had £125.0 million hedged at forward rates of between US$1.2311 and US$1.2413: £1.00 for the period July 2020 to January 2021, and €13,777,750 hedged at forward rates of between US$1.1039 and US$1.1061: EUR 1.00 for the period July 2020 to December 2020. / As at 31 December 2019, the Chrysaor Group had not entered into any exchange rate derivatives. As at 31 December 2019, a 10 per cent. increase in currency exchange rates against the functional currency of the Chrysaor Group's entities would have resulted in a decrease in non-US dollar denominated equity of US$133.6 million, while a 10 per cent. decrease would have resulted in an increase of US$133.6 million.

The Chrysaor Group is mainly exposed to fluctuations in other currencies against the US dollar, in particular pounds sterling. The Chrysaor Group 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-US dollar denominated monetary items and adjusts their translation at the period end for a 10 per cent. change in such non-US dollar rates. As at 30 June 2020, a 10 per cent. increase in currency exchange rates against the functional currency of the Chrysaor Group's entities would have resulted in a decrease in non-US dollar denominated equity of US$140.9 million, while a 10 per cent. decrease would have resulted in an increase of US$140.9 million.

Commodity price risk management

The Chrysaor Group is exposed to the impact of changes in oil and gas prices on its revenue and profits. On a rolling basis, its policy is to hedge the commodity price exposure associated with 40 per cent. to 60 per cent. of the next 12 months' production, between 30 per cent. and 50 per cent. in the following 12-month period, up to 40 per cent. in the subsequent 24-month period.

The following tables summarise the commodity hedges in place as at 30 June 2020:

Derivative	*Term*	*Volume*	*Average Price*
Oil Swaps	July 2020 – December 2022	25,082,750 bbls	US$62.53/bbl
Oil Collars	July 2020 – June 2021	1,095,000 bbls	US$55.00/bbl
Gas Swaps	July 2020 – March 2025	2,016,235,000 therms	45 pence/therm
Gas Collars	July 2020 – March 2023	882,700,000 therms	50 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 Chrysaor Existing RBL Facility, which has a floating interest rate. The Chrysaor Group manages interest rate risk using interest rate swaps from time to time. As at 30 June 2020, the Chrysaor Group had US$700.0 million hedged at an interest rate of 0.5561 per cent. for the period 1 July 2020 to 30 June 2025. As at 31 December 2019, the Chrysaor Group had not entered into any interest rate derivatives.

The Chrysaor Group may be affected by changes in market interest rates at the time it needs to refinance any of its indebtedness.

As 30 June 2020 the open interest rate contracts held by the Chrysaor Group were as follows:

Interest rate contracts	*Term*	*Volume*	*Average price*
Bullet Interest Rate Swaps	Jun 2020 – Jun 2025	US$300.0 million	0.54600%
Amortising Interest Rate Swaps	Jun 2020 – Jun 2025	US$400.0 million	0.56375%

Critical accounting estimates and judgments

The preparation of the Chrysaor Group's and Company's financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions at the date of the financial statements. 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 Chrysaor Group and Company have identified the following areas where significant judgement, estimates and assumptions are required.

Exploration and Evaluation Expenditure

As at 30 June 2020, the Chrysaor Group held a balance of US$439.8 million (as at 31 December 2019: US$425.3 million, 30 June 2019: US$92.7 million, 31 December 2018: US$52.5 million, 31 December 2017: US$35.5 million) relating to expenditure on unproved hydrocarbon resources within other intangible assets which represent active exploration and evaluation activities. The application of the Chrysaor Group'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.

Goodwill

The Chrysaor Group 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. Impairment losses relating to goodwill cannot be reversed in future periods.

Key Sources of Estimation Uncertainty

Recoverability of Oil and Gas Assets

The Chrysaor Group assesses each asset or cash generating unit each reporting period to determine whether any indication of impairment exists. 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. The assessments of fair value less cost of disposal 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.

The Chrysaor Group'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 percent, and a 2 percent change in the post-tax discount rate are considered to be reasonably possible for the purposes of sensitivity analysis, the result of which can be found in notes 10 and 12 to Part VIII (*Historical Financial Information relating to the Chrysaor Group*)

Decommissioning Costs

Decommissioning costs will be incurred by the Chrysaor Group at the end of the operating life of most of the Chrysaor Group's facilities and properties. The Chrysaor Group assesses its decommissioning provision at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors including 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 10 per cent. decrease in the discount rates used to assess the final decommissioning obligation at 30 June 2020, would result in increases to the decommissioning provision of US$440 million and US$62 million respectively. This change would be principally offset by a change to the value of the associated asset.

Accounting for Business Combination

On 1 November 2017, the Chrysaor Group acquired a package of assets in the UK North Sea from Shell for a price of US$3.0 billion with further payments between the two companies contingent upon future exploration results and commodity prices. The transaction comprised the direct acquisition of interests in certain joint operations and the acquisition of 100 per cent. of the issued share capital of the former Shell entity, BG International (CNS) Limited.

On 30 September 2019, the Chrysaor Group acquired the UK business of ConocoPhillips for a total consideration of US$2.5 billion, with the final value of consideration still under negotiation in accordance with the terms of the sales agreement.

The acquisition accounting for both transactions is set out in note 15 to Part VIII (*Historical Financial Information relating to the Chrysaor Group*).

In completing the accounting, management have been required to make estimates relating to the fair value of the assets and liabilities acquired. In particular, estimates have been made in assessing the valuation of tangible and intangible oil and gas assets, and decommissioning liabilities. The fair value of net assets acquired are primarily determined using discounted cashflow techniques using available data at the time of acquisition. For oil and gas assets, the Chrysaor Group estimates future cash flows from an assessment of economically recoverable reserves and discounts them to present value using a rate reflecting market assessments at the time value of money and risks specific to the asset. Determining the fair value of oil and gas assets requires the Chrysaor Group to apply long term assumptions of commodity prices.

The Chrysaor Group assesses the fair value of decommissioning liabilities based on the expected timing, extent and amount of expenditure using data available at the time of acquisition. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques or experience at production sites. The expected timing of expenditure can also change, and as a result there could be significant adjustments to the provisions which could affect future financial results.

Recovery of deferred tax assets

Deferred tax assets, including those arising from un-utilised tax losses, require management to estimate and assess the likelihood that the Chrysaor Group will generate sufficient taxable earnings in future periods, in order to utilise recognised deferred tax assets. Assumptions about the generation of future taxable income are based on forecasted cash flows from operations and judgement about the application of existing tax laws. Judgement is required to determine whether deferred tax assets are recognised in the balance sheet. Following completion of the transaction with Shell in 2017, the foreseeable future taxable profits of the Chrysaor Group increased sufficiently to allow previously unrecognised deferred tax associated with pre-acquisition losses to be recognised in full.

Climate Change

The Chrysaor Group recognises that there may be potential financial implications in the future from climate change risk. The Chrysaor Group expects that climate change policies, legislation and regulation will increase, and likely on accelerating timelines which, although will result in intended benefits, is likely to increase associated costs and administration requirements as well as potentially limiting the investment capital available to the industry. 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 at the balance sheet date the Chrysaor Group 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

IFRS 9

The Chrysaor Group adopted IFRS 9 Financial Instruments ("**IFRS 9**") on 1 January 2018 replacing IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 addresses the classification, measurement and recognition of financial assets and liabilities and hedge accounting. These changes have not materially changed the measurement of the financial assets of the Chrysaor Group. The IFRS 9 impairment model requiring the recognition of "expected credit losses", in contract to the requirement to recognise "incurred credit losses" under IAS 39 Financial Instruments: Recognition and Measurement has not had a material impact of the Chrysaor Group's historical financial information. Trade receivables are generally settled on a short time frame and the Chrysaor Group's other financial assets are due from counterparties without material credit risk concerns at the time of transition. See Note 2 to the Chrysaor Group's audited consolidated historical financial information as at and for the year ended 31 December 2018 for more information.

IFRS 15

The Chrysaor Group adopted IFRS 15 Revenue from Contracts with Customers ("**IFRS 15**") on 1 January 2018 which provides a structured five-step approach to the identification of customers and the measurement and recognition of associated revenues. In particular, revenue is recognised at an amount that reflects the consideration to which an entity expects to be entitled in exchange for transferring goods or services to a customer. The implementation of IFRS 15 has not impacted the presentation of the Chrysaor Group's sales revenue. Disclosure of disaggregated revenue information consistent with the requirement included in IFRS 15 has not had an impact on the revenue information presented in Note 4 of the Chrysaor Group's audited consolidated historical financial information as at and for the year ended 31 December 2018. The Chrysaor Group's accounting policy under IFRS 15 does not represent a substantive change from its previous accounting policy for recognising revenue from sales to customers. See Note 2 to the Chrysaor Group's consolidated historical financial information as at and for the year ended 31 December 2018 for more information.

IFRS 16 leases

The Chrysaor Group adopted IFRS 16 Leases ("**IFRS 16**") on 1 January 2019, following the modified retrospective method, without a restatement of comparative information, which is presented in line with the previous rules under IAS 17. IFRS 16 requires lessees to recognise a lease liability reflecting future lease payments and a right-of-use ("**ROU**") asset for lease contracts, subject to limited practical expedient exceptions for short-term leases and leases of low value assets. At transition, the Chrysaor Group applied the practical expedient within the standard not to reassess whether a contract contains a lease and also not to recognise ROU assets and liabilities for leases where the total lease term is less than or equal to 12 months, or for leases of low value. The main effect on the Chrysaor Group is that IFRS 16 introduces a single leassee accounting model and requires a lessee to recognise assets and liabilities where the practical expedients above are not applicable. It is estimated that on initial application the Chrysaor Group recognised right of use ("**ROU**") assets and lease liabilities for its office leases amounting to US$19.0 million, which is the present value of the remaining lease payments, discounted using an incremental borrowing rate on the implementation date and assuming the leases run to full term with no break clauses exercised. In contrast to the presentation to date of operating lease expenses, under IFRS 16, the ROU assets will be depreciated on a straight-line basis over the length of the lease and interest will be charged as the discount rate is unwound.

SECTION B: OPERATING AND FINANCIAL REVIEW RELATING TO THE COMBINED COP SUBSIDIARIES

The following discussion and analysis is intended to assist in providing an understanding of the Combined COP Subsidiaries' financial condition and results of operations as at and for the years ended 31 December 2017, 2018 and 2019.

The financial information as at and for each of the years ended 31 December 2017, 2018 and 2019 has been derived from the Combined COP Subsidiaries Historical Financial Information.

Combined COP Subsidiaries

The "**Combined COP Subsidiaries**" for the years ended 31 December 2017 to 2019 comprise Chrysaor Petroleum Company U.K. Limited (formerly ConocoPhillips Petroleum Company U.K. Limited), Chrysaor Resources (Irish Sea) Limited (formerly Burlington Resources (Irish Sea) Limited), Chrysaor (U.K.) Sigma Limited (formerly ConocoPhillips (U.K.) Sigma Limited) and their subsidiary and associate undertakings.

The combined financial information presented in the Combined COP Subsidiaries Historical Financial Information has been prepared specifically for this Prospectus and incorporates financial information of subsidiaries and affiliates comprised in the Combined COP Subsidiaries. The Combined COP Subsidiaries do not constitute a separate legal group. The Combined COP Subsidiaries Historical Financial Information is a combination of certain legal entities purchased by Chrysaor E&P Limited pursuant to the COP Acquisition and has been prepared specifically for the purpose of complying with the Prospectus Regulation.

From 1 January 2017 to 30 September 2019, the Combined COP Subsidiaries were under the common control of ConocoPhillips Company ("**ConocoPhillips**"). On 30 September 2019, Chrysaor E&P Limited completed the acquisition of the Combined COP Subsidiaries along with a number of other UK legal entities from ConocoPhillips pursuant to the COP Acquisition. From 30 September 2019, the Combined COP Subsidiaries have been part of the Chrysaor Group.

Key Factors Affecting the Combined COP Subsidiaries Historical and Future Results of Operations

Price of oil and gas

The prevailing price of crude oil and gas significantly affects the Combined COP Subsidiaries' operations and also affects the levels of its oil and gas reserves estimates, which in turn impact its depreciation, depletion and amortisation. The Combined COP Subsidiaries' 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 the Combined COP Subsidiaries' 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 to the Combined COP Subsidiaries' entitlement reserves estimates can 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. Production from US shale oil producers and increased production from Russia have further increased volatility in commodity prices.

The Combined COP Subsidiaries' 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. During the period under prior ownership by ConocoPhillips oil sales were priced against the average Platts Dated Brent crude oil benchmark price during the period of lifting, with a premium or discount by grade to account for crude quality.

The Combined COP Subsidiaries' gas sales are priced against the Point **UK NBP** benchmark bid price published in the ICIS European Spot Gas Market report, with daily balancing against National Grid intraday prices. During the period under prior ownership by ConocoPhillips gas sales were priced against the month-ahead UK NBP benchmark. See "*Key Factors Affecting the Chrysaor Group's Historical and Future Results of Operations—Price of oil and gas.*"

Production volumes

In addition to oil and gas prices, production volumes are a primary revenue driver. The Combined COP Subsidiaries' production levels also affect the level of its reserves and depreciation, depletion and amortisation. The volume of the Combined COP Subsidiaries 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, future oil and gas prices) are beyond the Combined COP Subsidiaries' control and therefore these estimates may prove to be incorrect over time.

The following table sets forth information on the Combined COP Subsidiaries oil and gas production and sales volumes for the years ended 2017, 2018 and 2019.

	Year ended 31 December		
	2017	*2018*	*2019*
Total average daily oil and NGL production for the period (mbopd)	14.4	15.9	14.0
Total average daily gas production for the period (MMscfd)	93.5	108.9	132.1
Total average daily production for the period (mboepd)	30.0	34.0	36.7
Total average daily sales volume for the period (mboepd)	30.1	34.2	36.8

Note: Gas conversion used for MMscf to mboe in 2017 and 2018 was 6 in line with ConocoPhillips reporting; Gas conversion used for MMscf to mboe in 2019 was 5.8 in line with Chrysaor reporting. Reported production and sales volumes are UK produced volumes and do not include crude purchases from other ConocoPhillips group companies

Reserves

The Combined COP Subsidiaries estimate their reserves using standard recognised evaluation techniques. This estimate is reviewed internally and for the year ended 31 December 2019 was reviewed by an independent consultant. The Combined COP Subsidiaries estimates future development costs by taking into account the level of development required to produce the reserves it has elected to develop and referencing it to similar operations where applicable, reviews by external engineers and the Combined COP Subsidiaries experience. See "*Key Factors Affecting the Chrysaor Group's Historical and Future Results of Operations—Reserves*."

Separately, the depletion of oil and gas assets charged within cost of sales in the Combined COP Subsidiaries income statement is dependent on the estimate of its oil and gas reserves. An increase in estimated reserves will cause a reduction to the Combined COP Subsidiaries 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 Combined COP Subsidiaries 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 would not impact the Combined COP Subsidiaries cash flow, nor its UK cash tax liabilities.

Exploration and appraisal success and exploration costs written off or impaired

The Combined COP Subsidiaries face inherent risks in connection with its exploration and appraisal activities. The success or failure of the Combined COP Subsidiaries exploration and appraisal activities will affect the level of its resources recognised and its future development plans for a particular license area. The value of the Combined COP Subsidiaries intangible assets is reviewed at least annually and, when appropriate, values are impaired or written off if the asset is not expected to make a sufficient economic return from the investment (for example, if an exploration well is dry or has insufficient resources to be commercial).

For the years ended 31 December 2017, 2018 and 2019 the Combined COP Subsidiaries wrote off costs totalling US$0.1 million, US$12.8 million and US$1.7 million, respectively in relation to its intangible exploration and evaluation assets following unsuccessful exploration and appraisal activities.

The Combined COP Subsidiaries oil and gas assets are analysed into **CGUs** for impairment review purposes, in accordance with the IAS 36 Impairment of Assets accounting standard, with 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 of the Combined COP Subsidiaries income statement. The Combined COP Subsidiaries accounts for such write offs using the successful efforts method of accounting. In line with the successful efforts method of accounting, all license acquisition, exploration and evaluation costs are initially capitalised as intangible oil and gas assets in cost centres by field or exploration area, as appropriate, pending determination of commerciality of the relevant property. Directly attributable administration costs are capitalised insofar as they relate to specific exploration activities. Pre-license costs and general exploration costs not specific to any particular license 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 once the field comes into production. 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 Combined COP Subsidiaries depletion and amortisation accounting policy. See "*Critical accounting estimates and judgments— Exploration and evaluation expenditure*."

See "*Key Factors Affecting the Chrysaor Group's Historical and Future Results of Operations—Exploration and appraisal success and exploration costs written off or impaired.*"

Development and production success and impairment

The Combined COP Subsidiaries face inherent risks in connection with its development and production activities. These risks include the difference between estimated and actual reserves, its cost efficiency in development, timing of production activities and its level of production. The Combined COP Subsidiaries reviews its development and production projects at least annually for indicators of impairment. In the event that such an indicator does exist, the Combined COP Subsidiaries 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, it records any impairment to its income statement.

For each of the years ended 31 December 2017, 2018 and 2019, the pre tax impairment charges in respect of the Combined COP Subsidiaries tangible oil and gas assets were US$49.3 million, credit of US$5.0 million and US$0.9 million respectively. The impairment in 2017 was principally in relation to the non-operated Clair field. Impairments in all years include amounts recognised as a result of changes in the decommissioning provision for non-producing assets.

See "*Key Factors Affecting the Chrysaor Group's Historical and Future Results of Operations—Exploration and appraisal success and exploration costs written off or impaired*."

Acquisitions and disposals

If the Combined COP Subsidiaries elect to divest an asset, it could impact several items in its 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 the Combined COP Subsidiaries enter the development phase of a project with a high equity stake and decide to farm out a portion of the equity in that license 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 per cent 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 the Combined COP Subsidiaries production volumes and revenues.

The Combined COP Subsidiaries results also may 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 during the periods presented are those set forth below

On 18 September 2019, Chrysaor Petroleum Company U.K. Limited sold its 100 per cent interest in ConocoPhillips Pension Plan Trustees Limited to ConocoPhillips (U.K.) Holdings Limited for cash consideration of US$128, reflecting the called up share capital of that company. No gain or loss arose on the disposal.

On 1 July 2019, Chrysaor Petroleum Company U.K. Limited sold its 40.25 per cent interest in Norpipe Terminal Holdco Limited to ConocoPhillips (U.K.) Teesside Operator Limited for cash consideration of US$144.1 million. A pre-tax gain on disposal of US$144.1 million has been recognised in the Combined COP Subsidiaries Historical Financial Information. No current tax arose on the disposal.

On 18 December 2018, Chrysaor (U.K.) Sigma Limited sold its entire 100 per cent shareholding in ConocoPhillips (U.K.) Psi Limited to BP for cash consideration of US$206.8 million. BP also subsequently settled debt of US$1,600.0 million. Prior to that transaction, on 12 December 2018, Chrysaor (U.K.) Sigma Limited transferred 16.5 per cent of its 24 per cent interest in the BP-operated Clair Field to ConocoPhillips (U.K.) Psi Limited. Chrysaor (U.K.) Sigma Limited continues to hold a 7.5 per cent interest in the Clair Field. A pre-tax gain on disposal of US$151.9 million has been recognised in the Combined COP Subsidiaries Historical Financial Information. No current tax arose on the disposal. A deferred tax liability of US$338.9 million was released and is reported as part of gain on disposal.

Operating costs

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 variable operating costs. The main variable operating costs that affect the Combined COP Subsidiaries 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 Combined COP Subsidiaries 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 programs 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.

Currency exchange rates

The Combined COP Subsidiaries presentational currency is the US dollar.

Each entity in the Combined COP Subsidiaries 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 Combined COP Subsidiaries are US Dollar and pound sterling. A significant amount of the Combined COP Subsidiaries' operating, staffing, and other administration costs are denominated in pounds sterling which will determine the functional currencies of the operating entities incurring these costs.

The functional currency of Chrysaor (U.K.) Sigma Limited was changed from pounds sterling to US dollars on 1 January 2019. A management decision was made to change the functional currency to US dollars to reflect the profile of the company's revenue and operating profit which, following first production from Clair Ridge at the end of 2018, is primarily generated in US dollars.

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. 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, the assets and liabilities of the Combined COP Subsidiaries' operations 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 the currency translation reserve.

Taxation

Taxation can have a significant impact on the results of operations of the Combined COP Subsidiaries.

Deferred tax assets are recognised to the extent that the future benefit is probable. Relevant tax law is considered, together with the ability to carry back abandonment tax losses against prior period profits. As at 31 December 2019, the deferred tax asset recognised is only partially offset by the deferred tax liability, resulting in an overall net deferred tax asset as at 31 December 2019 of US$26.2 million.

As at 31 December 2019, the Combined COP Subsidiaries had non-ring fence tax losses of US$19.3 million (2018: nil; 2017: nil). An associated deferred tax asset of US$3.7 million (2018: nil; 2017: nil) has not been recognised in respect of these losses due to uncertainty of recovery.

The tax expense of the Combined COP Subsidiaries for the year ended 31 December 2019 was reduced by US$57.6 million (2018: US$60.7 million) by non-taxable gains on sale which are further described under the section "Acquisitions and disposals" above.

The tax expense of the Combined COP Subsidiaries was increased by depreciation of non-tax deductible costs associated with the transfer of an interest in the Clair field to Chrysaor (U.K.) Sigma Limited from another group company in 2012. For the year ended 31 December 2019, the increase in tax expense was US$5.9 million (2018: US$29.9 million; 2017: US$24.2 million).

The Combined COP Subsidiaries' taxation is also affected by tax measures such as investment allowances. These allowances allow a company to reduce its UK supplementary charge (10 per cent since 1 January 2016) based on allowances tied to field production revenues and capital expenditures.

Description of Key Line Items

Revenue

The Combined COP Subsidiaries' revenue consists of crude oil, gas and condensate sales, tariff and other revenue. Oil, gas, and condensate revenues associated with the sale of these products to customers are recognised when the Combined COP Subsidiaries 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 the Combined COP Subsidiaries occurs when title passes at the point the customer takes physical delivery. The Combined COP Subsidiaries principally satisfies its performance obligations at this point in time. Revenues from the production of oil and natural gas properties in which it has an interest with joint venture partners are recognised on the basis of its working interest in those properties

Cost of sales

The Combined COP Subsidiaries' cost of sales consists of field operating costs and underlying operating costs such as transportation tariffs, DD&A and movements in over/underlift and in hydrocarbon inventories. During the period under prior ownership by ConocoPhillips, this also included the purchase of crude from other ConocoPhillips group undertakings.

The Combined COP Subsidiaries' movement in hydrocarbon inventories arise due to differences between volumes produced and sold. Inventories of hydrocarbons are stated at market value. The Combined COP Subsidiaries' movement in overlift and underlift arise due to differences between the production sold and its 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.

Exploration and evaluation expenses

The Combined COP Subsidiaries' E&E expenses include pre-license costs before the legal right to explore has been acquired, license 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.

Exploration costs written-off

Exploration costs written-off consists of write offs of costs for explorations evaluated to be uncommercial, including license relinquishments and uncommercial well evaluations.

The application of the Combined COP Subsidiaries' 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.

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 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.

Income and expenditure from joint arrangements

The Combined COP Subsidiaries' exploration, development, production and decommissioning activities are generally conducted in joint arrangements (which are not entities) with other companies. The COP Historical Financial Information reflect the relevant proportions of income, expenditure, assets and liabilities relating to these interests.

Gain on disposal of investments

The amount by which the proceeds received by the Combined COP Subsidiaries receive from the sale of investments exceed the carrying amount of the investments that were sold.

Finance income

Finance income includes bank interest receivable and foreign exchange gains.

Finance expenses

Finance expenses include loan notes interest payables, other interest, foreign exchange loss, bank and financing fees, unwinding of discount on contingent consideration and unwinding of discount on decommissioning and other provisions.

Share of net profit of associate undertaking

The investment in an associate undertaking is accounted for using the equity method of accounting.

Income tax (expense)/credit

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 the Combined COP Subsidiaries operate and generate 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 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 sheet date; (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 the Combined COP Subsidiaries to make a single net payment; and (iv) deferred taxation is not provided where a permanent difference arises between the tax basis of an asset and the carrying value of that asset.

Results of Operations

The following table summarises the Combined COP Subsidiaries' results of operation for the years ended 31 December 2017, 2018 and 2019.

	For the year ended 31 December		
	2017	*2018*	*2019*
		(US$ millions)	
Revenue	2,663.2	3,194.0	1,602.5
Other income	7.7	15.8	15.1
Revenue and other income	**2,670.9**	**3,209.8**	**1,617.6**
Cost of sales	(2,730.6)	(3,063.2)	(1,386.2)
Gross (loss)/profit	**(59.8)**	**146.7**	**231.4**
Exploration and evaluation expenses	(2.9)	(2.5)	(1.0)
Exploration costs written-off	(0.1)	(12.8)	(1.7)
Operating (loss)/profit	**(62.7)**	**131.3**	**228.8**
Gain on disposal of investments	—	151.9	144.1
(Loss)/profit before interest and taxation	**(62.7)**	**283.2**	**372.9**
Finance income	2.9	6.6	3.8
Finance expenses	(40.5)	(43.8)	(58.3)
Share of net profit of associate undertaking	10.7	14.3	7.5
(Loss)/profit before taxation	**(89.6)**	**260.2**	**325.8**
Tax credit/(expense)	67.0	(45.5)	(71.3)
(Loss)/profit for the financial year	**(22.6)**	**214.8**	**254.5**

Results of Operations for the year ended 31 December 2019 compared to the year ended 31 December 2018

The following table summarises the Combined COP Subsidiaries' results of operation for the years ended 31 December 2018 and 2019.

	For the year ended 31 December	
	2018	*2019*
	(US$ millions)	
Revenue	3,194.0	1,602.5
Other income	15.8	15.1
Revenue and other income	**3,209.8**	**1,617.6**
Cost of sales	(3,063.2)	(1,386.2)
Gross profit	**146.7**	**231.4**
Exploration and evaluation expenses	(2.5)	(1.0)
Exploration costs written-off	(12.8)	(1.7)
Operating profit	**131.3**	**228.8**
Gain on disposal of investments	151.9	144.1
Profit before interest and taxation	**283.2**	**372.9**
Finance income	6.6	3.8
Finance expenses	(43.8)	(58.3)
Share of net profit of associate undertaking	14.3	7.5
Profit before taxation	**260.2**	**325.8**
Tax expense	(45.5)	(71.3)
Profit for the financial year	**214.8**	**254.5**

Revenue

Revenue for the year ended 31 December 2019 was US$1,602.5 million, a decrease of US$1,591.5 million, or 49.8 per cent, compared to US$3,194.0 million for the year ended 31 December 2018. This decrease was principally as a result of a decrease in sales of ConocoPhillips Norwegian crude which was purchased and sold by Chrysaor Petroleum Company U.K. Limited. This activity ceased on 1 July 2019, prior to the acquisition of the ConocoPhillips UK business by Chrysaor.

Crude oil sales revenue decreased to US$1,290.0 million for the year ended 31 December 2019 from US$2,771.6 million for the year ended 31 December 2018, driven principally by the decrease in sales of ConocoPhillips Norwegian crude which was purchased and sold by Chrysaor Petroleum Company U.K. Limited. In addition there were lower revenues recorded in 2019 from the Clair field, as Chrysaor (U.K.) Sigma Limited sold its entire 100 per cent shareholding in ConocoPhillips (U.K.) Psi Limited, which contained 16.5 per cent of its 24 per cent interest in the BP-operated Clair Field, to BP on the 18th of December 2018. Average realised oil prices increased slightly to US$65/boe for the year ended 31 December 2019 from US$64/boe for the year ended 31 December 2018. The average Brent price movement was US$64/bbl for 2019 compared with US$71/bbl for 2018. Realised oil prices for each of the fields in the Combined COP Subsidiaries portfolio do not strictly follow the Brent crude oil price pattern, with some fields sold at a discount or premium to Brent and under contracts with differing timescales for pricing.

Gas volumes and revenues have decreased to revenue of US$255.3 million for the year ended 31 December 2019 from US$322.1 million for the year ended 31 December 2018, driven by increased production offset by lower commodity prices. For the year ended 31 December 2019, gas production averaged 22.8 mboepd compared to 18.1 mboepd for the year ended 31 December 2018. Average realised gas price for the year decreased to 42 pence/therm for the year ended 31 December 2019 compared to 62 pence/therm for the year ended 31 December 2018, in line with the movement in the NBP spot gas price.

For the year ended 31 December 2019, condensate and natural gas sales decreased to US$48.7 million from US$90.9 million for the year ended 31 December 2018. This decrease was primarily as a result of decreased sales volumes, compounded by lower commodity prices.

Cost of sales

Cost of sales for the year ended 31 December 2019 was US$1,386.2 million, a decrease of US$1,677.0 million or 54.7 per cent compared to US$3,063.2 million for the year ended 31 December 2018. This decrease was principally as a result of a decrease in purchases of ConocoPhillips Norwegian crude which was purchased and sold by Chrysaor Petroleum Company U.K. Limited. This activity ceased on 1 July 2019, prior to the acquisition of the ConocoPhillips UK business by Chrysaor. In addition there were lower cost of sales recorded in 2019 from the Clair field, as Chrysaor (U.K.) Sigma Limited sold its entire 100 per cent shareholding in ConocoPhillips (U.K.) Psi Limited, which contained 16.5 per cent of its 24 per cent interest in the BP-operated Clair Field, to BP on 18 December 2018.

DD&A charges on oil and gas assets also decreased significantly to US$151.4 million for the year ended 31 December 2019 from US$307.9 million for the year ended 31 December 2018. The principal reason for the change is from 1 January 2019, the Combined COP Subsidiaries prospectively changed their methodology for calculating the depreciation charge on capitalised oil and gas properties to be in line with the Chrysaor Group. Depreciation is provided using the unit of production method based on proved plus probable reserves. When there is a change in the estimated total recoverable proved plus probable reserves of a field, that change is accounted for prospectively in the depreciation charge over the revised remaining proved plus probable reserves. Prior to 1 January 2019, depreciation was provided using the unit of production method based on proved reserves, or proved developed reserves for well costs.

Exploration and evaluation expenses

Exploration and evaluation expenses for the year ended 31 December 2019 were US$1.0 million, a decrease of US$1.5 million or 60.0 per cent compared to US$2.5 million for the year ended 31 December 2018. This decrease was principally as a result of lower equity on the non-operated Clair field.*Exploration costs written-off*

Exploration costs written-off for the year ended 31 December 2019 were US$1.7 million, a decrease of US$11.1 million or 86.7 per cent from US$12.8 million for the year ended 31 December 2018. The decrease in exploration costs written-off was primarily due to no costs incurred for unsuccessful wells during 2019.

Gain on disposal of investments

Gain on disposal of investments for the year ended 31 December 2019 was US$144.1 million, a decrease of US$7.8 million or 5.1 per cent from US$151.9 million for the year ended 31 December 2018.

On 18 September 2019, Chrysaor Petroleum Company U.K. Limited sold its 100 per cent interest in ConocoPhillips Pension Plan Trustees Limited to ConocoPhillips (U.K.) Holdings Limited for cash consideration of US$128, reflecting the called up share capital of that company. No gain or loss arose on the disposal.

On 1 July 2019, Chrysaor Petroleum Company U.K. Limited sold its 40.25 per cent interest in Norpipe Terminal Holdco Limited to ConocoPhillips (U.K.) Teesside Operator Limited for cash consideration of US$144.1 million. A pre-tax gain on disposal of US$144.1 million has been recognised in the Combined COP Subsidiaries Historical Financial Information. No current tax arose on the disposal.

On 18 December 2018, Chrysaor (U.K.) Sigma Limited sold its entire 100 per cent shareholding in ConocoPhillips (U.K.) Psi Limited to BP for cash consideration of US$206.8 million. BP also subsequently settled debt of US$1,600.0 million. Prior to that transaction, on 12 December 2018, Chrysaor (U.K.) Sigma Limited transferred 16.5 per cent of its 24 per cent interest in the BP-operated Clair Field to ConocoPhillips (U.K.) Psi Limited. Chrysaor (U.K.) Sigma Limited continues to hold a 7.5 per cent interest in the Clair Field. A pre-tax gain on disposal of US$151.9 million has been recognised in the Combined COP Subsidiaries Historical Financial Information. No current tax arose on the disposal. A deferred tax liability of US$338.9 million was released and is reported as part of gain on disposal.

Finance income

Finance income for the year ended 31 December 2019 was US$3.8 million, a decrease of US$2.8 million, or 42.4 per cent, compared to US$6.6 million for the year ended 31 December 2018. This decrease was principally as a result of decreased intercompany interest and foreign exchange gains.

Finance expenses

Finance expenses for the year ended 31 December 2019 were US$58.3 million, an increase of US$14.5 million, or 33.1 per cent, compared to US$43.8 million for the year ended 31 December 2018. This increase was principally attributable to foreign exchange losses partially offset by lower expense on the unwinding on discount on decommissioning and other provisions.

Share of net profit of associate undertaking

The share of net profit of associate undertaking for the year ended 31 December 2019 was US$7.5 million, a decrease of US$6.8 million or 47.6 per cent from US$14.3 million for the year ended 31 December 2018. The decrease share of net profit of associate undertaking was due to Chrysaor Petroleum Company U.K. Limited selling its 40.25 per cent interest in Norpipe Terminal Holdco Limited to ConocoPhillips (U.K.) Teesside Operator Limited on 1 July 2019.

Income tax (expense)/credit

Income tax for the year ended 31 December 2019 resulted in an expense of US$71.3 million, an increase of US$25.8 million, or 56.7 per cent, compared to US$45.5 million in the year ended 31 December 2018. This increase was principally as a result of a higher level of profit before tax generated in 2019. There was also a decrease in both the level of investment allowance and the level of expenses not deductible for tax purposes arising in 2019, resulting from the Clair transaction noted as part of “Gain on disposal of investments”.

Results of Operations for the year ended 31 December 2018 compared to the year ended 31 December 2017

The following table summarises the Combined COP Subsidiaries’ results of operation for the years ended 31 December 2017 and 2018.

	For the year ended 31 December	
	2017	*2018*
	(US$ millions)	
Revenue	2,663.2	3,194.0
Other income	7.7	15.8
Revenue and other income	**2,670.9**	**3,209.8**
Cost of sales	(2,730.6)	(3,063.2)
Gross (loss)/profit	**(59.8)**	**146.7**
Exploration and evaluation expenses	(2.9)	(2.5)
Exploration costs written-off	(0.1)	(12.8)
Operating (loss)/profit	**(62.7)**	**131.3**
Gain on disposal of investments	—	151.9
(Loss)/profit before interest and taxation	**(62.7)**	**283.2**
Finance income	2.9	6.6
Finance expenses	(40.5)	(43.8)
Share of net profit of associate undertaking	10.7	14.3
(Loss)/profit before taxation	**(89.6)**	**260.2**
Tax credit/(expense)	67.0	(45.5)
(Loss)/profit for the financial year	**(22.6)**	**214.8**

Revenue

Revenue for the year ended 31 December 2018 was US$3,194.0 million, an increase of US$530.8 million, or 19.9 per cent, compared to US$2,663.2 million for the year ended 31 December 2017. This increase was principally as a result of an increase in sales of ConocoPhillips Norwegian crude which was purchased and sold by Chrysaor Petroleum Company U.K. Limited. This activity ceased on 1 July 2019, prior to the acquisition of ConocoPhillips UK business by Chrysaor. In addition, there were increased volumes and higher realised commodity prices.

Crude oil sales revenue increased to US$2,771.6 million for the year ended 31 December 2018 from US$2,350.1 million for the year ended 31 December 2017, principally driven by an increase in sales of ConocoPhillips Norwegian crude which was purchased and sold by Chrysaor Petroleum Company U.K. Limited. This activity ceased on 1 July 2019, prior to the acquisition of ConocoPhillips UK business by Chrysaor. In addition, there were higher revenues delivered from the Clair field. Average realised oil prices increased to US$64/bbl. in 2018 from US$52/bbl. in 2017. This is in line with the average Brent price movement to US$71/bbl. for 2018 compared with US$54/bbl. for 2017. While realised oil prices for each of the fields in the Combined COP Subsidiaries portfolio do not strictly follow the Brent price pattern, with some fields sold at a discount or premium to Brent and under contracts with differing timescales for pricing, the average realised price for all the fields traded broadly in line with the price of Brent crude oil.

Gas volumes and revenues increased significantly to revenue of US$322.1 million for the year ended 31 December 2018 from US$208.4 million for the year ended 31 December 2017, driven by increased volumes and higher commodity prices. For the year ended 31 December 2018 gas production averaged 18.1 mboepd compared to 15.6 mboepd for the year ended 31 December 2017. Average realised gas price for the year increased to 62 pence/therm for the year ended 31 December 2018 compared to 49 pence/therm for the year ended 31 December 2017, in line with the movement in the NBP spot gas price.

For the year ended 31 December 2018, condensate and natural gas liquid sales decreased to US$90.9 million from US$95.0 million for the year ended 31 December 2017, driven by lower volumes.

Cost of sales

Cost of sales for the year ended 31 December 2018 was US$3,063.2 million, an increase of US$332.6 million or 12.2 per cent compared to US$2,730.6 million for the year ended 31 December 2017. This increase was principally as a result of an increase in purchases of ConocoPhillips Norwegian crude which was purchased and sold by Chrysaor Petroleum Company U.K. Limited. This activity ceased on 1 July 2019, prior to the acquisition of ConocoPhillips UK business by Chrysaor.

DD&A charges on oil and gas assets also increased slightly to U$307.9 million for the year ended 31 December 2018 from US$303.5 million for the year ended 31 December 2018.

Exploration and evaluation expenses

Exploration and evaluation expenses for the year ended 31 December 2018 were US$2.5 million, an increase of US$0.4 million from US$2.9 million for the year ended 31 December 2017.

Exploration costs written-off

Exploration costs written-off for the year ended 31 December 2018 were US$12.8 million, an increase of US$12.7 million from US$0.1 million for the year ended 31 December 2017. The increase in exploration costs written-off was primarily due to the costs of an unsuccessful well.

Gain on disposal of investments

Gain on disposal of investments for the year ended 31 December 2018 was US$151.9 million compared to nil for the year ended 31 December 2017.

On 18 December 2018, Chrysaor (U.K.) Sigma Limited sold its entire 100 per cent shareholding in ConocoPhillips (U.K.) Psi Limited to BP for cash consideration of US$206.8 million. BP also subsequently settled debt of US$1,600.0 million. Prior to that transaction, on 12 December 2018, Chrysaor (U.K.) Sigma Limited transferred 16.5 per cent of its 24 per cent interest in the BP-operated Clair Field to ConocoPhillips (U.K.) Psi Limited. Chrysaor (U.K.) Sigma Limited continues to hold a 7.5 per cent interest in the Clair Field. A pre-tax gain on disposal of US$151.9 million has been recognised in the Combined COP Subsidiaries Historical Financial Information. No current tax arose on the disposal. A deferred tax liability of US$338.9 million was released and is reported as part of gain on disposal.

Finance income

Finance income for the year ended 31 December 2018 was US$6.6 million, an increase of US$3.7 million, or 127.6per cent, compared to US$2.9 million for the year ended 31 December 2017. This increase was principally as a result of increased bank interest and foreign exchange gains.

Finance expenses

Finance expenses for the year ended 31 December 2018 were US$43.8 million, an increase of US$3.3 million, or 8.1 per cent, compared to US$40.5 million for the year ended 31 December 2017. This increase was principally attributable to increased bank interest expense, increased cost associated with the unwinding of discount on decommissioning provisions and increased lease interest payable expense.

Share of net profit of associate undertaking

The share of net profit of associate undertaking for the year ended 31 December 2018 was US$14.3 million, an increase of US$3.6 million or 33.6 per cent from US$10.7 million for the year ended 31 December 2018. Chrysaor Petroleum Company U.K. Limited sold its 40.25 per cent interest in Norpipe Terminal Holdco Limited to ConocoPhillips (U.K.) Teesside Operator Limited on 1 July 2019.

Income tax (expense)/credit

Income tax for the year ended 31 December 2018 resulted in an expense of US$45.5 million compared to a credit of US$67.0 million in the year ended 31 December 2017. This change was principally as a result of the Combined COP Subsidiaries generating a profit before taxation in 2018 but a loss before taxation in 2017. Additionally, in the year ended 31 December 2018, the tax expense was also reduced by a non-taxable gain noted in “Gain on disposal of investments” above. In the year ended 31 December 2017, the tax credit was increased by group relief payable from a fellow group company for consideration.

Liquidity and capital resources

The Combined COP Subsidiaries’ liquidity requirements arose principally from their capital investment and working capital demands. For the periods presented, liquidity requirements were met primarily from existing cash within the entities and ongoing cashflow generation from its producing assets.

Cash and cash equivalents includes cash in hand and bank overdrafts and was US($1,483.6) million, US$498.2 million and US$0.02 million as at 31 December 2017, 2018 and 2019, respectively.

Cash flow

The following table presents a summary of the Combined COP Subsidiaries cash flow for the years ended 31 December 2017, 2018 and 2019.

	For the year ended 31 December		
	2017	*2018*	*2019*
		(US$ millions)	
Net cash flows from operating activities	267.4	440.1	224.4
Net cash flows (used in)/from investing activities	(1,870.8)	3,222.7	(633.1)
Net cash flows (used in) financing activities	(16.3)	(1,663.5)	(109.4)
Cash and cash equivalents at the end of the period	(1,483.6)	498.2	0.0
Cash and cash equivalents consists of:			
Cash at bank and in hand	997.5	1,113.5	0.0
Bank overdraft	(2,481.1)	(615.3)	—
	(1,483.6)	498.2	0.0

Net Cash flows from operating activities

	For the year ended 31 December		
	2017	*2018*	*2019*
		(US$ millions)	
(Loss)/profit before taxation	(89.6)	260.2	325.8
Finance cost, excluding foreign exchange	37.2	43.8	39.2
Finance income, excluding foreign exchange	(2.9)	(5.6)	(3.8)
Depreciation, depletion and amortisation	311.5	323.6	166.3
Impairment (incl. amounts due to change in decommissioning provision)	49.3	(5.0)	0.9
Exploration write-off	0.1	12.8	1.7
Inventory write-off	1.0	0.2	—
Release of deferred income	(1.5)	0.0	—
Income from interest in associate undertaking	(10.7)	(14.3)	(7.5)
Gain on sale of investment in associated undertaking	—	—	(144.1)
Gain on sale of investment in subsidiary undertaking	—	(151.9)	—
Unrealised foreign-exchange loss/(gain)	2.4	(1.8)	22.9
Decommissioning payments	(3.4)	(7.7)	(6.3)
Working-capital adjustments			
(Increase)/decrease in inventories	(5.5)	(0.2)	2.6
(Increase)/decrease in trade and other receivables	(11.8)	(178.2)	215.2
Increase/(decrease) in trade and other payables	26.1	228.7	(364.0)
Cash generated from operations	**302.0**	**504.6**	**249.1**
Income tax paid	(34.6)	(64.5)	(24.7)
Net cash inflow from operating activities	**267.4**	**440.1**	**224.4**

Net cash generated from operating activities was US$224.4 million for the year ended 31 December 2019 compared to US$440.1 million generated for the year ended 31 December 2018. The decrease was primarily due to working capital adjustments for trade and other receivables and trade and other payables.

Net cash generated from operating activities was US$440.1 million for the year ended 31 December 2018 compared to US$267.4 million for the year ended 31 December 2017. The increase was primarily due to an increased operating cashflow from increased volumes and commodity prices.

Net cash (used in)/from investing activities

	For the year ended 31 December		
	2017	*2018*	*2019*
		(US$ millions)	
Expenditure on exploration and evaluation assets	(0.8)	(13.0)	(19.0)
Expenditure on property, plant and equipment	(210.5)	(184.9)	(71.4)
New loans issued to group companies	(1,672.3)	—	(701.3)
Repayment of loans by group companies	—	1,662.3	10.0
Interest received	2.9	5.6	3.8
Proceeds from sale of investment subsidiary undertaking	—	1,806.8	—
Proceeds from sale of investment in associate undertaking	—	—	144.1
Dividends received from associate undertaking	9.8	9.8	0.7
Net cash disposed of with subsidiary undertaking	—	(64.0)	—
Net cash (outflow)/inflow from investing activities	(1,870.8)	3,222.7	(633.1)

Net cash used in investing activities was US$633.1 million for the year ended 31 December 2019, compared to US$3,222.7 million of net cash received from investing activities for the year ended 31 December 2018. This was primarily due to proceeds from the sale of investment in

ConocoPhillips (U.K.) Psi Limited being recognised in 2018 and the repayment of a short term loan issued to ConocoPhillips outstanding at 31 December 2017 being repaid in 2018.

Net cash received from investing activities was US$3,222.7 million for the year ended 31 December 2018, compared to US$1,870.8 million of net cash used in investing activities for the year ended 31 December 2017. The cash flows for the year ended 31 December 2018 were primarily associated with proceeds from the sale of investment in ConocoPhillips (U.K.) Psi Limited and the repayment of a short term loan issued to ConocoPhillips outstanding at 31 December 2017 being repaid in 2018. Cash flows for the year ended 31 December 2017 related primarily to the issue of a new short term loan to ConocoPhillips which remained outstanding at 31 December 2017.

Net cash from financing activities

	For the year ended 31 December		
	2017	*2018*	*2019*
		(US$ millions)	
New loans received from group companies	—	—	548.4
Lease payments	(12.7)	(25.5)	(24.3)
Interest paid and bank charges	(0.8)	(3.0)	(2.5)
Dividends paid preference shares	(2.8)	(2.9)	(2.9)
Dividends paid ordinary shares	—	(1,632.0)	(628.2)
Net cash outflow from financing activities	(16.3)	(1,663.5)	(109.4)

Net cash used in financing activities was US$109.4 million for the year ended 31 December 2019, compared to US$1,663.5 million of net cash used in financing activities for the year ended 31 December 2018. Cash flows for both 2019 and 2018 were primarily associated with dividends paid on ordinary shares.

Net cash used in financing activities was US$1,663.5 million for the year ended 31 December 2018, compared to US$16.3 million of net cash used in financing activities for the year ended 31 December 2017. Cash flows for 2018 were primarily associated with dividends paid on ordinary shares.

Capital Resources

The Combined COP Subsidiaries liquidity requirements arose principally from its capital investment, working capital demands. For the periods presented, the Combined COP Subsidiaries met their capital investment, working capital and debt servicing requirements primarily from cash flows from operations.

Cash and Cash equivalents

As at 31 December 2019, the Combined COP Subsidiaries held US$0.02 million, of cash and cash equivalents.

Capital investment

The primary objective of the Combined COP Subsidiaries capital management is to optimise the return on investment, by managing its capital structure to achieve capital efficiency while maintaining flexibility for future acquisitions. The Combined COP Subsidiaries 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.

Capital investment represents the Combined COP Subsidiaries organic 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 comprises expenditures on property plant and equipment and expenditures on exploration and evaluation. The following table sets forth the

Combined COP Subsidiaries capital investments for the years ended 31 December 2017, 2018 and 2019.

	For the year ended 31 December		
	2017	*2018*	*2019*
		(US$ millions)	
Property plant and equipment expenditure	(214.2)	(183.3)	(81.1)
Exploration and evaluation expenditure	(0.8)	(13.4)	(19.8)
Capital investment	(215.0)	(196.7)	(100.9)

The Combined COP Subsidiaries' capital investment in the year ended 31 December 2019 was US$100.9 million. The investment program was centred on a drilling campaign on the operated J-Area assets and the ongoing infill drilling campaign on the non-operated Clair Ridge asset.

The Combined COP Subsidiaries' capital investment in the year ended 31 December 2018 was US$196.7 million. The investment program was centred on a drilling campaign on the operated J-Area assets and the development of the non-operated Clair Ridge field.

The Combined COP Subsidiaries' capital investment in the year ended 31 December 2017 was US$215.0 million. The investment program was centred on the drilling campaign on the operated J-Area assets and on the non-operated Clair Phase 1 field, and the development of the non-operated Clair Ridge field.

Future capital investment

The Combined COP Subsidiaries' capital investments are driven largely by full phase expenditure on existing producing fields, new development projects and exploration and appraisal activities. As at 31 December 2019, the Combined COP Subsidiaries had commitments for future capital expenditure amounting to US$40.4 million. The majority of the planned capital expenditure is spread across all of the assets in the production portfolio as well as on certain pre-development and exploration assets at the front end of the lifecycle.

The capitalisation and indebtedness information as at 31 December 2019 has been extracted without material adjustment from the Combined COP Subsidiaries audited accounting records.

Contractual obligations and contingent liabilities

The following table sets forth the Combined COP Subsidiaries' remaining contractual maturity for its non derivative financial liabilities with contractual repayment periods as at 31 December 2019. The table reflects the undiscounted cash flows of financial liabilities based on the earliest date on which the Combined COP Subsidiaries could be required to pay.

	Payments due by period As of 31 December 2019				
	Total	*Less than 1 year*	*1-2 Years*	*2-5 Years*	*Over 5 years*
			(US$ millions)		
Loans from group undertakings	592.1	592.1	—	—	—
Trade and other payables	252.6	252.6	—	—	—
Lease obligations	80.9	27.6	29.2	17.1	6.9
Total	925.5	872.3	29.2	17.1	6.9

The Combined COP Subsidiaries also have certain liabilities for future decommissioning activities on some of its oil and gas assets. The Combined COP Subsidiaries calculates total future decommissioning liability based on its 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 it makes represent the present value of decommissioning costs which are expected to be incurred assuming no further development of its assets. As at 31 December 2019, the Combined COP Subsidiaries used a risk-free rate of between 2.3 per cent and 2.8 per cent and an inflation rate of 2 per cent over the varying lives of the assets to calculate a present value of the Combined COP Subsidiaries decommissioning liabilities of US$1,081.4 million. These decommissioning costs are expected to be incurred at various intervals over the next 10 to 40 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 the Combined COP Subsidiaries 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. No assurance can be given that actual decommissioning costs will not be materially greater than estimated.

PART VII

HISTORICAL FINANCIAL INFORMATION RELATING TO THE PREMIER GROUP

1. Basis of financial information

The audited consolidated financial statements of Premier included in the Annual Reports and Accounts of Premier for the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019 together with the audit reports thereon are incorporated by reference into this document. All of these financial statements have been prepared in accordance with IFRS as adopted by the EU. In addition, the consolidated financial statements of Premier included in the Premier Group's unaudited interim financial statements for the six months ended 30 June 2020 together with the independent review report thereon is incorporated by reference into this document. The accounting policies that applied to the unaudited interim financial statements are consistent with those of the audited consolidated financial statements of Premier for the year ended 31 December 2019.

There are no qualifications in the auditor's reports on the consolidated financial statements of Premier for the years ended 31 December 2017, 31 December 2018 and 31 December 2019.

2. Cross-reference list

The following list is intended to enable investors to identify easily specific items of information which have been incorporated by reference into this document. The sections of the documents listed below which are not incorporated by reference are either not relevant to investors or are superseded by information elsewhere in this document.

2.1 2017 Annual Report and Financial Statements (for the financial year ended 31 December 2017)

- Independent Auditors' Report – pages 118 to 127.
- Consolidated Income Statement – page 134.
- Consolidated Statement of Comprehensive Income – page 135.
- Consolidated Balance Sheet – page 136.
- Consolidated Statement of Changes in Equity – page 137.
- Consolidated Cash Flow Statement – page 138.
- Notes to the Consolidated Financial Statements – pages 139 to 173.
- Business Performance reconciliation table — page 39.

2.2 2018 Annual Report and Financial Statements (for the financial year ended 31 December 2018)

- Independent Auditors' Report – pages 112 to 120.
- Consolidated Income Statement – page 128.
- Consolidated Statement of Comprehensive Income – page 129.
- Consolidated Balance Sheet – page 130.
- Consolidated Statement of Changes in Equity – page 131.
- Consolidated Cash Flow Statement – page 132.
- Notes to the Consolidated Financial Statements – pages 133 to 165.
- Business Performance reconciliation table – page 30.

2.3 2019 Annual Report and Financial Statements (for the financial year ended 31 December 2019)

- Independent Auditors' Report – pages 117 to 126.
- Consolidated Income Statement – page 134.

- Consolidated Statement of Comprehensive Income – page 135.
- Consolidated Balance Sheet – page 136.
- Consolidated Statement of Changes in Equity – page 137.
- Consolidated Cash Flow Statement – page 138.
- Notes to the Consolidated Financial Statements – pages 139 to 171
- Business Performance reconciliation table — page 46.

2.4 2020 Unaudited Interim financial Statements (for the half year ended 30 June 2020)

- Independent Review Report.
- Condensed Consolidated Income Statement.
- Condensed Consolidated Statement of Comprehensive Income.
- Condensed Consolidated Balance Sheet.
- Condensed Consolidated Statement of Changes in Equity.
- Condensed Consolidated Cash Flow Statement.
- Notes to the Condensed Financial Statements.

PART VIII

HISTORICAL FINANCIAL INFORMATION RELATING TO THE CHRYSAOR GROUP

This part of the Prospectus includes consolidated and combined Historical Financial Information as well as an accountant's reports thereon prepared by PricewaterhouseCoopers LLP and is set out in four sections as follows:

– Section A sets out PricewaterhouseCoopers LLP's report in respect of the consolidated - Historical Financial Information relating to the Chrysaor Group, as of and for the three and half years ended 30 June 2020;

– Section B sets out the Chrysaor Group's consolidated Historical Financial Information and includes the accounting policies and notes to the consolidated financial information;

– Section C sets out PricewaterhouseCoopers LLP's report in respect of the combined Historical Financial Information relating to the Combined COP Subsidiaries, as of and for the three years ended 31 December 2019; and

– Section D sets out the Combined COP Subsidiaries' financial information and includes the accounting policies and notes to the combined financial information.

SECTION A

ACCOUNTANT'S REPORT IN RESPECT OF THE HISTORICAL FINANCIAL INFORMATION RELATING TO THE CHRYSAOR GROUP

The Directors and Proposed Directors (together the "Directors")
Premier Oil plc
23 Lower Belgrave St
Belgravia
London SW1W 0NR
United Kingdom

RBC Europe Limited
100 Bishopsgate
London EC2N 4AA
United Kingdom

16 December 2020

Dear Ladies and Gentlemen

The reverse takeover of Premier Oil plc ("Premier") by Chrysaor Holdings Limited ("Chrysaor") and the proposed readmission of the ordinary shares of Premier to the premium segment of the Official List maintained by the Financial Conduct Authority (the "FCA") and the proposed admission of those shares to trading on the London Stock Exchange's main market for listed securities (the "Transaction").

We report on the financial information of Chrysaor for the three years ended 31 December 2017, 31 December 2018 and 31 December 2019 and for the six months ended 30 June 2020 set out in section B of Part VIII below (the "**Historical Financial Information relating to the Chrysaor Group**").

This report is required by item 18.3.1 of Annex 1 to the PR Regulation and is given for the purpose of complying with that item and for no other purpose.

We have not audited or reviewed the financial information for the six months ended 30 June 2019 which has been included for comparative purposes only, and accordingly do not express an opinion thereon.

Opinion on financial information

In our opinion, the Historical Financial Information relating to the Chrysaor Group gives, for the purposes of the prospectus dated 16 December 2020 (the "**Prospectus**") of Premier, a true and fair view of the state of affairs of the Chrysaor Group as at the dates stated and of its profits and losses, cash flows and changes in equity for the years ended 31 December 2017, 31 December 2018 and 31 December 2019 and for the six months ended 30 June 2020 in accordance with International Financial Reporting Standards as adopted by the European Union.

Responsibilities

The Proposed Directors and the Directors of Premier (together the "**Directors**") are responsible for preparing the Historical Financial Information relating to the Chrysaor Group in accordance with International Financial Reporting Standards as adopted by the European Union.

PricewaterhouseCoopers LLP, 1 Embankment Place, London, WC2N 6RH

Tel: +44 (0) 20 7583 5000, Fax: +44 (0) 20 7212 4652

It is our responsibility to form an opinion on the Historical Financial Information relating to the Chrysaor Group and to report our opinion to you.

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and for any responsibility arising under item 5.3.2R(2)(f) of the Prospectus Regulation Rules 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 PR Regulation, consenting to its inclusion in the Prospectus.

Basis of Preparation

The Historical Financial Information relating to the Chrysaor Group has been prepared for inclusion in the Prospectus of Premier on the basis of the accounting policies set out in Note 1 to 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. 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.

Our work included an assessment of evidence relevant to the amounts and disclosures in the Historical Financial Information relating to the Chrysaor Group. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the entity's circumstances, consistently applied and adequately disclosed.

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 financial information is free from material misstatement whether caused by fraud or other irregularity or error.

Conclusions Relating to Going Concern

We are required to report if we have anything material to add or draw attention to in respect of the Directors' statement in the Historical Financial Information relating to the Chrysaor Group about whether the Directors considered it appropriate to adopt the going concern basis of accounting in preparing the Historical Financial Information relating to the Chrysaor Group and the Directors' identification of any material uncertainties to Chrysaor's ability to continue as a going concern over a period of at least twelve months from the date of this Prospectus.

We have nothing material to add or to draw attention to. However, because not all future events or conditions can be predicted, this statement is not a guarantee as to Chrysaor's ability to continue as a going concern.

Declaration

For the purposes of Prospectus Regulation Rule PRR 5.3.2 R (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 make 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

PricewaterhouseCoopers LLP
Chartered Accountants

SECTION B

HISTORICAL FINANCIAL INFORMATION RELATING TO THE CHRYSAOR GROUP

Consolidated Income Statement

	Note	For the years ended 31 December			For the six months ended	
		2017 audited $000	2018 audited $000	2019 audited $000	30 June 2020 audited $000	30 June 2019 unaudited $000
Revenue	4	313,500	1,965,602	2,357,789	1,230,054	1,055,064
Other income	4	—	—	8,995	13,570	—
Revenue and other income		313,500	1,965,602	2,366,784	1,243,624	1,055,064
Cost of sales		(190,146)	(1,120,867)	(1,516,498)	(1,018,015)	(568,336)
Gross profit		123,354	844,735	850,286	225,609	486,728
Impairment of property, plant and equipment	12	—	—	—	(250,629)	—
Impairment of Goodwill	10	—	—	—	(55,735)	—
Provision for onerous service contracts	21	—	—	—	(27,943)	—
Exploration and evaluation expenses	5	(11,323)	(7,917)	(15,033)	(4,190)	(8,077)
Exploration costs written-off	5	(7,276)	(10,731)	(222)	(38,851)	(132)
Loss on disposal of exploration and evaluation asset	11	—	—	—	(55)	—
Remeasurements	5	(30,204)	810	2,974	473	(21,336)
General and administrative expenses		(29,447)	(24,687)	(75,488)	(29,201)	(22,255)
Operating profit/(loss)		45,104	802,210	762,517	(180,522)	434,928
Finance income	7	260	46,484	31,611	105,068	10,190
Finance expenses	7	(44,893)	(270,293)	(338,570)	(148,768)	(121,413)
Profit/(loss) before taxation		471	578,401	455,558	(224,222)	323,705
Income tax (expense)/credit	9	258,527	(209,501)	(236,711)	69,771	(149,327)
Profit/(loss) for the financial period		258,998	368,900	218,847	(154,451)	174,378

Consolidated Statement of Comprehensive Income

	For the years ended 31 December			For the six months ended	
	2017 audited $000	2018 audited $000	2019 audited $000	30 June 2020 audited $000	30 June 2019 unaudited $000
Profit for the financial period	258,998	368,900	218,847	(154,451)	174,378
Fair value (losses)/gains on cash flow hedges	(72,911)	447,840	(53,722)	520,306	(283,255)
Tax credit/(expense) on cash flow hedges	29,164	(179,584)	21,625	(210,167)	113,302
Share based payments (1)	—	—	10,905	—	—
Currency exchange differences	8,287	(20,763)	99,787	(135,216)	(911)
Total other comprehensive income for the financial period, net of tax	(35,460)	247,493	78,595	174,923	(170,864)
Total comprehensive income for the financial period	223,538	616,393	297,442	20,472	3,514
Total comprehensive income attributable to:					
Equity holders of the parent	223,538	616,393	297,442	20,472	3,514

(1) Only item above not expected to be reclassified subsequently to the income statement.

Consolidated Balance Sheet

	Note	As at 31 December			As at 30 June
		2017 audited $000	2018 audited $000	2019 audited $000	2020 audited $000
Assets					
Non-current assets					
Goodwill	10	500,080	493,084	1,404,334	1,343,616
Other intangible assets	11	59,022	73,531	453,604	492,119
Property, plant and equipment	12	4,235,792	3,729,223	7,656,530	6,519,213
Right of use assets	13	—	—	221,223	144,016
Other receivables	17	—	—	2,604	2,871
Other financial assets	23	14,673	191,514	202,230	313,531
Total non-current assets		4,809,567	4,487,352	9,940,525	8,815,366
Current assets					
Inventories	16	91,563	89,791	146,881	153,044
Trade and other receivables	17	258,499	231,530	474,118	269,432
Other financial assets	23	3,000	299,049	193,888	614,390
Cash and cash equivalents	18	299,541	316,311	573,182	369,391
Total current assets		652,603	936,681	1,388,069	1,406,257
Total assets		5,462,170	5,424,033	11,328,594	10,221,623
Equity and liabilities					
Equity					
Share capital	25	22	22	71	71
Share premium		234,801	234,801	910,020	910,020
Cash flow hedge reserve		(43,747)	219,678	176,123	494,048
Costs of hedging reserve		—	4,831	16,289	8,503
Currency translation reserve		(2,419)	(23,182)	76,605	(58,611)
Retained earnings		131,192	500,092	729,844	575,393
Equity		319,849	936,242	1,908,952	1,929,424
Total equity		319,849	936,242	1,908,952	1,929,424
Non-current liabilities					
Borrowings	22	2,414,333	1,709,317	2,205,322	2,170,189
Provisions	21	1,758,712	1,475,734	3,766,739	3,368,416
Deferred tax	9	374,606	768,746	1,649,290	1,564,731
Trade and other payables	20	—	—	52,375	46,420
Lease creditor	13	—	—	145,403	96,384
Other financial liabilities	23	72,740	75,486	3,663	14,547
Total non-current liabilities		4,620,391	4,029,283	7,822,792	7,260,687
Current liabilities					
Trade and other payables	20	478,492	296,434	676,436	556,103
Borrowings	22	—	95,572	617,363	11,886
Lease creditor	13	—	—	79,525	53,782
Current tax liabilities		1,028	—	—	202,926
Provisions	21	—	—	183,081	206,704
Other financial liabilities	23	42,410	66,502	40,445	111
Total current liabilities		521,930	458,508	1,596,850	1,031,512
Total liabilities		5,142,321	4,487,791	9,419,642	8,292,199
Total equity and liabilities		5,462,170	5,424,033	11,328,594	10,221,623

Consolidated Statement of Changes in Equity

	Note	Share capital $000	Share premium $000	Cash flow hedge reserve $000	Costs of hedging reserve $000	Currency translation reserve $000	Undeclared dividend reserve $000	Share option reserve $000	(Accumulated losses)/ retained earnings $000	Total equity
As at 1 January 2017		1,794	167,437	—	—	(10,706)	154,498	65	(257,540)	55,548
Profit for the financial year		—	—	—	—	—	—	—	258,998	258,998
Other comprehensive (loss)/income		—	—	(43,747)	—	8,287	—	—	—	(35,460)
Share options exercised		2	59	—	—	—	—	(65)	8	4
Cumulative dividends not paid		—	—	—	—	—	2,084	—	(2,084)	—
Cancellation of undeclared dividends	25	—	—	—	—	—	(156,582)	—	156,582	—
Cancellation of shares		(1,796)	—	—	—	—	—	—	(24,756)	(26,552)
Issue of new shares		22	67,918	—	—	—	—	—	(16)	67,924
Share issue expenses		—	(613)	—	—	—	—	—	—	(613)
As 31 December 2017 (audited)		22	234,801	(43,747)	—	(2,419)	—	—	131,192	319,849
Profit for the financial year		—	—	—	—	—	—	—	368,900	368,900
Total comprehensive income/(loss)		—	—	263,425	4,831	(20,763)	—	—	—	247,493
At 31 December 2018 (audited)		22	234,801	219,678	4,831	(23,182)	—	—	500,092	936,242
Profit for the financial year		—	—	—	—	—	—	—	218,847	218,847
Issue of new shares	25	49	675,219	—	—	—	—	—	—	675,268
Share based payments	5	—	—	—	—	—	—	—	10,905	10,905
Total comprehensive (loss)/income		—	—	(43,555)	11,458	99,787	—	—	—	67,690
At 31 December 2019 (audited)		71	910,020	176,123	16,289	76,605	—	—	729,844	1,908,952
Loss for the half year		—	—	—	—	—	—	—	(154,451)	(154,451)
Total comprehensive profit/(loss)		—	—	317,925	(7,786)	(135,216)	—	—	—	174,923
At 30 June 2020 (audited)		71	910,020	494,048	8,503	(58,611)	—	—	575,393	1,929,424

Consolidated Statement of Cash Flows

		For the years ended 31 December			For the six months ended	
	Note	2017 audited $000	2018 audited $000	2019 audited $000	30 June 2020 audited $000	30 June Unaudited $000
Net cash inflow from operating activities	26	54,027	1,447,842	1,518,661	946,096	774,222
Cash flows from investing activities						
Expenditure on exploration and evaluation assets		(8,818)	(28,801)	(82,634)	(46,519)	(43,266)
Expenditure on property, plant and equipment		(26,715)	(313,406)	(439,706)	(274,820)	(180,722)
Expenditure on non-oil and gas intangible assets		—	(7,956)	(7,937)	(32,882)	(4,394)
Proceeds from sale of exploration and evaluation asset		—	—	—	20	—
Expenditure on business combinations and acquisitions net of cash acquired		(2,062,302)	(240,360)	(2,255,236)	(12,495)	(302,579)
Interest received		260	8,622	9,453	3,460	4,662
Net cash (outflow) from investing activities		(2,097,575)	(581,901)	(2,776,060)	(363,236)	(526,299)
Cash flows from financing activities						
Repayment of borrowings	22,26	—	(735,000)	(200,000)	(634,000)	(200,000)
Proceeds from new financing arrangement	22,26	—	20,400	29,600		15,000
Proceeds from share issue		67,313	—	4	—	—
Redemption of loan notes		—	—	—	(46,860)	—
Proceeds from new borrowings	22,26	2,272,026	—	1,843,275	2,596	—
Lease payments		—	—	(20,598)	(32,649)	(471)
Interest paid and bank charges		(29)	(132,825)	(143,914)	(75,332)	(89,709)
Net cash inflow/(outflow) from financing activities		2,339,310	(847,425)	1,508,367	(786,245)	(275,180)
Net increase/(decrease) in cash and cash equivalents		295,762	18,516	250,968	(203,385)	(27,257)
Effect of exchange rates on cash and cash equivalents		(303)	(1,746)	5,903	(406)	359
Cash and cash equivalents at beginning of period		4,082	299,541	316,311	573,182	316,311
Cash and cash equivalents at end of period	18	299,541	316,311	573,182	369,391	289,413

Notes to the Financial Statements

1. Corporate Information

The consolidated financial statements of Chrysaor Holdings Limited for the years ended 31 December 2017 to 2019 and for the six month periods ended 30 June 2020 and 30 June 2019, which comprise the parent company, Chrysaor Holdings Limited ("**Chrysaor**") and all its subsidiaries (the "**Chrysaor Group**"), were authorised for issue in accordance with a resolution of the directors on 10 December 2020. Chrysaor is a private company limited by share capital incorporated in the Cayman Islands and domiciled in the United Kingdom. Chrysaor's registered office is Ugland House, South Church Crescent, George Town, Grand Cayman.

The Chrysaor Group's principal activities are the acquisition, exploration, development and production of oil and gas reserves on the UK and Norwegian Continental Shelves.

2. Accounting Policies

Basis of Preparation

The principal accounting policies applied in the preparation of the consolidated historical financial information are set out below. These policies have been consistently applied to all the periods presented, unless otherwise stated. The financial information presented is at and for the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019, and the six-month periods to 30 June 2020, and 30 June 2019 (which is unaudited). Financial year and period ends have been referred to as 31 December and 30 June throughout the consolidated historical financial information as per the Chrysaor Group's accounting reference date. Financial years are referred to as 2017, 2018 and 2019 in this historical financial information.

The consolidated financial statements of the Chrysaor Group have been prepared on a going concern basis in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**") and as adopted by the European Union. The Chrysaor Group financial statements are presented in US Dollars ("**USD**") and all values are rounded to the nearest thousand dollars ($'000) except when otherwise stated.

The financial statements have been prepared on the historical cost basis, except for certain financial assets and liabilities (including derivative financial instruments) which have been measured at fair value and assets classified as held for sale which are carried at fair value less cost to sell.

The accounting policies which follow set out those policies which apply in preparing the financial statements for the year ended 31 December 2019. All accounting policies have been applied consistently other than where new policies have been adopted.

The Chrysaor Group historical financial information has been prepared under accounting policies consistent with those of Premier Oil plc in its last published Annual Report.

Basis of Consolidation

The Chrysaor Group financial statements consolidate the financial statements of Chrysaor and its subsidiary undertakings drawn up to each 31 December financial year-end and each 30 June period-end. Subsidiaries are those entities over which the Chrysaor Group has control. Control is achieved where Chrysaor has the power over the subsidiary, is exposed, or has rights to variable returns from the subsidiary and has the ability to use its power to affect its returns. All subsidiaries are 100 per cent. owned by Chrysaor and therefore the Chrysaor Group does not have any non-controlling interests.

All intercompany balances have been eliminated on consolidation.

New Accounting Standards and Interpretations

The Chrysaor Group adopted new and revised accounting standards and interpretations relevant to its business and effective for accounting periods beginning on or after 1 January 2017, including:

IFRS 9 Financial Instruments

The classification and measurement of financial assets has changed with the implementation of IFRS 9. However, this has not materially changed the measurement of financial assets of the Chrysaor Group. The IFRS 9 impairment model requiring the recognition of 'expected credit losses', in contrast to the requirement to recognise 'incurred credit losses' under IAS 39, has not had a material impact on the Chrysaor Group's financial statements. Trade receivables are generally settled on a short time frame and the Chrysaor Group's other financial assets are due from counterparties without material credit risk concerns at the time of transition.

IFRS 15 Revenue from Contracts with Customers

The implementation of IFRS 15 has not impacted the presentation of the Chrysaor Group's sales revenue. Disclosure of disaggregated revenue information consistent with the requirement included in IFRS 15 has not had an impact on the information presented in note 4. The Chrysaor Group's accounting policy under IFRS 15 is detailed within "Revenue from Contracts with Customers" and does not, therefore, represent a substantive change from the Chrysaor Group's previous accounting policy for recognising revenue from sales to customers.

IFRS 16 Leases

The Chrysaor Group adopted IFRS 16 'Leases' from the effective date of 1 January 2019. IFRS 16 replaced the previous standard on accounting for leases, IAS 17, and the related interpretations. Transition to IFRS 16 was made in accordance with the modified retrospective approach and therefore, the prior year figures have not been adjusted. As part of the project conducted on initial application, the Chrysaor Group used the practical expedient within the standard not to reassess whether a contract contains a lease and also not to recognise right of use assets and liabilities for leases where the total lease term is less than or equal to 12 months, or for leases of low value. The main effect on the Group is that IFRS 16 has introduced a single lessee accounting model and requires a lessee to recognise assets and liabilities for all leases where the practical expedients above are not applicable.

From 1 January 2019, 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 Chrysaor Group. These liabilities 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 Chrysaor Group assuming leases run to full term with no break clauses exercised. These liabilities are discounted using the lessee's incremental borrowing rate as of 1 January 2019, being the rate that the Chrysaor Group 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. The weighted average lessee's incremental borrowing rate applied to the lease liabilities on 1 January 2019 was 5.9 per cent.. 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. The right-of-use asset is depreciated over the lease term on a straight-line basis.

The Chrysaor Group 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 Chrysaor Group is reasonably certain to exercise such options impacts the lease term, which significantly impacts the amount of lease liabilities and right-of-use assets recognised.

The impact of the adoption of the leasing standard and the new accounting policies are disclosed in note 13.

Amendments to IFRS 3: Definition of a Business

In October 2018, the IASB issued amendments to the definition of a business in IFRS 3 Business Combinations to help entities determine whether an acquired set of activities and assets is a business or not. They clarify the minimum requirements for a business, remove the assessment of whether market participants are capable of replacing any missing elements, add guidance to help entities assess whether an acquired process is substantive, narrow the definitions of a business and of outputs, and introduce an optional fair value concentration test. New illustrative examples were provided along with the amendments. This amendment is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after 1 January 2020, and to asset acquisitions that occur on or after the beginning of that period. Application of this amendment will be effective post EU endorsement.

Since the amendments apply prospectively to transactions or other events that occur on or after the date of first application, the Chrysaor Group has not been affected by these amendments on the date of transition.

Amendments to IAS 1 and IAS 8: Definition of Material

In October 2018, the IASB issued amendments to IAS 1 Presentation of Financial Statements and IAS 8 Accounting Policies, Changes in Accounting Estimates and Errors to align the definition of 'material' across the standards and to clarify certain aspects of the definition. The new definition states that, 'Information is material if omitting, misstating or obscuring it could reasonably be expected to influence decisions that the primary users of general purpose financial statements make on the basis of those financial statements, which provide financial information about a specific reporting entity.'

The amendments to the definition of material has not had a significant impact on the Chrysaor Group's consolidated financial statements.

The other pronouncements did not have any impact on the Chrysaor Group's accounting policies and did not require retrospective adjustments.

Accounting Standards Issued but Not Yet Effective

The new and amended standards and interpretations that are issued, but not yet effective, up to the date of issuance of the Chrysaor Group's financial statements are disclosed below. The Chrysaor Group intends to adopt these new and amended standards and interpretations, if applicable, when they become effective.

IFRS17 Insurance Contracts

IFRS 17 is effective for annual reporting periods beginning on or after 1 January 2023 with earlier application permitted as long as IFRS 9 is also applied. The standard combines current measurement of the future cash flows with the recognition of profit over the period that services are provided under the contract. Insurance service results (including presentation of insurance revenue) are presented separately from insurance finance income or expenses. It also requires an entity to make an accounting policy choice of whether to recognise all insurance finance income or expenses in profit or loss or to recognise some of that income or expenses in other comprehensive income. The Chrysaor Group does not expect any existing contracts to be impacted by the new standard however, this will be assessed closer to adoption of 1 January 2023.

Amendments to IAS 1, 'Presentation of financial statements' – Classification of liabilities as current or non-current

On 23 January 2020, the 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. The Chrysaor Group will consider if its liabilities are either current or non-current when the standard is effective from 1 January 2022.

IBOR reform and the effects on financial reporting

The International Accounting Standards Board ("**IASB**") issued Interest Rate Benchmark Reform—Phase 2, which amends IFRS 9 Financial Instruments, IAS 39 Financial Instruments: Recognition and Measurement, IFRS 7 Financial Instruments: Disclosures, IFRS 4 Insurance Contracts and IFRS 16 Leases. IASB identified two groups of accounting issues that could have financial reporting implications. In 2019, the Board issued its initial amendments in Phase 1 of the project, applicable to 2020 reporting, it covers reporting in the period before the replacement of an existing interest rate benchmark with an alternative RFR (Risk Free Rate). This addressed hedge accounting requirements: the highly probable requirement; prospective assessments; and separately identifiable risk components. The Chrysaor Group has assessed the requirements of Phase 1 which apply for the first time in 2020, none of which impact the financial statements of the Chrysaor Group because there is no material hedge accounting of interest rate exposures. Phase 2 addresses financial reporting when an existing interest rate benchmark is replaced with an alternative RFR, including the effects of changes to contractual cash flows or hedging relationships arising from the replacement of an interest rate benchmark with an alternative benchmark rate (replacement issues). The Chrysaor Group has not early adopted Phase 2 requirements.

Segment Reporting

The Chrysaor Group's activities consist of one class of business – the acquisition, exploration, development and production of oil and gas reserves and related activities in two geographical areas presently being the UK North Sea and the Norwegian North Sea.

Pensions

Contributions made to defined contribution pension schemes are recognised in the income statement in the period in which they become payable.

Joint Arrangements

Exploration and production operations are usually conducted through joint arrangements with other parties. The Chrysaor Group reviews all joint arrangements and classifies them as either joint operations or joint ventures depending on the rights and obligations of each party to the arrangement and whether the arrangement is structured through a separate vehicle. All interests in joint arrangements held by the Chrysaor Group are classified as joint operations.

In relation to its interests in joint operations, the Chrysaor Group recognises its:

- Assets, including its share of any assets held jointly
- Liabilities, including its share of any liabilities incurred jointly
- Revenue from the sale of its share of the output arising from the joint operation
- Share of the revenue from the sale of the output by the joint operation, and
- Expenses, including its share of any expenses incurred jointly

Foreign Currency Translation

Each entity in the Chrysaor Group determines its own functional currency, 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 consolidated financial statements are presented in US Dollars.

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, the assets and liabilities of the Chrysaor Group's operations 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 period. 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 Chrysaor Group's translation reserve.

Business Combinations

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the fair value of the assets transferred, equity instruments issued and liabilities incurred or assumed at the date of completion of the acquisition. Acquisition costs incurred are expensed and included in administrative expenses. Where applicable, the consideration for the acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its fair value at acquisition.

The identifiable assets, liabilities and contingent liabilities acquired that meet the conditions for recognition under IFRS 3 are recognised at their fair value at the acquisition date, except that:

- Deferred tax assets or liabilities and liabilities or assets related to employee benefit arrangements are recognised and measured in accordance with IAS 12 Income Taxes and IAS 19 Employee Benefits respectively.

- Liabilities or equity instruments related to the replacement by the Chrysaor Group of an acquirer's share-based payment awards are measured in accordance with IFRS 2 Share-based Payment, and
- Assets (or disposal groups) that are classified as held for sale in accordance with IFRS 5 Non-current Assets Held for Sale and discontinued operations are measured in accordance with that Standard.

If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Chrysaor Group reports provisional amounts for the items for which the accounting is incomplete. Those provisional amounts are adjusted during the measurement period, or additional assets or liabilities are recognised to reflect new information obtained about facts and circumstances that existed as of the acquisition date that, if known, would have affected the amounts recognised as of that date. The measurement period is the period from the date of acquisition to the date the Chrysaor Group obtains complete information about facts and circumstances that existed as of the acquisition date, subject to a maximum of one year.

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. Goodwill is initially measured at cost. Following initial recognition, goodwill is measured at cost less any accumulated impairment. Goodwill is treated as an asset of the relevant entity to which it relates and accordingly non-US Dollar goodwill is translated into US Dollars at the closing rate of exchange at each reporting date.

Goodwill, as disclosed in note 10, is reviewed for impairment at least annually by assessing the recoverable amount of the cash generating units to which the goodwill relates. Where the carrying amount of the cash generating unit and related goodwill is higher than the recoverable amount of the cash generating unit, an impairment loss is recognised.

Intangible Assets – Exploration and Evaluation Assets

Exploration and evaluation expenditure is accounted for using the successful efforts method of accounting.

(a) Pre-Licence Costs

Pre-licencing costs are expensed in the period in which they are incurred.

(b) Licencing 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 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. 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.

(c) 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 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. No amortisation is charged during the exploration and evaluation phase.

(d) Farm-Outs – In the Exploration and Evaluation Phase

The Chrysaor Group does not record any expenditure made by the farmee on its account. It also does not recognise any gain or loss on its exploration and evaluation farm-out arrangements but re-designates any costs previously capitalised in relation to the whole interest as relating to the partial interest retained. Any cash consideration received directly from the farmee is credited against costs previously capitalised in relation to the whole interest with any excess accounted for by the farmor as a gain on disposal.

Property, Plant and Equipment – Oil and Gas Development and Production Assets

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells including unsuccessful development or delineation wells, 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 (where relevant), 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. Until the adoption of IFRS 16 Leases, the capitalised value of a finance lease was included within property, plant and equipment within the Chrysaor Group's financial statements.

All costs relating to a development are accumulated and not depreciated until the commencement of production. Depreciation is provided using the unit of production method based on proved plus probable reserves. When there is a change in the estimated total recoverable proved plus probable reserves of a field, that change is accounted for prospectively in the depreciation charge over the revised remaining proved plus probable reserves.

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 from its use or disposal. 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 refits, inspections or repairs comprises 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 Chrysaor Group, the expenditure is capitalised. All other day-to-day repairs and maintenance costs are expensed as incurred.

Fixtures and Fittings and Office Equipment

Fixtures and fittings and office equipment (non-oil and gas property, plant and equipment) is stated at cost less accumulated depreciation and impairment. Depreciation is provided for on a straight-line basis at rates sufficient to write off the cost of the asset less any residual value over their estimated useful economic lives. The depreciation periods for the principal categories of assets are as follows:

Fixtures and fittings	Up to 10 years
Office furniture and equipment	Up to 5 years

Intangible assets

Intangible assets, which principally comprise IT software, are carried at cost less any accumulated amortisation. These assets are amortised on a straight-line basis over their useful economic lives of up to three years.

Impairment of Non-Current Assets (excluding goodwill)

The Chrysaor Group assesses, at each reporting date, whether there is an indication that an asset may be impaired. If any indication exists, the Chrysaor Group 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.

Financial Instruments

a. Financial Assets

Chrysaor uses two criteria to determine the classification of financial assets: Chrysaor's business model and contractual cash flow characteristics of the financial assets. Where appropriate Chrysaor 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 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 at bank and in hand in the balance sheet comprise cash deposits with banks and in hand.

Impairment of Financial Assets

Chrysaor recognises an allowance for expected credit losses ("**ECLs**") for all debt instruments not held at fair value through profit or loss. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that Chrysaor expects to receive, discounted at an approximation of the original 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). 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 Chrysaor Group applies a simplified approach in calculating ECLs. 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 and the economic environment and the Chrysaor Group's historical credit loss experience.

Credit Impaired Financial Assets

At each reporting date, the Chrysaor Group 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 Chrysaor Group on terms that the Chrysaor Group would otherwise not consider

— it is becoming probable that the borrower will enter bankruptcy or other financial reorganisation, – or the disappearance of an active market for a security because of financial difficulties

b. Financial Liabilities

Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, loans and borrowings, payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate. All financial liabilities are recognised initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs.

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 accrual basis in the income statement using the effective interest 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 or 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.

c. Derivative Financial Instruments

Derivative financial instruments are initially recognised and subsequently re-measured at fair value. Certain derivative financial instruments are designated as cash flow hedges in line with Chrysaor's risk management policies. When derivatives do not qualify for hedge accounting or are not designated as accounting hedges, changes in the fair value of the instrument 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 and subsequently transferred to the income statement in the period the hedged transaction is recognised in the income statement. 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 could arise if volumes of the hedging instruments are greater than the hedged item of production, or where the credit worthiness of the counterparty is significant and may dominate the transaction and lead to losses.

d. Fair Values

The fair value of financial instruments that are traded in active markets at the reporting date is determined by reference to quoted market prices or dealer price quotations, without any deduction for transaction costs.

For financial instruments not traded in an active market, the fair value is determined using appropriate valuation techniques.

Equity

Share Capital

Share capital includes the total net proceeds, both nominal and share premium, on the issue of ordinary and preference shares of Chrysaor.

Cash Flow Hedge Reserves

The cash flow hedge and cost of hedging reserves represents gains and losses on derivatives classified as effective cash flow hedges.

Currency Translation Reserve

This reserve comprises exchange differences arising on consolidation of the Chrysaor Group's operations with a functional currency other than the USD.

Share Based Payments

The Chrysaor Group has applied the requirements of IFRS 2 Share-based Payments. The Chrysaor Group has share-based awards that are equity and cash settled as defined by IFRS 2. The fair value of the equity settled awards has been determined at the date of grant of the award allowing for the effect of any market-based conditions. For cash-settled awards, a liability is recognised for the goods or service acquired. This is measured initially at the fair value of the liability. The fair value of the liability is subsequently remeasured at each balance sheet date until the liability is settled, and at the date of settlement, with any changes in fair value recognised in the income statement.

Inventories

Hydrocarbon inventories are stated at net realisable value with movements recognised in the income statement. All other inventories are stated at the lower of cost and net realisable value. The cost of materials is the purchase cost, determined on a first-in, first-out basis.

Provisions for Liabilities

A provision is recognised when the Chrysaor Group 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 at the commencement of oil and gas production. The amount provided is the present value of the estimated future restoration cost. A non-current asset is also recognised. Any changes to estimated costs or discount rates are dealt with prospectively.

Trade Payables

Initial recognition of trade payables is at fair value. Subsequently they are stated at amortised cost.

Taxes

i. 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 the Chrysaor Group 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.

ii. 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:

- 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 reporting date.
- 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 the Chrysaor Group to make a single net payment.

Revenue from Contracts with Customers

Revenue from contracts with customers is recognised when Chrysaor 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. Revenue associated with the sale of crude oil, natural gas, and natural gas liquids 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. The transfer of control of oil, natural gas, natural gas liquids and other items sold by Chrysaor occurs when title passes at the point the customer takes physical delivery. Chrysaor principally satisfies its performance obligations at this point in time.

Over/Underlift

Revenues from the production of oil and natural gas properties in which the Chrysaor Group has an interest with partners are recognised based on the Chrysaor Group's working interest in those properties (the entitlement method). Differences between the production sold and the Chrysaor Group's share of production result in an overlift or an underlift. Overlift and underlift are valued at market value and included within payables or receivables respectively. Movements during the accounting period are recognised within cost of sales in the income statement such that gross profit is recognised on an entitlement basis.

Interest Income

Interest income is recognised on an accruals basis, by reference to the principal outstanding and at the effective interest rate method.

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.

Critical Accounting Judgements and Estimates

The preparation of the Chrysaor Group's financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions at the date of the financial statements. 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 Chrysaor Group have identified the following areas where significant judgement, estimates and assumptions are required.

- *Exploration and Evaluation Expenditure*

  As at 30 June 2020, the Chrysaor Group held a balance of US$439.8 million (as at 31 December 2019: US$425.3 million, 30 June 2019: US$92.7 million, 31 December 2018: US$52.5 million, 31 December 2017: US$35.5 million) relating to expenditure on unproved hydrocarbon resources within other intangible assets which represent active exploration and evaluation activities. The application of the Chrysaor Group'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.

- *Goodwill*

  The Chrysaor Group 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 cash generating unit ("**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.

Key Sources of Estimation Uncertainty

- *Recoverability of Oil and Gas Assets*

  The Chrysaor Group assesses each asset or cash generating unit each reporting period to determine whether any indication of impairment exists. 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. The assessments of fair value less cost of disposal 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.

  The Chrysaor Group'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 2 per cent. change in the post-tax discount rate are considered to be reasonably possible for the purposes of sensitivity analysis, the result of which can be found in notes 10 and 12.

- *Decommissioning Costs*

  Decommissioning costs will be incurred by the Chrysaor Group at the end of the operating life of most of the Chrysaor Group's facilities and properties. The Chrysaor Group assesses its decommissioning provision at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors including 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 10 per cent. decrease in the discount rates used to assess the final decommissioning obligation at 30 June 2020, would result in increases to the decommissioning provision of US$440 million and US$62 million respectively. This change would be principally offset by a change to the value of the associated asset.

- *Accounting for Business Combinations*

  On 1 November 2017, the Chrysaor Group acquired a package of assets in the UK North Sea from Shell for a price of US$3.0 billion with further payments between the two companies contingent upon future exploration results and commodity prices. The transaction comprised the direct acquisition of interests in certain joint operations and the acquisition of 100 per cent. of the issued share capital of the former Shell entity, BG International (CNS) Limited.

  On 30 September 2019, the Chrysaor Group acquired the UK business of ConocoPhillips for a total consideration of US$2.5 billion, with the final value of consideration still under negotiation in accordance with the terms of the sales agreement.

  The acquisition accounting for both transactions is set out in note 15 to these financial statements.

  In completing the accounting, management have been required to make estimates relating to the fair value of the assets and liabilities acquired. In particular, estimates have been made in assessing the valuation of tangible and intangible oil and gas assets, and decommissioning liabilities. The fair value of net assets acquired are primarily determined using discounted cashflow techniques using available data at the time of acquisition. For oil and gas assets, the Chrysaor Group estimates future cash flows from an assessment of economically recoverable reserves and discounts them to present value using a rate reflecting market assessments at the time value of money and risks specific to the asset. Determining the fair value of oil and gas assets requires the Chrysaor Group to apply long term assumptions of commodity prices.

The Chrysaor Group assesses the fair value of decommissioning liabilities based on the expected timing, extent and amount of expenditure using data available at the time of acquisition. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques or experience at production sites. The expected timing of expenditure can also change, and as a result there could be significant adjustments to the provisions which could affect future financial results.

- *Recovery of deferred tax assets*

  Deferred tax assets, including those arising from un-utilised tax losses, require management to estimate and assess the likelihood that the Chrysaor Group will generate sufficient taxable earnings in future periods, in order to utilise recognised deferred tax assets. Assumptions about the generation of future taxable income are based on forecasted cash flows from operations and judgement about the application of existing tax laws. Judgement is required to determine whether deferred tax assets are recognised in the balance sheet. Following completion of the transaction with Shell in 2017, the foreseeable future taxable profits of the Chrysaor Group increased sufficiently to allow previously unrecognised deferred tax associated with pre-acquisition losses to be recognised in full.

- *Climate Change*

  The Chrysaor Group recognises that there may be potential financial implications in the future from climate change risk. The Chrysaor Group expects that climate change policies, legislation and regulation will increase, and likely on accelerating timelines which, although will result in intended benefits, is likely to increase associated costs and administration requirements as well as potentially limiting the investment capital available to the industry. 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 at the balance sheet date the Chrysaor Group 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.

3. Segment Information

The chief operating decision maker, who is responsible for allocating resources and assessing performance of the Chrysaor Group's business segments, has been identified as the Chief Executive Officer.

The Chrysaor Group's activities consist of one class of business being the acquisition, exploration, development and production of oil and gas reserves and related activities, and are split geographically and managed in two regions, namely the UK North Sea and the Norwegian North Sea. The Norwegian business unit currently does not generate revenue or have any material operating income, and as such all revenues are attributable to the UK.

Information on major customers can be found in note 4.

Income statement	Year ended 31 December 2017 $000	Year ended 31 December 2018 $000	Year ended 31 December 2019 $000	Six months ended 30 June 2020 $000	Six months ended 30 June 2019 $000
UK	45,104	810,159	772,820	(177,397)	442,992
Norway	—	(7,949)	(10,303)	(3,125)	(8,064)
Chrysaor Group Operating Profit/(Loss)	45,104	802,210	762,517	(180,522)	434,928
Finance income	260	46,484	31,611	105,068	10,190
Finance expenses	(44,893)	(270,293)	(338,570)	(148,768)	(121,413)
Profit/(loss) before income tax	471	578,401	455,558	(224,222)	323,705
Income tax expense	258,527	(209,501)	(236,711)	69,771	(149,327)
Profit/(loss) for the financial period	258,998	368,900	218,847	(154,451)	174,378

Balance sheet ***Segment assets***	*2017 $000*	*2018 $000*	*2019 $000*	*30 June 2020 $000*
UK	5,462,170	5,415,424	11,296,039	10,178,260
Norway	—	8,609	32,555	43,363
Total assets	5,462,170	5,424,033	11,328,594	10,221,623

Segment liabilities	*2017 $000*	*2018 $000*	*2019 $000*	*30 June 2020 $000*
UK	(5,142,321)	(4,477,140)	(9,404,440)	(8,262,232)
Norway	—	(10,651)	(15,202)	(29,967)
Total liabilities	(5,142,321)	(4,487,791)	(9,419,642)	(8,292,199)

Other information ***Capital expenditure***	*2017 $000*	*2018 $000*	*2019 $000*	*30 June 2020 $000*
UK	66,665	409,104	574,342	305,600
Norway	—	762	5,670	11,200
Total capital expenditure	66,665	409,866	580,012	316,800

	Year ended 31 Dec 2017 $000	*Year ended 31 Dec 2018 $000*	*Year ended 31 Dec 2019 $000*	*Six months ended 30 June 2020 $000*	*Six months ended 30 June 2019 $000*
Depreciation, depletion & amortisation					
UK	100,847	629,134	916,603	723,222	359,102
Norway	—	20	412	246	205
Total depreciation, depletion & amortisation	100,847	629,154	917,015	723,468	359,307

	Year ended 31 Dec 2017 $000	Year ended 31 Dec 2018 $000	Year ended 31 Dec 2019 $000	Six months ended 30 June 2020 $000	Six months ended 30 June 2019 $000
Exploration & evaluation expenses					
UK	11,323	1,994	5,052	1,990	743
Norway	—	5,923	9,981	2,200	7,334
Total exploration & evaluation expenses	11,323	7,917	15,033	4,190	8,077

All exploration costs written-off of US$38.9 million (Dec 2019: US$0.2 million; June 2019: US$0.1 million; Dec 2018: US$10.7 million; Dec 2017: $7.3 million) relate to the UK business unit.

4. Revenue and Other Income

	For the years ended 31 December			*For the six months ended*	
	2017 *$000*	*2018* *$000*	*2019* *$000*	*30 June 2020* *$000*	*30 June 2019* *$000*
Crude oil sales	203,551	1,278,637	1,568,166	722,584	703,412
Gas sales	86,016	516,790	625,489	413,438	268,247
Condensate sales	23,933	154,823	145,501	70,385	74,247
Hydrocarbon revenue	313,500	1,950,250	2,339,156	1,206,407	1,045,906
Tariff revenue	—	14,692	13,972	22,685	6,865
Other revenue	—	660	4,661	962	2,293
Total revenue from production activities	313,500	1,965,602	2,357,789	1,230,054	1,055,064
Other income – IFRS16 lease accounting-partner recovery	—	—	8,995	—	—
Total revenue and other income	313,500	1,965,602	2,366,784	1,230,054	1,055,064

Revenue of US$755.9 million (Dec 2019: US$2,195.7 million; June 2019: US$1,017.5 million; Dec 2018: US$2,017.4 million; Dec 2017: US$313.5 million) were from contracts with customers. Revenue from contracts with customers excludes realised hedging gains on crude and gas sales in the period of US$474.1 million (Dec 2019: US$162.2 million; June 2019: US$37.6 million; Dec 2018: losses of US$51.8 million; Dec 2017: nil). Approximately 96 per cent. (Dec 2019: 97 per cent.; June 2019: 96 per cent.; Dec 2018: 96 per cent.; Dec 2017: 95 per cent.) of the revenues were attributable to energy trading companies of the Shell group.

The revenues from 2019 reflect the three months of oil and gas production from the ConocoPhillips UK business following the acquisition on 30 September 2019, as described in note 15.

5. Operating Profit

This is stated after charging/(crediting):

	For the years ended 31 December			For the six months ended	
	2017 $000	2018 $000	2019 $000	30 June 2020 $000	30 June 2019 $000
Movement in over/under-lift balances and hydrocarbon inventories	4,799	50,772	26,249	(62,850)	(47,162)
Production, insurance and transportation costs	85,771	494,908	586,224	370,141	263,231
Depreciation of oil and gas assets	98,9711	617,024	889,226	696,504	351,178
Depreciation of non-oil and gas assets	1,260	3,096	4,905	3,077	2,158
Amortisation of oil and gas intangible assets	606	2,797	2,097	870	1,089
Amortisation of non-oil and gas intangible assets	10	6,237	9,275	6,526	3,733
Depreciation of right of use oil and gas assets	—	—	16,963	28,777	—
Capitalisation of IFRS16 lease depreciation on oil and gas assets	—	—	(8,695)	(15,426)	—
Depreciation of right of use non-oil and gas assets	—	—	3,244	3,140	1,149
Credit due to reduction in decommissioning provision	—	(44,485)	—	—	—
Ineffectiveness of cash flow hedges	332	—	—	—	—
Onerous contract provision (note 21)	—	—	—	27,943	—
Share based payments expense	—	—	10,905	—	—
Impairment of property, plant and equipment	—	—	—	250,629	—
Impairment of goodwill	—	—	—	55,735	—
Exploration and evaluation expenditure	11,323	7,917	15,033	4,190	8,077
Exploration costs written-off (note 11)	7,276	10,731	222	38,851	132
Remeasurement of royalty valuation	9,171	(1,327)	(2,400)	(280)	(1,400)
Remeasurement of commodity price contingent consideration	21,033	734	7,199	—	22,460
Remeasurement of exploration contingent consideration	—	(217)	(7,773)	—	276
Remeasurement of acquisition completion adjustments	—	—	—	391	—
Remeasurement – gain on termination of lease	—	—	—	(584)	—
Auditors' remuneration – audit of the financial statements	557	466	1,357	820	842
– other fees to auditors – taxation services	340	533	400	—	—
Operating lease payments	1,684	949	—	—	—

Share based payments expense represents the cost of 660 M shares awarded to key management as remuneration. The expense of $US10.9m charged during the year is calculated based on the value paid by Harbour in purchasing these shares in November 2019. In prior years there was no shared based payment charge since the fair value was nil.

During 2015, the Chrysaor Group sold its entire interest in a pre-production development. Part of the consideration received was a beneficial interest in a royalty agreement. The remeasurement of this interest of US$0.3 million (Dec 2019: US$2.4 million; June 2019: US$1.4 million; Dec 2018: US$1.3 million; Dec 2017: (US$9.2 million)) represents the updated valuation of the contingent consideration in respect of the royalty payments due to the Chrysaor Group (note 23).

During 2017, the Chrysaor Group acquired a package of assets in the UK North Sea from Shell. The transaction included provisions for additional payments to the sellers of up to US$600 million and consideration refundable from the sellers of up to US$100 million, dependent on future commodity prices over the four-year period ending 31 December 2021. These contingent payments and receipts represent derivative instruments, the remeasurement of which is recognised through the income statement in the periods to 31 December 2019 (note 23). The contingent consideration exposure in relation to the 2020 and 2021 calendar years was settled in October 2019 and the contingent consideration in relation to the 2019 calendar year was fully settled in March 2020 and as a result there have been no further movements on the fair value of crude based derivative instruments reported through the 2020 income statement.

6. Staff Costs

	For the years ended 31 December			For the six months ended	
	2017 $000	2018 $000	2019 $000	30 June 2020 $000	30 June 2019 $000
Wages and salaries	18,837	54,262	82,479	73,182	32,329
Social security costs	1,711	6,910	12,408	11,945	4,923
Pension costs	1,276	6,836	11,173	11,812	3,735
Other staff costs including benefits	535	2,724	20,031	10,015	2,664
	22,359	70,732	126,091	106,954	43,651

	For the years ended 31 December			For the six months ended	
	2017 No.	2018 No.	2019 No.	30 June 2020 No.	30 June 2019 No.
Offshore based	26	156	206	398	177
Office and administration	62	213	357	646	245
	88	369	563	1,044	422

Staff costs above are recharged to joint venture partners or are capitalised to the extent that they are directly attributable to capital or decommissioning projects. The above costs include share-based payments to key management as disclosed in note 5.

Employment contracts are held by three subsidiaries of the Chrysaor Group, Chrysaor E&P Services Limited, Chrysaor Norge AS and Chrysaor Production (U.K.) Limited.

All employees were engaged in the acquisition, exploration, development and production of oil and gas reserves.

The Chrysaor Group operates a defined contribution pension plan and the amounts charged to the income statement represent the contributions payable in the period.

7. Finance income and Finance Expenses

	For the years ended 31 December			For the six months ended	
Finance income:	2017 $000	2018 $000	2019 $000	30 June 2020 $000	30 June 2019 $000
Bank interest receivable	260	8,622	9,345	2,390	4,662
Other interest	—	—	22,266	1,070	5,528
Foreign exchange gains	—	37,862	—	101,608	—
	260	46,484	31,611	105,068	10,190
Finance expenses:					
Interest payable on Reserves Based Loan and junior facilities	15,906	99,914	83,955	58,995	33,703
Interest payable on loan notes	15,199	83,911	69,767	13,419	45,055
Other interest	—	3,924	3,072	1,532	328
Lease interest	—	—	2,541	3,853	570
Foreign exchange losses	915	—	82,171	—	424
Bank and financing fees	5,264	37,187	39,272	22,412	20,704
Unwinding of discount on deferred consideration	463	—	80	92	—
Unwinding of discount on contingent consideration	—	925	83	—	—
Unwinding of discount on decommissioning and other provisions	7,146	44,432	57,629	48,465	20,629
	44,893	270,293	338,570	148,768	121,413

Bank and financing fees include an amount of US$7.6 million (Dec 2019: US$15.6 million; June 2019: US$8.1 million; Dec 2018: US$17.3 million; Dec 2017: US$2.8 million) relating to the amortisation of transaction costs capitalised against the Chrysaor Group's long-term borrowings (note 22).

Net other interest expense of US$0.5m (2019: US$5.2 million credit) includes a US$1.1 million charge (Dec 2019 US$19.7 million credit; June 2019: US$5.2 million credit; Dec 2018: US$3.9 million charge; Dec 2017: nil) which represents interest under a financing arrangement (note 22).

8. Directors' Remuneration

	For the years ended 31 December			*For the six months ended*	
	2017	*2018*	*2019*	*30 June 2020*	*30 June 2019*
	$000	*$000*	*$000*	*$000*	*$000*
Directors' remuneration	901	2,215	1,952	1,420	1,233
Payments made in lieu of pension contributions	53	179	171	106	87
Pension costs	12	25	20	7	10
	966	2,419	2,143	1,533	1,330

Included above are the emoluments of the two Executive Directors of the Chrysaor Group. The payments made in lieu of pension contributions were made at the same rate as pension contributions made to employees. The other Directors who served during the year received no emoluments from Chrysaor Group companies in respect of their services.

The directors did not receive any other remuneration.

The above amounts for remuneration include the following in respect of the highest paid director:

	For the years ended 31 December			*For the six months ended*	
	2017	*2018*	*2019*	*30 June 2020*	*30 June 2019*
	$000	*$000*	*$000*	*$000*	*$000*
Directors' remuneration	495	1,286	1,114	809	696
Payments made in lieu of pension contributions	33	105	101	64	51
Pension costs	6	12	10	4	5
	534	1,403	1,225	877	752

9. Income Tax

The major components of income tax expense/(credit) are:

	For the years ended 31 December			For the six months ended	
	2017 $000	2018 $000	2019 $000	30 June 2020 $000	30 June 2019 $000
Current income tax expense/(credit):					
UK corporation tax	6,033	1,977	105,076	214,847	(145)
Overseas tax	—	(5,534)	(11,779)	(11,273)	(6,590)
Adjustments in respect of prior years	—	(1,008)	1,521	7,383	—
Total current income tax expense/(credit)	6,033	(4,565)	94,818	210,957	(6,735)
Deferred tax expense/(credit):					
UK corporation tax	(264,560)	229,327	155,234	(282,074)	158,262
Overseas tax	—	(312)	2,170	8,708	235
Adjustments in respect of prior years	—	(14,949)	(15,511)	(7,362)	(2,435)
Total deferred tax expense/(credit)	(264,560)	214,066	141,893	(280,728)	156,062
Tax expense/(credit) in the income statement	(258,527)	209,501	236,711	(69,771)	149,327
The tax expense/(credit) in the income statement is disclosed as follows:					
Income tax expense/(credit) on continuing operations	(258,527)	209,501	236,711	(69,771)	149,327
	(258,527)	209,501	236,711	(69,771)	149,327

A reconciliation between total tax charge/(credit) and the accounting profit multiplied by the standard rate of corporation tax and supplementary charge applying to UK oil and gas production operations for the years ended 31 December 2019, 2018 and 2017 and the six month periods ended 30 June 2020 and 2019 is as follows:

	For the years ended 31 December			For the six months ended	
	2017 $000	2018 $000	2019 $000	30 June 2020 $000	30 June 2019 $000
Profit/(loss) before taxation	471	578,401	455,558	(224,222)	323,705
Chrysaor Group profit/(loss) before taxation at 40.0% weighted average	188	231,128	182,224	(89,689)	129,482
Effects of:					
Expenses not deductible for tax purposes	16,989	17,282	13,143	28,918	18,567
Interest not deductible for supplementary charge	—	9,411	9,544	4,135	4,728
Adjustments in respect of prior years	—	(15,956)	(13,990)	21	(2,575)
Income not taxable	—	—	—	(5)	—
Ring fence expenditure supplement	(44,119)	(24,877)	—	—	—
Movement in unrecognised deferred tax assets	(234,853)	2,877	29,231	3,507	2,361
Impact of profits/(losses) relieved at different rates	2,909	17,714	43,514	(1,931)	9,854
Investment allowance	(395)	(28,078)	(27,150)	(13,009)	(13,090)
Petroleum revenue tax (net of corporation tax)	—	—	—	(1,656)	—
Changes in tax rates	(615)	—	—	—	—
Currency translation adjustment	1,305	—	195	(62)	—
Other	64	—	—	—	—
Total tax expense/(credit) reported in the consolidated income statement	(258,527)	209,501	236,711	(69,771)	149,327

The origination of and reversal of temporary differences are, as shown in the next table, related primarily to movement in the carrying amounts and tax base values of expenditure and Chrysaor Group losses for the current and prior periods and the timing of when these items are charged and/or credited against accounting and taxable profit.

Deferred tax

Deferred tax is presented net on the Chrysaor Group balance sheet is as follows:

	Accelerated Capital Allowances $000	*Abandonment $000*	*Losses $000*	*Fair value on derivatives $000*	*Other $000*	*Total $000*
As at 1 January 2017	(9)	—	21,678	—	—	21,669
Deferred tax (expense)/ credit	(314,230)	5,015	573,775	—	—	264,560
Comprehensive income	—	—	—	29,164	—	29,164
Acquisition accounting	(1,382,599)	692,600	—	—	—	(689,999)
As at 31 December 2017	(1,696,838)	697,615	595,453	29,164	—	(374,606)
Deferred tax (expense)/ credit	212,560	(121,527)	(337,842)	—	32,743	(214,066)
Comprehensive (loss)	—	—	—	(179,584)	(3,468)	(183,052)
Acquisition accounting	(8,198)	11,176	—	—	—	2,978
As at 31 December 2018	(1,492,476)	587,264	257,611	(150,420)	29,275	(768,746)
Deferred tax credit/ (expense)	138,882	11,848	(255,651)	—	(36,972)	(141,893)
Comprehensive (loss)/ income	(20,061)	15,647	—	21,625	5,044	22,255
Acquisition accounting	(1,790,753)	974,065	—	—	55,782	(760,906)
As at 31 December 2019	(3,164,408)	1,588,824	1,960	(128,795)	53,129	(1,649,290)
Deferred tax credit/ (expense)	365,445	(92,791)	255	(1,481)	9,300	280,728
Comprehensive (loss)	—	—	—	(210,167)	—	(210,167)
Foreign exchange	88,554	(70,976)	(186)	1,185	(4,579)	13,998
As at 30 June 2020	(2,710,409)	1,425,057	2,029	(339,258)	57,850	(1,564,731)

Deferred tax assets are recognised to the extent that the future benefit from the underlying tax losses carried forward is probable. Relevant tax law is considered as to the availability of the tax losses to offset future income. To determine the future taxable income from which the losses may be deducted, reference was made to the profit forecasts for the Chrysaor Group as at 30 June 2020. These profit forecasts showed sufficient future taxable income to recognise the deferred tax asset.

The Norwegian related tax losses are not expected to be recovered within the next twelve months. Companies operating on the Norwegian Continental Shelf under the offshore tax regime can claim the tax value of any unused tax losses or other tax credits related to its offshore activities to be paid in cash (including interest) from the tax authorities when operations cease. Deferred tax assets that are based on offshore tax losses carried forward are therefore normally recognised in full. There is no time limit on the right to carry tax losses forward in Norway.

The Chrysaor Group has tax losses, mainly from non-ring fence activities, of US$135.6 million (2019: US$132.4 million), a portion of which may potentially be available for offset against future taxable profits in the companies in which the losses arose. An associated deferred tax asset of US$28.0 million (2019: US$27.7 million) has not been recognised in respect of these losses as they may not be used to offset taxable profits elsewhere in the Chrysaor Group due to uncertainty of recovery. The Chrysaor Group has recognised a deferred tax asset of US$2.0 million (2019: US$2.0 million) in relation to tax losses only to the extent of anticipated future taxable profits.

The Chrysaor Group has not recognised a deferred tax asset of US$5.6m (2019: US$2.8m) in relation to accelerated capital allowances, or a deferred tax asset of US$0.8 million (2019: nil) in relation to fair value movements on derivatives, on the basis that these deferred tax assets will not be recoverable in the foreseeable future.

Changes in tax rate

Legislation introduced in Finance Bill 2020, which was substantively enacted on 17 March 2020, retained the main rate of UK corporation tax for non-ring fence profits at 19 per cent. from 1 April 2020. This has no material impact on the Chrysaor Group.

10. Goodwill

	As at 31 December			*As at 30 June*
Group	*2017*	*2018*	*2019*	*2020*
Cost:	*$000*	*$000*	*$000*	*$000*
At start of period	—	500,080	493,084	1,404,334
Additions (note 15)	498,978	2,943	908,359	—
Impairment charge	—	—	—	(55,735)
Finalisation of 2017 business combination (note 15)	—	(5,463)	—	—
Currency translation adjustment	1,102	(4,476)	2,891	(4,983)
At end of period	500,080	493,084	1,404,334	1,343,616

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.

The goodwill balance arose on the acquisition of UK North Sea assets from Shell which completed on 1 November 2017 (US$493.5 million) and on the acquisition of additional equity in the Armada, Maria and Seymour fields from Spirit Energy which completed on 1 June 2018 (US$2.9 million). The goodwill balance in 2019 of US$908.4 million arose on the acquisition of the ConocoPhillips UK business which completed on 30 September 2019. See note 15 for further details.

Goodwill acquired through business combinations has been allocated to a single CGU, the UK Continental Shelf ("**UKCS**"), and this is therefore the lowest level at which goodwill is reviewed.

Impairment Testing of Goodwill

In accordance with 'IAS 36: Impairment of Assets', goodwill has been reviewed for impairment at the year-end. In assessing whether goodwill has been impaired, the carrying amount of the CGU for goodwill is compared with its recoverable amount.

The Chrysaor Group tests goodwill annually for impairment, or more frequently if there are indications that goodwill might be impaired. At each year-end, and at 30 June 2020, the Chrysaor Group tested for impairment in accordance with accounting policy. No impairment had been identified in the financial years ended 31 December 2017-2019. At 30 June 2020, following changes to the Chrysaor Group's long-term commodity price assumptions linked to the significant deterioration in the macroeconomic environment for the oil and gas industry, a goodwill impairment of US$55.7 million was recognised.

Determining Recoverable Amount

The recoverable amounts of the CGU and fields have been determined on a fair value less costs to sell basis. The key assumptions used in determining the fair value are often subjective, such as the future long-term oil price assumption, or the operational performance of the assets. Discounted cash flow models comprising asset-by-asset life of field projections using Level 3 inputs (based on IFRS 13 fair value hierarchy) have been used to determine the recoverable amounts. The cash flows at 30 June 2020 have been modelled on a post-tax and post-decommissioning basis at the Chrysaor Group's post-tax discount rate of 6 per cent. (2019: 6 per cent.; 2018: 6 per cent.; 2017: 6 per cent.). Risks specific to assets within the CGU are reflected within the cash flow forecasts. Risks specific to assets within the CGU are reflected within the cash flow forecasts.

Key Assumptions Used in Calculations

Assumptions involved in impairment measurement include estimates of reserves and production volumes, future oil and gas prices, discount rates and the level and timing of expenditures, all of which are inherently uncertain.

Oil and gas prices are based on an internal view of management expectations derived from external financial analysts view of current prices for the first three years transitioning to a flat long term price from 2023 – the long-term commodity prices used were US$60 per barrel for crude and 45p per therm for gas. Management's long-term assumptions are benchmarked against a range of external forward price curves on a regular basis. Individual field price differentials are then applied.

Production volumes are based on life of field production profiles for each asset within the CGU. Proved plus probable reserves are estimates of the amount of oil and gas that can be economically extracted from the Chrysaor Group's oil and gas assets. The Chrysaor Group estimates its reserves using standard recognised evaluation techniques and is assessed at least annually by management and by an independent consultant. Proved plus probable reserves are determined using estimates of oil and gas in place, recovery factors and future commodity prices.

Operating expenditure, capital expenditure and decommissioning costs are derived from the Chrysaor Group's Business Plan.

The discount rate reflects management's estimate of the Chrysaor Group's Weighted Average Cost of Capital ("**WACC**"), considering both debt and equity. The cost of equity is derived from an expected return on investment by the Chrysaor Group's investors, and the cost of debt is based on its interest-bearing borrowings. Segment risk is incorporated by applying a beta factor based on publicly available market data. The discount rate is based on an assessment of a relevant peer group's post-tax WACC.

Foreign exchange rates are based on management's long-term rate assumptions, with reference to a range of underlying economic indicators.

Sensitivity to Changes in Assumptions Used in Calculations

The Chrysaor Group has run sensitivities on its long-term commodity price assumptions, which have been based on long range forecasts from external financial analysts, using alternate long-term price assumptions and discount rates. These are considered to be reasonably possible changes for the purposes of sensitivity analysis. Sensitivity analysis indicates that a 10 per cent. reduction in the oil and gas price deck applied in the impairment test would result in a further impairment to goodwill of US$666.6 million, and a 2 per cent. increase in the discount rate would result in a further impairment to goodwill of US$222.3 million.

11. Other Intangible Assets

Cost:	*Oil and gas assets $000*	*Non-oil and gas assets $000*	*Capacity rights $000*	*Total $000*
At 1 January 2017	7,280	293	—	7,573
Additions	8,818	13,301	—	22,119
Additions from business combinations and joint arrangements (note 15)	25,935	—	10,029	35,964
Unsuccessful exploration written-off	(7,276)	—	—	(7,276)
Currency translation adjustment	776	291	419	1,486
At 31 December 2017	35,533	13,885	10,448	59,866
Additions	28,196	7,956	—	36,152
Unsuccessful exploration written-off	(10,731)	—	—	(10,731)
Currency translation adjustment	(455)	(1,029)	(814)	(2,298)
At 31 December 2018	52,543	20,812	9,634	82,989
Additions	81,792	12,773	—	94,565
Additions from business combinations and joint arrangements (note 15)	325,880	4,912	—	330,792
Transfers to property, plant & equipment	(39,002)	—	—	(39,002)
Unsuccessful exploration written-off	(222)	—	—	(222)
Currency translation adjustment	4,262	1,476	374	6,112
At 31 December 2019	425,253	39,973	10,008	475,234
Additions	44,763	33,362	—	78,125
Transfers from property, plant and equipment	33,273	—	—	33,273
Reduction in decommissioning asset	(5,295)	—	—	(5,295)
Disposals	(75)	—	—	(75)
Unsuccessful exploration written-off	(38,851)	—	—	(38,851)
Currency translation adjustment	(19,219)	(2,982)	(645)	(22,846)
At 30 June 2020	439,849	70,353	9,363	519,565
Accumulated Amortisation:				
At 1 January 2017	—	281	—	281
Charge for the year	—	10	606	616
Currency translation adjustment	—	(53)	—	(53)
At 31 December 2017	—	238	606	844
Charge for the year	—	6,237	2,797	9,034
Currency translation adjustment	—	(265)	(155)	(420)
At 31 December 2018	—	6,210	3,248	9,458
Charge for the year	—	9,275	2,097	11,372
Currency translation adjustment	—	592	208	800
At 31 December 2019	—	16,077	5,553	21,630
Charge for the period	—	6,526	870	7,396
Currency translation adjustment	—	(1,197)	(383)	(1,580)
At 30 June 2020	—	21,406	6,040	27,446
Net book value				
At 30 June 2020	439,849	48,947	3,323	492,119
At 31 December 2019	425,253	23,896	4,455	453,604
At 31 December 2018	52,543	14,602	6,386	73,531
At 31 December 2017	35,533	13,647	9,842	59,022

Exploration costs written-off relates to costs associated with licence relinquishments and uncommercial well evaluations.

Non-oil and gas assets relate to expenditure on the Acorn project, a project focussed on carbon dioxide (CO_2) capture and storage which is planned to use existing technology to this new area of application. The costs are held within intangible assets until an assessment of its economic commerciality is determined.

The capacity rights represent National Transmission System ("**NTS**") entry capacity at Bacton and Teesside acquired as part of the business combination completed in 2017. These rights have a remaining useful life of three years and are amortised on a contractual volume basis.

12. Property, Plant and Equipment

	Oil and gas assets $000	*Fixtures and fittings & office equipment $000*	*Total $000*
Cost:			
At 1 January 2017	—	316	316
Additions	35,494	9,052	44,546
Additions from business combinations and joint arrangements (note 15)	4,280,359	—	4,280,359
Currency translation adjustment	10,783	384	11,167
At 31 December 2017	4,326,636	9,752	4,336,388
Additions	370,124	3,590	373,714
Additions from business combinations and joint arrangements (note 15)	20,495	—	20,495
Reduction in decommissioning asset	(299,543)	—	(299,543)
Currency translation adjustment	19,385	(625)	18,760
At 31 December 2018	4,437,097	12,717	4,449,814
Additions	480,448	4,999	485,447
Additions from business combinations and joint arrangements (note 15)	4,248,567	2,606	4,251,173
Reduction in decommissioning asset	(4,327)	—	(4,327)
Transfer of intangible assets	39,002	—	39,002
Currency translation adjustment	57,532	832	58,364
At 31 December 2019	9,258,319	21,154	9,279,473
Additions	236,525	2,150	238,675
Reduction in decommissioning asset	(189,620)	—	(189,620)
Transfer of intangible assets	(33,273)	—	(33,273)
Currency translation adjustment	(224,870)	(1,434)	(226,304)
At 30 June 2020	9,047,081	21,870	9,068,951
Accumulated Depreciation:			
At 1 January 2017	—	257	257
Charge for the year	98,971	1,260	100,231
Currency translation adjustment	(12)	120	108
At 31 December 2017	98,959	1,637	100,596
Charge for the year	617,024	3,096	620,120
Currency translation adjustment	59	(184)	(125)
At 31 December 2018	716,042	4,549	720,591
Charge for the year	889,226	4,905	894,131
Currency translation adjustment	7,873	348	8,221
At 31 December 2019	1,613,141	9,802	1,622,943
Charge for the period	696,504	3,077	699,581
Impairment charge	250,629	—	250,629
Currency translation adjustment	(22,718)	(697)	(23,415)
At 30 June 2020	2,537,556	12,182	2,549,738
Net book value:			
At 30 June 2020	6,509,525	9,688	6,519,213
At 31 December 2019	7,645,178	11,352	7,656,530
At 31 December 2018	3,721,055	8,168	3,729,223
At 31 December 2017	4,227,677	8,115	4,235,792

During the six-month period to 30 June 2020, the Chrysaor Group recognised a net pre-tax impairment charge of US$250.6 million (post-tax US$150.5 million) within the income statement. This represents a write-down of US$340.4 million on the Chrysaor Group's older gas assets as a result of the Chrysaor Group's revised view of long-term commodity prices, and a pre-tax impairment credit of (US$89.8 million) in respect of reductions to decommissioning estimates on the Chrysaor Group's non-producing assets (see note 21). No impairment charges were recognised in either of the years ended 31 December 2019, 2018 and 2017.

The Chrysaor Group uses the fair value less cost of disposal method ("**FVLCD**") to calculate the recoverable amount of the CGU consistent with a level 3 fair value measurement. In determining FVLCD, appropriate discounted-cash-flow valuation models were used, incorporating market-based assumptions. Oil and gas prices are based on an internal view of management expectations derived from external financial analysts view of current prices for the first three years transitioning to a flat long term price from 2023 – the long-term commodity prices used were US$60 per barrel for crude and 45p per therm for gas.

A reduction or increase in oil and gas prices of 10 per cent. are considered to be reasonably possible changes for the purpose of sensitivity analysis. Decreases to oil and gas prices specified above would result in a further post-tax impairment of US$117.1 million. A 10 per cent. rise in the oil and gas price deck would lead to a reduction in the post-tax impairment of US$132.4 million. Considering the discount rates, a 2 per cent. decrease in the post-tax rate would lead to a further post-tax impairment of US$35.3 million, whereas a 2 per cent. increase in the post-tax rate would lead to a reduction in the post-tax impairment of US$34.1 million. The Chrysaor Group believes a 2 per cent. change in the pre-tax discount rate to be a reasonable possibility for the purpose of sensitivity analysis. The impairment was calculated as detailed above.

A decrease in the decommissioning assets of US$189.6 million was made during the six-month period to 30 June 2020 (Dec 2019: US$4.3 million; Dec 2018: US$299.5 million; Dec 2017: nil) as a result of an update to the decommissioning estimates (note 21).

Further information on additions from business combinations and joint arrangements can be found in note 15.

13. Leases – Right of Use Assets

(i) This note provides information for leases where the Chrysaor Group is a lessee.

	As at 31 December			*As at 30 June*
Right of Use Assets	*2017 $000*	*2018 $000*	*2019 $000*	*2020 $000*
Land and buildings	—	—	58,092	54,299
Drilling rigs	—	—	159,945	87,666
Equipment	—	—	3,186	2,051
	—	—	221,223	144,016

Prior to 1 January 2019, the Chrysaor Group only recognised lease assets and lease liabilities in relation to leases that were classified as 'finance leases' under IAS 17, 'Leases'.

	As at 31 December			*As at 30 June*
Lease Liabilities	*2017 $000*	*2018 $000*	*2019 $000*	*2020 $000*
Current	—	—	79,525	53,782
Non-Current	—	—	145,403	96,384
	—	—	224,928	150,166

During the six months to 30 June 2020, a lease liability in relation to the *Transocean 712* drilling rig was terminated, resulting in a gain of US$0.6 million. In addition, a cost revision to the right-of-use asset and lease liability was made, resulting in reductions of US$10.0 million.

There were no additions to the right-of-use assets during the six months to 30 June 2020 (Dec 2019: US$226.4 million

(ii) The consolidated income statement includes the following amounts relating to leases:

Depreciation charge of Right of Use Assets

	For the years ended 31 December			*For the six months ended*	
	2017	*2018*	*2019*	*30 June 2020*	*30 June 2019*
	$000	*$000*	*$000*	*$000*	*$000*
Land and buildings	—	—	3,244	3,644	1,149
Drilling rigs	—	—	16,585	27,576	—
Equipment	—	—	378	697	—
	—	—	20,207	31,917	1,149
Capitalisation of IFRS16 lease depreciation					
Drilling rigs	—	—	(8,580)	(14,991)	—
Equipment	—	—	(115)	(435)	—
Depreciation charge included within Consolidated Income Statement	—	—	11,512	16,491	1,149

Of the US$15.4 million capitalised IFRS16 lease depreciation, US$8.2 million (2019: US$3.9 million) has been capitalised within property, plant and equipment and US$7.2 million within provisions (2019: US$4.8 million).

	For the years ended 31 December			*For the six months ended*	
	2017	*2018*	*2019*	*30 June 2020*	*30 June 2019*
	$000	*$000*	*$000*	*$000*	$000
Lease interest (included in finance expenses – note 7)	—	—	2,541	3,853	570

The total cash outflow for leases in the six-month period to 30 June 2020 was US$32.6 million (Dec 2019: US$20.6 million; June 2019: US$0.5 million; Dec 2018: nil; Dec 2017: nil).

(iii) The Chrysaor Group's leasing activities and how these are accounted for

The Chrysaor Group leases an office in London until 2023, in Oslo for a fixed period of five years, and two offices in Aberdeen with fixed periods of five and 10 years. The five-year lease on the Aberdeen office has an extension option of up to 10 years. Land leases expire between 13 and 14 years, and oil and gas production leases expire between 2 and 3 years. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. Until the 2018 financial year, these leases were classified as operating leases and payments made under these leases (net of any incentives received from the lessor) were charged to the income statement on a straight-line basis over the period of the lease.

From 1 January 2019, leases have been 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 Chrysaor Group. 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. The right-of-use asset is depreciated over the lease term on a straight-line basis.

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 Chrysaor Group assuming leases run to full term. The Chrysaor Group 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 Chrysaor Group is reasonably certain to exercise such options impacts the lease term, which significantly impacts the amount of lease liabilities and right-of-use assets recognised.

The lease payments are discounted using the Chrysaor Group's incremental borrowing rate, being the rate that the Chrysaor Group 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 Chrysaor Group 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;
- makes adjustments specific to the lease, for example term, country, currency and security

The Chrysaor Group is exposed to potential future increases in variable lease payments based on an index or rate, which are not included in the lease liability until they take effect. 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. The finance cost is charged to profit or loss 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 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 useful life and the lease term on a straight-line basis.

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.

14. Investments and Amounts Due from Subsidiary Undertakings

At 30 June 2020, the subsidiary undertakings of Chrysaor which were all wholly owned were:

Name of company	*Country of incorporation*	*Main activity*
Chrysaor E&P Limited	UK	Holding company
Chrysaor Production Holdings Limited (i)	UK	Holding company
Chrysaor Resources (UK) Holdings Limited (i)	UK	Holding company
Chrysaor E&P Finance Limited (i)	UK	Financing company
Chrysaor E&P Services Limited (i)	UK	Service company
Chrysaor North Sea Limited (i)	UK	Oil and gas
Chrysaor Limited (i)	UK	Oil and gas
Chrysaor CNS Limited (i)	UK	Oil and gas
Chrysaor Norge AS (i)	Norway	Oil and gas
Chrysaor Resources (Irish Sea) Limited (ii)	UK	Oil and gas
Chrysaor Marketing Limited (i)	UK	Dormant company
Chrysaor Production Limited (iii)	UK	Holding company
Chrysaor Production (U.K.) Limited (v)	UK	Oil and gas
Chrysaor Petroleum Company U.K. Limited (iii)	UK	Oil and gas
Chrysaor (U.K.) Theta Limited (vii)	UK	Oil and gas
Chrysaor (U.K.) Alpha Limited (vi)	UK	Oil and gas
Chrysaor (U.K.) Beta Limited (xi)	UK	Oil and gas
Chrysaor Developments Limited (vi)	UK	Oil and gas
Chrysaor Petroleum Limited (vi)	UK	Oil and gas
Chrysaor (U.K.) Sigma Limited (viii)	UK	Oil and gas
Chrysaor (Glen) Limited (vi)	UK	Non-trading
Chrysaor (U.K.) Zeta Limited (vi)	UK	Non-trading holding company
Chrysaor (U.K.) Eta Limited (x)	UK	Non-trading
Chrysaor (U.K.) Delta Limited (vi)	UK	Non-trading holding company
Chrysaor Supply and Trading Limited (iii)	UK	Non-trading
Chrysaor (U.K.) Lambda Limited (ix)	ROI	Dormant company
Chrysaor Investments Limited (vi)	UK	Dormant company
Chrysaor Production Oil (GB) Limited (iv)	UK	Dormant company
Chrysaor Petroleum Chemicals U.K. Limited (iv)	UK	Dormant company
Chrysaor (U.K.) Britannia Limited (vi)	UK	Dormant company

(i) Held by Chrysaor E&P Limited
(ii) Held by Chrysaor Resources (UK) Holdings Limited
(iii) Held by Chrysaor Production Holdings Limited
(iv) Held by Chrysaor Petroleum Company U.K. Limited
(v) Held by Chrysaor Production Limited
(vi) Held by Chrysaor Production (U.K.) Limited
(vii) Held by Chrysaor (U.K.) Sigma Limited
(viii) 98.04 per cent. held by Chrysaor Production (U.K.) Limited and 1.96 per cent. held by Chrysaor (U.K.) Delta Limited
(ix) 99.999 per cent. held by Chrysaor (U.K.) Theta Limited and 0.001 per cent. held by Chrysaor (U.K.) Eta Limited
(x) Held by Chrysaor (U.K.) Zeta Limited
(xi) Held by Chrysaor (U.K.) Alpha Limited

Chrysaor holds 100 per cent. of the share capital and voting rights in each of the companies above, unless otherwise stated.

All the subsidiaries are registered in England and Wales, with the exception of Chrysaor Norge AS, which is registered in Norway, and Chrysaor (U.K.) Lambda Limited, which is registered in the Republic of Ireland. The registered office of all subsidiaries noted above is Brettenham House, Lancaster Place, London, United Kingdom, WC2E 7EN, apart from Chrysaor Norge AS whose registered office is Haakon VII's gate 1, 4th Floor, 0161 Oslo, Norway, and Chrysaor (U.K.) Lambda Limited whose registered office is Riverside One, Sir John Rogerson's Quay, Dublin 2, Ireland.

15. Business Combinations and Acquisition of Interests in Joint Arrangements

Business Combinations During the Year Ended 31 December 2019

In April 2019, Chrysaor entered into an agreement to acquire the ConocoPhillips UK business for a headline consideration of US$2.675 billion, comprising cash consideration of US$2.43 billion and novation of an intercompany loan of US$0.25 billion.

The transaction completed on 30 September 2019 and adds two new operated hubs to Chrysaor's portfolio in the UK Central North Sea, Greater Britannia Area and J-Area, in addition to a non-operated interest in the Clair Field area. The fair values of the net identifiable assets acquired from the transaction are as follows:

	Total *$000*
Exploration, evaluation and other intangible assets	330,792
Property, plant and equipment – oil and gas assets	4,248,567
Property, plant and equipment – non-oil and gas assets	2,606
Property, plant and equipment – right of use assets	206,978
Total fixed assets	4,788,943
Inventories	54,203
Cash	247,034
Trade and other receivables	223,884
Trade and other payables	(324,830)
Deferred tax	(760,906)
Provision for decommissioning	(2,408,211)
IFRS16 lease liabilities	(206,978)
Fair value of identifiable net assets acquired	1,613,139
Cash consideration	2,430,049
Additional completion adjustments	91,449
Total consideration	2,521,498
Goodwill Recognised	908,359

In November 2019, US$38.2 million of additional completion adjustments were paid to ConocoPhillips US, representing the first of four annual payments to be made during 2019 to 2022.

Acquisition related costs of US$7.6 million were incurred during 2019 and recognised as an expense within General and Administrative costs.

The cash consideration was funded from existing cash resources and additional RBL funding of US$1.68 billion from the upsized US$3 billion debt facility.

In September 2019, the ConocoPhillips UK business lent US$0.25 billion to ConocoPhillips US. At completion of the acquisition of the ConocoPhillips UK business, the loan liability of US$0.25 billion was novated from ConocoPhillips US to Chrysaor E&P Limited, reducing the cash required on completion by US$0.25 billion.

Goodwill of US$908.4 million, which has arisen principally due to the requirement to recognise deferred tax on the difference between the assigned fair values and the tax bases of assets and liabilities acquired in a business combination, was recognised on the acquisition, representing the excess of the total consideration transferred over the fair value of the net assets acquired. The fair values for the oil and gas assets recognised as property, plant and equipment were determined by reference to commodity forward price curves for the first three years following the acquisition date and, for subsequent years, based on a market consensus. None of the goodwill is deductible for corporation tax.

From the date of acquisition, the business contributed US$264.6 million of revenue and (US$88 million) to the profit before tax from continuing operations of the Chrysaor Group. Had the acquisition been affected at 1 January 2019, the business would have contributed revenue of US$1.0 billion in the year to 31 December 2019, and US$32.4 million of a loss towards profit before taxation.

As at the date of this report and financial statements, pursuant to the terms of the Put and Call Options Agreement ("**PCOA**"), negotiations were ongoing as to the final consideration payable as a result of the review of the interim and pre-effective date period transactions.

Business Combinations During the Year Ended 31 December 2018

On 1 June 2018, the Chrysaor Group acquired the remaining equity in Armada, Maria and Seymour fields from Spirit Energy and so now holds 100 per cent. in the Armada hub. The fair values of the net identifiable assets acquired from the transaction are as follows:

	Total *$000*
Property, plant and equipment – oil and gas assets	20,495
Inventories	85
Trade and other receivables	6,936
Trade and other payables	(5,136)
Deferred tax	2,978
Provision for decommissioning	(27,941)
Fair value of identifiable net liabilities acquired	(2,583)
Cash consideration	360
Goodwill recognised	2,943

From the date of acquisition, the business contributed US$13.8 million of revenue and US$1.3 million of a loss to the profit before taxation from continuing operations of the Chrysaor Group. Had the acquisition been affected at 1 January 2018, the business would have contributed revenue of US$22.3 million in the year to 31 December 2018, and US$4.3 million of a loss towards profit before taxation.

Business combinations during the year ended 31 December 2017

In January 2017, the Chrysaor Group signed an agreement to acquire a package of assets in the UK North Sea from Shell for a price of approximately US$3.0 billion with further payments between the two companies contingent upon future exploration results and commodity prices.

The transaction completed on 1 November 2017 and comprised the direct acquisition of interests in certain joint operations and the acquisition of 100 per cent. of the issued share capital of the former Shell entity, BG International (CNS) Limited. The fair values of the net identifiable assets acquired from the transaction are as follows:

	Joint Operations $000	*BGI CNS Limited $000*	*Total $000*
Exploration, evaluation and other intangible assets	25,935	10,029	35,964
Property, plant and equipment – oil and gas assets	3,688,543	591,816	4,280,359
Inventories	100,951	22,996	123,947
Trade and other receivables	36,685	30,930	67,615
Trade and other payables	(118,759)	(46,768)	(165,831)
Deferred tax	(614,031)	(76,272)	(689,999)
Provision for decommissioning	(1,313,400)	(418,100)	(1,731,500)
Fair value of identifiable net assets acquired	1,805,924	114,631	1,920,555
Cash consideration	1,977,881	197,230	2,175,111
Deferred consideration	213,612	—	213,612
Contingent consideration	25,347	—	25,347
Total consideration	2,216,840	197,230	2,414,070
Goodwill recognised	410,916	82,599	493,515
Finalisation of 2017 acquisition			
As reported at 31 December 2017			
Fair value of identifiable net assets acquired	1,786,394	115,889	1,902,283
Total consideration	2,207,552	193,709	2,401,261
Goodwill recognised	421,158	77,820	498,978
Movement in the year ended 31 December 2018			
Fair value of identifiable net assets acquired	19,530	(1,258)	18,272
Total consideration	9,288	3,521	12,809
Goodwill recognised	(10,242)	4,779	(5,463)

Acquisition related costs of US$5.5 million were incurred during 2017 and recognised as an expense within operating costs.

The cash consideration included a US$100 million advance by a private equity investor of Chrysaor on behalf of the Chrysaor Group, the amount was subsequently settled with the shareholder by the issuance of loan notes. A final payment of US$12.8m was made and the value of trade and other payables was reduced by US$18.3 million following full and final settlement with Shell in August 2018. The numbers in the table above have been updated for these changes and goodwill reduced by US$5.5 million. The deferred consideration represented US$215 million payable to the seller no later than six months following the acquisition date and was included in the consideration transferred at a discounted value. The US$215 million was settled in April 2018.

The transaction included provisions for additional payments to the sellers of up to US$600 million and refundable from the sellers of up to US$100 million, dependent on future commodity prices over the four-year period ended 31 December 2021. These contingent payments and receipts represent derivative instruments. The contingent consideration transferred included an amount of

US$17.6 million, representing an estimate of the fair value of these derivative instruments at the acquisition date. The contingent consideration also included an amount of US$7.7 million, representing the estimated fair value of additional payments to the sellers which are dependent upon future exploration results. Contingent consideration balances are assessed at each reporting date with any change in the valuation reported through the income statement.

Goodwill of US$493.5 million, which has arisen principally due to the requirement to recognise deferred tax on the difference between the assigned fair values and the tax bases of assets and liabilities acquired in a business combination, was recognised on the acquisition, representing the excess of the total consideration transferred over the fair value of the net assets acquired. The fair values for the oil and gas assets recognised as property, plant and equipment were determined by reference to commodity forward price curves for the first three years following the acquisition date and, for subsequent years, based on a market consensus. None of the goodwill is deductible for corporation tax.

The consolidated results of the Chrysaor Group for the year ended 31 December 2017 included revenue of US$313.5 million and an estimated operating profit of US$50 million attributable to the acquired businesses. Prior to the acquisition, the Chrysaor Group had no revenues. The acquisition substantially consisted of the purchase of individual assets that had never been held together in the same corporate entity. For this reason, the Chrysaor Group does not hold the historic financial information to be able to determine a reliable estimate of what the results of the Chrysaor Group would have been had the acquisition occurred at the beginning of the accounting period.

16. Inventories

	As at 31 December			*As at 30 June*
	2017 \$000	*2018 \$000*	*2019 \$000*	*2020 \$000*
Hydrocarbons	18,295	17,972	35,170	36,954
Consumables and subsea supplies	73,268	71,819	111,711	116,090
	91,563	89,791	146,881	153,044

Hydrocarbon inventories are measured at net realisable value. Inventories of consumables and subsea supplies include a provision of US$9.6 million (Dec 2019: US$9.7 million; Dec 2018: US$2.2 million; Dec 2017: US$0.2 million) where it is considered that the net realisable value is lower than the original cost.

Inventories recognised as an expense during the six months to 30 June 2020 amounted to US$1.8 million (year ended 31 December 2019: US$8.1 million; six months ended 30 June 2019: US$0.4 million; year ended 31 December 2018: US$3.5 million; year ended 31 December 2017: US$1.7 million). These expenses are included within production costs.

17. Trade and Other Receivables

Current	*As at 31 December* 2017 $000	2018 $000	2019 $000	*As at 30 June* 2020 $000
Trade debtors	159,637	66,548	186,593	131,906
Under-lift position	60,735	18,646	34,358	37,050
Other debtors	23,190	29,625	177,072	86,661
Prepayments and accrued income	14,937	112,086	60,417	13,815
Corporation tax receivable	—	4,625	15,678	—
	258,499	231,530	474,118	269,432

Trade debtors are non-interest bearing and are generally on 20 to 30 days' terms. As at 30 June 2020, there were no credit loss provisions (2019: nil; 2018: nil; 2017: nil).

Other debtors mainly relate to amounts due from joint venture partners.

The carrying value of the trade and other receivables are equal to their fair value as at the balance sheet date.

Non-Current	*As at 31 December* 2017 $000	2018 $000	2019 $000	*As at 30 June* 2020 $000
Other receivables	—	—	2,604	2,871
	—	—	2,604	2,871

18. Cash and Cash Equivalents

	As at 31 December 2017 $000	2018 $000	2019 $000	*As at 30 June* 2020 $000
Cash at bank and in hand	299,541	316,311	573,182	369,391

Cash at bank earns interest at floating rates based on daily bank deposit rates. The Chrysaor Group only deposits cash with major banks of high-quality credit standing.

19. Commitments

Capital Commitments

As at 30 June 2020, the Chrysaor Group had commitments for future capital expenditure amounting to US$359.0 million (Dec 2019: US$420.5 million; Dec 2018 US$445.2 million; Dec 2017 US$344.9 million). Where the commitment relates to a joint arrangement, the amount represents the Chrysaor Group's net share of the commitment. Where the Chrysaor Group is not the operator of the joint arrangement then the amounts are based on the Chrysaor Group's net share of committed future work programmes.

20. Trade and Other Payables

Current	*As at 31 December* 2017	2018	2019	*As at 30 June 2020 $000*
Trade payables	27,810	22,387	116,221	131,387
Overlift position	47,180	48,212	83,370	25,208
Deferred consideration	214,075	—	—	—
Other payables	7,792	2,191	40,970	79,399
Accruals and deferred income	181,635	223,644	435,875	320,109
	478,492	296,434	676,436	556,103

Amounts owed to Chrysaor Group undertakings are unsecured, interest free and repayable on demand.

Non-Current	*2017 $000*	*2018 $000*	*2019 $000*	*30 June 2020 $000*
Other payables	—	—	52,375	46,420
	—	—	52,375	46,420

Other payables, within both current (US$18.8 million) (2019: US$19.9 million) and non-current (US$37.5 million) (2019: US$39.7 million) 'trade and other payables', includes the present value of additional completion payments payable to ConocoPhillips as part of the acquisition of the ConocoPhillips UK business. The amounts are payable in 3 further instalments between October 2020 and October 2022.

21. Provisions

	Decommissioning provision $000	Other $000	Total $000
At 1 January 2017	—	—	—
Additions from business combinations and joint arrangements (note 15)	1,731,500	7,760	1,739,260
Additions	6,522	—	6,522
Amounts used	(1,124)	—	(1,124)
Unwinding of discount	7,146	—	7,146
Currency translation adjustment	6,908	—	6,908
At 31 December 2017	1,750,952	7,760	1,758,712
Additions from business combinations and joint arrangements (note 15)	27,941	—	27,941
Additions	18,941	—	18,941
Changes in estimates – decrease in decommissioning asset	(299,543)	—	(299,543)
Changes in estimates – credit to income statement	(44,485)	—	(44,485)
Remeasurements	—	(217)	(217)
Amounts used	(21,502)	—	(21,502)
Unwinding of discount	44,285	147	44,432
Currency translation adjustment	(8,545)	—	(8,545)
At 31 December 2018	1,468,044	7,690	1,475,734
Additions from business combinations and joint arrangements (note 15)	2,408,211	—	2,408,211
Additions	28,389	—	28,389
Changes in estimates – decrease to decommissioning asset	(4,327)	—	(4,327)
Remeasurements	—	(7,773)	(7,773)
Amounts used	(46,816)	—	(46,816)
Interest on decommissioning lease	(1,076)	—	(1,076)
Depreciation, depletion & amortisation on decommissioning right-of-use leased asset	(4,821)	—	(4,821)
Unwinding of discount	57,629	83	57,712
Currency translation adjustment	44,587	—	44,587
At 31 December 2019	3,949,820	—	3,949,820
Additions	9,753	27,943	37,696
Changes in estimates – decrease to decommissioning asset	(114,908)	—	(114,908)
Changes in estimates – credit to income statement	(89,760)	—	(89,760)
Amounts used	(82,406)	—	(82,406)
Unwinding of discount	48,465	—	48,465
Currency translation adjustment	(173,787)	—	(173,787)
At 30 June 2020	3,547,177	27,943	3,575,120

Classified within:	*Non-current liabilities $000*	*Current Liabilities $000*	*Total* $000
At 30 June 2020	3,368,416	206,704	3,575,120
At 31 December 2019	3,766,739	183,081	3,949,820
At 31 December 2018	1,475,734	—	1,475,734
At 31 December 2017	1,758,712	—	1,758,712

The Chrysaor Group provides for the estimated future decommissioning costs on its oil and gas assets at the balance sheet date. The payment dates of expected decommissioning costs are uncertain and are based on economic assumptions of the fields concerned. The Chrysaor Group 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 provisions at 30 June 2020 are discounted at a risk-free rate of between 1.8 per cent. and 2.5 per cent. (Dec 2019: 2.3 per cent. and 2.8 per cent.; Dec 2018: 2.8 per cent.; Dec 2017: 2.5 per cent.) and the unwinding of the discount is presented within finance costs.

These provisions have been created based on internal and third-party estimates. Assumptions based on the current economic environment have been made, which management believe 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.

Following the acquisition of the Shell and ConocoPhillips UK assets in 2017 and 2019 respectively, an in-depth review of decommissioning cost estimates was undertaken to align financial and strategic assumptions.

Other provisions in the period to 31 December 2019 relate to contingent consideration arrangements with the previous owners of the UK North Sea asset package acquired by the Chrysaor Group in November 2017. The consideration is payable subject to future exploration success on certain prospects before 2025. The provision for contingent consideration represents the best estimate of amounts payable under the purchase agreement as at the balance sheet date and will be reviewed at least annually, considering actual drilling results and planned activities. Changes to the contingent consideration provision will be presented in the income statement on a prospective basis.

Other provisions at 30 June 2020 relate to a provision for an onerous lease contract in respect of long-term standby costs on the *Deepsea Aberdeen* rig, which has been operating within the Schiehallion field, whereby no future approved activities have resulted in the rig potentially remaining on standby until the end of the contract in April 2022.

22. Borrowings and Facilities

The Chrysaor Group's borrowings are carried at amortised cost and denominated in US Dollars.

	2017 *$000*	*2018* *$000*	*2019* *$000*	*30 June 2020* *$000*
Reserves Based Loan facility	1,183,915	464,277	2,067,339	1,439,706
Junior facility	392,326	394,285	395,613	396,014
10% Unsecured C loan notes 2027	28,985	31,886	34,355	30,845
10% Unsecured D loan notes 2027	233,124	256,469	282,151	252,220
10% Unsecured E loan notes 2029	575,983	633,648	—	—
Exploration finance facility	—	—	8,999	11,088
Other loans	—	24,324	34,228	35,284
	2,414,333	1,804,889	2,822,685	2,165,157
Classified within				
Non-current liabilities	2,414,333	1,709,317	2,205,322	2,170,189
Current liabilities	—	95,572	617,363	11,886
	2,414,333	1,804,889	2,822,685	2,182,075
Current assets (deferred fees)	—	—	—	(16,918)
	2,414,333	1,804,889	2,822,685	2,165,157

Interest of US$10.9 million (Dec 2019: US$11.7 million; Dec 2018: US$0.2 million; Dec 2017: US$15.9 million) on the Reserve Based Loan ("**RBL**") and junior facilities had accrued by the balance sheet date and have been classified within accruals and deferred income.

In 2017, the Chrysaor Group entered into a number of borrowing arrangements and facilities to fund the acquisition of the UK North Sea assets. The primary arrangement was an RBL facility of US$1.5 billion, being a six-year facility with a consortium consisting of 17 banks and secured by a pledge over the Chrysaor Group's oil and gas interests in the North Sea. During 2018 the decision was taken to exercise the option of the US$0.5 billion accordion, increasing the facility to US$2.0 billion.

In June 2019, the Chrysaor Group extended the terms of the RBL facility to 31 December 2025 and increased the syndicate to 19 banks and facility size to US$3.0 billion (with an option for a further US$1 billion accordion) in order to assist the financing of the ConocoPhillips UK acquisition. Subject to the maximum size of the facility which reduces every six months on a straight-line basis from 1 January 2022 to the maturity date of 31 December 2025, the amount available under the facility is determined semi-annually based on a valuation of the Chrysaor Group's borrowing base assets under certain forward-looking assumptions. The facility was also amended in June 2019 and now carries interest at USD LIBOR plus a margin of 3.25 per cent., rising to a margin of 3.5 per cent. after four years. Certain fees are also payable including fees on available commitments at 40 per cent. of the applicable margin and commission on letters of credit issued at 50 per cent. of the applicable margin.

The junior facility of US$400 million was extended and amended at the same time as the RBL facility and now carries interest at 6-month USD LIBOR plus a margin of 5.25 per cent., rising to a margin of 5.5 per cent. after four years, and is repayable in semi-annual instalments between 30 June 2022 and 30 June 2026.

During 2019, Chrysaor entered into a NOK 750 million exploration finance facility with Skandinaviska Enskilda Banken in relation to part-financing the exploration activities of Chrysaor Norge AS. At the balance sheet date, the amount drawn down on the facility was NOK 110 million (Dec 2019: NOK 83 million).

In June 2020, certain other amendments were made to the RBL facility in conjunction with the normal redetermination process. No changes were made to the existing US$3.0 billion facility size, but the debt availability grew to US$2.5 billion, to be redetermined now on an annual basis. Other amendments included the revision of certain governance requirements to be in line with peers, and the incorporation of a margin adjustment linked to carbon-emission reductions. The syndication group now stands at 18 banks.

The extensions and amendments made to the senior and junior facilities were such that they were not deemed to be a replacement of the existing Chrysaor Group's borrowing facilities.

Incremental transaction costs of US$53.6 million and US$8 million were incorporated into the initial carrying amount of the RBL and junior facilities respectively, when those facilities were completed in 2017, and a further US$45.1 million and US$0.8 million of transaction costs were capitalised when the terms of the RBL were extended in June 2019 and June 2020 respectively; these amounts are being amortised over the term of the relevant arrangement. During the six months to 30 June 2020 US$7.6 million (Dec 2019: US$15.6 million; Dec 2018: US$17.3 million; Dec 2017: US$2.8 million) of transaction costs have been amortised and are included within financing costs.

At 30 June 2020, the outstanding RBL and junior loan balances excluding incremental transaction costs were US$1,500 million and US$400 million respectively (Dec 2019: US$2,134 million and US$400 million; Dec 2018: US$500 million and US$400 million; Dec 2017: US$1,235 million and US$400 million). At 30 June 2020, the junior facility remained fully drawn and US$1,030 million remained available for drawdown under the RBL facility.

The unsecured loan notes were issued in 2017 and are listed on The International Stock Exchange (formerly the Channel Islands Securities Exchange). They incur interest of 10 per cent. per annum which, at the election of Chrysaor, is capitalised and added to the principal amount each 31 December. The C loan notes and D loan notes rank junior to any senior bank debt. None of the loan notes carry voting rights.

On 31 August 2019, the 10 per cent. Unsecured E Loan notes held by Harbour Energy, with a principal and accrued interest value of US$675.3 million, were exchanged for 4,013,524 F ordinary shares of £0.01 each.

The Chrysaor Group has Letters of Credit facilities of US$528 million (Dec 2019: US$599 million; Dec 2018: US$168 million; Dec 2017: US$175 million) held in respect of future abandonment liabilities.

Other loans represent a commercial financing arrangement with BHGE, covering a 3-year work programme for drilling, completion and subsea tie-in of development wells on Chrysaor's operated assets. As part of the deal, BHGE contribute to the costs of the work programme by funding a portion of the capital expenditure, in exchange for a greater exposure to returns, as well as risks, should certain targets and success criteria, both operational and geological, be met. Interest on this financing arrangement has been calculated using the effective interest method with reference to the expected cash flows, using an estimated reserve case.

The table below details the change in the carrying amount of the Chrysaor Group's borrowings arising from financing cash flows.

	$000
Total borrowings as at 1 January 2017	—
Gross cash inflow from Reserve Based Lending and Junior facility	1,635,000
Transaction costs paid and capitalised	(57,754)
Cash inflow from issue of Loan Notes	694,780
Loan Notes issued for non-cash consideration	128,113
Loan Note interest capitalised	15,199
Accrued transaction costs capitalised	(1,500)
Amortisation of transaction costs	2,820
Currency translation adjustments	(2,325)
Total borrowings as at 31 December 2017	2,414,333
Repayment of senior debt	(735,000)
Proceeds from financing arrangement	20,400
Loan notes interest capitalised	83,911
Other loan interest capitalised	3,924
Amortisation of transaction costs	17,321
Total borrowings as at 31 December 2018	1,804,889
Repayment of senior debt	(200,000)
Proceeds from drawdown of borrowing facilities	1,834,000
Proceeds from financing arrangement	29,600
Proceeds from exploration financing facility	9,275
Conversion of E loan notes to equity	(675,264)
Transaction costs on senior debt paid and capitalised	(45,134)
Transaction costs on exploration financing facility paid and capitalised	(507)
Currency translation adjustments	174
Loan notes interest capitalised	69,767
Financing arrangement interest receivable	(19,696)
Amortisation of transaction costs	15,581
Total borrowings as at 31 December 2019	2,822,685
Proceeds from exploration-financing facility loan	2,596
Repayment of senior debt	(634,000)
Transaction costs capitalised	(765)
Loan notes partial redemption	(46,860)
Financing-arrangement interest payable	1,055
Amortisation of transaction costs capitalised	7,605
Currency translation adjustment on EFF loan	(617)
Currency translation adjustment on transaction costs	39
Loan notes interest capitalised	13,419
Total borrowings as at 30 June 2020	2,165,157

23. Other Financial Assets and Liabilities

The Chrysaor Group held the following financial instruments at fair value. The fair values of all derivative financial instruments are based on estimates from observable inputs and are all level 2 in the IFRS 13 hierarchy, except for the royalty valuation and the Shell contingent consideration, which both include estimates based on unobservable inputs and are level 3 in the IFRS 13 hierarchy.

	As at 31 December						*As at 30 June*	
	2017		*2018*		*2019*		*2020*	
	Assets $000	*Liabilities $000*	*Assets $000*	*Liabilities $000*	*Assets $000*	*Liabilities $000*	*Assets $000*	*Liabilities $000*
Measured at fair value through profit and loss								
Royalty consideration	3,000	—	3,000	—	3,000	—	4,920	—
Commodity derivatives – contingent consideration	—	(18,320)	—	(35,078)	—	(12,495)	—	—
	3,000	(18,320)	3,000	(35,078)	3,000	(12,495)	4,920	—
Measured at fair value through other comprehensive income								
Carbon swaps – cash flow hedges	—	—	—	—	—	—	477	—
Foreign exchange derivatives – cash flow hedges	—	—	—	—	—	—	924	—
Commodity derivatives – cash flow hedges	—	(24,090)	296,049	(31,424)	190,888	(27,950)	608,069	(111)
	—	(24,090)	296,049	(31,424)	190,888	(27,950)	609,470	(111)
Total current	3,000	(42,410)	299,049	(66,502)	193,888	(40,445)	614,390	(111)
Measured at fair value through profit and loss								
Royalty consideration	11,373	—	9,700	—	9,100	—	6,380	—
Commodity derivatives – contingent consideration	—	(20,300)	—	(4,276)	—	—	—	—
	11,373	(20,300)	9,700	(4,276)	9,100	—	6,380	—
Measured at fair value through other comprehensive income								
Commodity derivatives – cash flow hedges	3,300	(52,440)	181,814	(71,210)	193,130	(3,663)	292,150	(9,688)
Interest rate derivatives – cash flow hedges	—	—	—	—	—	—	—	(4,859)
Carbon swaps – cash flow hedges	—	—	—	—	—	—	15,001	—
	3,300	(52,440)	181,814	(71,210)	193,130	(3,663)	307,151	(14,547)
Total non-current	14,673	(72,740)	191,514	(75,486)	202,230	(3,663)	313,531	(14,547)
Total current and non-current	17,673	(115,150)	490,563	(141,988)	396,118	(44,108)	927,921	(14,658)

Fair Value Measurements

All financial instruments that are initially recognised and subsequently re-measured 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.

	Financial assets		Financial liabilities	
As at 30 June 2020	*Level 2 $000*	*Level 3 $000*	*Level 2 $000*	*Level 3 $000*
Royalty valuation	—	11,300	—	—
Commodity derivatives – cash flow hedges	900,219	—	(9,799)	—
Foreign exchange derivatives – cash flow hedges	924	—	—	—
Carbon swaps – cash flow hedges	15,478	—	—	—
Interest rate derivatives – cash flow hedges	—	—	(4,859)	—
	916,621	11,300	(14,658)	—

	Financial assets		Financial liabilities	
As at 31 December 2019	*Level 2 $000*	*Level 3 $000*	*Level 2 $000*	*Level 3 $000*
Royalty valuation	—	12,100	—	—
Commodity derivatives – cash flow hedges	384,018	—	(31,613)	—
Commodity derivatives – contingent consideration	—	—	—	(12,495)
	384,018	12,100	(31,613)	(12,495)

	Financial assets		Financial liabilities	
As at 31 December 2018	*Level 2 $000*	*Level 3 $000*	*Level 2 $000*	*Level 3 $000*
Royalty valuation	—	12,700	—	—
Commodity derivatives – cash flow hedges	477,863	—	(102,634)	—
Commodity derivatives – contingent consideration	—	—	—	(39,354)
	477,863	12,700	(102,634)	(39,354)

	Financial assets		Financial liabilities	
As at 31 December 2017	*Level 2 $000*	*Level 3 $000*	*Level 2 $000*	*Level 3 $000*
Royalty valuation	—	14,373	—	—
Commodity derivatives – cash flow hedges	3,300	—	(76,530)	—
Commodity derivatives – contingent consideration	—	—	—	(38,620)
	3,300	14,373	(76,530)	(38,620)

There were no transfers between fair value levels in the year. The movements in the year associated with financial assets and liabilities measured in accordance with level 3 of the fair value hierarchy are shown below:

	Financial assets				*Financial liabilities*			
	2017 $000	*2018 $000*	*2019 $000*	*30 June 2020 $000*	*2017 $000*	*2018 $000*	*2019 $000*	*30 June 2020 $000*
Fair value as at beginning of period	26,542	14,373	12,700	12,100	—	(38,620)	(39,354)	(12,495)
Additions	—	—	—	—	(17,587)	—	—	—
Settlements	(3,000)	(3,000)	(3,000)	(1,080)	—	—	34,058	12,495
Gains and losses recognised in the income statement	(9,171)	1,327	2,400	280	(21,033)	(734)	(7,199)	—
Currency translation adjustments	2	—	—	—	—	—		—
Fair value as at end of period	14,373	12,700	12,100	11,300	(38,620)	(39,354)	(12,495)	—

Part of the consideration received on the sale of the Chrysaor Group's interest in a pre-production development in 2015 was a royalty interest, which is recognised on the balance sheet as a financial asset. At 30 June 2020, the Chrysaor Group valued the outstanding consideration receivable at US$11.3 million (Dec 2019: US$12.1 million; Dec 2018: US$12.7 million; Dec 2017: US$14.4 million) of which US$4.9 million (Dec 2019: US$3.0 million; Dec 2018: US$3.0 million; Dec 2017: US$3.0 million) is considered to be receivable within one year.

The agreement with the sellers of the UK North Sea assets purchased by the Chrysaor Group in 2017 includes contingent consideration dependent on future commodity prices over the four-year period ended 31 December 2021. These contingent payments and receipts represent a series of option contracts. The fair value of the contingent payments are presented as a financial liability and estimated using valuation techniques, the key inputs for which include future commodity prices and volatility.

Fair value movements recognised in the income statement on financial instruments are shown below.

	For the years ended 31 December			*For the six months ended*	
	2017 $000	*2018 $000*	*2018 $000*	*30 June 2020 $000*	*30 June 2019 $000*
Income/(expense) included in the income statement					
Ineffectiveness of cash flow hedges	(332)	—	—	—	—
Remeasurement of royalty valuation	(9,171)	1,327	2,400	280	1,400
Remeasurement of commodity price contingent consideration	(21,033)	(734)	(7,199)	—	(22,460)
	(30,536)	593	(4,799)	280	(21,060)

Fair Values of Other Financial Instruments

The following financial instruments are measured at amortised cost and are considered to have fair values different to their book values.

	2017		*2018*		*2019*		*30 June 2020*	
	Book value $000	*Fair value $000*	*Book value $000*	*Fair value $000*	*Book value $000*	*Fair value $000*	*Book value $000*	*Fair value $000*
Long-term borrowings – loan notes	(838,092)	(870,925)	(922,003)	(934,687)	(316,506)	(357,676)	(283,065)	(388,335)

The fair values of the loan notes are within level 2 of the fair value hierarchy and have been estimated by discounting all future cash flows by the relevant market yield curve at the balance sheet date adjusted for an appropriate credit margin. The fair values of other financial instruments not measured at fair value including cash and short-term deposits, trade receivables, trade payables and floating rate borrowings approximate their carrying amounts.

Cash Flow Hedge Accounting

The Chrysaor Group uses a combination of fixed price physical sales contracts and cash-settled fixed price commodity swaps, and options to manage the price risk associated with its underlying oil and gas revenues. As at 30 June 2020, all of the Chrysaor Group's cash-settled fixed price commodity swap derivatives have been designated as cash flow hedges of highly probable forecast sales of oil and gas.

The following table indicates the volumes, average hedged price and timings associated with Chrysaor Group's financial commodity derivatives. Volumes hedged through fixed price contracts with customers for physical delivery are excluded.

Position as at 30 June 2020	*2020*	*2021*	*2022*	*2023*	*2024*	*2025*
Oil volume hedged (thousand bbls)	12,742	12,341	1,095	—	—	—
Weighted average hedged price (US$/bbl)	62.10	62.52	60.07	—	—	—
Gas volume hedged (million therms)	393	687	999	525	235	60
Weighted average hedged price (p/therm)	46p	49p	46p	45p	44p	44p

As at 30 June 2020, the fair value of net financial commodity derivatives designated as cash flow hedges was US$890.4 million (Dec 2019: US$352.4 million; Dec 2018: US$375.2 million; Dec 2017: US$(73.2) million) and net unrealised pre-tax gains of US$829.8 million (Dec 2019: US$321.2 million; Dec 2018: US$374.9 million; Dec 2017: losses US$72.9 million) was deferred in other comprehensive income in respect of the effective portion of the hedge relationships. Amounts deferred in other comprehensive income will be released to the income statement as the underlying hedged transactions occur. As at 30 June 2020, net deferred pre-tax gains of US$607.9 million (Dec 2019: US$162.9 million; Dec 2018: US$264.6 million; Dec 2017: losses US$24.1 million) are expected to be released to the income statement within one year.

24. Financial Risk Factors and Risk Management

The Chrysaor Group's principal financial assets and liabilities comprise trade and other receivables, cash and short-term deposits accounts, trade payables, interest bearing loans and derivative financial instruments. The main purpose of these financial instruments is to manage short-term cash flow and price exposures and raise finance for the Chrysaor Group's expenditure programme. Further information on the Chrysaor Group's financial instrument risk management objectives, policies and strategies are set out in the discussion of capital management policies in the Risk Factors section of this document.

Risk Exposures and Responses

The Chrysaor Group manages its exposure to key financial risks in accordance with its financial risk management policy. The objective of the policy is to support the delivery of the Chrysaor Group's financial targets while protecting future financial security. The main risks that could adversely affect the Chrysaor Group's financial assets, liabilities or future cash flows are: market risks comprising commodity price risk, interest rate risk and foreign currency risk, liquidity risk, and credit risk. Management reviews and agreed policies for managing each of these risks are summarised in this note.

The Chrysaor Group's senior management oversees the management of financial risks. The Chrysaor Group's senior management ensures that financial risk-taking activities are governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with Chrysaor Group policies and risk objectives. All derivative activities for risk management purposes are carried out by specialist teams that have the appropriate skills, experience and supervision. It is the Chrysaor Group's policy that no trading in derivatives for speculative purposes shall be undertaken.

Market Risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: commodity price risk, interest rate risk and foreign currency risk. Financial instruments mainly affected by market risk include loans and borrowings, deposits and derivative financial instruments.

The sensitivity analyses in the following sections relate to the position as at 30 June 2020, 31 December 2019, 2018 and 2017.

The sensitivity analyses have been prepared on the basis that the number of financial instruments are all constant. The sensitivity analyses are intended to illustrate the sensitivity to changes in market variables on the composition of the Chrysaor Group's financial instruments at the balance sheet date and show the impact on profit or loss and shareholders' equity, where applicable.

The following assumptions have been made in calculating the sensitivity analyses:

- The sensitivity of the relevant profit before tax item and/or equity is the effect of the assumed changes in respective market risks for the full year based on the financial assets and financial liabilities held at the balance sheet date.
- The sensitivities indicate the effect of a reasonable increase in each market variable. Unless otherwise stated, the effect of a corresponding decrease in these variables is considered approximately equal and opposite.
- Fair value changes from derivative instruments designated as cash flow hedges are considered fully effective and recorded in shareholders' equity, net of tax.
- Fair value changes from derivatives and other financial instruments not designated as cash flow hedges are presented as a sensitivity to profit before tax only and not included in shareholders' equity.

a. Commodity Price Risk

The Chrysaor Group is exposed to the risk of fluctuations in prevailing market commodity prices on the mix of oil and gas products. On a rolling basis, the Chrysaor Group's policy is to hedge the commodity price exposure associated with 40 to 60 per cent. of the next 12 months' production, between 30 and 50 per cent. in the following 12-month period, and up to 40 per cent. in the subsequent 24-month period. The Chrysaor Group manages these risks through the use of fixed priced contracts with customers for physical delivery and derivative financial instruments including fixed priced swaps and options.

The following table summarises the impact on the Chrysaor Group's pre-tax profit and equity from a reasonably foreseeable movement in commodity prices on the fair value of commodity based derivative instruments held by the Chrysaor Group at the balance sheet date. There were no derivative financial instruments held by Chrysaor in the current year or in the previous year.

As at 30 June 2020	*Market movement*	*Effect on profit before tax $000*	*Effect on equity $000*
Brent oil price	USD10/bbl increase	—	(150,497)
Brent oil price	USD10/bbl decrease	—	150,497
NBP gas price	GBP 0.1/therm increase	—	(123,883)
NBP gas price	GBP 0.1/therm decrease	—	123,883

As at 31 December 2019	*Market movement*	*Effect on profit before tax $000*	*Effect on equity $000*
Brent oil price	USD10/bbl increase	—	(208,370)
Brent oil price	USD10/bbl decrease	—	208,370
NBP gas price	GBP 0.1/therm increase	—	(135,893)
NBP gas price	GBP 0.1/therm decrease	—	135,893

As at 31 December 2018	*Market movement*	*Effect on profit before tax $000*	*Effect on equity $000*
Brent oil price	USD10/bbl increase	(40,965)	(194,575)
Brent oil price	USD10/bbl decrease	28,507	194,575
NBP gas price	GBP 0.1/therm increase	—	(65,435)
NBP gas price	GBP 0.1/therm decrease	—	65,435

As at 31 December 2017	*Market movement*	*Effect on profit before tax $000*	*Effect on equity $000*
Brent oil price	USD10/bbl increase	(67,153)	(73,416)
Brent oil price	USD10/bbl decrease	50,968	73,416
NBP gas price	GBP 0.1/therm increase	—	(38,430)
NBP gas price	GBP 0.1/therm decrease	—	38,430

Note: the "effect on profit before tax" as at 31 December 2018 above represented estimated movements on the fair value of crude based derivative instruments from a reasonably foreseeable change in crude prices at that time, in relation to contingent consideration as part of the 2017 Shell acquisition, which would be reported through the income statement. The contingent consideration in relation to the 2019 calendar year was fully settled in March 2020 and as a result there will be no further movements on the fair value of crude based derivative instruments reported through the income statement.

b. Interest Rate Risk

Floating rate borrowings comprise bank loans under the RBL and junior facilities which incur interest fixed six months in advance at USD Libor plus a margin of 3.25 to 5.25 per cent.. Fixed rate borrowings comprise a series of shareholder loan notes which incur interest at 10 per cent. per annum. At the option of Chrysaor, interest on the shareholder loan notes can be capitalised into the principal amount and settled at maturity. Floating rate financial assets comprise cash and cash equivalents which earn interest at the relevant market rate. The Chrysaor Group monitors its exposure to fluctuations in interest rates and uses interest rate derivatives to manage the fixed and floating composition of its borrowings.

The table below represents interest rate financial instruments in place at 30 June 2020:

Derivative	Currency	Period of hedge	Terms
Interest rate swaps	US$700 million	Jun 20 – Jun 25	Average 0.5561%

There were no interest rate financial instruments in place at 31 December 2019, 31 December 2018 or 31 December 2017.

The interest rate and currency profile of the Chrysaor Group's interest-bearing financial assets and liabilities is shown below.

As at 30 June 2020	*Cash at bank $000*	*Fixed rate borrowings $000*	*Floating rate borrowings $000*	*Total $000*
US Dollars	328,396	(283,065)	(1,871,004)	(1,825,673)
Pound Sterling	39,545	—	—	39,545
Norwegian Krone	1,413	—	(11,088)	(9,675)
Other	37	—	—	37
	369,391	(283,065)	(1,882,092)	(1,795,766)

As at 31 December 2019	*Cash at bank $000*	*Fixed rate borrowings $000*	*Floating rate borrowings $000*	*Total $000*
US Dollars	510,109	(316,506)	(2,497,180)	(2,303,577)
Pound Sterling	53,694	—	—	53,694
Norwegian Krone	15	—	(8,999)	(8,984)
Other	9,364	—	—	9,364
	573,182	(316,506)	(2,506,179)	(2,249,503)

As at 31 December 2018	*Cash at bank $000*	*Fixed rate borrowings $000*	*Floating rate borrowings $000*	*Total $000*
US Dollars	302,940	(922,003)	(882,886)	(1,501,949)
Pound Sterling	12,372	—	—	12,372
Norwegian Krone	856	—	—	856
Other	143	—	—	143
	316,311	(922,003)	(882,886)	(1,488,578)

As at 31 December 2017	Cash at bank $000	Fixed rate borrowings $000	Floating rate borrowings $000	Total $000
US Dollars	279,250	(838,092)	(1,576,241)	(2,135,083)
Pound Sterling	20,288	—	—	20,288
Other	3	—	—	3
	299,541	(838,092)	(1,576,241)	(2,114,792)

The following table illustrates the indicative pre-tax effect on profit and equity of applying a reasonably foreseeable increase in interest rates to the Chrysaor Group's financial assets and liabilities at the balance sheet dates. Chrysaor had no significant floating rate asset or liabilities in the current period or previous financial years.

	Market movement	Effect on profit before tax $000	Effect on equity $000
2020			
US interest rates	+100 basis points	(15,716)	—
2019			
US interest rates	+100 basis points	(20,239)	—
2018			
US interest rates	+100 basis points	(5,981)	—
2017			
US interest rates	+100 basis points	(13,355)	—

c. *Foreign Currency Risk*

The Chrysaor Group is exposed to foreign exchange risks to the extent it transacts in various currencies, while measuring and reporting its results in US Dollars. Since time passes between the recording of a receivable or payable transaction and its collection or payment, the Chrysaor Group is exposed to gains or losses on non-USD amounts and on balance sheet translation of monetary accounts denominated in non-USD amounts upon spot rate fluctuations from period to period. 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. The Chrysaor Group has subsidiaries with functional currencies of Pounds Sterling, US Dollar and Norwegian Krone. Exposures can also arise from sales or purchases denominated in currencies other than the functional currency of the relevant entity, and such exposures are monitored and hedged with agreement from the Board.

In 2020, the Chrysaor Group entered into forward contracts as a means of hedging its exposure to foreign exchange rate risks. As at 30 June 2020, the Chrysaor Group had £125.0 million hedged at forward rates of between US$1.2311 and US$1.2413: £1 for the period July 2020 to January 2021, and EUR 13,777,750 hedged at forward rates of between US$1.1039 and US$1.1061: EUR for the period July 2020 to December 2020.

As at 31 December 2019, 31 December 2018 and 31 December 2017, the Chrysaor Group had not entered into any exchange rate derivatives.

The following table demonstrates the sensitivity to a reasonably foreseeable change in US Dollar against Pounds Sterling with all other variables held constant, of the Chrysaor Group's profit before tax (due to foreign exchange translation of monetary assets and liabilities). The impact of translating the net assets of foreign operations into US Dollars is excluded from the sensitivity analysis.

	Market movement	*Effect on profit before tax $000*	*Effect on equity $000*
2020			
US dollar/Sterling	10% strengthening	140,922	—
US dollar/Sterling	10% weakening	(140,922)	—
2019			
US dollar/Sterling	10% strengthening	133,595	—
US dollar/Sterling	10% weakening	(133,595)	—
2018			
US dollar/Sterling	10% strengthening	42,607	—
US dollar/Sterling	10% weakening	(42,607)	—
2017			
US dollar/Sterling	10% strengthening	(5,542)	—
US dollar/Sterling	10% weakening	4,667	—

d. Credit Risk

Credit risk is the risk that a counterparty will not meet its obligations under a financial instrument or customer contract, leading to financial loss. The Chrysaor Group is exposed to credit risk from its operating activities (primarily for trade receivables) and from its financing activities, including deposits with banks and derivative financial instruments.

The Chrysaor Group only sells hydrocarbons to recognised and creditworthy parties, typically the trading arm of large, international oil and gas companies. An indication of the concentration of credit risk on trade receivables is shown in note 4, whereby the revenue from one customer averages 96 per cent. of the Chrysaor Group's consolidated revenue across the reporting periods.

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.

There are no significant concentrations of credit risk within the Chrysaor Group unless otherwise disclosed, and credit losses are expected to be near to zero. The maximum credit risk exposure relating to financial assets is represented by carrying value as at the balance sheet date.

e. Liquidity Risk

The Chrysaor Group monitors the amount of borrowings maturing within any specific period and proposes to meet its financing commitments from the operating cash flows of the business and existing committed lines of credit.

The table below summarises the maturity profile of the Chrysaor Group's financial liabilities at 30 June 2020, 31 December 2019, 31 December 2018 and 31 December 2017 based on contractual undiscounted payments.

As at 30 June 2020	*Within one year $000*	*1 to 2 years $000*	*2 to 5 years $000*	*Over 5 years $000*	*Total $000*
Non-derivative Financial Liabilities					
Reserves Based Loan facility	55,778	57,422	1,285,698	339,578	1,738,476
Junior facility	22,770	111,570	272,398	74,479	481,217
Loan notes	—	—	—	561,840	561,840
Exploration finance facility	8,624	2,805	—	—	11,429
Other loans	606	15,519	35,834	7,849	59,808
Trade and other payables	733,821	27,673	18,747	—	780,241
Lease obligations	53,634	53,555	30,145	33,916	171,250
	875,233	268,544	1,642,822	1,017,662	3,804,261
Derivative Financial Liabilities					
Net-settled commodity derivatives	109	—	9,688	—	9,797
Net-settled interest rate derivatives	—	—	—	4,859	4,859
Total as at 30 June 2020	875,342	268,544	1,652,510	1,022,521	3,818,917

As at 31 December 2019	*Within one year $000*	*1 to 2 years $000*	*2 to 5 years $000*	*Over 5 years $000*	*Total $000*
Non-derivative Financial Liabilities					
Reserves Based Loan facility	713,412	580,844	1,030,513	79,060	2,403,829
Junior facility	29,154	29,075	354,062	105,674	517,965
Loan notes	—	—	—	660,052	660,052
Exploration finance facility	9,732	—	—	—	9,732
Other loans	16,046	13,290	23,856	—	53,192
Trade and other payables	593,066	32,575	19,800	—	645,441
Lease obligations	80,045	72,220	54,938	30,302	237,505
	1,441,455	728,004	1,483,169	875,088	4,527,716
Derivative Financial Liabilities					
Net-settled commodity derivatives	40,445	1,330	2,333	—	44,108
Total as at 31 December 2019	1,481,900	729,334	1,485,502	875,088	4,571,824

As at 31 December 2018	*Within one year $000*	*1 to 2 years $000*	*2 to 5 years $000*	*Over 5 years $000*	*Total $000*
Non-derivative Financial Liabilities					
Reserves Based Loan facility	—	513,604	71,047	—	584,651
Junior facility	—	127,118	332,855	47,070	507,043
Loan notes	—	—	—	2,446,204	2,446,204
Other loans	22,966	1,358	—	—	24,324
Trade and other payables	248,222	—	—	—	248,222
	271,188	642,080	403,902	2,493,274	3,810,444
Derivative Financial Liabilities					
Net-settled commodity derivatives	66,502	68,987	6,499	—	141,988
Total as at 31 December 2018	337,690	711,067	410,401	2,493,274	3,952,432

As at 31 December 2017	Within one year $000	1 to 2 years $000	2 to 5 years $000	Over 5 years $000	Total $000
Non-derivative Financial Liabilities					
Reserves Based Loan facility	133,998	523,827	774,247	—	1,432,072
Junior facility	17,594	124,864	333,411	50,427	526,296
Loan notes	—	—	—	2,446,204	2,446,204
Short-term payables	432,340	—	—	—	432,340
	583,932	648,691	1,107,658	2,496,631	4,836,912
Derivative Financial Liabilities					
Net-settled commodity derivatives	42,410	39,873	32,867	—	115,150
Total as at 31 December 2017	626,342	688,564	1,140,525	2,496,631	4,952,062

The maturity profile in the above tables reflect only one side of the Chrysaor Group's liquidity position. Interest bearing loans and borrowings and trade payables mainly originate from the financing of assets used in the Chrysaor Group's ongoing operations such as property, plant and equipment and working capital such as inventories. These assets are considered part of the Chrysaor Group's overall liquidity risk.

25. Called Up Share Capital

	As at 31 December						As at 30 June	
	2017		2018		2019		2020	
Allotted, called up and fully paid	*No.*	*$000*	*No.*	*$000*	*No.*	*$000*	*No.*	*$000*
F Ordinary shares of £0.01 each	981,100	12	981,100	12	4,994,624	61	4,994,624	61
G Ordinary shares of £0.40 each	18,900	10	18,900	10	18,900	10	18,900	10
M Ordinary shares of £0.01 each	9,305	—	9,580	—	9,865	—	9,865	—
		22		22		71		71

In January 2017, following the agreement to acquire the package of North Sea assets from Shell, the Chrysaor Group completed a financial restructure in conjunction with the Chrysaor Group's private equity investors.

The restructure included:

— the cancellation or redemption of Chrysaor's existing equity share capital consisting of 650,000 £0.05 A and 350,000 £0.05 B ordinary shares, 98.5 million £0.01 10 per cent. cumulative redeemable preference shares and 68.0 million US$0.0001 D ordinary shares;

— the redemption of 26.3 million US$0.01 C convertible redeemable preference shares in exchange for 10% unsecured C loan notes with a principal value of US$26.6 million. The C loan notes are classified as a financial liability and presented on the balance sheet as long-term borrowings (note 22);

— the issuance of 226,555 F ordinary shares of £0.01 each for a cash consideration of US$32.0 million and 9,305 M ordinary shares of £0.01 each for a cash consideration of US$0.1 million.

— the re-designation of 501,000 preference shares of a par value of £0.01 each as F ordinary shares of a part value of £0.01 each;

— the re-designation of 756,000 preference shares as G ordinary shares of a par value of £0.01 each and the further consolidation of the 756,000 G ordinary shares, re-designated into 18,900 G ordinary shares of a par value of £0.40 each;

Following the January 2017 financial restructure, further issues of F ordinary shares for total cash consideration of US$35.8 million occurred in April 2017 (56,640 shares), June 2017 (50,550 shares) and August 2017 (146,255 shares).

A further 275 M ordinary shares were issued in 2018 which is held in trust but not paid up.

On 31 August 2019, the 10 per cent. Unsecured E Loan notes held by Harbour Energy, with a principal and accrued interest value of US$675.3 million, were exchanged for 4,013,524 F ordinary shares of £0.01 each.

In November 2019, Chrysaor issued 285 M shares at £10 per share for a cash consideration of US$3,689.

As at each balance sheet date, the share capital comprised of three classes of ordinary shares. Each F and G ordinary share carries equal voting and dividend rights. M ordinary shares carry no voting rights and are subordinate to both F and G ordinary shares regarding rights to dividend and other distributions.

26. Notes to the Statement of Cash Flows

Net cash flows from operating activities consist of:

	For the years ended 31 December			*For the six-month period ended*	
	2017 $000	*2018 $000*	*2019 $000*	*30 June 2020*	*30 June 2019*
Profit/(loss) before taxation	471	578,401	455,558	(224,222)	323,705
Finance cost, excluding foreign exchange	43,978	270,293	256,399	148,768	123,470
Finance income, excluding foreign exchange	(260)	(8,622)	(31,611)	(3,460)	(10,190)
Depreciation, depletion and amortisation	100,847	629,154	917,015	723,468	359,307
Impairment of property, plant and equipment	—	—	—	250,629	—
Impairment of goodwill				55,735	
Taxes (paid)/received	—	—	(90,183)	6,583	—
Share based payments	—	—	10,905	—	—
Credit due to reduction in decommissioning provision	—	(44,485)	—	—	—
Decommissioning payments	—	(21,502)	(28,955)	(96,636)	(5,260)
Exploration costs written-off	7,276	10,731	222	38,851	132
Remeasurement on commodity price contingent consideration	21,033	734	7,199	—	22,460
Ineffectiveness of cash flow hedges	332				
Onerous contract provision	—	—	—	27,943	—
Share option reserve	2	—	—	—	—
Remeasurement on exploration contingent consideration	—	(217)	(7,773)	—	276
Remeasurement of acquisition completion adjustments	—	—	—	391	—
Gain on termination of IFRS16 lease	—	—	—	(584)	—
Loss on disposal of exploration and evaluation asset	—	—	—	55	—
Decrease in royalty consideration receivable	12,171	1,673	600	800	1,600
Realised cash flow hedges not yet settled	—	(693)	(23,747)	(34,691)	(8,082)
Unrealised foreign exchange loss/(gain)	1,724	(36,904)	63,767	(104,662)	(2,057)
Working capital adjustments:					
Decrease/(increase) in inventories	29,758	1,857	208	(9,738)	(4,743)
(Increase)/decrease in trade and other receivables	(193,913)	32,578	(6,085)	202,875	(50,387)
(Decrease)/increase in trade and other payables	30,608	34,844	(4,858)	(36,009)	23,991
Net cash inflow from operating activities	54,027	1,447,842	1,518,661	946,096	774,222

Reconciliation of Net Cash Flow to Movement in Net Borrowings

	For the years ended 31 December			For the six months ended
	2017 *$000*	*2018* *$000*	*2019* *$000*	*30 June 2020*
Proceeds from drawdown of borrowing facilities	(1,635,000)	—	(1,834,000)	—
Proceeds from issue of loan notes	(822,893)	—	—	—
Proceeds from financing arrangement	—	(20,400)	(29,600)	—
Conversion of E loan notes to equity	—	—	675,264	—
Proceeds from exploration financing facility loan	—	—	(9,275)	(2,596)
Repayment of senior debt		735,000	200,000	634,000
Transaction costs capitalised	59,254	—	45,641	765
Loan notes partial redemption	—	—	—	46,860
Financing arrangement interest receivable/ (payable)		(3,924)	19,696	(1,055)
Amortisation of transaction costs capitalised	(2,820)	(17,321)	(15,581)	(7,605)
Currency translation adjustment on exploration financing facility loan	—	—	(175)	617
Currency translation adjustment on transaction costs	2,325	—	1	(39)
Loan notes interest capitalised	(15,199)	(83,911)	(69,767)	(13,419)
Movement in total borrowings	(2,414,333)	609,444	(1,017,796)	657,528
Movement in cash and cash equivalents	295,459	16,770	256,871	(203,791)
(Increase)/decrease in net borrowings in the year	(2,118,874)	626,214	(760,925)	453,737
Opening net borrowings	4,082	(2,114,792)	(1,488,578)	(2,249,503)
Closing net borrowings	(2,114,792)	(1,488,578)	(2,249,503)	(1,795,766)

Analysis of Net Borrowings

	For the years ended 31 December			For the six months ended
	2017 *$000*	*2018* *$000*	*2019* *$000*	*30 June 2020*
Cash and cash equivalents	299,541	316,311	573,182	369,391
Reserves Based Loan facility	(1,183,915)	(464,277)	(2,067,339)	(1,439,706)
Junior facility	(392,326)	(394,285)	(395,613)	(396,014)
Net debt	(1,276,700)	(542,251)	(1,889,770)	(1,466,329)
Shareholder loan notes	(838,092)	(922,003)	(316,506)	(283,065)
Exploration financing facility	—	—	(8,999)	(11,088)
Financing arrangement	—	(24,324)	(34,228)	(35,284)
Closing net borrowings	(2,114,792)	(1,488,578)	(2,249,503)	(1,795,766)

27. Related Party Disclosures

The consolidated financial statements include the financial statements of the Company and its subsidiaries, a list of which is contained in note 14.

The Chrysaor Group's main related parties comprise members of key management personnel and Harbour Energy Ltd (Harbour Energy) along with affiliated persons and entities. Harbour Energy is an energy investment vehicle formed by EIG Global Energy Partners and is the Chrysaor Group's primary private equity investor. Transactions with these related parties are disclosed below.

Share Capital

On 31 August 2019, the 10 per cent. Unsecured E Loan notes held by Harbour Energy, with a principal and accrued interest value of US$675.3 million, were exchanged for 4,013,524 F ordinary shares of £0.01 each. In November 2019, 225 M ordinary shares of £0.01 each were issued to certain members of key management for a cash consideration of £10 per share.

Shareholder Loan Notes

At the end of 2018, Harbour Energy held E loan notes with a principal value of US$566.9 million plus accrued interest. On 31 August 2019, all the E Loan Notes including accrued interest were exchanged for F ordinary shares, at a value of US$675.3 million. The main impact of the exchange is that Harbour Energy's direct equity interest in CHL increased to 89.6 per cent. from 48 per cent.. In February 2020, a partial redemption of both the C Loan Notes and D Loan Notes took place, of US$4.9 million and US$42.0 million respectively.

As at 30 June 2020, the carrying amount of D loan notes due to Harbour Energy was US$252.2 million (Dec 2019: US$282.2 million; Dec 2018: US$256.5 million; Dec 2017: US$233.1 million) and the value of C loan notes due to key management personnel was US$1.8 million (Dec 2019: US$2.0 million; Dec 2018: US$1.9 million; Dec 2017: US$1.7 million). The amount of interest charged to the income statement associated with all loan notes payable to Harbour Energy and key management was US$12.1 million and US$0.1 million respectively in the six month period to 30 June 2020 (Dec 2019: US$67.3 million and US$0.1 million respectively; Dec 2018: US$81.0 million and US$0.2 million respectively; Dec 2017: US$12.8 million and US$0.1 million respectively).

The Chrysaor Group also pays governance and monitoring fees to its institutional shareholders. For the six months ended 30 June 2020, the total fees payable to Harbour Energy amounted to US$4.3 million (Dec 2019: US$8.6 million; Dec 2018: US$8.6 million; Dec 2017: US$2.6 million) and to other shareholders US$0.5 million (Dec 2019: US$1.0 million; Dec 2018: US$1.0 million; Dec 2017: US$1.0 million) with US$0.5 million outstanding as at the balance sheet date (Dec 2019: US$1.0 million; Dec 2018: US$nil; Dec 2017: US$nil).

Controlling Party

The immediate parent undertaking is Harbour Chrysaor Equity Holdings Ltd (Cayman). The ultimate parent undertaking and the largest and smallest group to consolidate these financial statements is Harbour Energy Holdings Ltd (Cayman). Copies of the Harbour Energy Holdings Ltd consolidated financial statements can be obtained from the company secretary at 7th Floor, 20 St. James's Street, London, SW1A 1ES.

Key Management Compensation

Remuneration of key management personnel of the Chrysaor Group is shown below. The remuneration of the Non-Executive Chairman is wholly paid by EIG Management Company. The remuneration of the Harbour-appointed directors for their board roles of Chrysaor is wholly paid by Harbour Energy.

	For the years ended 31 December			*6 months to 30 June*	*6 months to 30 June*
	2017	*2018*	*2019*	*2020*	*2019*
	$000	*$000*	*$000*	*$000*	*$000*
Salaries and short-term benefits	2,755	5,749	8,859	4,937	3,526
Payments made in lieu of pension contributions	153	525	346	356	244
Pension benefits	76	122	170	55	63
	2,984	6,396	9,375	5,348	3,833

28. Post Balance Sheet Events

In September 2020, the Chrysaor Group put in place a new Long-Term Incentive Plan (‘**LTIP**’) scheme for senior employees. The LTIP is a cash settled scheme based on a number of notional shares multiplied by a notional share price. The scheme has a maximum number of notional shares that can vest. Performance conditions determine the final number of vesting notional shares and there are three performance measures covering absolute and relative total shareholder return and return on capital employed. The vesting period is three years from the scheme grant date with cash settlement to the employees twelve months after the vesting period provided the individual remains in employment.

On the 6 October 2020, Chrysaor announced that agreement had been reached with Premier Oil plc and Harbour Energy regarding a proposed reverse takeover all share merger between Premier and Chrysaor and the reorganisation of Premier’s existing debt and cross-currency swaps. Completion of the transaction is subject to regulatory approvals, approval by Premier’s shareholders, the existing creditors and expected in 1Q 2021.

The transaction will create the largest independent oil and gas company listed on the London Stock Exchange with combined production of over 250 mboepd as at 30 June 2020 and 2P reserves of 717 mmboe as at 31 December 2019. The Combined Group will be of significant scale and diversification with a strong balance sheet and significant international growth opportunities.

Glossary

- *2C Contingent resources (best estimate)*
- *2P Proved plus probable reserves*
- *bbl Barrel*
- *BMS Business Management System*
- *boe Barrel of oil equivalent*
- *boepd Barrel of oil equivalent per day*
- *CEO Chief Executive Officer*
- *CUI Corrosion under insulation*
- *DD&A Depreciation, depletion and amortisation*
- *DNV Det Norske Veritas-Germanischer Lloyd*
- *ESR Elected safety representative*
- *FID Final investment decision*
- *FPS Forties Pipeline System*
- *HSEx Health & Safety Executive*
- *HSEQ Health, Safety, Environment and Quality*
- *MAE Major Accident Event*
- *mboepd Thousand barrels of oil equivalent per day*
- *mmboe Million barrels of oil equivalent*
- *MPE Ministry of Petroleum and Energy, Norway*
- *OPPC Oil pollution prevention and control*
- *OPRED Offshore Petroleum Regulator for Environment & Decommissioning*
- *OSDR Offshore Safety Directive Regulator*
- *PCOA Put and call options agreement*
- *POP Platform Operating Procedure*
- *SWE Safe Working Essentials*
- *TAR Turnaround*
- *TRIF Total Recordable Incident Frequency*
- *WOSPS West of Shetland Pipeline System*

Non-IFRS Measures

The Chrysaor Group uses certain measures of performance that are not specifically defined under IFRS or other generally accepted accounting principles. These non-IFRS measures, which are presented within the Financial Review are EBITDAX, Cost per barrel, Depreciation, depletion and amortisation per barrel, free cash flow and net debt and are defined below.

- *EBITDAX*: is defined as earnings before tax, interest, depreciation and amortisation, remeasurements and exploration expenditure. This is a useful indicator of underlying business performance.
- *Operating Cost Per Barrel*: direct operating costs (excluding over/underlift) for the year including tariff expense and insurance costs less tariff income, divided by working interest production. This is a useful indicator of ongoing operating costs from the Chrysaor Group's producing assets.

- *Depreciation, Depletion and Amortisation per barrel (DD&A)*: depreciation and amortisation of oil and gas properties for the year divided by working interest production. This is a useful indicator of ongoing rates of depreciation and amortisation of the Chrysaor Group's producing assets.
- *Free Cash Flow*: defined as EBITDAX less capital expenditure.
- *Net Debt*: the cash and cash equivalents less total senior and junior debt recognised on the consolidated balance sheet. This is an indicator of the Chrysaor Group's indebtedness and contribution to capital structure.

SECTION C: ACCOUNTANT'S REPORT IN RESPECT OF THE HISTORICAL FINANCIAL INFORMATION RELATING TO THE COMBINED COP SUBSIDIARIES

The Directors and Proposed Directors (together the "Directors")
Premier Oil plc
23 Lower Belgrave St
Belgravia
London SW1W 0NR
United Kingdom

RBC Europe Limited
100 Bishopsgate
London EC2N 4AA
United Kingdom

16 December 2020

Dear Ladies and Gentlemen

The reverse takeover of Premier Oil plc ("Premier") by Chrysaor Holdings Limited ("Chrysaor") and the proposed readmission of the ordinary shares of Premier to the premium segment of the Official List maintained by the Financial Conduct Authority (the "FCA") and the proposed admission of those shares to trading on the London Stock Exchange's main market for listed securities (the "Transaction").

We report on the combined financial information of Chrysaor Petroleum Company U.K. Limited (formerly ConocoPhillips Petroleum Company U.K. Limited), Chrysaor Resources (Irish Sea) Limited (formerly Burlington Resources (Irish Sea) Limited), Chrysaor (U.K.) Sigma Limited (formerly ConocoPhillips (U.K.) Sigma Limited) and their subsidiary and associate undertakings (the "**Combined COP Subsidiaries**") for the three years ended 31 December 2017, 31 December 2018 and 31 December 2019 set out in Section D of Part VIII below (the "**Historical Financial Information relating to the Combined COP Subsidiaries**").

This report is required by item 18.3.1 of Annex 1 to 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 relating to the Combined COP Subsidiaries gives, for the purposes of the prospectus dated 16 December 2020 (the "**Prospectus**") of Premier, a true and fair view of the state of affairs of the Combined COP Subsidiaries as at the dates stated and of its profits and losses, cash flows and changes in invested capital for the years ended 31 December 2017, 31 December 2018 and 31 December 2019 in accordance with International Financial Reporting Standards as adopted by the European Union.

Responsibilities

The Proposed Directors and the Directors of Premier (together the "**Directors**") are responsible for preparing the Historical Financial Information relating to the Combined COP Subsidiaries in accordance with International Financial Reporting Standards as adopted by the European Union.

PricewaterhouseCoopers LLP, 1 Embankment Place, London, WC2N 6RH

Tel: +44 (0) 20 7583 5000, Fax: +44 (0) 20 7212 4652

It is our responsibility to form an opinion on the Historical Financial Information relating to the Combined COP Subsidiaries and to report our opinion to you.

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and for any responsibility arising under item 5.3.2R(2)(f) of the Prospectus Regulation Rules 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 PR Regulation, consenting to its inclusion in the Prospectus.

Basis of Preparation

The Historical Financial Information relating to the Combined COP Subsidiaries has been prepared for inclusion in the Prospectus of Premier on the basis of the accounting policies set out in Note 1 to 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. 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.

Our work included an assessment of evidence relevant to the amounts and disclosures in the Historical Financial Information relating to the Combined COP Subsidiaries. It also included an assessment of significant estimates and judgments made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the entity's circumstances, consistently applied and adequately disclosed.

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 financial information is free from material misstatement whether caused by fraud or other irregularity or error.

Conclusions Relating to Going Concern

We are required to report if we have anything material to add or draw attention to in respect of the Directors' statement in the Historical Financial Information relating to the Combined COP Subsidiaries about whether the Directors considered it appropriate to adopt the going concern basis of accounting in preparing the Historical Financial Information relating to the Combined COP Subsidiaries and the Directors' identification of any material uncertainties to the Combined COP Subsidiaries' ability to continue as a going concern over a period of at least twelve months from the date of this Prospectus.

We have nothing material to add or to draw attention to. However, because not all future events or conditions can be predicted, this statement is not a guarantee as to the ability of the Combined COP Subsidiaries to continue as a going concern.

Declaration

For the purposes of Prospectus Regulation Rule PR 5.3.2 R (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 make 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

PricewaterhouseCoopers LLP
Chartered Accountants

SECTION D: HISTORICAL FINANCIAL INFORMATION RELATING TO THE COMBINED COP SUBSIDIARIES

Combined Income Statement

	Note	2017 $000	2018 $000	2019 $000
		For the years ended 31 December		
Revenue	4	2,663,163	3,193,995	1,602,542
Other income	4	7,694	15,841	15,076
Revenue and other income		2,670,857	3,209,836	1,617,618
Cost of sales		(2,730,609)	(3,063,159)	(1,386,172)
Gross (loss)/profit		(59,752)	146,677	231,446
Exploration and evaluation expenses	5	(2,932)	(2,544)	(969)
Exploration costs written-off	5	(56)	(12,820)	(1,683)
Operating (loss)/profit		(62,740)	131,313	228,794
Gain on disposal of subsidiary undertaking	6	—	151,864	—
Gain on disposal of investment in associate undertaking	6	—	—	144,075
(Loss)/profit before interest and taxation		(62,740)	283,177	372,869
Finance income	8	2,943	6,569	3,751
Finance expenses	8	(40,522)	(43,814)	(58,310)
Share of net profit of associate undertaking	16	10,700	14,312	7,526
(Loss)/profit before taxation		(89,619)	260,244	325,836
Income tax credit/(expense)	10	67,025	(45,473)	(71,341)
(Loss)/profit for the financial year		(22,594)	214,771	254,495

Combined Statement of Comprehensive Income

	For the years ended 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
(Loss)/profit for the financial year	(22,594)	214,771	254,495
Items that may be reclassed to income statement			
Share of movement in net liabilities of associate undertaking resulting from group reconstruction and adjustment to investment carrying value (note 16)	—	(22,587)	(6,840)
Currency exchange differences	249,988	(182,215)	20,714
Total other comprehensive income/(loss) for the financial year, net of tax	249,988	(204,802)	13,874
Total comprehensive income for the financial year	227,394	9,969	268,369
Total comprehensive income attributable to:			
Equity holders of the ultimate parent company	227,394	9,969	268,369

Combined Balance Sheet

	Note	*As at 1 January 2017 $000*	*As at 31 December 2017 $000*	*2018 $000*	*2019 $000*
Assets					
Non-current assets					
Other intangible assets	12	156,116	173,086	68,526	73,069
Property, plant and equipment	13	3,576,755	3,862,370	1,544,930	1,538,677
Right of use assets	14	12,199	113,119	84,235	63,594
Investments	16	14,519	16,847	—	—
Deferred tax	10	—	—	—	26,216
Other receivables	18	—	—	1,170	—
Amounts due from group undertakings	19	98,736	108,184	102,280	832,545
Total non-current assets		3,858,325	4,273,606	1,801,141	2,534,101
Current assets					
Inventories	17	49,757	59,336	39,645	38,148
Trade and other receivables	18	259,588	313,684	416,688	101,272
Amounts due from group undertakings	19	60,897	1,804,341	115,069	207,076
Cash and cash equivalents	20	723,240	997,531	1,113,470	18
Total current assets		1,093,482	3,174,892	1,684,872	346,514
Total assets		4,951,807	7,448,498	3,486,013	2,880,615
Equity and liabilities					
Invested capital					
Invested capital		2,575,160	2,802,554	1,180,537	820,715
Total invested capital		2,575,160	2,802,554	1,180,537	820,715
Non-current liabilities					
Provisions	23	987,820	1,199,681	982,749	1,060,179
Deferred tax	10	404,677	385,918	160	—
Other payables	22	50,000	50,000	50,000	50,000
Lease creditor	14	10,999	95,704	70,541	48,708
Total non-current liabilities		1,453,496	1,731,303	1,103,450	1,158,887
Current liabilities					
Trade and other payables	22	316,546	409,197	553,521	855,594
Bank overdraft		601,491	2,481,123	615,315	—
Lease creditor	14	1,200	19,973	19,938	24,205
Provisions	23	3,914	4,348	13,252	21,214
Total current liabilities		923,151	2,914,641	1,202,026	901,013
Total liabilities		2,376,647	4,645,944	2,305,476	2,059,900
Total invested capital and liabilities		4,951,807	7,448,498	3,486,013	2,880,615

Combined Statement of Changes in Invested Capital

	Invested capital $000
As at 1 January 2017	2,575,160
Loss for the financial year	(22,594)
Other comprehensive income	249,988
As at 31 December 2017	2,802,554
Profit for the financial year	214,771
Dividends paid	(1,631,986)
Other comprehensive loss	(204,802)
At 31 December 2018	1,180,537
Profit for the financial year	254,495
Dividends paid	(628,191)
Other comprehensive income	13,874
At 31 December 2019	820,715

Combined Statement of Cash Flows

	Note	*For the years ended 31 December* 2017 $000	2018 $000	2019 $000
Net cash inflow from operating activities	26	267,365	440,146	224,350
Cash flows from investing activities				
Expenditure on exploration and evaluation assets		(789)	(12,992)	(18,973)
Expenditure on property, plant and equipment		(210,453)	(184,901)	(71,407)
New loans issued to group companies	19	(1,672,338)	—	(701,250)
Repayment of loans by group companies	19	—	1,662,315	10,023
Interest received		2,943	5,646	3,751
Proceeds from sale of subsidiary undertaking	6	—	1,806,780	—
Proceeds from sale of investment in associate undertaking	6	—	—	144,075
Dividends received from associate undertaking	16	9,809	9,788	686
Net cash disposed of with subsidiary undertaking		—	(63,976)	—
Net cash (outflow)/inflow from investing activities		(1,870,828)	3,222,660	(633,095)
Cash flows from financing activities				
New loans received from group companies		—	—	548,444
Dividends paid on preference shares		(2,823)	(2,909)	(2,860)
Dividends paid on ordinary shares		—	(1,631,986)	(628,191)
Lease payments		(9,263)	(19,788)	(19,885)
Interest paid and bank charges		(4,254)	(8,784)	(6,946)
Net cash outflow from financing activities		(16,340)	(1,663,467)	(109,438)
Net (decrease)/increase in cash and cash equivalents		(1,619,803)	1,999,339	(518,183)
Effect of exchange rates on cash and cash equivalents		14,462	(17,592)	20,046
Cash and cash equivalents at 1 January		121,749	(1,483,592)	498,155
Cash and cash equivalents at 31 December		(1,483,592)	498,155	18
Cash and cash equivalents consists of:				
Cash at bank and in hand	20	997,531	1,113,470	18
Bank overdraft		(2,481,123)	(615,315)	—
		(1,483,592)	498,155	18

Notes to the Combined Historical Financial Information

1. Corporate Information

The "Combined COP Subsidiaries" (or "the **Companies**") for the years ended 31 December 2017 to 2019 comprise Chrysaor Petroleum Company U.K. Limited (formerly ConocoPhillips Petroleum Company U.K. Limited), Chrysaor Resources (Irish Sea) Limited (formerly Burlington Resources (Irish Sea) Limited), Chrysaor (U.K.) Sigma Limited (formerly ConocoPhillips (U.K.) Sigma Limited) and their subsidiary and associate undertakings (notes 15 and 16).

The combined financial information presented in this "Combined COP Subsidiaries Historical Financial Information" has been prepared specifically for this Investment Circular and incorporates financial information of subsidiaries and affiliates comprised in the Combined COP Subsidiaries. The Combined COP Subsidiaries do not constitute a separate legal group.

From 1 January 2017 to 30 September 2019, the Companies were under the common control of ConocoPhillips Company ("**ConocoPhillips**"). On 30 September 2019, Chrysaor E&P Limited completed the acquisition of the Companies along with a number of other UK legal entities from ConocoPhillips. From 30 September 2019, the Companies have been part of the Chrysaor group of companies (the "**Chrysaor Group**"). At 31 December 2019, the ultimate parent undertaking and controlling party of all the Companies is Harbour Energy Holdings Ltd (Cayman).

The Companies are private companies limited by share capital, incorporated and domiciled in the United Kingdom. The Companies' principal place of business is London, United Kingdom and their registered office is Brettenham House, Lancaster Place, London, WC2E 7EN.

The Companies' principal activities are the acquisition, exploration, development and production of oil and gas reserves on the UK Continental Shelf.

2. Accounting Policies

Basis of Preparation

The Combined COP Subsidiaries do not constitute a separate legal group. The Combined COP Subsidiaries Historical Financial Information is a combination of certain legal entities purchased by Chrysaor E&P Limited from ConocoPhillips and has been prepared specifically for the purpose of complying with the Prospectus Rules.

The Combined COP Subsidiaries historical financial information has been prepared under accounting policies consistent with those of Premier Oil plc in its last published Annual Report.

The Combined COP Subsidiaries Historical Financial Information is prepared on a basis that combines the results, assets and liabilities of each of the companies constituting the Combined COP Subsidiaries and their subsidiary and associate undertakings (notes 15 and 16) by applying the principles underlying the consolidation procedures of IFRS 10 'Consolidated Financial Statements' ("IFRS 10") for each of the three years to 31 December 2017, 2018 and 2019 and as at 1 January 2017, 31 December 2017, 2018 and 2019. On such basis, the combined historical financial information sets out the Combined COP Subsidiaries balance sheet as at 1 January 2017, 31 December 2017, 2018 and 2019 and the combined results of the Combined COP Subsidiaries operations and cash flows for the three years ended 31 December 2017, 2018 and 2019. Recharges for central costs from other entities were recorded within the books of each statutory entity included within this combination. The total combined amount of costs re-charged in the period are set out in note 27.

The Combined COP Subsidiaries Historical Financial Information presents the financial track record of the Combined COP Subsidiaries as at and for the three years ended 31 December 2019 and is prepared specifically to be included in the Prospectus and Investment Circular in connection with the proposed application for re-admission of the entire ordinary share capital of Premier Oil plc to listing on the premium listing segment of the Official List of the Financial Conduct Authority and to trading on the London Stock Exchange plc's main market for listed securities. This combined financial information has been prepared in accordance with the requirements of the Prospectus Directive regulation, the Listing Rules, this basis of preparation, and with those parts of the Companies Act 2006 as applicable to companies reporting under IFRS.

This basis of preparation describes how the Combined COP Subsidiaries Historical Financial Information has been prepared in accordance with International Financial Reporting Standards as adopted by the European Union and the IFRS Interpretation Committee interpretations (together "**IFRS**").

IFRS does not provide for the preparation of combined historical financial information and, accordingly, in preparing the Combined COP Subsidiaries Historical Financial Information certain accounting conventions commonly used for the preparation of historical financial information for inclusion in investment circulars as described in the Annexure to SIR 2000 "Standards for Investment Reporting applicable to public reporting engagements on historical financial information" issued by the UK Auditing Practices Board have been applied.

The Combined COP Subsidiaries has not in the past constituted a separate legal group and therefore it is not meaningful to show share capital or an analysis of reserves for this combined group. As such, the net assets of the Combined COP Subsidiaries are represented by the cumulative investment of the then parent group (shown as "**Invested Capital**").

The Historical Financial Information has been prepared on the historical cost basis, except for certain financial assets and liabilities (including derivative financial instruments, hydrocarbon inventories and over/underlift) which have been measured at fair value.

The Historical Financial Information is presented in US Dollars (USD) and all values are rounded to the nearest thousand dollars ($'000) except when otherwise stated.

This is the first financial information presented in accordance with IFRS for the Combined COP Subsidiaries. The beginning of the first period presented is 1 January 2017 and as required by IFRS 1 a balance sheet has been presented at this date.

The accounting policies which follow set out those policies which apply in preparing the Historical Financial Information for the years ended 31 December 2017, 31 December 2018 and 31 December 2019. All accounting policies have been applied consistently unless otherwise stated.

Basis of Combination

The Combined COP Subsidiaries Historical Financial Information combines the financial statements of the three legal entities disclosed in the Corporate Information and their subsidiary and associate undertakings drawn up to each 31 December financial year end. Subsidiaries are those entities over which the Companies have control. Control is achieved where a company has the power over the subsidiary or has rights to variable returns from the subsidiary and has the ability to use its power to affect its returns. All subsidiaries are 100 per cent. owned by the Companies. The investment in an associate undertaking is accounted for using the equity method (note 16).

All intercompany balances have been eliminated on consolidation.

New Accounting Standards and Interpretations

This is the first financial information presented for the Combined COP Subsidiaries. The financial information is presented in accordance with IFRS and no comparison is presented with any other GAAP as no GAAP accounting had previously been prepared for this combination. The beginning of the first period presented is 1 January 2017. The changes to the previously reported financial information for the standalone legal entities comprised within the Combined COP Subsidiaries are in relation to the adoption of IFRS 16 "Leases", the valuation of under/overlift, and the re-presentation of certain income statement and balance sheet line items to align with the requirements of IAS1 "Presentation of Financial Statements". All other policies applied under the Companies' previous accounting framework are not materially different to IFRS and have not impacted on equity or profit or loss.

The Combined COP Subsidiaries adopted new and revised accounting standards and interpretations relevant to its business and effective for accounting periods beginning on or after 1 January 2017, including:

IFRS 9 Financial Instruments

The classification and measurement of financial assets has changed with the implementation of IFRS 9. However, this has not materially changed the measurement of financial assets of the Companies. The IFRS 9 impairment model requiring the recognition of 'expected credit losses', in contrast to the requirement to recognise 'incurred credit losses' under IAS 39, has not had a material impact on the Combined COP Subsidiaries Historical Financial Information. Trade and other receivables are generally settled on a short time frame and the Companies' other financial assets (including balances with group undertakings not included in this combination) are due from counterparties without material credit risk concerns at the time of transition.

IFRS 15 Revenue from Contracts with Customers

The implementation of IFRS 15 has not impacted the presentation of the Companies' sales revenue. Disclosure of disaggregated revenue information consistent with the requirement included in IFRS 15 has not had an impact on the information presented in note 4. The Companies' accounting policy under IFRS 15 is detailed within "Revenue from Contracts with Customers" and does not represent a substantive change from the Companies' previous accounting policy for recognising revenue from sales to customers.

IFRS 16 Leases

The Companies adopted IFRS 16 'Leases' from the effective date of 1 January 2019. IFRS 16 replaced the previous standard on accounting for leases, IAS 17, and the related interpretations. As this is the first financial information presented in accordance with IFRS for the Combined COP Subsidiaries, the transition to IFRS 16 was made by restating the prior year balances to reflect the adoption of IFRS 16 from 1 January 2017.

As part of the project conducted on initial application, the Companies applied the modified retrospective approach.

The main effect on the Companies is that IFRS 16 has introduced a single lessee accounting model and requires a lessee to recognise assets and liabilities for all leases where the practical expedients above are not applicable.

From 1 January 2017, 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 Companies. The Companies have applied the exemption within IFRS 1 'First-time Adoption of International Financial Reporting Standards' to measure lease liabilities and right-of-use assets at the date of transition to IRFs. For the Combined COP Subsidiaries, 1 January 2017 is the beginning of the first period presented in this Historical Financial Information and the date of transition to IFRSs. These liabilities 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 Companies assuming leases run to full term with no break clauses exercised. These liabilities are discounted using the lessee's incremental borrowing rate as of 1 January 2017, being the rate that the Companies 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. The weighted average lessee's incremental borrowing rate applied to the lease liabilities on 1 January 2017 was 5.32 per cent. and for new lease liabilities recognised in 2017 was 5.46 per cent.. There were no new lease liabilities recognised in 2018 or 2019. 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. The right-of-use asset is depreciated over the lease term on a straight-line basis.

The Companies have 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 Companies are reasonably certain to exercise such options impacts the lease term, which significantly impacts the amount of lease liabilities and right-of-use assets recognised.

The impact of the adoption of the leasing standard and the new accounting policies are disclosed in note 14.

The other pronouncements did not have any impact on the Companies' accounting policies and did not require retrospective adjustments.

Segment Reporting

The Companies' activities consist of one class of business – the acquisition, exploration, development and production of oil and gas reserves and related activities in one geographical area being the UK North Sea.

Joint Arrangements

Exploration and production operations are usually conducted through joint arrangements with other parties. All joint arrangements are reviewed and classified as either joint operations or joint ventures depending on the rights and obligations of each party to the arrangement and whether the arrangement is structured through a separate vehicle. All interests in joint arrangements held by the Companies are classified as joint operations.

In relation to its interests in joint operations, the Companies recognise their:

- Assets, including their share of any assets held jointly
- Liabilities, including their share of any liabilities incurred jointly
- Revenue from the sale of their share of the output arising from the joint operation
- Share of the revenue from the sale of the output by the joint operation, and
- Expenses, including their share of any expenses incurred jointly

Foreign Currency Translation

Each entity in the Combined COP Subsidiaries determines its own functional currency, being the currency of the primary economic environment in which the entity operates, and items included in the Historical Financial Information for each entity are measured using that functional currency.

The functional currency of Chrysaor (U.K.) Sigma was changed from Great British Pounds to US dollars on 1 January 2019. A management decision was made to change the functional currency to US dollars to reflect the profile of the company's revenue and operating profit which, following first production from Clair Ridge at the end of 2018, is primarily generated in US dollars.

The combined Historical Financial Information of the Combined COP Subsidiaries is presented in US Dollars.

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. 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, the assets and liabilities of the Companies' operations 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 balances are 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 currency translation reserve.

Intangible Assets – Exploration and Evaluation Assets

Exploration and evaluation expenditure is accounted for using the successful efforts method of accounting.

(a) Pre-Licence Costs

Pre-licencing costs are expensed in the period in which they are incurred.

(b) Licencing 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 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. 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.

(c) 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 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. No amortisation is charged during the exploration and evaluation phase.

Property, Plant and Equipment – Oil and Gas Development and Production Assets

Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells including unsuccessful development or delineation wells, 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 (where relevant), 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.

All costs relating to a development are accumulated and not depreciated until the commencement of production. From 1 January 2019, the Companies prospectively changed their methodology for calculating the depreciation charge on capitalised oil and gas properties to be in line with the Chrysaor Group. Depreciation is provided using the unit of production method based on proven plus probable reserves. When there is a change in the estimated total recoverable proved plus probable reserves of a field, that change is accounted for prospectively in the depreciation charge over the revised remaining proved plus probable reserves. Prior to 1 January 2019, depreciation was provided using the unit of production method based on proved reserves, or proved developed reserves for well costs.

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 from its use or disposal. 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 refits, inspections or repairs comprises 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 Companies, the expenditure is capitalised. All other day-to-day repairs and maintenance costs are expensed as incurred.

Impairment of Non-Current Assets

The Companies assess, at each reporting date, whether there is an indication that an asset may be impaired. If any indication exists, the Companies estimate 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.

Financial Instruments

a. Financial Assets

The Companies use two criteria to determine the classification of financial assets: the Chrysaor Group's business model and contractual cash flow characteristics of the financial assets. Where appropriate the Companies identify 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 receivables 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 at bank and in hand in the balance sheet comprise cash deposits with banks and in hand.

Impairment of Financial Assets

The Companies recognise an allowance for expected credit losses ("**ECLs**") for all debt instruments not held at fair value through profit or loss. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Companies expect to receive, discounted at an approximation of the original 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). 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 Companies apply a simplified approach in calculating ECLs. 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 and the economic environment and the Chrysaor Group's historical credit loss experience.

Credit Impaired Financial Assets

At each reporting date, the Companies assess 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 Chrysaor Group on terms that the Chrysaor Group would otherwise not consider

— it is becoming probable that the borrower will enter bankruptcy or other financial reorganisation, – or the disappearance of an active market for a security because of financial difficulties

b. Financial Liabilities

Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, loans and borrowings, payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate. All financial liabilities are recognised initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs.

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 accrual basis in the income statement using the effective interest 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 or 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.

c. Derivative Financial Instruments

Derivative financial instruments are initially recognised and subsequently re-measured at fair value. Changes in the fair value of the instrument are recognised within the Income statement.

In the period under prior ownership by ConocoPhillips, Chrysaor Petroleum Company U.K. Limited, through arrangements with an affiliate company, Chrysaor Production (U.K.) Limited (formerly ConocoPhillips (U.K.) Limited), used derivative instruments to hedge the effects of fluctuations in the price of crude oil. Any gains or losses arising from commodity derivative contracts are recognised in the income statement in line with the underlying sales transaction.

d. Fair Values

The fair value of financial instruments that are traded in active markets at the reporting date is determined by reference to quoted market prices or dealer price quotations, without any deduction for transaction costs.

For financial instruments not traded in an active market, the fair value is determined using appropriate valuation techniques.

Preference Share Capital

Preference shares in Chrysaor Petroleum Company U.K. Limited are classified as liabilities (note 22) and the dividends on these preference shares are recognised in the Income statement as finance costs.

Share Based Payments

The Combined COP Subsidiaries Historical Financial Information has applied the requirements of IFRS2 "Share-based Payment". The entity receiving the benefit of service should recognise an expense relating to share based payments irrespective of whether the entity holds the employee's contract of service.

In the period under prior ownership by ConocoPhillips, all employees were eligible to participate in the ConocoPhillips Share Incentive Plan. The shares in the former ultimate parent company, ConocoPhillips, purchased by the employees were eligible for matching by Chrysaor Petroleum Company U.K. Limited. In accordance with IFRS2, Chrysaor Petroleum Company U.K. Limited recorded an expense of obtaining the matching shares to satisfy the terms of the Partnership Share Agreement for employees who provided services to the company.

Certain eligible employees were also awarded Restricted Stock Units as part of the Restricted Stock Programme granted by ConocoPhillips. The awards were held in escrow until the restrictions lapsed. Chrysaor Petroleum Company U.K. Limited recorded the expense of obtaining the shares in the former ultimate parent company, ConocoPhillips, to satisfy its obligations to the employees who provided services to the company. A liability equal to the cost of obtaining the shares to satisfy the company's obligations to employees was recognised for each cash-settled share based payment.

All obligations of Chrysaor Petroleum Company U.K. Limited under the ConocoPhillips Share Incentive Plan and Restricted Stock Programme ceased when the company became part of the Chrysaor Group.

Inventories

Hydrocarbon inventories are stated at net realisable value with movements recognised in the income statement. All other inventories are stated at the lower of cost and net realisable value. The cost of materials is the purchase cost, determined on first-in, first-out basis.

Provisions for Liabilities

A provision is recognised when the Companies have 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 at the commencement of oil and gas production. The amount provided is the present value of the estimated future restoration cost. A non-current asset is also recognised. Any changes to estimated costs or discount rates are dealt with prospectively.

Trade Payables

Initial recognition of trade payables is at fair value. Subsequently they are stated at amortised cost.

Taxes

i. 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 the Companies operate and generate 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.

ii. 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 Historical Financial Information with the following exceptions:

- 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 reporting sheet date.
- 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 the Companies to make a single net payment.
- Deferred taxation is not provided where a permanent difference arises between the tax basis of an asset and the carrying value of that asset.

Revenue from Contracts with Customers

Revenue from contracts with customers is recognised when the Companies satisfy 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. Revenue associated with the sale of crude oil, natural gas, and natural gas liquids 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. The transfer of control of oil, natural gas, natural gas liquids and other items sold by the Companies occurs when title passes at the point the customer takes physical delivery. The Companies principally satisfy their performance obligations at this point in time.

Over/Underlift

Revenues from the production of oil and natural gas properties in which the Companies have an interest with partners are recognised based on the Companies' working interest in those properties (the entitlement method). Differences between the production sold and the Companies' share of production result in an overlift or an underlift. Overlift and underlift are valued at market value and included within payables or receivables respectively. Movements during the accounting period are recognised within cost of sales in the income statement such that gross profit is recognised on an entitlement basis.

Interest Income

Interest income is recognised on an accruals basis, by reference to the principal outstanding and at the effective interest rate method.

Critical Accounting Judgements and Estimates

The preparation of the Historical Financial Information of the Combined COP Subsidiaries in conformity with IFRS requires management to make judgements, estimates and assumptions at the date of the 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 Companies have identified the following areas where significant judgement, estimates and assumptions are required.

- *Exploration and Evaluation Expenditure*

As at 31 December 2019, the Combined COP Subsidiaries held a balance of US$73.1 million (31 December 2018: US$68.5 million, 31 December 2017: US$173.1 million) relating to expenditure on unproved hydrocarbon resources within other intangible assets which represent active exploration and evaluation activities. The application of the Companies' 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.

Key Sources of Estimation Uncertainty

- *Recoverability of Oil and Gas Assets*

The Companies assess each asset or cash generating unit each reporting period to determine whether any indication of impairment exists. 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. The assessments of fair value less cost of disposal 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. The Companies' 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 2 per cent. change in the post-tax discount rate are considered to be reasonably possible for the purposes of sensitivity analysis, the result of which can be found in note 13.

- *Decommissioning Costs*

Decommissioning costs will be incurred by the Companies at the end of the operating life of most of the Companies' facilities and properties. The Companies assess the 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 10 per cent. decrease in the discount rates used to assess the final decommissioning obligation at 31 December 2019 would result in increases to the decommissioning provision of approximately US$105 million and US$43 million respectively. This change would be principally offset by a change to the value of the associated asset.

- *Recovery of Deferred Tax Assets*

Deferred tax assets, including those arising from un-utilised tax losses, require management to assess the likelihood that the Companies will recover the value. This includes ensuring that the Companies have the ability to carry back abandonment tax losses against prior period profits.

- *Climate Change*

The Chrysaor Group recognises that there may be potential financial implications in the future from climate change risk. The Chrysaor Group expects that climate change policies, legislation and regulation will increase, and likely on accelerating timelines which, although will result in intended benefits, is likely to increase associated costs and administration requirements as well as potentially limiting the investment capital available to the industry. 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 at the balance sheet date the Chrysaor Group believes there is no material impact on balance sheet carrying values of assets or liabilities in the Historical Financial Information of the Combined COP Subsidiaries. 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.

3. Segment Information

The Combined COP Subsidiaries' activities consist of one class of business – the acquisition, exploration, development and production of oil and gas reserves and related activities in one geographical area being the UK North Sea.

4. Revenue and Other Income

	For the years ended 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
Crude oil sales	2,350,075	2,771,630	1,289,993
Gas sales	208,373	322,111	255,293
Condensate sales	94,957	90,899	48,665
Hydrocarbon revenue	2,653,405	3,184,640	1,593,951
Tariff and other revenue	9,758	9,355	8,591
Total revenue from production activities	2,663,163	3,193,995	1,602,542
Other income – IFRS16 lease accounting-partner recovery	7,694	15,841	15,076
Total revenue and other income	2,670,857	3,209,836	1,617,618

Revenue of US$1,558.3 million (2018: US$3,220.1 million; 2017: US$2,640.4 million) were from contracts with customers. Revenue from contracts with customers excludes realised hedging gains on crude and gas sales of US$44.2 million (2018: losses of US$26.1 million; 2017: gains of US$22.8 million).

5. Operating (Loss)/Profit

This is stated after charging/(crediting):

	For the years ended 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
Movement in over/under-lift balances and hydrocarbon inventories	4,955	19,379	5,087
Purchase of crude from ConocoPhillips group undertakings	2,158,468	2,509,460	1,016,394
Production, insurance and transportation costs	203,984	214,052	196,299
Depreciation of property, plant and equipment (note 13)	303,526	307,878	151,420
Depreciation of IFRS 16 right of use assets (note 14)	11,690	23,799	22,648
Capitalisation of IFRS16 lease depreciation (note 14)	(3,728)	(8,124)	(7,731)
Impairment (credit)/charge due to change in decommissioning provision (note 13)	(3,124)	(4,960)	942
Impairment of property, plant and equipment (note 13)	52,388	—	—
Impairment loss on inventory	969	181	—
Exploration and evaluation expenses	2,932	2,544	969
Exploration costs written-off (note 12)	56	12,820	1,683
Share based payments expense (note 11)	1,481	1,494	1,113
Auditors' remuneration – audit of the financial statements	—	—	—

For the year ended 31 December 2019, the auditors' remuneration of US$370,000 (2018: US$132,000; 2017: US$123,000) for the audit of the Companies' financial statements was borne by another group company and was not recharged to the Companies.

6. Gain on disposal of investments in subsidiary and associate undertakings

On 18 September 2019, Chrysaor Petroleum Company U.K. Limited sold its 100 per cent. interest in ConocoPhillips Pension Plan Trustees Limited to ConocoPhillips (U.K.) Holdings Limited for cash consideration of US$128, reflecting the called up share capital of that company. No gain or loss arose on the disposal of this subsidiary undertaking.

On 1 July 2019, Chrysaor Petroleum Company U.K. Limited sold its 40.25 per cent. interest in an associate undertaking, Norpipe Terminal Holdco Limited, to ConocoPhillips (U.K.) Teesside Operator Limited for cash consideration of US$144.1 million. A pre-tax gain on disposal of US$144.1 million has been recognised in the Combined COP Subsidiaries Historical Financial Information. No current tax arose on the disposal.

On 18 December 2018, Chrysaor (U.K.) Sigma Limited sold its entire 100 per cent. shareholding in ConocoPhillips (U.K.) Psi Limited to BP for cash consideration of US$206.8 million. BP also subsequently settled debt of US$1,600.0 million. Prior to that transaction, on 12 December 2018, Chrysaor (U.K.) Sigma Limited transferred 16.5 per cent. of its 24 per cent. interest in the BP-operated Clair Field to ConocoPhillips (U.K.) Psi Limited. Chrysaor (U.K.) Sigma Limited continues to hold a 7.5 per cent. interest in the Clair Field. A pre-tax gain on disposal of US$151.9 million has been recognised in the Combined COP Subsidiaries Historical Financial Information. No current tax arose on the disposal. A deferred tax liability of US$338.9 million was released and is reported as part of gain on disposal.

7. Staff Costs

The Companies had no employees during the year (2018: nil; 2017: nil). All employees' contracts of employment were held by another group undertaking not included in the combination.

8. Finance Income and Finance Expenses

	For the years ended 31 December		
	2017	*2018*	*2019*
	$000	*$000*	*$000*
Finance income:			
Bank interest receivable	269	2,743	2,341
Other interest	606	9	357
Intercompany interest	2,068	2,894	1,053
Foreign exchange gains	—	923	—
	2,943	6,569	3,751
Finance expenses:			
Other interest	(114)	(46)	(1,112)
Lease interest (note 14)	(3,422)	(5,750)	(4,421)
Dividends paid on preference shares	(2,823)	(2,909)	(2,860)
Foreign exchange losses	(3,361)	—	(19,116)
Bank interest	(718)	(2,988)	(1,413)
Unwinding of discount on decommissioning and other provisions (note 23)	(30,084)	(32,121)	(29,388)
	(40,522)	(43,814)	(58,310)

9. Directors' Remuneration

a) For the period under prior ownership:

For the first 9 months of the year ended 31 December 2019 and the years ended 31 December 2018 and 31 December 2017, no remuneration was paid to the directors for their qualifying services in respect of the Companies. As ConocoPhillips managed its operations at a divisional and geographical level it was not deemed practicable to apportion directors' remuneration between qualifying services for the Companies and other group companies in which they held office. No directors received any compensation for loss of office.

b) For the period under Chrysaor Group ownership:

For the final 3 months of the year ended 31 December 2019 when the Companies were under Chrysaor Group ownership, directors' remuneration, including total salaries, other emoluments and benefits was paid by Chrysaor E&P Services Limited. The directors do not believe that it is practicable to apportion their remuneration between their services as directors of the Companies and their services as directors or employees of other companies in the Chrysaor Group.

10. Income Tax

	For the years ended 31 December		
	2017	*2018*	*2019*
	$000	*$000*	*$000*
Current income tax (credit)/expense:			
UK corporation tax	19,362	92,456	93,418
UK petroleum revenue tax	(250)	—	(17)
Group relief prior year	(27,186)	(3,813)	1,805
Adjustments in respect of prior years	(4,392)	67	(3,317)
Total current income tax (credit)/expense	(12,466)	88,710	91,889
Deferred tax (credit)/expense:			
UK petroleum revenue tax	581	485	372
Origination and reversal of temporary differences	(56,716)	(43,722)	(20,952)
Adjustments in respect of prior years	1,576	—	32
Total deferred tax (credit)	(54,559)	(43,237)	(20,548)
Tax (credit)/expense in the income statement	(67,025)	45,473	71,341
The tax (credit)/expense in the income statement is disclosed as follows:			
Income tax (credit)/expense on continuing operations	(67,025)	45,473	71,341
	(67,025)	45,473	71,341

The major components of income tax (credit)/expense are:

A reconciliation between total tax (credit)/expense and the accounting profit multiplied by the standard rate of corporation tax and supplementary charge applying to UK oil and gas production operations for the years ended 31 December 2019, 2018 and 2017 is as follows:

	For the years ended 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
(Loss)/profit before taxation	(89,619)	260,244	325,836
(Loss)/profit before taxation at 40.0%	(35,848)	104,098	130,334
Effects of:			
Expenses not deductible for tax purposes	25,264	26,162	4,610
Adjustments in respect of prior years	(2,816)	67	(3,285)
Impact of profits/(losses) relieved at different rates	(2,206)	3,642	(4,229)
Investment allowance	(11,216)	(18,503)	(5,179)
Petroleum revenue tax (net of corporation tax)	199	291	213
Group/other reliefs	(27,186)	(3,813)	1,805
Non-ring fence losses not recognised	—	—	7,712
Share of net profit of associate undertaking	(4,280)	(5,725)	(3,010)
Held over gains taxable in fellow group company	(8,936)	—	—
Gain on sale not taxable	—	(60,746)	(57,630)
Total tax (credit)/expense reported in the combined income statement	(67,025)	45,473	71,341

The origination of and reversal of temporary differences are, as shown in the next table, related primarily to movement in the carrying amounts and tax base values of expenditure for the current and prior periods and the timing of when these items are charged and/or credited against accounting and taxable profit.

Deferred tax

Deferred tax presented net on the Combined COP Subsidiaries balance sheet is as follows:

	Accelerated Capital Allowances *$000*	*Abandonment* *$000*	*Investment Allowance* *$000*	*Deferred PRT* *$000*	*Other* *$000*	*Total* *$000*
As at 1 January 2017	(810,214)	398,809	12,769	2,550	(8,591)	(404,677)
Deferred tax (expense)/credit	(4,536)	42,370	7,076	(348)	9,997	54,559
Foreign exchange	(77,772)	40,433	1,601	225	(287)	(35,800)
As at 31 December 2017	(892,522)	481,612	21,446	2,427	1,119	(385,918)
Deferred tax credit/(expense)	47,170	(20,601)	15,298	(291)	1,661	43,237
Disposals	377,935	(39,043)	—	—	—	338,892
Foreign exchange	29,318	(23,566)	(1,867)	(119)	(137)	3,629
As at 31 December 2018	(438,099)	398,402	34,877	2,017	2,643	(160)
Deferred tax credit/(expense)	3,046	20,591	(2,060)	(224)	(805)	20,548
Foreign exchange	(8,958)	13,566	1,100	60	60	5,828
As at 31 December 2019	(444,011)	432,559	33,917	1,853	1,898	26,216

Deferred tax assets are recognised to the extent that the future benefit is probable. Relevant tax law is considered, together with the ability to carry back abandonment tax losses against prior period profits.

In 2018, the Combined COP Subsidiaries disposed of a subsidiary undertaking which held a 16.5 per cent. interest in the BP-operated Clair Field (note 6).

At 31 December 2019, the deferred tax asset recognised is only partially offset by the deferred tax liability, resulting in an overall net deferred tax asset as at 31 December 2019.

The Companies have non-ring fence tax losses of US$19.3 million (2018: US$nil; 2017: US$nil). An associated deferred tax asset of US$3.7 million (2018: US$nil; 2017: US$nil) has not been recognised in respect of these losses due to uncertainty of recovery.

Changes in tax rate

Legislation introduced in Finance Bill 2020, which was substantively enacted on 17 March 2020, retained the main rate of UK corporation tax for non-ring fence profits at 19 per cent. from 1 April 2020. This has no material impact on the Companies.

11. Cash Settled Share Based Payments

Share Incentive Plan

The Companies have applied the requirements of IFRS2 "Share-based Payment". The Companies have recognised an expense relating to share based payments for employees who provided services to the Companies even though these entities did not hold the employees' contracts of service.

During the period under prior ownership, all ConocoPhillips employees were eligible to participate in the ConocoPhillips Share Incentive Plan. Employees could contribute a portion of their pre-tax monthly salary. The employee's contributions were then used to purchase shares in the Companies' former ultimate parent company, ConocoPhillips, at market value. Contributions up to 2.5 per cent. of base salary (2018: 2.5 per cent.) were eligible for company matching on a "2 for 1" basis. The matching shares had to be left in the plan for at least five years to qualify for tax relief.

All obligations of the Companies' under the ConocoPhillips Share Incentive Plan ceased when the Companies became part of the Chrysaor Group. For employees transferring to the Chrysaor Group on 30 September 2019, all shares received from the plan qualified for tax relief.

For the period under prior ownership by ConocoPhillips, to satisfy the obligations under the ConocoPhillips Share Incentive Plan, the Companies' recognised an expense of:

	For the years ended 31 December		
	2017	*2018*	*2019*
	$000	*$000*	*$000*
Matching shares	941	1,014	686
	No.	No.	No.
Number of issued ordinary shares	19,413	15,291	10,717
Average price of ordinary shares issued (US$)	48.71	67.64	64.08

Restricted Stock Units

During the period under prior ownership, certain eligible ConocoPhillips employees were awarded Restricted Stock Units (RSUs) as part of the ConocoPhillips Restricted Stock Programme. Each award was held in escrow until the restrictions on the award lapsed. When the restrictions lapsed, the number of shares of unrestricted stock in the Companies' former ultimate parent company, ConocoPhillips, equal to the number of RSUs, was registered in the name of the employee and the RSUs were terminated.

All obligations of the Companies' under the Restricted Stock Programme ceased when the Companies became part of the Chrysaor Group. For employees transferring to the Chrysaor Group on 30 September 2019, all restrictions on awards lapsed.

For the period under prior ownership by ConocoPhillips, to satisfy the obligations under the Restricted Stock Programme, the Companies recognised an expense of:

	For the years ended 31 December		
	2017	*2018*	*2019*
	$000	*$000*	*$000*
Restricted stock units	540	480	427
	No.	No.	No.
Number of lapsed RSU awards and ordinary shares issued	9,319	6,071	9,392
Exercise price of ordinary shares (US$)	48.07	54.65	69.90

12. Other Intangible Assets

	Oil and gas assets *$000*
Cost and Net Book Value:	
At 1 January 2017	156,116
Additions	789
Transfers to property, plant & equipment	23
Revision of decommissioning asset	1,172
Unsuccessful exploration written-off	(56)
Currency translation adjustment	15,042
At 31 December 2017	173,086
Additions	13,376
Transfers to property, plant & equipment	(486)
Disposals	(97,735)
Revision of decommissioning asset	(2,006)
Unsuccessful exploration written-off	(12,820)
Currency translation adjustment	(4,889)
At 31 December 2018	68,526
Additions	19,840
Transfers to property, plant & equipment	(15,016)
Revision of decommissioning asset	516
Unsuccessful exploration written-off	(1,683)
Currency translation adjustment	886
At 31 December 2019	73,069

Exploration costs written-off relates to costs associated with uncommercial well evaluations.

In 2018, the Combined COP Subsidiaries disposed of a subsidiary undertaking which held a 16.5 per cent. interest in the BP-operated Clair Field (note 6).

An increase in the decommissioning assets of US$0.5 million (2018: decrease US$2.0 million; 2017: increase of US$1.2 million) was made as a result of an update to the decommissioning estimates (note 23).

13. Property, Plant and Equipment

	Oil and gas assets $000
Cost:	
At 1 January 2017	7,329,952
Additions	214,195
Transfers of intangible assets	(23)
Revision of decommissioning asset	84,855
Currency translation adjustment	717,416
At 31 December 2017	8,346,395
Additions	183,339
Transfers of intangible assets	486
Disposals	(2,356,391)
Revision in decommissioning asset	(73,773)
Currency translation adjustment	(352,796)
At 31 December 2018	5,747,260
Additions	81,073
Transfer of intangible assets	15,016
Revision in decommissioning asset	28,194
Currency translation adjustment	164,093
At 31 December 2019	6,035,636
Accumulated Depreciation:	
At 1 January 2017	3,753,197
Charge for the year	303,526
Impairment	49,264
Currency translation adjustment	378,038
At 31 December 2017	4,484,025
Charge for the year	307,878
Impairment	(4,960)
Depreciation on disposals	(341,676)
Currency translation adjustment	(242,937)
At 31 December 2018	4,202,330
Charge for the year	151,420
Impairment	942
Currency translation adjustment	142,267
At 31 December 2019	4,496,959
Net book value:	
At 31 December 2019	1,538,677
At 31 December 2018	1,544,930
At 31 December 2017	3,862,370

In 2018, the Combined COP Subsidiaries disposed of a subsidiary undertaking which held a 16.5 per cent. interest in the BP-operated Clair Field (note 6).

An increase in the decommissioning assets of US$28.2 million (2018: decrease US$73.8 million; 2017: increase of US$84.9 million) was made as a result of an update to the decommissioning estimates (note 23). The Companies recognised a pre-tax impairment charge of US$0.9 million

(2018: credit of US$5.0 million; 2017: credit of US$3.1 million) within the income statement in respect of changes to decommissioning estimates on the Companies' non-producing assets.

No impairment charges were recognised in the years ended 31 December 2019 or 31 December 2018. In 2017, an impairment charge of US$52.4 million was recognised principally in relation to the non-operated Clair field.

The Companies use the fair value less cost of disposal method (FVLCD) to calculate the recoverable amount of the cash generating units (CGU) consistent with a level 3 fair value measurement. In determining FVLCD, appropriate discounted-cash-flow valuation models were used, incorporating market-based assumptions. Oil and gas prices are based on an internal view of management expectations derived from external financial analysts view of current prices for the first three years transitioning to a flat long term price from 2023. At 31 December 2019, the long-term commodity prices used were US$65 per barrel for crude and 50p per therm for gas.

Sensitivity analysis indicates that a 10 per cent. reduction in the oil and gas price deck applied in the impairment test at 31 December 2019 would not give rise to an impairment charge. Considering the discount rates at 31 December 2019, a 2 per cent. decrease in the post-tax rate would not give rise to an impairment charge. The impairment was calculated as detailed above.

Impairment tests were conducted for the Chrysaor Group, including the Companies, as at 30 June 2020. These resulted in an impairment charge being recognised in the Chrysaor Holdings Limited financial statements on some older gas assets as a result of the Chrysaor Group's revised view of long-term commodity prices. This would not result in a material impairment charge in the Combined COP Subsidiaries.

14. Leases – Right of Use Assets

(i) This note provides information for leases where the Companies are a lessee.

Right of Use Assets	*Land and buildings $000*	*Drilling Rigs $000*	*Equipment $000*	*Total $000*
Cost:				
At 1 January 2017	12,199	—	—	12,199
Additions	—	101,062	5,309	106,371
Currency translation adjustment	1,167	5,414	284	6,865
At 31 December 2017	13,366	106,476	5,593	125,435
Currency translation adjustment	(729)	(5,811)	(305)	(6,845)
At 31 December 2018	12,637	100,665	5,288	118,590
Currency translation adjustment	425	3,386	178	3,989
At 31 December 2019	13,062	104,051	5,466	122,579
Accumulated Depreciation:				
At 1 January 2017	—	—	—	—
Charge for the year	1,478	9,663	549	11,690
Currency translation adjustment	79	518	29	626
At 31 December 2017	1,557	10,181	578	12,316
Charge for the year	1,543	21,109	1,147	23,799
Currency translation adjustment	(155)	(1,521)	(84)	(1,760)
At 31 December 2018	2,945	29,769	1,641	34,355
Charge for the year	1,467	20,089	1,092	22,648
Currency translation adjustment	153	1,734	95	1,982
At 31 December 2019	4,565	51,592	2,828	58,985
Net book value:				
At 31 December 2019	8,497	52,459	2,638	63,594
At 31 December 2018	9,692	70,896	3,647	84,235
At 31 December 2017	11,809	96,295	5,015	113,119

	As at 31 December		
Lease Liabilities	*2017 $000*	*2018 $000*	*2019 $000*
Current	19,973	19,938	24,205
Non-Current	95,704	70,541	48,708
	115,677	90,479	72,913

(ii) The combined income statement includes the following amounts relating to leases:

Depreciation charge of Right of Use Assets

	For the Years Ended 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
Land and buildings	1,478	1,543	1,467
Drilling rigs	9,663	21,109	20,089
Equipment	549	1,147	1,092
	11,690	23,799	22,648
Capitalisation of IFRS16 lease depreciation			
Drilling rigs	(3,527)	(7,705)	(7,332)
Equipment	(201)	(419)	(399)
Depreciation charge included within combined income statement	7,962	15,675	14,917

The depreciation charge associated with drilling rigs and equipment used in the construction of oil and gas assets has been capitalised within property, plant and equipment.

	For the years ended 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
Lease interest (included in finance expenses – note 8)	3,422	5,750	4,421

The total cash outflow for leases was US$24.3 million (2018: US$25.5 million; 2017: US$12.7 million).

(iii) The Companies' leasing activities and how these are accounted for

The Companies leases buildings, drilling rigs and ancillary equipment as part of their oil and gas operations, with the leases expiring in 2020 through to 2033. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. Until the 2016 financial year, these leases were classified as operating leases and payments made under these leases (net of any incentives received from the lessor) were charged to the income statement on a straight-line basis over the period of the lease.

From 1 January 2017, 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 Companies. 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. The right-of-use asset is depreciated over the lease term on a straight-line basis.

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 Companies assuming leases run to full term. The Companies have 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 Companies are reasonably certain to exercise such options impacts the lease term, which significantly impacts the amount of lease liabilities and right-of-use assets recognised.

The lease payments are discounted using the Chrysaor Group's incremental borrowing rate, being the rate that the Companies 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 Chrysaor Group 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;
- makes adjustments specific to the lease, for example term, country, currency and security

The weighted average lessee's incremental borrowing rate applied to the lease liabilities on 1 January 2017 was 5.32 per cent. and for new lease liabilities recognised in 2017 was 5.46 per cent.. There were no new lease liabilities recognised in 2018 or 2019.

The Companies are exposed to potential future increases in variable lease payments based on an index or rate, which are not included in the lease liability until they take effect. 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. The finance cost is charged to profit or loss 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 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
- any initial direct costs and restoration costs

Right-of-use assets are generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis.

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. The Companies have no short-term leases or leases of low value recognised as an expense in the income statement.

15. Investments in subsidiaries

At 31 December 2019 the subsidiary undertakings of the Companies were:

Name of company	*Country of incorporation*	*Main activity*
Chrysaor (U.K.) Theta Limited (i)	UK	Oil and gas
Chrysaor (U.K.) Chi Limited (ii)	UK	Dormant company
Chrysaor (U.K.) Phi Limited (ii)	UK	Dormant company
Chrysaor (U.K.) Lambda Limited (iii)	ROI	Dormant company
Chrysaor Production Oil (GB) Limited (iv)	UK	Dormant company
Chrysaor Petroleum Chemicals U.K. Limited (iv)	UK	Dormant company

(i) Held by Chrysaor (U.K.) Sigma Limited

(ii) Held by Chrysaor (U.K.) Sigma Limited; dissolved on 7 April 2020

(iii) Held by Chrysaor (U.K.) Theta Limited

(iv) Held by Chrysaor Petroleum Company U.K. Limited

The Companies hold 100 per cent. of the share capital and voting rights in each of the companies above, unless otherwise stated. Chrysaor (U.K.) Theta Limited holds 100 per cent. of the ordinary share capital and voting rights and 99 per cent. of the €1.26997 shares in Chrysaor (U.K.) Lambda Limited.

All the subsidiaries are registered in England and Wales, with the exception of Chrysaor (U.K.) Lambda Limited, which is registered in the Republic of Ireland. The registered office of all subsidiaries noted above is Brettenham House, Lancaster Place, London, United Kingdom, WC2E 7EN, apart from Chrysaor (U.K.) Lambda Limited whose registered office is Riverside One, Sir John Rogerson's Quay, Dublin 2, Ireland.

During the period covered by the Historical Financial Information, the companies below were also subsidiary undertakings of the Companies:

Name of company	*Country of incorporation*	*Main activity*
ConocoPhillips (U.K.) Psi Limited (v)	UK	Oil and gas
ConocoPhillips Pension Plan Trustees Limited (vi)	UK	Dormant company

(v) Held by Chrysaor (U.K.) Sigma Limited; sold on 18 December 2018

(vi) Held by Chrysaor Petroleum Company U.K. Limited; sold on 18 September 2019

Chrysaor Petroleum Company U.K. Limited's 100 per cent. interest in ConocoPhillips Pension Plan Trustees Limited was sold on 18 September 2019 to ConocoPhillips (U.K.) Holdings Limited for cash consideration of US$128, reflecting the called up share capital of that company.

During 2018 Chrysaor (U.K.) Sigma Limited acquired additional shares in ConocoPhillips (U.K.) Psi Limited and as a result increased its investment in that company by US$67.3 million. On 18 December 2018, the company sold its 100 per cent. interest in ConocoPhillips (U.K.) Psi Limited to BP for a cash consideration of US$206.8 million.

16. Investments accounted for using the equity method

Investment in associate undertaking

	$000
At 1 January 2017	14,519
Share of net profit of associate undertaking	10,700
Share of dividends paid and declared by associate undertaking	(9,809)
Currency translation adjustment	1,437
At 31 December 2017	16,847
Share of net profit of associate undertaking	14,312
Share of dividends paid and declared by associate undertaking	(9,788)
Share of movement in net liabilities resulting from group reconstruction	(51,231)
Currency translation adjustment	1,216
Share of net liabilities at 31 December 2018	(28,644)
Adjustment to investment carrying value	28,644
At 31 December 2018	—
Share of net profit of associate undertaking	7,526
Share of dividends paid and declared by associate undertaking	(686)
Adjustment to investment carrying value	(6,840)
Investment carrying value at date of disposal	—
Disposal of investment	—
At 31 December 2019	—

Particulars of associate undertaking:	**Proportion of shares & voting rights**
Norpipe Terminal Holdco Limited	40.25% (held by Chrysaor Petroleum Company U.K. Limited prior to sale on 1 July 2019)

In July 2018, Chrysaor Petroleum Company U.K. Limited increased its shareholding in its associated undertaking from 29.26 per cent. to 40.25 per cent. after the existing shareholders agreed to acquire their pro-rata share of Equinor's 27.3 per cent. interest in Norsea Pipeline Limited. Following changes in the group structure Chrysaor Petroleum Company U.K. Limited held a 40.25 per cent.

investment in Norpipe Terminal Holdco Limited, which, in turn, held 100 per cent. of Norsea Pipeline Limited.

Following the group reconstruction, as at 31 December 2018 and 1 July 2019, Norpipe Terminal Holdco Limited had net liabilities. The share of movement in net liabilities of the associate undertaking and the subsequent adjustment to investment carrying value to record this as US$nil is reflected in the Combined Statement of Comprehensive Income. No specific support or guarantees were provided to the associate company.

Chrysaor Petroleum Company U.K. Limited's 40.25 per cent. interest in Norpipe Terminal Holdco Limited was sold on 1 July 2019 to ConocoPhillips (U.K.) Teesside Operator Limited for cash consideration of US$144.1 million.

Investments accounted for using the equity method

Summarised financial information for associate undertaking:

	As at 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
Non-current assets	231,848	260,231	—
Current assets	30,757	32,990	—
Total assets	262,605	293,221	—
Current liabilities	(141,535)	(179,415)	—
Non-current liabilities	(63,492)	(184,972)	—
Total liabilities	(205,027)	(364,387)	—
Net assets/(liabilities)	57,578	(71,166)	—
Chrysaor Petroleum Company U.K. Limited's share in %	29.26%	40.25%	—
Chrysaor Petroleum Company U.K. Limited's share of net assets/(liabilities)	16,847	(28,644)	—
Adjustment to investment carrying value	—	28,644	—
Investment carrying value	16,847	—	—
Revenue	144,560	134,724	122,460
Profit for the financial year	37,396	42,293	36,570
Chrysaor Petroleum Company U.K. Limited's share of Profit for the financial year in %	29.26%	33.84% average equity for year	40.25% pro-rated for 6 months
Chrysaor Petroleum Company U.K. Limited's share of Profit for the financial year	10,700	14,312	7,526

17. Inventories

	As at 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
Hydrocarbons	22,583	7,889	2,617
Consumables and subsea supplies	36,753	31,756	35,531
	59,336	39,645	38,148

Hydrocarbon inventories are measured at net realisable value. Following a review of inventories, no impairment charge was recognised in 2019 (2018: US$0.2 million, 2017: US$1.0 million).

18. Trade and Other Receivables

	As at 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
Current			
Trade debtors	281,821	365,686	87,120
Under-lift position	19,059	20,009	3,045
Amounts owed by related parties (note 27)	2,776	3,956	—
Other debtors	8,960	12,643	9,834
Prepayments and accrued income	1,068	7,235	1,273
Corporation tax receivable	—	7,159	—
	313,684	416,688	101,272

Trade and other debtors are non-interest bearing and are generally on 20 to 30 days' terms. As at 31 December 2019, no ECLs have been recognised relating to any receivable balance (2018: US$nil; 2017: US$nil).

	As at 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
Non-Current			
Prepayments and accrued income	—	1,170	—

19. Amounts Due from Group Undertakings

	As at 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
Current			
Amounts owed by group undertakings	1,710,193	102,115	192,276
Amounts owed by parent companies in respect of taxation	94,148	12,954	14,800
	1,804,341	115,069	207,076

All amounts owed by group companies at 31 December 2019 are unsecured, interest free and are repayable on demand. Short term group loans of US$10.0 million were outstanding with ConocoPhillips at 31 December 2018 (2017: US$1,672.3 million). These loans were interest bearing with a variable interest rate which was linked to LIBOR.

As at 31 December 2019, no ECLs have been recognised relating to any receivable balance (2018: US$nil; 2017: US$nil).

	As at 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
Non-Current			
Amounts owed by group undertakings	108,184	102,280	832,545

All amounts owed by group companies at 31 December 2019 are unsecured, interest free and are repayable on demand. A new loan of US$701.3 million was advanced to the Companies during 2019 by a group undertaking not included in this combination.

The Companies have confirmed that they will not seek repayment of the group loans outstanding at 31 December 2019 of US$832.5 million until at least 12 months from the date of approval of this Historical Financial Information and so the loans have been classified as long term.

Loans of US$102.3 million owed by group companies outstanding at 31 December 2018 (2017: US$108.2 million) were interest bearing with a variable interest rate which was linked to LIBOR.

As at 31 December 2019, no ECLs have been recognised relating to any receivable balance (2018: US$nil; 2017: US$nil).

20. Cash and Cash Equivalents

	As at 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
Cash at bank and in hand	997,531	1,113,470	18

Cash at bank earns interest at floating rates based on daily bank deposit rates. The Companies only deposit cash with major banks of high-quality credit standing.

21. Commitments

Capital Commitments

As at 30 December 2019, the Companies had commitments for future capital expenditure amounting to US$40.4 million (2018: US$56.4 million; 2017: US$217.7 million). Where the commitment relates to a joint arrangement, the amount represents the Companies' net share of the commitment. Where the Companies are not the operator of the joint arrangement then the amounts are based on the Companies' net share of committed future work programmes.

22. Trade and Other Payables

	As at 31 December		
	2017 $000	2018 $000	2019 $000
Current			
Trade payables	72,406	49,914	23,123
Overlift position	1,112	27,450	10,934
Amounts owed to group undertakings	225,462	398,515	680,428
Amounts due to parent companies in respect of taxation	—	1,561	1,480
Other payables	6,882	6,576	3,408
Accruals and deferred income	58,985	69,505	72,503
Corporation tax payable	44,350	—	63,718
	409,197	553,521	855,594

All amounts owed to group undertakings are unsecured, interest free and repayable on demand. Included in amounts owed to group undertakings at 31 December 2019 is a loan of US$592.1 million which is unsecured, interest free and repayable on demand.

Non-Current

	2017 $000	2018 $000	2019 $000
Preference share capital	50,000	50,000	50,000
	50,000	50,000	50,000

The cumulative redeemable preference shares, which were issued in 1996, are redeemable at any time upon one months' notice from the Company. They carry a fixed dividend of 5.75 per cent. payable quarterly in arrears and carry no voting rights unless the preference dividend is in arrears by six months or more. They have no premium paid on redemption and have preferential rights over the ordinary shares to receive on winding up the amount of US$100 per share together with the accrued dividend.

Preference shares are classified as liabilities and the dividends on these preference shares are recognised in the Income statement as finance costs.

23. Provisions

	Decommissioning provision $000	*Other $000*	*Total $000*
At 1 January 2017	990,301	1,433	991,734
Additions	7,460	—	7,460
Changes in estimates – increase in decommissioning asset	78,567	—	78,567
Amounts used	(3,193)	(1,490)	(4,683)
Unwinding of discount (note 8)	30,084	—	30,084
Currency translation adjustment	100,810	57	100,867
At 31 December 2017	1,204,029	—	1,204,029
Additions	3,609	—	3,609
Changes in estimates – decrease in decommissioning asset	(79,388)	—	(79,388)
Disposals	(97,620)	—	(97,620)
Amounts used	(7,862)	—	(7,862)
Unwinding of discount (note 8)	32,121	—	32,121
Currency translation adjustment	(58,888)	—	(58,888)
At 31 December 2018	996,001	—	996,001
Additions	8,053	—	8,053
Changes in estimates – increase to decommissioning asset	20,657	—	20,657
Amounts used	(6,622)	—	(6,622)
Unwinding of discount (note 8)	29,388	—	29,388
Currency translation adjustment	33,916	—	33,916
At 31 December 2019	1,081,393	—	1,081,393
At 31 December 2019 classified within:			
Current liabilities	21,214	—	21,214
Non-current liabilities	1,060,179	—	1,060,179
	1,081,393	—	1,081,393
At 31 December 2018 classified within:			
Current liabilities	13,252	—	13,252
Non-current liabilities	982,749	—	982,749
	996,001	—	996,001
At 31 December 2017 classified within:			
Current liabilities	4,348	—	4,348
Non-current liabilities	1,199,681	—	1,199,681
	1,204,029	—	1,204,029

In 2018, the Combined COP Subsidiaries disposed of a subsidiary undertaking which held a 16.5 per cent. interest in the BP-operated Clair Field (note 6).

The Companies provide for the estimated future decommissioning costs on their oil and gas assets at the balance sheet date. The payment dates of expected decommissioning costs are uncertain and are based on economic assumptions of the fields concerned. The Companies currently expect 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 provisions are discounted at a risk-free rate of between 2.3 per cent. and 2.8 per cent. (2018: 2.7 per cent. and 3.0 per cent.; 2017: 2.4 per cent. and 2.7 per cent.) and the unwinding of the discount is presented within finance costs.

These provisions have been created based on internal and third-party estimates. Assumptions based on the current economic environment have been made, which management believe 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.

The changes in decommissioning estimates recorded in each financial year include the impact of both changes to expected cost estimates and changes in the discount rates applied.

24. Derivative Financial Instruments

In the period under prior ownership by ConocoPhillips, Chrysaor Petroleum Company U.K. Limited, through arrangements with an affiliate company, Chrysaor Production (U.K.) Limited (formerly ConocoPhillips (U.K.) Limited), used derivative instruments to hedge the effects of fluctuations in the price of crude oil. Any gains or losses arising from commodity derivative contracts are recognised in the income statement in line with the underlying sales transaction.

There were no open derivative contracts held by the Companies as at 31 December 2019, 31 December 2018 or 31 December 2017.

Changes in the fair value of derivative financial instruments recognised within the income statement are as follows:

Non-Current

	2017 *$000*	*2018* *$000*	*2019* *$000*
Net gain/(loss) on derivative instruments	22,793	(26,066)	44,199

25. Financial Risk Factors and Risk Management

The Companies' principal financial assets and liabilities comprise trade and other receivables, cash and bank overdrafts, trade and other payables, and interest bearing and non-interest bearing intercompany loans. The main purpose of these financial instruments is to manage short-term cash flow and price exposures and raise finance for the Companies' expenditure programmes.

Risk Exposures and Responses

In the periods under prior ownership by ConocoPhillips, the Companies managed their exposure to key financial risks in accordance with ConocoPhillips group financial risk management policy. In the period under ownership by the Chrysaor Group, these risks are managed in accordance with the Chrysaor Group financial risk management policy. The objectives of both policies are to support the delivery of the group financial targets while protecting future financial security.

The main risks that could adversely affect the Companies' financial assets, liabilities, or future cash flows are: market risks comprising commodity price risk, interest rate risk and foreign currency risk, liquidity risk, and credit risk. The policies for managing each of these risks are summarised below.

For the respective periods of ownership, the management of financial risks has been overseen by senior management of the ConocoPhillips group and Chrysaor Group to ensure that financial risk-taking activities are governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with the relevant group policies and risk objectives. All derivative activities for risk management purposes are carried out by specialist teams that have the appropriate skills, experience, and supervision. No trading in derivatives for speculative purposes is undertaken by the Companies.

Market Risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk comprises three types of risk: commodity price risk, interest rate risk and foreign currency risk. Financial instruments mainly affected by market risk include intercompany loans, cash, and derivative financial instruments.

a. Commodity Price Risk

The Companies are exposed to the risk of fluctuations in prevailing market commodity prices on the mix of oil and gas products.

In the periods under prior ownership by ConocoPhillips, generally the group policy was to remain exposed to market prices of commodities, however, executive management could elect to use derivative instruments to hedge the price risk of crude oil and gas production. In the period under prior ownership by ConocoPhillips, Chrysaor Petroleum Company U.K. Limited, through arrangements with an affiliate company, Chrysaor Production (U.K.) Limited (formerly ConocoPhillips (U.K.) Limited), used derivative instruments to hedge the effects of fluctuations in the price of crude oil. Any gains or losses arising from commodity derivative contracts are recognised in the income statement in line with the underlying sales transaction (note 24).

At 31 December 2019, on a rolling basis, the Chrysaor Group's policy was to hedge the commodity price exposure associated with 40 to 60 per cent. of the next 12 months' production, between 30 and 50 per cent. in the following 12-month period, and up to 40 per cent. in the subsequent 24-month period. The Chrysaor Group manages these risks through the use of fixed priced contracts with customers for physical delivery and derivative financial instruments including fixed priced swaps and options. All derivative financial instruments are held by another Chrysaor Group undertaking and there were no derivative financial instruments held by the Companies during the period under Chrysaor Group ownership.

Financial Risk Factors and Risk Management

b. Interest Rate Risk

The Companies may be exposed to interest rate risk resulting from intercompany loans and banking arrangements.

In the periods under prior ownership by ConocoPhillips, interest charged on group loans was linked to LIBOR and therefore was exposed to movements in UK rates. The ConocoPhillips group did not comprehensively hedge its exposure to interest rate changes. No derivative contracts were entered into by the Companies during the periods under prior ownership by ConocoPhillips to hedge their exposure to interest rate changes.

The Chrysaor Group monitors its exposure to fluctuations in interest rates and uses interest rate derivatives to manage the fixed and floating composition of its borrowings. All Chrysaor Group cash balances are held by Chrysaor E&P Finance Limited. All intercompany loans held by the Companies are now interest free.

c. Foreign Currency Risk

The Companies are exposed to foreign exchange risks to the extent they transact in various currencies, while measuring and reporting their results in US Dollars. Since time passes between the recording of a receivable or payable transaction and its collection or payment, the Companies are exposed to gains or losses on non-USD amounts and on balance sheet translation of monetary accounts denominated in non-USD amounts upon spot rate fluctuations from period to period. 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. The Companies included in the Combined COP Subsidiaries have functional currencies of Pounds Sterling and US Dollar. Exposures can also arise from sales or purchases denominated in currencies other than the functional currency of the relevant entity.

In the periods under prior ownership by ConocoPhillips, the ConocoPhillips group did not comprehensively hedge its exposure to foreign currency risk. No derivative contracts were entered into by the Companies during the periods under prior ownership by ConocoPhillips to hedge their exposure to foreign currency rate risk.

The Chrysaor Group monitors its exposure to fluctuations in foreign currency rates and such exposures are monitored and hedged with agreement from the Board. As at 31 December 2019 the Companies had not entered into any exchange rate derivatives.

The following table demonstrates the sensitivity to a reasonably foreseeable change in US Dollar against Pounds Sterling with all other variables held constant, of the Companies' profit before tax (due to foreign exchange translation of monetary assets and liabilities) in the years ended 31 December 2019, 2018 and 2017 based on the financial assets and financial liabilities held at the balance sheet date. The impact of translating the net assets of Pounds Sterling functional companies into US Dollars is excluded from the sensitivity analysis.

	Market movement	*Effect on profit before tax $000*
2019		
US dollar/Sterling	10% strengthening	76,159
US dollar/Sterling	10% weakening	(76.159)
2018		
US dollar/Sterling	10% strengthening	10,527
US dollar/Sterling	10% weakening	(10,527)
2017		
US dollar/Sterling	10% strengthening	7,355
US dollar/Sterling	10% weakening	(7,355)

Financial Risk Factors and Risk Management

d. *Credit Risk*

Credit risk is the risk that a counterparty will not meet its obligations under a financial instrument or customer contract, leading to financial loss. The Companies are exposed to credit risk from their operating activities (primarily for trade receivables) and from their financing activities, including deposits with banks.

The Companies only sell hydrocarbons to recognised and creditworthy parties. The credit risk on liquid funds is limited because the counterparties are internationally recognised banking institutions and are considered to represent minimal credit risk.

There are no significant concentrations of credit risk within the Companies and credit losses are expected to be near to zero. The maximum credit risk exposure relating to financial assets is represented by carrying value as at the balance sheet date.

e. *Liquidity Risk*

The Companies finance their operations with a combination of cash and loans to and from other group undertakings.

In the periods under prior ownership by ConocoPhillips, the group's treasury subsidiary managed the liquidity of group cash balances by entering into derivative transactions; mainly in the form of currency swaps.

The Chrysaor Group monitors the amount of borrowings maturing within any specific period and proposes to meet its financing commitments from the operating cash flows of the business and existing committed lines of credit.

The table below summarises the maturity profile of the Companies' financial liabilities at 31 December 2019, 31 December 2018 and 31 December 2017 based on contractual undiscounted payments.

	Within one year $000	*1 to 2 years $000*	*2 to 5 years $000*	*Over 5 years $000*	*Total $000*
Non-derivative Financial Liabilities					
Loans from group undertakings	592,070	—	—	—	592,070
Trade and other payables	252,590	—	—	—	252,590
Lease obligations	27,610	29,205	17,130	6,912	80,557
As at 31 December 2019	872,270	29,205	17,130	6,912	925,217

	Within one year $000	*1 to 2 years $000*	*2 to 5 years $000*	*Over 5 years $000*	*Total $000*
Non-derivative Financial Liabilities					
Bank overdraft	615,315	—	—	—	615,315
Trade and other payables	526,071	—	—	—	526,071
Lease obligations	24,371	26,711	43,997	7,517	102,596
As at 31 December 2018	1,165,757	26,711	43,997	7,517	1,243,982

Financial Risk Factors and Risk Management

	Within one year $000	*1 to 2 years $000*	*2 to 5 years $000*	*Over 5 years $000*	*Total $000*
Non-derivative Financial Liabilities					
Bank overdraft	2,481,123	—	—	—	2,481,123
Trade and other payables	408,085	—	—	—	408,085
Lease obligations	25,778	25,778	73,912	8,829	134,297
As at 31 December 2017	2,914,986	25,778	73,912	8,829	3,023,505

The maturity profile in the above tables reflect only one side of the Companies' liquidity position. Loans and trade and other payables mainly originate from the financing of assets used in the Companies' ongoing operations such as property, plant and equipment and working capital such as inventories. These assets are considered part of the Companies' overall liquidity risk.

26. Notes to the Statement of Cash Flows

Net cash flows from operating activities consist of:

	For the years ended 31 December		
	2017 *$000*	*2018* *$000*	*2019* *$000*
(Loss)/profit before taxation	(89,619)	260,244	325,836
Finance cost, excluding foreign exchange	37,161	43,814	39,194
Finance income, excluding foreign exchange	(2,943)	(5,646)	(3,751)
Depreciation, depletion and amortisation	311,488	323,553	166,337
Impairment of property, plant and equipment	49,264	(4,960)	942
Decommissioning payments	(3,350)	(7,729)	(6,265)
Exploration costs written-off	56	12,820	1,683
Inventory write-off	969	181	—
Release of deferred income	(1,490)	—	—
Income from interest in associate undertaking	(10,700)	(14,312)	(7,526)
Gain on sale of investment in associated undertaking	—	—	(144,075)
Gain on sale of investment in subsidiary undertaking	—	(151,864)	—
Unrealised foreign exchange loss/(gain)	2,373	(1,778)	22,926
Tax paid	(34,599)	(64,469)	(24,744)
Working capital adjustments:			
(Increase)/decrease in inventories	(5,542)	(243)	2,556
(Increase)/decrease in trade and other receivables	(11,817)	(178,164)	215,202
Increase/(decrease) in trade and other payables	26,114	228,699	(363,965)
Net cash inflow from operating activities	267,365	440,146	224,350

27. Related Party Disclosures

The Combined COP Subsidiaries Historical Financial Information includes the financial statements of the Companies and their subsidiary undertakings, as listed in note 15. The investment in an associate undertaking is accounted for using the equity method (note 16). The Combined COP Subsidiaries do not constitute a separate legal group. The Combined COP Subsidiaries Historical Financial Information is a combination of certain legal entities purchased by the Chrysaor Group from ConocoPhillips and has been prepared specifically for the purpose of complying with the Prospectus Rule requirement to present 75 per cent. of the business to be listed throughout the track record period.

Controlling Party

The immediate parent undertaking of each of the Companies is:

Company	*Immediate parent undertaking*
Chrysaor Petroleum Company U.K. Limited	Chrysaor Production Holdings Limited
Chrysaor Resources (Irish Sea) Limited	Chrysaor Resources (U.K.) Holdings Limited
Chrysaor (U.K.) Sigma Limited	Chrysaor Production (U.K.) Limited

At 31 December 2019, the ultimate parent undertaking and controlling party is Harbour Energy Holdings Ltd (Cayman).

Group undertakings not included in the combination

From 1 January 2017 to 30 September 2019, the Companies were under the common control of ConocoPhillips. From 30 September, the Companies have been part of the Chrysaor Group.

Transactions and balances with group undertakings not included in the Combined COP Subsidiaries Historical Financial Information are summarised below:

	Amounts owed by/(to) group undertakings at 31 December								
	2017 $000			*2018 $000*			*2019 $000*		
	Loans Receivable /(Payable)	*Trading Receivable /(Payable)*	*Taxation Receivable /(Payable)*	*Loans Receivable /(Payable)*	*Trading Receivable /(Payable)*	*Taxation Receivable /(Payable)*	*Loans Receivable /(Payable)*	*Trading Receivable /(Payable)*	*Taxation Receivable /(Payable)*
Chrysaor Production (U.K.) Limited and other legal entities acquired by Chrysaor (i)	108,184	37,797 (33,254)	94,148	102,280	92,076 (188,844)	12,954 (1,561)	832,545 (592,070)	48,670 (88,358)	14,800 (1,480)
ConocoPhillips Company (ii)	1,672,338	58 (8,080)	—	10,023	16 (841)	—	—	—	—
ConocoPhillips Skandinavia AS and other ConocoPhillips legal entities not acquired by Chrysaor (iii)	—	(184,128)	—	—	(208,830)	—	—	—	—
Chrysaor Group companies (iv)	—	—		—	—	—	—	143,606	—

(i) All loan receivable and payable balances are with Chrysaor Production (U.K.) Limited (see notes 19 and 22); trading and taxation balances are predominantly with Chrysaor Production (U.K.) Limited
(ii) Short term interest bearing loan receivable balances with ConocoPhillips Company (see note 19)
(iii) Trading balances are predominantly with ConocoPhillips Skandinavia AS and arise from the purchase of Norwegian crude for onward sale
(iv) The Companies have trading balances at 31 December 2019 with Chrysaor E&P Finance Limited, Chrysaor Limited, Chrysaor E&P Limited, Chrysaor E&P Services Limited and Chrysaor North Sea Limited

	Transactions during the years ended 31 December								
	2017 $000			*2018 $000*			*2019 $000*		
	Sales	*Purchases and Recharges*	*Interest income*	*Sales*	*Purchases and Recharges*	*Interest income*	*Sales*	*Purchases and Recharges*	*Interest income/ (expense)*
Chrysaor Production (U.K.) Limited and other legal entities acquired by Chrysaor (i)	324,024	(255,049)	905	450,117	(336,951)	1,135	329,017	(76,027)	1,053
ConocoPhillips Company (ii)	—	—	1,163	—	—	1,759	—	—	—
ConocoPhillips Skandinavia AS and other ConocoPhillips legal entities not acquired by Chrysaor (iii)	562	(1,916,969)	—	551	(2,183,659)	—	68,630	(944,497)	—
Chrysaor Group companies (iv)	—	—	—	—	—	—	—	30,198	

(i) Transactions are predominantly with Chrysaor Production (U.K.) Limited
(ii) Interest income on short term loan receivable balances with ConocoPhillips Company (see note 19)
(iii) Transactions are predominantly with ConocoPhillips Skandinavia AS for the purchase of Norwegian crude for onward sale
(iv) Transactions with Chrysaor Limited, Chrysaor E&P Services Limited and Chrysaor North Sea Limited

Associate undertaking and entities under common control

In the period under prior ownership by ConocoPhillips, the Company had an interest in an associate undertaking, Norpipe Terminal Holdco Limited, accounted for using the equity method as detailed in Note 16.

Other related parties and their relationship to the Company during the period of prior ownership by ConocoPhillips are as follows:

Company name	**Relationship**
Norsea Pipeline Limited	Common control
Norpipe Petroleum UK Limited	Common control
Norpipe Oil AS	Common control

	Net Recharges to/(from) related parties			*Amounts owed by/(to) related parties at 31 December*		
	2017 $000	*2018 $000*	*2019 $000*	*2017 $000*	*2018 $000*	*2019 $000*
Norsea Pipeline Limited	97,872	157,399	98,492	279	3,195	—
Norpipe Petroleum UK Limited	43,664	37,993	19,819	2,058	(139)	—
Norpipe Oil AS	2,505	2,286	1,763	439	900	—

28. Post Balance Sheet Events

In response to the COVID-19 outbreak, the Chrysaor Group mobilised its Crisis Management and Business Continuity Teams to monitor Government advice and manage business operations with the top priority being the safety of the workforce. A review of operational activities for the year was carried out and the level of work has been reduced to undertake only what is necessary to keep the workforce safe and to maintain continuing safe operations in all locations for as long as is necessary.

Commodity prices fell significantly in early 2020 with a degree of recovery thereafter. The Company reviewed activities for the year resulting in operating and capital expenditure being significantly reduced reflecting the lower level of activities.

PART IX

UNAUDITED PRO FORMA FINANCIAL INFORMATION

SECTION A

UNAUDITED PRO FORMA FINANCIAL INFORMATION OF THE COMBINED GROUP

Basis of preparation

The unaudited *pro forma* statement of net assets and *pro forma* income statement (together the "**Unaudited *Pro Forma* Financial Information**") of the Combined Group set out below has been prepared in accordance with Annex 20 of the Commission Delegated Regulation (EU) 2019/980.

The unaudited *pro forma* statement of net assets has been prepared to illustrate the effect on the consolidated net assets of Premier as at 30 June 2020 as if the Merger and the Debt Restructuring had each taken place on 30 June 2020.

The unaudited *pro forma* income statement has been prepared to illustrate the effect on the consolidated earnings of Premier for the six month period ended 30 June 2020 as if the Merger and Debt Restructuring had each taken place on 1 January 2020.

The Unaudited *Pro Forma* Financial Information has been prepared for illustrative purposes only. The hypothetical financial position or results included in the Unaudited *Pro Forma* Financial Information may differ from the Combined Group's actual financial position or results.

The Unaudited *Pro Forma* Financial Information has been prepared on the basis set out in the notes below and has been prepared in a manner consistent with the accounting policies that will be applied by the Combined Group for the year ending 31 December 2020 and in accordance with the requirements of sections 1 and 2 of Annex 20 of Commission Delegated Regulation (EU) 2019/980.

The Unaudited *Pro Forma* Financial Information does not constitute financial statements within the meaning of section 434 of the Companies Act 2006. Ernst and Young LLP's accountant's report on the Unaudited *Pro Forma* Financial Information is set out in Section B of this Part IX.

Unaudited Pro Forma Statement of Net Assets of the Combined Group as at 30 June 2020

			Adjustments				
Note	*Premier 30 June 2020 US$ million* 1	*Chrysaor 30 June 2020 US$ million* 2	*Acquisition Adjustment US$ million* 3	*Debt Restructuring and New RBL Facility US$ million* 4	*Conversion of Loan Notes to equity US$ million* 5	*Transaction costs/LTIP/ Other US$ million* 6	*Unaudited pro forma Combined Group net assets US$ million*
Non-current assets:							
Goodwill	**240.8**	**1,343.6**	—	—	—	—	**1,584.4**
Other intangible assets	**742.8**	**492.1**	—	—	—	—	**1,234.9**
Property, plant and equipment	**1,745.6**	**6,519.3**	—	—	—	—	**8,264.9**
Right of use assets	**561.3**	**144.0**	—	—	—	—	**705.3**
Investments	**—**	**—**	—	—	—	—	**—**
Other receivables	**230.4**	**2.9**	—	—	—	—	**233.3**
Other financial assets	**—**	**313.5**	—	—	—	—	**313.5**
Deferred tax assets	**1,199.1**	**—**	—	—	—	—	**1,199.1**
	4,720.0	**8,815.4**	—	—	—	—	**13,535.4**
Current assets:							
Inventories	**13.3**	**153.0**	—	—	—	—	**166.3**
Trade and other receivables	**277.4**	**269.4**	—	—	—	—	**546.8**
Other financial assets	**130.9**	**614.4**	—	—	—	—	**745.3**
Cash and cash equivalents	**139.7**	**369.4**	(61.2)	**—**	(166.0)	(57.8)	**224.1**
	561.3	**1,406.2**	(61.2)	—	(166.0)	(57.8)	**1,682.5**
Total Assets	**5,281.3**	**10,221.6**	**(61.2)**	**—**	**(166.0)**	**(57.8)**	**15,217.9**
Current liabilities:							
Trade and other payables	**(394.2)**	**(556.1)**	—	—	—	—	**(950.3)**
Borrowings	**(2,101.8)**	**(11.9)**	52.2	2,049.5	—	—	**(12.0)**
Lease creditor	**(92.8)**	**(53.8)**	—	—	—	—	**(146.6)**
Current tax liabilities	**—**	**(202.9)**	—	—	—	—	**(202.9)**
Provisions	**(93.7)**	**(206.7)**	—	—	—	—	**(300.4)**
Other financial liabilities	**(151.0)**	**(0.1)**	—	141.0	—	—	**(10.1)**
Deferred income	**(15.6)**	**—**	—	—	—	—	**(15.6)**
	(2,849.1)	**(1,031.5)**	52.2	2,190.5	—	—	**(1,638.0)**
Net Current Assets	**(2,287.8)**	**374.7**	**(9.0)**	**2,190.5**	**(166.0)**	**(57.8)**	**44.6**
Non-current liabilities:							
Borrowings	**—**	**(2,170.2)**	—	(1,405.0)	283.0	—	**(3,292.2)**
Provisions	**(1,171.7)**	**(3,368.4)**	—	—	—	—	**(4,540.1)**
Deferred tax	**(114.9)**	**(1,564.8)**	—	—	—	—	**(1,679.7)**
Trade and other payables	**—**	**(46.4)**	—	—	—	—	**(46.4)**
Lease creditor	**(607.3)**	**(96.4)**	—	—	—	—	**(703.7)**
Other financial liabilities	**—**	**(14.5)**	—	—	—	—	**(14.5)**
Deferred income	**(48.1)**	**—**	—	—	—	—	**(48.1)**
	(1,942.0)	**(7,260.7)**	—	(1,405.0)	283.0	—	**(10,324.7)**
Total Liabilities	**(4,791.1)**	**(8,292.2)**	**52.2**	**785.5**	**283.0**	**—**	**(11,967.7)**
Net Assets	**490.2**	**1,929.4**	**(9.0)**	**785.5**	**117.0**	**(57.8)**	**3,255.3**

Unaudited Pro Forma Income Statement of the Combined Group for the six months ended 30 June 2020

	Note	Premier Half year period ended 30 June 2020 US$ million	Chrysaor Half year period ended 30 June 2020 US$ million	Adjustments: Acquisition Accounting Adjustment US$ million	Adjustments: Debt Restructuring and New RBL Facility US$ million	Adjustments: Conversion of Loan Notes to equity US$ million	Adjustments: Transaction costs/LTIP/ Other US$ million	Unaudited pro forma Combined Group results
		1	*2*	*3*	*4*	*5*	*6*	
Continuing operations								
Revenue		530.6	1,230.1	—	—	—	—	1,760.7
Other income		1.0	13.5	—	—	—	—	14.5
Revenue and other income		**531.6**	**1,243.6**	—	—	—	—	1,775.2
Costs of Sales		(405.6)	(1,018.0)	—	—	—	—	(1,423.6)
Gross Profit		**126.0**	**225.6**	—	—	—	—	351.6
Impairment of property, plant and equipment		(79.6)	(250.7)	—	—	—	—	(330.3)
Impairments of goodwill		—	(55.7)	—	—	—	—	(55.7)
Negative goodwill on acquisition		—	—	214.4	—	—	—	214.4
Provision for onerous service contracts		—	(27.9)	—	—	—	—	(27.9)
Exploration and evaluation expense		(19.9)	(4.2)	—	—	—	—	(24.1)
Exploration costs written-off		(222.2)	(38.9)	—	—	—	—	(261.1)
Re-measurements		—	0.5	—	—	—	—	0.5
Profit on disposal of non-current assets		0.6	—	—	—	—	—	0.6
General and administration costs		(4.2)	(29.2)	—	—	—	(57.8)	(91.2)
Operating Profit		**(199.3)**	**(180.5)**	**214.4**	**—**	**—**	**(57.8)**	**(223.2)**
Interest revenue, finance and other gains		31.4	105.1	—	—	—	—	136.5
Finance costs, other finance expenses and losses		(166.9)	(148.8)	—	54.6	—	—	(261.1)
Profit / (loss) before tax from continuing operations		**(334.8)**	**(224.2)**	**214.4**	**54.6**	**—**	**(57.8)**	**(347.8)**
Tax		(336.7)	69.7	—	—	—	—	(267.0)
Profit / (loss) after tax		**(671.5)**	**(154.5)**	**214.4**	**54.6**	**—**	**(57.8)**	**(614.8)**

Notes:

(1) The net assets of Premier as at 30 June 2020 and the income statement for the six month period ended 30 June 2020 have been extracted without material adjustment from the unaudited interim consolidated financial statements of Premier for the six month period ended 30 June 2020, incorporated by reference in section 1 of Part V (*Operating and Financial Review relating to the Premier Group*) of this document.

No accounting policy differences have been identified between the unaudited interim consolidated financial statements of Premier for the six month period ended 30 June 2020 and the historical financial information of Chrysaor for the six month period ended 30 June 2020, however differences in the presentation of certain line items have been identified. As the Combined Group will adopt Chrysaor's financial presentation, certain of Premier's net asset and income statement line items have been reclassified to be consistent with Chrysaor's line item classification. A reconciliation of the reclassification differences is set out below:

Unaudited reconciliation of Premier's consolidated net assets under Chrysaor's balance sheet presentation as at 30 June 2020

Statement of net assets line items – Premier	*Premier as at 30 June 2020 as reported (a) US$ million*	*Reclassifications (b) US$ million*	*Premier's statement of net assets under the statement of net assets presentation of Chrysaor as at 30 June 2020 (c) US$ million*	*Statement of net assets line items – Chrysaor (c)*
Non-current assets:				**Non-current assets:**
Goodwill	240.8	—	240.8	Goodwill
Intangible exploration and evaluation assets	742.8	—	742.8	Other intangible assets
Property, plant and equipment	2,306.9	(561.3)	1,745.6	Property, plant and equipment
		561.3	561.3	Right of use assets
		—	—	Investments
Long-term receivables	230.4	—	230.4	Other receivables
		—	—	Other financial assets
Deferred tax assets	1,199.1	—	1,199.1	Deferred tax assets
Current assets:	**4,720.0**	**—**	**4,720.0**	**Current assets:**
Inventories	13.3	—	13.3	Inventories
Trade and other receivables	277.4	—	277.4	Trade and other receivables
Derivative financial instruments	130.9	—	130.9	Other financial assets
Cash and cash equivalents	139.7	—	139.7	Cash and cash equivalents
	561.3	**—**	**561.3**	
Total assets	**5,281.3**	**—**	**5,281.3**	**Total Assets**
Current liabilities:				**Current liabilities:**
Trade and other payables	(394.2)	—	(394.2)	Trade and other payables
Borrowings	(2,101.8)	—	(2,101.8)	Borrowings
Lease liabilities	(138.5)	—	(138.5)	Lease creditor
		—	—	Current tax liabilities
Short term provisions	(93.7)	—	(93.7)	Provisions
Derivative financial instruments	(151.0)	—	(151.0)	Other financial liabilities
Deferred income	(15.6)	—	(15.6)	Deferred income
	(2,894.8)	**—**	**(2,894.8)**	
Net current assets	**(2,333.5)**	**—**	**(2,333.5)**	**Net Current Assets**
Non-current liabilities:				**Non-current liabilities:**
Borrowings	—	—	—	Borrowings
Long-term provisions	(1,171.7)	—	(1,171.7)	Provisions
Deferred tax liabilities	(114.9)	—	(114.9)	Deferred tax
		—	—	Trade and other payables
Lease liabilities	(561.6)	—	(561.6)	Lease creditor
		—	—	Other financial liabilities
Deferred income	(48.1)	—	(48.1)	Deferred income
	(1,896.3)	**—**	**(1,896.3)**	
Total liabilities	**(4,791.1)**	**—**	**(4,791.1)**	**Total Liabilities**
Net assets	**490.2**	**—**	**490.2**	**Net Assets**

Unaudited reconciliation of Premier's consolidated income statement under Chrysaor's income statement presentation for the six month period ended 30 June 2020

Income statement line items – Premier	*Premier for the six months ended 30 June 2020 as reported (a) US$ million*	*Reclassifications (b) US$ million*	*Premier's income statement under the income statement presentation of Chrysaor for the six months ended 30 June 2020 (c) US$ million*	*Income statement line items – Chrysaor (c)*
Continuing operations				**Continuing operations**
Sales revenues	530.6	—	530.6	Revenue
Other operating (costs)/income	1.0	—	1.0	Other income
		—	**531.6**	**Revenue and other income**
Costs of operation	(175.0)	(230.6)	(405.6)	Cost of Sales
			126.0	**Gross profit**
Depreciation, depletion, amortisation and impairment	(310.2)	230.6	(79.6)	Impairment of property, plant and equipment
		—	—	Impairments of goodwill
		—	—	Negative goodwill on acquisition
		—	—	Provision for onerous service contracts
Exploration expense and pre-licence cost	(242.1)	222.2	(19.9)	Exploration and evaluation expense
		(222.2)	(222.2)	Exploration costs written-off
		—	—	Re-measurements
Profit on disposal of non-current assets	0.6	—	0.6	Profit on disposal of non-current assets
General and administration costs	(4.2)	—	(4.2)	General and administration costs
Operating Profit	**(199.3)**	**—**	**(199.3)**	**Operating Profit**
Interest revenue, finance and other gains	31.4	—	31.4	Interest revenue, finance and other gains
Finance costs, other finance expenses and losses	(166.9)	—	(166.9)	Finance costs, other finance expenses and losses
Profit / (loss) before tax from continuing operations	**(334.8)**	**—**	**(334.8)**	**Profit / (loss) before tax from continuing operations**
Tax (charge) / credit	(336.7)	—	(336.7)	Tax
Profit / (loss) from continuing operations	**(671.5)**	**—**	**(671.5)**	**Profit / (loss) after tax**

Notes:

a) The Premier net asset and income line items have been extracted without material adjustment from the unaudited interim consolidated financial statements of Premier for the six month period ended 30 June 2020, incorporated by reference in section 1 of Part V (*Operating and Financial Review relating to the Premier Group)*) of this document.

b) The following reclassifications were made to reflect the difference in accounting presentation under Chrysaor's presentation as opposed to that of Premier:

i. Right of use assets have been reclassified from Property, Plant and Equipment ("**PP&E**") and have been presented as a separate line item within the statement of net assets.

ii. Depreciation, depletion and amortisation of Premier's PP&E assets have been separated from the impairment charge and combined with Costs of Operation and presented in aggregate as Costs of Sales within the income statement.

iii. Exploration costs written-off have been reclassified from Exploration and pre-licence costs and have been presented as a separate line item within the income statement. Remaining costs within Exploration and pre- licence costs have been renamed as Exploration and evaluation expense, in line with Chrysaor's naming convention.

c) The names of certain financial statement line items have been changed to align with Chrysaor's naming convention. Except as noted in (b) above there are no other changes to these line items other than alignment of naming conventions.

(2) The net assets of Chrysaor as at 30 June 2020 and the income statement for the six months ended 30 June 2020 have been extracted from the historical financial information of Chrysaor for the six months ended 30 June 2020, which have been prepared in accordance with the IFRS as adopted by the EU and Premier's accounting policies, and are set out in Part VIII (*Historical financial information relating to the Chrysaor Group*) of this document.

(3) The unaudited *pro forma* statement of net assets has been prepared on the basis that the Merger will be treated as a business combination in accordance with IFRS 3 *Business Combinations*. However, it does not reflect any fair value adjustments to the acquired assets and liabilities, except for those discussed in paragraph 3(iii) below, as the fair value measurement of these items will only be performed as at the date of completion of the Merger.

The fair value adjustments, when finalised, may be material. For the purposes of the Unaudited *Pro Forma* Financial Information, it has been assumed that the Merger will represent a reverse acquisition under the requirements of IFRS 3 and that, from an accounting perspective, Premier will be the legal acquirer and accounting acquiree and Chrysaor will be the legal acquiree and accounting acquirer.

Estimated purchase consideration and related excess purchase consideration over book value of net assets acquired are as follows:

	US$ million	*US$ million*
Estimated purchase consideration		
Premier shares currently in issue to existing shareholders (i)	266.8	
Estimated purchase consideration		*266.8*
Less carrying value of net assets acquired as at 30 June 2020		
Premier net assets (excluding borrowings and cross currency swap liabilities) (ii)	2,732.9	
Premier borrowings and cross currency swap liabilities at fair value (iii)	(2,190.5)	
Premier transaction costs incurred in relation to the Merger and Debt Restructuring (iv)	(61.2)	
Adjusted net assets acquired		*481.2*
Negative goodwill credited to income statement (v)		**214.4**

(i) In accordance with IFRS 3 as it applies to reverse acquisitions, the consideration for Premier's net assets is calculated as 925.5 million Ordinary Shares at a closing price of 21.6 pence on 14 December 2020, being the Latest Practicable Date, at a foreign exchange rate of GBP:USD 1.3346.

(ii) The value of Premier net assets of US$2,732.9 million is calculated by excluding the carrying values of US$2,101.7 million of borrowings and US$141.0 million of cross currency swap liabilities which are subject to the Debt Restructuring from the US$490.2 million of Premier net assets as at 30 June 2020.

(iii) This amount reflects Premier's borrowings and cross currency swap liabilities, which are the subject to the Debt Restructuring, at the value of consideration the Restructuring Plan Creditors will receive in satisfaction of these liabilities. Under the agreed Debt Restructuring terms, Premier's existing creditors will receive a cash payment of approximately US$1,230.0 million and a maximum of 3,331.9 million Ordinary Shares at a closing price of 21.6 pence on 14 December 2020, being the Latest Practicable Date, at a foreign exchange rate of GBP:USD 1.3346 in satisfaction of part of the Premier's existing debt and cross-currency swaps.

Each Restructuring Plan Creditor can elect to receive a Partial Cash Alternative to receiving Restructuring Ordinary Shares, subject to a maximum of US$175.0 million *pro rata* across existing Premier Plan Creditors who elect for the Partial Cash Alternative, and/or can elect to receive New Equity Warrants rather than Ordinary Shares. Furthermore, through making the Top-up Election, Senior Creditors and Senior XCCY Hedge Counterparties may subscribe in cash at a pre-agreed price for any unallocated Ordinary Shares which would have been issued to Senior Creditors and Senior XCCY Hedge Counterparties had they not elected to take the Partial Cash Alternative. At the date of preparation of this balance sheet, the intentions by the Creditors to elect to take up the Partial Cash Alternative and/or make a Top-Up Election and/or elect to receive New Equity Warrants rather than Ordinary Shares are unknown.

For the purposes of the Unaudited *Pro Forma* Financial Information, it has been assumed that the Restructuring Plan Creditors will collectively elect to take up the Partial Cash Alternative of US$175.0 million in full, which will have the effect of reducing the number of Premier shares issued under the Top-Up Election to 2,724.9 million Ordinary Shares, assuming a share price of 21.6 pence per Ordinary Share at 14 December 2020, being the Latest Practicable Date, and a foreign exchange rate of GBP:USD of 1.3346. It has been assumed that after the full take up of the Partial Cash Alternative, the Restructuring Plan Creditors do not elect to make a Top-up Election or to receive New Equity Warrants instead of Creditor Shares.

On the basis set out above, the consideration to the Restructuring Plan Creditors comprises a combination of US$1,230.0 million of cash, US$175.0 million of additional cash payment under the Partial Cash Alternative and US$785.5 million of Ordinary Shares valued at a closing price of 21.6 pence on 14 December 2020, being the Latest Practicable Date, at a foreign exchange rate of GBP:USD 1.3346 which in total equates to US$2,190.5 million, which approximates the fair value of the Premier borrowings and cross currency swap liabilities subject to the Debt Restructuring. The adjustment to current borrowings (US$52.2 million) in the *pro forma* statement of net assets reflects this fair value adjustment, recorded as the difference between the fair value of borrowings and cross currency swaps and Premier's carrying values at 30 June 2020 for these financial statement lines.

(iv) Transaction costs incurred and paid by Premier in connection with the Merger of US$20.5 million and the Debt Restructuring of US$40.7 million totalling US$61.2 million have the effect of reducing acquired Premier's net assets, and hence Premier's net assets as at 30 June 2020 have been adjusted for this amount. The transaction fees have been deducted from cash and cash equivalents.

(v) The gross difference of US$214.4 million between the adjusted book value of net assets acquired and the estimated consideration has, therefore, been presented as a single value in as a credit to the *pro forma* income statement representing negative goodwill. Following completion of the Merger and the Debt Restructuring, the assets and liabilities of Premier will be subject to a fair value assessment under the requirements of IFRS 3, and as a result the final goodwill or negative goodwill figure may differ materially from that shown.

(4) At 30 June 2020, Premier's borrowings and cross currency swap liabilities were presented as current liabilities on Premier's balance sheet owing to their maturity date of May 2021. These borrowings (at fair value of US$2,049.5 million) and cross currency swap liabilities (at fair value of US$141.0 million) will be extinguished under the Debt Restructuring through the exchange for cash and share consideration, as noted above.

The Combined Group on completion will enter into a US$4.5 billion New RBL Facility that is being fully underwritten by Bank of Montreal (London Branch), BNP Paribas, DNB (UK) Limited and Lloyds Bank plc. US$1,495 million is drawn down under the New RBL Facility to fund the cash payments to Premier's creditors of US$1,230 million, the Partial Cash Alternative of

US$175.0 million and the transaction fees in relation to the arrangement of the New RBL Facility of US$90.0 million. As the cash received from the draw down of the New RBL Facility equals the cash outflows set out above, there is no adjustment to the cash and cash equivalents financial statements line.

Fees incurred in relation to the arrangement of the New RBL Facility of US$90.0 million have been capitalised against the US$1,495 million drawn down under the new RBL facility, leading to an adjustment to non-current borrowings of US$1,405 million.

An adjustment is shown in the *pro forma* income statement to reduce finance costs by US$103.7 million for interest charges recognised by Premier in its unaudited results for the six month period ended 30 June 2020 for the debt facilities which will be extinguished under the Debt Restructuring.

This is offset by a charge of US$49.1 million recognised in the *pro forma* income statement as a finance cost to reflect six months of amortisation of the New RBL Facility fees (US$10.1 million) and an uplift in the Combined Group interest charge (US$39.0 million) charged at LIBOR plus a margin of 3.25 per cent.

(5) Chrysaor has outstanding unsecured C and D loan note borrowings of US$283.0 million as at 30 June 2020. It is expected that US$166.0 million of these loan note borrowings will be cash settled and a further US$131.0 million will be converted to equity as part of the Merger.

(6) Other cash payments of US$11.8 million are expected to be incurred have been assumed to be expensed on completion of the Merger and the Debt Restructuring which relate to the crystallisation of Chrysaor long term incentive plans. In addition, Chrysaor costs in relation to the Merger of US$46.0 million have been expensed as additional General & Administration costs in the period. A total adjustment to cash and cash equivalents of US$57.8 million is shown in the *pro forma* statement of net assets.

(7) No adjustment has been made to eliminate any inter-group trading between Premier and Chrysaor as its impact is not considered material.

(8) All of the adjustments to the unaudited *pro forma* statement of income are considered to be non-recurring with the exception of the expected reduction in finance costs.

(9) No adjustments made to reflect the changes in the financial position or trading results of Premier or Chrysaor since 30 June 2020.

SECTION B

ACCOUNTANT'S REPORT ON THE UNAUDITED PRO FORMA FINANCIAL INFORMATION

The Directors and the Proposed Directors
Premier Oil plc
23 Lower Belgrave St, Belgravia,
London SW1W 0NR

16 December 2020

Dear Sirs

Premier Oil plc (the "Company")

We report on the *pro forma* financial information (the "***Pro Forma* Financial Information**") set out in Section A of Part IX of the prospectus dated 16 December 2020 (the "**Prospectus**").

This report is required by Section 3 of Annex 20 of Commission Delegated Regulation (EU) 2019/980 and is given for the purpose of complying with that section 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 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 and proposed directors of the Company to prepare the *Pro Forma* Financial Information in accordance with Sections 1 and 2 of Annex 20 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 Commission Delegated Regulation (EU) 2019/980, as to the proper compilation of the *Pro Forma* Financial Information and to report that opinion to you.

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. No reports or opinions have been made by us on any financial information of Chrysaor Holdings Limited 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.

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 merger with Chrysaor Holdings Limited and debt restructuring might have affected the financial information presented on the basis of the accounting policies to be adopted by the Company in preparing the financial statements for the period ending 31 December 2020.

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 this report contains no omission likely to affect its import. This declaration is included in the Prospectus in compliance with item 1.2 of Annex 1 of Commission Delegated Regulation (EU) 2019/980 supplementing Regulation (EU) 2017/1129.

Yours faithfully

Ernst & Young LLP

PART X

COMPETENT PERSON'S REPORT ON THE CHRYSAOR GROUP

In view of its size relative to that of Premier, the Merger constitute 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 this document, along with a glossary of the technical terms used in such report. ERCE has been commissioned to prepare the independent mineral expert's report in relation to the Chrysaor Group (referred to as the Chrysaor CPR), which is set out in full below. The Chrysaor CPR was prepared on the basis of the reporting date of 30 June 2020.

The report was prepared on the basis of the following oil and gas price assumptions, which reflect ERCE's in-house models:

Oil (US$):

2020	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*
42	48	54	61	62	64	66

UK NBP Gas (p/therm):

2020	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*
24.5	37.0	42.3	44.7	46.8	48.4	51.7

Chrysaor Holdings Limited

Competent Person’s Report

As of 30 June 2020

Prepared For:	Chrysaor Holdings Limited
By:	ERCE
Date:	December 2020

ERCE
Independent Energy Experts

Peer Review Record

Date.	Description	Approved By
24/09/2020	Initial Peer Review	
21/10/2020	Mid-Project Peer Review	
29/10/2020	Final Peer Review	

Prepared and Approved by: Mr. Paul Taylor

Date released to client: 14 December 2020

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The Directors and Proposed Directors
Premier Oil plc
23 Lower Belgrave Street
London SW1W 0NR

The Directors
Chrysaor Holdings Limited
Brettenham House
Lancaster Place
London WC2E 7EN

RBC Europe Limited
Riverbank House
2 Swan Lane
London EC4R 3BF

Dear Sirs,

Re: Competent Person's Report

In accordance with the terms of our engagement letter dated 14 December 2020, ERC Equipoise Ltd ("ERCE") has prepared a Competent Person's Report ("CPR") for the hydrocarbon Reserves and Contingent Resources associated with Chrysaor Holding Limited's ("Chrysaor") portfolio of assets. The effective date of this report is 30 June 2020 (the "Effective Date").

For the preparation of this CPR, ERCE was provided by Chrysaor with data and information up to the Effective Date. In certain cases, data or information arising after the Effective Date has been used if it was considered material to the CPR; a list of this data and information is included in Section 2.1 of this CPR.

The CPR has been prepared in accordance with the June 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resources Management System ("PRMS"). A summary of the PRMS is found in Appendix 1 of the CPR. The full text can be downloaded from:-

https://secure.spee.org/sites/spee.org/files/prmgmtsystem_final_2018.pdf.

Nomenclature that may be used in this CPR is summarised in Appendix 2.

Use of the Report

ERCE understands that this CPR has been prepared for the purposes of being included, in its entirety, in a class 1 circular (the "Circular") to be published by Premier Oil plc ("Premier") in connection with the proposed merger of Premier with Chrysaor (the "Merger") and a prospectus (the "Prospectus") to be published by Premier in connection with the readmission of the existing ordinary shares of Premier and readmission of new ordinary shares of Premier to be issued in connection with the Merger and associated debt restructuring 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 plc. ERCE hereby consents to the inclusion of this CPR in the Circular, Prospectus and any related investor presentation and also to using references to the CPR in any other applicable disclosure document. This CPR may not be used for any other purpose without the prior written approval of a Director of ERCE.

For the purposes of Prospectus Regulation Rule 5.3.2 R(2)(f), ERCE accepts responsibility for the information contained in the CPR and declares that to the best of its knowledge, the information contained in the CPR is in accordance with the facts and makes no omission likely to affect its import of such information.

Disclaimer

In the case that any part of this report is delivered in digital format, ERCE does not accept any responsibility for edits carried out by the client or any third party or otherwise after the CPR has been prepared and issued by ERCE.

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data. ERCE has estimated the degree of this uncertainty and determined the range of petroleum initially in place and recoverable hydrocarbon volumes. In applying these procedures and tests, nothing came to the attention of ERCE that would suggest that information provided by Chrysaor was not complete and accurate.

ERCE does not guarantee the correctness of any interpretation of information contained in the CPR and shall not be liable or responsible for any loss, costs, damages or expenses incurred or sustained by anyone resulting from any interpretation made by any of its officers, agents or employees.

ERCE reserves the right to review all calculations referred to or included in this report and to revise the estimates in light of erroneous data supplied or information existing but not made available which becomes known subsequent to the preparation of this CPR.

The accuracy of any Reserves, Contingent Resources and production estimates is a function of the quality and quantity of available data and of engineering interpretation and judgment.

While Reserves, Contingent Resources and production estimates presented herein are considered reasonable, the estimates should be accepted with the understanding that reservoir performance subsequent to the date of the estimate may justify revision, either upward or downward.

Revenue projections presented in this report are based in part on forecasts of market prices, currency rates, inflation, market demand and government policy which are subject to many uncertainties and may, in future, differ materially from the forecasts utilised herein. Present values of revenues documented in this report do not necessarily represent the fair market value of the Reserves evaluated herein.

In the case of Contingent Resources presented in this report, there is no certainty that it will be commercially viable to produce any portion of the resources.

No site visits were undertaken in the preparation of this CPR.

Professional Qualifications

ERCE is an independent consultancy specialising in geoscience evaluation, engineering and economic assessment.

For the purposes of this CPR a Competent Person is defined as someone who:

- is professionally qualified and a member in good standing of an appropriate recognised professional association;
- has at least five years relevant experience in the estimation, assessment and evaluation of the type of oil and gas assets under consideration;
- is independent of the company, its directors, senior management and advisers;
- is not remunerated by way of a fee dependent on the findings of the CPR; and
- is not a sole practitioner

ERCE will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this CPR and ERCE will receive no other benefit for the preparation of this CPR.

Neither ERCE nor the Competent Person who is responsible for authoring this CPR, nor any Directors of ERCE have at the date of this report, nor have had within the previous two years, any shareholding in Chrysaor or Premier. Consequently, ERCE, the Competent Person and the Directors of ERCE consider themselves to be independent of both Chrysaor and Premier, their directors and senior management.

ERCE has the relevant and appropriate qualifications, experience and technical knowledge to appraise professionally and independently the assets.

The preparation of this report has been prepared and supervised by Mr. Paul Taylor, Head of Reserves and Resources at ERCE and is the Competent Person. Mr. Taylor has over 30 years of experience in the evaluation of oil and gas fields, preparation of development plans and assessment of reserves and resources. He holds a MEng degree in Chemical Engineering from Nottingham University. He is a Chartered Petroleum Engineer with the UK Engineering Council, a member of the Energy Institute and is a member of and has served on the Board of Directors of the Society of Petroleum Evaluation Engineers. Mr. Taylor therefore possesses the required competencies, being professionally qualified and a member in good standing of an appropriate recognised professional association.

Yours faithfully

P. Taylor

Mr. Paul Taylor, CEng

Head of Reserves and Resources, ERCE

1. Executive Summary

Chrysaor's portfolio of assets are located within a number of United Kingdom and Norwegian licence blocks. A summary of the assets is presented in Table 1. All the assets are on the UK Continental Shelf ("UKCS") except for three undeveloped discoveries on the Norwegian Continental Shelf ("NCS").

Table 1-1: Chrysaor's Licence Interests

Asset	Field	Operator	Chrysaor Working Interest %	Status
Armada Area	Armada	Chrysaor	100.00	Producing
	Maria	Chrysaor	100.00	Producing
	Seymour	Chrysaor	100.00	Producing
	Mabel	Chrysaor	100.00	Discovery
Beryl Area	Beryl	Apache	39.44	Producing
	Ness/Nevis Central	Apache	39.44	Producing
	Nevis South	Apache	42.82	Producing
	Nevis West	Apache	49.09	Shut-in
	Buckland	Apache	37.47	Producing
	Skene	Apache	34.04	Producing
	Storr	Apache	41.00	Producing
	Callater	Apache	45.00	Producing
	Corona	Apache	39.44	Discovery
	Solar	Apache	39.44	Discovery
Bressay	Bressay	Equinor	18.38	Discovery
Buzzard	Buzzard	CNOOC	21.73	Producing
Clair Area	Clair Phase 1	BP	7.50	Producing
	Clair Ridge	BP	7.50	Producing
	Clair South	BP	7.50	Discovery
	Clair North	BP	7.50	Discovery
East Irish Sea	Calder	Spirit Energy(1)	100.00	Producing
	Millom/Dalton	Spirit Energy(1)	100.00	Producing
	Darwen	Spirit Energy(1)	100.00	Discovery
	Crossans	Spirit Energy(1)	100.00	Discovery
Elgin Area	Elgin	Total	14.11	Producing
	Franklin	Total	14.11	Producing
	West Franklin	Total	14.11	Producing
	Glenelg	Total	14.70	Producing
Everest Area	Everest	Chrysaor	100.00	Producing
	Lomond	Chrysaor	100.00	Producing
	Erskine	Ithaca	32.00	Producing
	Ockley	Chrysaor	85.00	Discovery
	Mortimer	Chrysaor	100.00	Discovery
	Teme	Chrysaor	100.00	Discovery
	Faraday	Chrysaor	85.00	Discovery

Asset	Field	Operator	Chrysaor Working Interest %	Status
Galleon	Galleon	Shell	8.40	Producing
Greater Britannia Area	Britannia	Chrysaor	58.65	Producing
	Brodgar	Chrysaor	87.50	Producing
	Callanish	Chrysaor	83.50	Producing
	Enochdhu	Chrysaor	50.00	Producing
	Alder	Ithaca	26.32	Producing
	Leverett	Chrysaor	39(2)	Discovery
	MacLeod	Chrysaor	65.00	Discovery
	Shirley	Chrysaor	65.00	Discovery
J Area	Jade	Chrysaor	67.50	Producing
	Jasmine	Chrysaor	67.00	Producing
	Joanne	Chrysaor	67.00	Producing
	Judy	Chrysaor	67.00	Producing
	Peach	Chrysaor	67.00	Discovery
	Appleton	Chrysaor	100.00	Discovery
	Romeo	Chrysaor	100.00	Discovery
	Talbot	Chrysaor	67.00	Discovery
Schiehallion	Schiehallion	BP	10.00	Producing
Norwegian Continental Shelf	Grevling	OKEA ASA	35.00	Discovery
	Storskrymten	OKEA ASA	40.00	Discovery
	2/7-29 Discovery	OMV	40.00	Discovery

Notes

1. Legally Chrysaor is the Operator of the East Irish Sea assets. The facilities are managed by Spirit Energy under a contract with and on behalf of Chrysaor.
2. Leverett Working Interest (WI) is not yet unitized. The WI shown is based on the proportion of the target development area estimated by Chrysaor to be within blocks where Chrysaor has a working interest.

Asset Overview and Highlights

Armada Area – Chrysaor Interest 100%

The Armada asset comprises several gas-condensate/oil fields located 250 km ENE of Aberdeen in the Central North Sea close to the Norwegian border.

The Fleming, Drake, Hawkins, SW Seymour, and Seymour Horst fields have been developed from a fixed 21 slot wellhead and accommodation platform and the NW Seymour and Maria fields have been developed by subsea tie backs. First production occurred in 1997 from the Drake and Fleming fields. Gas and NGLs are transported via the Central Area Transmission System ("CATS") and condensate and oil are sent through the Forties Pipeline System ("FPS"). The platform production plateau was approximately 450 MMscf/d until early 2002 and since then has declined to around 40 MMscf/d with 2,500 stb/d of oil and condensate.

Currently there are three wells producing in Fleming, one well in Drake, one well in Hawkins, two wells in Maria, and one well in each area of Seymour. Towards the end of 2019 an infill well on the Hawkins field and the first development well on Seymour Horst were drilled. Although both wells were stimulated with multi-stage fracture treatments, the subsequent performance has not met pre-drill expectations.

A NW Seymour subsea well originally planned to be drilled in 2021 has been deferred to Q3 2023.

Beryl Area – Chrysaor Interests 34.04% to 49.09%

The Beryl Area assets comprise several oil and gas fields located 335 km NE of Aberdeen in Quad 9 UKCS. The Beryl field is developed via two fixed platforms: Beryl Alpha (built in 1974) and Beryl Bravo (built in 1984). The Ness-Nevis cluster, Buckland, Skene and Callater fields are developed as subsea tiebacks to the Beryl platforms. Oil is exported by tanker and gas via the SAGE pipeline to the SAGE gas plant at St. Fergus.

There are currently 30 oil producing and seven water injecting wells in the Beryl field (Alpha and Bravo) with 14 wells producing mainly from Triassic and Jurassic reservoirs (Alpha Secondaries) on the Alpha platform and 16 wells producing from Beryl reservoir on the Bravo platform.

During 1H 2020 three wells were drilled. One producer and one water injector were completed but the third well intended as a producer found insufficient reservoir for completion. As of 30 June 2020, the Beryl field (Alpha and Bravo) was producing some 10,050 stb/d oil at a water-cut of 76% and an average GOR of 3,710 scf/stb.

The current Beryl infill drilling programme runs until end the of 2023. Drilling is in two phases from the Alpha platform. There is a 6-month drilling break when the rig crew will be temporarily redeployed to another field. While explicit targets are not represented on the Apache drill schedule, Chrysaor assume this will include 12 infill wells (six wells in each phase).

The Ness-Nevis field cluster comprises seven distinct oil accumulation: Ness South, Nevis South, Nevis Central, Nevis West, Nevis North, and Nevis Far North. The Ness field came on stream in 1978. At present there are 12 production wells across these seven fields delivering an aggregated oil rate of 4,250 stb/d with varying water-cuts between some 5 to 83%. Well NSHW (Nevis South Heather West) is being progressed to be drilled as a long horizontal well during 2H 2021.

The Buckland oil field lies south of the Beryl field and started production in August 1999. Currently two wells are active. As of 30 June 2020, the Buckland field was producing 6,050 stb/d oil at 32% water cut and average GOR of 1,740 scf/stb.

The Skene field, brought online in 2001, is a structurally complex gas-condensate field, located some 15 km southeast of the Beryl Alpha production platform. Callater and Storr were in turn tied-back to Skene in 2Q 2017 and 4Q 2019, respectively. As of 30 June 2020, the three remaining active wells in the field produced 6.9 MMscf/d gas and 300 bbl/d condensate.

The Callater field, which came online April 2017, is a Jurassic and Triassic oil accumulation located 3.9 km west of the Skene field subsea facilities and 12 km southeast of the Beryl Alpha platform. The initial flow rates of Callater Well CC3 drilled in 2Q 2020 are reported as lower than expected and investigations into this are ongoing. As of 30 June 2020, with Well CC3 not yet on production, the Callater field was producing 1,900 stb/d at 5% water cut and 15.5 MMscf/d gas from four wells.

The Storr field is a Jurassic age gas and oil accumulation located 7 km south of the Skene field subsea facilities. Production commenced in November 2019 from a single first phase development well. The rate of this well has declined faster than anticipated. As of 30 June 2020, Storr was producing 28 MMscf/d gas and a condensate rate of 1,000 stb/d. The Operator is planning an infill well to be drilled during 2H 2021.

Buzzard – Chrysaor Interest 21.73%

The Buzzard field located in the Outer Moray Firth of the North Sea and came on stream in 2007. Oil is exported via the Forties Pipeline System (FPS) to the Kinneil Terminal at Cruden Bay, and gas via the Frigg pipeline system to the St. Fergus gas terminal. There are currently 32 producing wells and 34 water injectors. As of 30 June 2020, average oil production was 83,000 stb/d with 22 MMscf/d gas and a water cut above 70%.

A six well infill drilling campaign from the Buzzard wellhead platform Drilling Centre One (“DC1”) started in September 2018. Four producers were drilled during 2019 and one injector PRC6 in 1H 2020. The final well was cancelled and will no longer be drilled.

A Phase II six well infill drilling campaign on the Northern Terrace and Northern Panel from a subsea manifold Drilling Centre Two (“DC2”) commenced in 2019. As of September 2020, all six DC2 wells have been drilled. Two of the planned producers were suspended due to lack of sufficient reservoir. Hence, only four wells will be completed (two oil producers and two water injectors). Tie-back of the DC2 wells will be in 2021 with first oil scheduled for December 2021.

Clair Area – Chrysaor Interest 7.5%

The Greater Clair Area assets are located some 70 km West of Shetland ("WoS").

The Clair Area contains the Clair Phase 1 development with an integrated drilling and production platform, the Clair Ridge development with its two bridge linked platforms which ties into the Phase 1 pipelines to the Sullom Voe Terminal, and the Clair South and Clair North discoveries.

The Phase 1 area came on stream in 2005, producing from four different reservoir segments with different characteristics. Currently 21 wells are active producers and water injectors. Future plans include five infill wells targeting Segment 3A, Core, and Basement areas of the field. The infill well campaign is scheduled to start 2H 2021 and to be finished towards the end of 2023. As of 30 June 2020, average oil production was 32,000 stb/d with 12 MMscf/d gas and a water cut of 45%.

The Clair Ridge development achieved first oil in November 2018 from two wells, followed in 2019 by two further producers plus one water injector. Initial performance has been lower than prognosed with wells producing at lower than expected rates and three wells have seen water breakthrough. The next few wells to be drilled should give further insight into the performance of the development as they are forecast to be some of the best wells in terms of ultimate recovery.

The Clair South discovery, which remains in the select optimisation phase, has not yet progressed to a sanctionable project. The Contingent Resources are currently being targeted for development in 2026. The Clair North area, which is relatively under appraised, remains as an uncertain future add-on to the Clair Ridge development.

East Irish Sea – Chrysaor Interest 100%

Chrysaor's East Irish Sea ("EIS") assets are located in quadrants 110 and 113 offshore of the north-west coast of England, near the developed North and South Morecambe fields. The EIS Area consists of the Millom and Dalton gas fields and the Rivers Complex, which comprises one field, Calder and three sour gas discoveries. Most of the current EIS Area production comes from two fields, Millom (sweet gas) and Calder (sour gas). The gas has no appreciable liquids content.

Millom and Dalton production is transported to shore by pipeline via the North Morecambe platform. Currently four wells deplete Millom West and three produce from Millom East. Dalton is shut-in due to insufficient pressure. No further wells are planned. Sour gas from the three Calder platform wells is transported direct to the Rivers Terminal onshore. There have been operability issues in recent years with the onshore facilities. Recent improvements led to an increase in uptime in 2019, which is expected to be sustainable. No further drilling on Calder is envisaged.

During June 2020, gas production was 1.8 MMscf/d from Millom and 24 MMscf/d from Calder.

Elgin Area – Chrysaor Interests 14.11 to 14.70%

The Elgin Hub is located in the Central Graben Area, UK Central North Sea, approximately 240 km east of Aberdeen.

The Elgin Hub is operated by Total E&P and comprises four producing high-pressure high temperature ("HPHT") gas-condensate fields: Elgin, Franklin, West Franklin, and Glenelg. The fields are developed by four wellhead platforms, and a process, utilities, and accommodation platform. Sales gas is exported via the Shearwater Elgin Area Line ("SEAL") to the Shell Bacton terminal, and hydrocarbon liquids are transported via FPS to Cruden Bay.

First production was achieved in 2001. All fields were shut down between March 2012 and March 2013 due to an integrity issue with Well G4. Few wells have been reused after this incident and most have been replaced with new wells.

Currently production is via 15 gas wells including a single well in the Glenelg field which is produced cyclically. This well stock includes two wells brought on stream in 2019. The Q2 2020 average wellhead gas production rate from the hub was around 440 MMscf/d with 63,000 bbl/d of condensate.

A Franklin infill well is currently being drilled and is due on-stream November 2020 and an Elgin infill well is due to spud in Q4 2020. The Operator is planning investment to extend the life of the facilities to take production beyond 2034 and up to 2040.

Everest Area – Chrysaor Interests 32 – 100%

The Everest Area comprises the Everest, Lomond and Erskine fields located in the Central North Sea 240 km east of Aberdeen. The fields are late-life gas-condensate fields all tied back to the CATS riser tower alongside the Everest field platform. In common with the Armada area, sales gas is transported via CATS to the Teesside terminal and condensate is exported via the FPS to Cruden Bay.

As of 30 June 2020, ten wells in Everest were producing 63 MMscf/d and 2,245 bbl/d, five wells in Lomond were producing 31 MMscf/d and 630 bbl/d and five wells in Erskine were producing 51 MMscf/d and 6,300 bbl/d.

The future development plans include drilling another well at Everest scheduled for 2022 and Lomond and Everest Late Life Compression ("LLC") projects currently planned for 2021 and 2023, respectively. Typical late life issues such as well integrity and liquid holdup are starting to occur. Lomond benefits from the processing of third-party production as does the CATS tower at Everest, which helps reduce operating costs.

Galleon – Chrysaor Interest 8.40%

Galleon is a dry gas field in the Southern North Sea, developed through two platforms and brought on stream in 1994. Both platforms are tied back to the Barque and Clipper facilities via dedicated pipelines. Gas is exported to Bacton via the Sole Pit gas export line.

During June 2020, six wells were producing on the PG platform and three on the PN platform. Average production during 1H 2020 was some 35 MMscf/d of dry gas.

Following the repair of a sub-surface safety valve ("SSSV") a key well (PN04) was returned to production in January 2020 boosting production by 10 MMscf/d. Well PN09 drilled during 2019 is currently suspended due to several drilling issues; the plan is to re-drill or sidetrack the well during the 2H 2021.

Greater Britannia Area – Chrysaor Interests 26.32 – 87.5%

The Greater Britannia Area ("GBA") assets are located in the Central North Sea some 210 km northeast of Aberdeen. They include the Britannia field and four subsea tiebacks: Brodgar, Callanish, Enochdhu, and Alder. Sales gas is exported via a dedicated pipeline to the Scottish Area Gas Evacuation system ("SAGE") terminal at St. Fergus and hydrocarbon liquids are transported via FPS to Cruden Bay.

Production started from the Britannia gas-condensate field in 1998 from a 36-slot production platform and a subsea template. In 2008 a new bridge linked platform was installed to process hydrocarbons from the Callanish oil and Brodgar gas-condensate fields. More recently the Enochdhu oil field and the Alder HPHT gas-condensate field commenced production in 2015 and 2016, respectively.

During June 2020, 28 wells on the Britannia field were on continuous production and 10 wells on cyclic production to manage liquid loading (on average 33 wells were online). Water breakthrough and liquid loading are the primary production risks and management of liquid loading is the focus of recent and future workover activity. The gas and condensate rates at the end of June 2020 were 125 MMscf/d and 2,900 stb/d, respectively.

Brodgar has had four wells drilled to date. Production started in 2008 from two subsea wells but both were closed in during 2015 following water breakthrough. A third well was drilled in 2015 and more recently Well H4 was added in October 2019. At end June 2020, Well H4 was producing 82 MMscf/d and 3,700 stb/d out of a field total of 100 MMscf/d of gas and 4,600 stb/d of condensate. Water breakthrough and possible problems with the MEG system are the main risk to these rates.

Callanish is underlain by a strong aquifer and field production is now at 90% water cut. At end June 2020, three wells were producing at a liquid rate of 29,000 bbl/d, an oil rate of 2,900 stb/d and a gas rate of 3.5 MMscf/d. The plan is to drill another horizontal well during 2H 2020 with first oil in April 2021.

Enochdhu is analogous to Callanish albeit smaller and has been developed by one well. After initially producing at 10,000 stb/d the rate has declined with increasing water cut. At end June 2020 the well was producing 1,800 stb/d of oil and 2 MMscf/d of gas with a water cut of 70%.

Alder is a HPHT gas-condensate field which consists of a single subsea well development brought on stream in 2016. As of end June 2020, the gas rate was 23 MMscf/d and the condensate rate was 1,500 stb/d.

The long-term compression ("LTC") plan for Britannia includes a re-wheel of the Britannia booster compressors in Q1 2021 allowing a reduction in the separator pressure from 5.2 barg (90 psia) to around 3.9 barg (71 psia). From Q4 2021, following minor modification to the Britannia facilities, Alder will be set up to flow into the LTC system and also benefit from lower separator pressure.

J-Area – Chrysaor Interests 67 – 67.5%

The J-Area fields are located 240 km southeast of Aberdeen in the UK Central North Sea. The cluster comprises four producing oil and gas-condensate fields: Judy, Joanne, Jade and Jasmine. The gas is exported via CATS and oil is exported via the Norpipe system both to Teesside.

First production was in 1996 from the Judy and Joanne fields. A central processing platform was installed at Judy with Joanne produced from wells drilled from the Judy platform and from wells drilled from a dedicated Joanne subsea template tied back to the Judy platform. The Jade HPHT field came onstream in 2002 and the Jasmine HPHT field in 2013 both with wellhead platforms tied back to the Judy platform. Gas production rates peaked in 2007 at 500 MMscf/d and hydrocarbon liquids peaked at 60,000 stb/d in 2014. During Q2 2020 the fields averaged 140 MMscf/d of gas and 16,300 stb/d of hydrocarbon liquids.

The Judy field produces from Triassic reservoirs and in June 2020 there were nine wells still in production with five of them produced cyclically due to water loading problems. As a result, the Judy field produces at variable rates that depend on which wells are contributing to flow and on allocation between the Judy and Joanne fields. Average Q2 2020 gas and hydrocarbon liquid rates were 29 MMscf/d and 3,078 stb/d, respectively.

The Joanne field currently has four wells producing from the Palaeocene, six wells from the Joanne Chalk and one well from the Judy North chalk. Average Q2 2020 gas and hydrocarbon liquid rates were 22 MMscf/d and 7,150 stb/d, respectively.

The Jade field currently has eight wells producing from the Triassic with average Q2 2020 gas and condensate rates of 54 MMscf/d and 2,052 stb/d, respectively.

The Jasmine field has nine wells producing predominately from the Triassic with average Q2 2020 gas and hydrocarbon liquid rates of 53 MMscf/d and 4,019 stb/d, respectively.

Future development activity on the J-Area is dominated by the plans for the Joanne field where the Operator has drilled two wells as part of the Joanne Palaeocene field reactivation campaign. A total of eight new development wells and one workover are planned over the next four years in the J-Area. Approved plans for the J-Area also include facilities projects designed to maintain and improve existing well performance. Most wells in the Judy and Joanne fields are in late life and are produced cyclically. The Jade and Jasmine fields are likely to require cycled production in the future. There is evidence of liner deformation in both the Jade and Jasmine fields which may cause later well integrity issues.

Schiehallion – Chrysaor Interest 10%

The Schiehallion field is located 130 km West of Shetlands. The field has been developed with an FPSO and subsea development. Oil is exported via shuttle tanker and gas is exported via the West of Shetlands Pipeline System to Sullom Voe.

The field produced for a 15-year period between 1998 and 2013 recovering 323 MMstb of oil from 21 producers supported by 23 water injectors. The FPSO suffered from integrity issues throughout this period and a decision was taken to carry out a redevelopment. A new FPSO (the Glen Lyon) was built and production re-started in May 2017.

Drilling of the 17 planned Phase 1 redevelopment wells commenced in 2016 and has now been completed with the last two producers brought onstream in May 2020. A Phase 2 drilling campaign is still under consideration with four wells likely to be drilled in the first tranche and further wells in a subsequent tranche. However, the Operator at the 2nd July 2020 OCM recommended termination of the Deepsea Aberdeen rig contract and hence the timing of and commitment to any further drilling is uncertain.

Since 2017 the FPSO water injection system has presented commissioning challenges which have continued into 2020. The average injection rate over the first half of 2020 was 140,000 bbl/d against a target of approximately 200,000 bbl/d.

During 1H 2020 the average oil production was 52,000 stb/d versus a 2020 budget estimate of 71,000 stb/d. Production facility deferrals have been caused by several issues with the most significant being related to compression, separation and produced water handling. In addition, some wells are being choked back due to sand production. At the end of June 2020 there had been an improvement in the operational efficiency with the field producing 70,000 stb/d of oil and 45 MMscf/d of gas. The field is due to become fuel gas deficient circa. 2030 which will need to be addressed.

Reserves

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 further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates as Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P).*

The Reserves are reported on a field gross and a Company net working interest basis as of 30 June 2020. As there are no royalties payable to others, the Company net working interest Reserves are also equivalent to the Company net entitlement Reserves. Both developed and Undeveloped Reserves are reported for each cluster area and by product type. Gas Reserves are based on sales volumes and exclude fuel and flare. Oil equivalent Reserves are reported based on an energy equivalent conversion of the gas Reserves (conversion factors for each field are presented in Appendix 3). Developed Reserves are presented in Table 1-2 and Undeveloped Reserves are presented in Table 1-3. Total Reserves (Developed plus Undeveloped) are presented in Table 1-4.

The ERCE estimates of Developed Reserves in producing fields are based on decline curve analysis ("DCA") and/or the results of the Operators' simulation modelling. Estimates of Undeveloped Reserves are based on hydrocarbon in place and recovery efficiency estimates, analogue type curves, stochastic historic well performance analysis and/or dynamic modelling. The specific methods used are specified in the detailed field description sections of this report.

In accordance with the PRMS guidelines, the Cessation of Production ("CoP") date used to estimate reserves is defined as the end of the last 6 months period that the operating cash flow is positive, or the end of the technical field life, whichever occurs soonest. In cases where the existing production licenses are due to expire prior to the estimated cessation of field production date, it has been assumed that the licenses will be extended.

The Reserve totals in Table 1-2, Table 1-3 and Table 1-4, are aggregated by arithmetic summation as recommended in the PRMS reporting guidelines. However, as such the summed 1P may be a conservative and the summed 3P may be an optimistic estimate due to portfolio effects.

Table 1-2: Developed Reserves as of 30 June 2020

Developed Reserves as of 30 June 2020							
	Field Gross on Licence			Company Net			
Asset/Field	1P	2P	3P	1P	2P	3P	Operator
Oil+NGLs (MMstb)							
Armada Area	3.05	3.47	7.37	3.05	3.47	7.37	Chrysaor
Beryl Area	19.24	29.93	40.27	7.80	12.12	16.31	Apache
Buzzard	87.59	183.24	265.63	19.03	39.82	57.72	CNOOC
Clair Area	100.68	138.96	197.18	7.55	10.42	14.79	BP
East Irish Sea	0.00	0.00	0.00	0.00	0.00	0.00	Spirit Energy
Elgin Area	90.28	120.73	154.05	12.74	17.04	21.74	Total E&P
Everest Area	13.80	23.18	31.33	8.60	14.06	18.63	Chrysaor
Galleon	0.00	0.00	0.00	0.00	0.00	0.00	Shell
Greater Britannia Area	15.27	22.33	32.39	10.62	15.76	23.01	Chrysaor
J Area	34.90	56.13	83.06	23.43	37.67	55.75	Chrysaor
Schiehallion	146.48	236.12	288.74	14.65	23.61	28.87	BP
Total Oil+NGLs	**511.28**	**814.09**	**1100.02**	**107.46**	**173.97**	**244.18**	
Gas (Bscf)							
Armada Area	18.41	23.04	46.26	18.41	23.04	46.26	Chrysaor
Beryl Area	43.55	67.99	93.40	17.66	27.55	37.85	Apache
Buzzard	0.26	0.57	0.85	0.06	0.12	0.19	CNOOC
Clair Area	1.11	2.64	5.21	0.08	0.20	0.39	BP
East Irish Sea	90.32	106.69	117.31	90.32	106.69	117.31	Spirit Energy
Elgin Area	719.40	908.65	1055.68	101.55	128.25	149.00	Total E&P
Everest Area	136.63	229.67	311.58	105.68	174.56	233.51	Chrysaor[3]
Galleon	38.50	56.59	80.55	3.23	4.75	6.77	Shell
Greater Britannia Area	207.95	297.31	433.17	133.48	195.66	289.22	Chrysaor[3]
J Area	249.22	376.51	539.86	167.54	253.04	362.78	Chrysaor
Schiehallion	22.26	37.90	54.76	2.23	3.79	5.48	BP
Total Gas	**1527.60**	**2107.55**	**2738.62**	**640.24**	**917.66**	**1248.75**	

Notes

1. Company Net Reserves are based on the working interest share of the field gross Reserves (there are no royalty payments)
2. Totals are added arithmetically which means statistically there is a greater than 90% chance of exceeding the Total 1P and less than a 10% chance of exceeding the Total 3P
3. Ithaca operates the Erskine and Alder fields

Table 1-3: Undeveloped Reserves as of 30 June 2020

Undeveloped Reserves as of 30 June 2020							
	Field Gross on Licence			Company Net			
Asset/Field	1P	2P	3P	1P	2P	3P	Operator
Oil+NGLs (MMstb)							
Armada Area	0.00	7.12	9.36	0.00	7.12	9.36	Chrysaor
Beryl Area	2.98	16.49	29.74	1.27	6.59	11.78	Apache
Buzzard	7.80	21.03	44.23	1.70	4.57	9.61	CNOOC
Clair Area	353.65	506.63	699.71	26.52	38.00	52.48	BP
East Irish Sea	0.00	0.00	0.00	0.00	0.00	0.00	Spirit Energy
Elgin Area	9.25	33.83	57.45	1.31	4.77	8.11	Total E&P
Everest Area	0.20	1.04	1.95	0.06	1.04	1.77	Chrysaor[3]
Galleon	0.00	0.00	0.00	0.00	0.00	0.00	Shell
Greater Britannia Area	0.24	5.21	10.94	0.14	4.16	8.94	Chrysaor[3]
J Area	17.96	37.10	46.21	12.09	24.94	31.06	Chrysaor
Schiehallion	0.00	0.00	0.00	0.00	0.00	0.00	BP
Total Oil+NGLs	**392.08**	**628.45**	**899.59**	**43.09**	**91.19**	**133.10**	
Gas (Bscf)							
Armada Area	0.00	28.91	32.14	0.00	28.91	32.14	Chrysaor
Beryl Area	4.37	57.18	111.23	1.86	22.55	43.28	Apache
Buzzard	0.04	2.02	4.40	0.01	0.44	0.96	CNOOC
Clair Area	30.86	70.41	124.77	2.31	5.28	9.36	BP
East Irish Sea	0.00	0.00	0.00	0.00	0.00	0.00	Spirit Energy
Elgin Area	67.14	236.31	372.63	9.47	33.34	52.58	Total E&P
Everest Area	0.97	15.85	27.73	0.31	15.85	26.68	Chrysaor[3]
Galleon	0.00	30.16	40.67	0.00	2.53	3.42	Shell
Greater Britannia Area	7.71	20.98	31.91	4.52	13.37	21.36	Chrysaor[3]
J Area	114.06	227.88	277.01	76.86	153.28	186.30	Chrysaor
Schiehallion	0.00	0.00	0.00	0.00	0.00	0.00	BP
Total Gas	**225.16**	**689.70**	**1022.49**	**95.35**	**275.55**	**376.07**	

Notes

1. Company Net Reserves are based on the working interest share of the field gross Reserves (there are no royalty payments)
2. Totals are added arithmetically which means statistically there is a greater than 90% chance of exceeding the Total 1P and less than a 10% chance of exceeding the Total 3P
3. Ithaca operates the Erskine and Alder fields

Table 1-4: Total Reserves as of 30 June 2020

Total Reserves as of 30 June 2020							
	Field Gross on Licence			Company Net			
Asset/Field	1P	2P	3P	1P	2P	3P	Operator
Oil+NGLs (MMstb)							
Armada Area	3.05	10.59	16.72	3.05	10.59	16.72	Chrysaor
Beryl Area	22.22	46.42	70.01	9.07	18.71	28.09	Apache
Buzzard	95.39	204.27	309.86	20.73	44.39	67.33	CNOOC
Clair Area	454.33	645.59	896.89	34.07	48.42	67.27	BP
East Irish Sea	0.00	0.00	0.00	0.00	0.00	0.00	Spirit Energy
Elgin Area	99.53	154.56	211.50	14.04	21.81	29.84	Total E&P
Everest Area	13.99	24.21	33.28	8.67	15.10	20.39	Chrysaor[3]
Galleon	0.00	0.00	0.00	0.00	0.00	0.00	Shell
Greater Britannia Area	15.51	27.54	43.33	10.76	19.92	30.68	Chrysaor[3]
J Area	52.86	93.23	129.28	35.52	62.61	86.81	Chrysaor
Schiehallion	146.48	236.12	288.74	14.65	23.61	28.87	BP
Total Oil+NGLs	**903.36**	**1442.53**	**1999.61**	**150.56**	**265.16**	**376.01**	
Gas (Bscf)							
Armada Area	18.41	51.94	78.40	18.41	51.94	78.40	Chrysaor
Beryl Area	47.92	125.17	204.63	19.52	50.10	81.13	Apache
Buzzard	0.30	2.59	5.26	0.07	0.56	1.14	CNOOC
Clair Area	31.98	73.05	129.98	2.40	5.48	9.75	BP
East Irish Sea	90.32	106.69	117.31	90.32	106.69	117.31	Spirit Energy
Elgin Area	786.53	1144.95	1428.31	111.02	161.60	201.58	Total E&P
Everest Area	137.60	245.52	339.31	105.99	190.42	260.20	Chrysaor[3]
Galleon	38.50	86.75	121.22	3.23	7.29	10.18	Shell
Greater Britannia Area	215.66	318.29	465.08	138.00	209.03	310.58	Chrysaor[3]
J Area	363.28	604.39	816.86	244.40	406.32	549.08	Chrysaor
Schiehallion	22.26	37.90	54.76	2.23	3.79	5.48	BP
Total Gas	**1752.76**	**2797.24**	**3761.11**	**735.59**	**1193.21**	**1624.82**	

Notes

1. Company Net Reserves are based on the working interest share of the field gross Reserves (there are no royalty payments)
2. Totals are added arithmetically which means statistically there is a greater than 90% chance of exceeding the Total 1P and less than a 10% chance of exceeding the Total 3P
3. Ithaca operates the Erskine and Alder fields

Table 1-5: Total Barrel of Oil Equivalent Reserves as of 30 June 2020

Total Reserves as of 30 June 2020							
	Field Gross on Licence			Company Net			
Asset/Field	1P	2P	3P	1P	2P	3P	Operator
MMboe							
Armada Area	6.73	21.09	32.61	6.73	21.09	32.61	Chrysaor
Beryl Area	30.96	69.16	107.18	12.63	27.81	42.82	Apache
Buzzard	95.45	204.78	310.88	20.74	44.50	67.55	CNOOC
Clair Area	460.18	658.95	920.66	34.51	49.42	69.05	BP
East Irish Sea	15.97	18.84	20.69	15.97	18.84	20.69	Spirit Energy
Elgin Area	247.63	370.15	480.45	34.95	52.24	67.80	Total E&P
Everest Area	41.43	73.18	100.90	30.04	53.50	72.84	Chrysaor[4]
Galleon	6.89	15.53	21.70	0.58	1.30	1.82	Shell
Greater Britannia Area	57.35	89.27	133.55	37.53	60.47	92.19	Chrysaor[4]
J Area	119.51	204.11	279.14	80.36	137.15	187.55	Chrysaor
Schiehallion	150.75	243.40	299.25	15.07	24.34	29.93	BP
Total MMboe	**1232.84**	**1968.46**	**2707.01**	**289.11**	**490.66**	**684.86**	

Notes

1. Company Net Reserves are based on the working interest share of the field gross Reserves (there are no royalty payments)
2. Conversion of gas to boe volumes was based on energy equivalent conversion by field as detailed in Appendix 3
3. Totals are added arithmetically which means statistically there is a greater than 90% chance of exceeding the Total 1P and less than a 10% chance of exceeding the Total 3P
4. Ithaca operates the Erskine and Alder fields

Contingent Resources

Contingent Resources *are 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. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates as 1C, 2C and 3C.*

In addition to quantities that are classified by ERCE as Reserves, the assets include quantities that have been classified by ERCE as Contingent Resources. The projects associated with Contingent Resources are, by definition, commercially less mature than the Reserves projects and the data available to ERCE were more limited than required for a fully independent assessment of all opportunities.

ERCE has carried out an audit of Chrysaor’s Contingent Resources. Projects which in aggregate comprise just over 70% of Chrysaor’s estimate of total net 2C resources (expressed as barrels of oil equivalent, boe), were independently assessed. These comprised 16 out of a total of 59 projects.

During the audit differences between the ERCE and Chrysaor 2C estimates for Ockley were discussed and resolved; Chrysaor has adopted the ERCE Contingent Resources estimates for Ockley. After this adjustment, ERCE’s 1C and 3C estimates in aggregate are within 10% of Chrysaor’s aggregate estimates; in the case of the 2C level of confidence, ERCE’s aggregate estimate is the same as Chrysaor’s.

ERCE is therefore of the opinion that Chrysaor’s estimates of Contingent Resources, expressed as barrels of oil equivalent, for those projects reviewed are fair and reasonable. Further, ERCE believes that if its audit had included all of Chrysaor’s projects then it would have been able to express the same opinion.

The resulting Contingent Resources are presented on a project basis in Table 6-1 in Section 6 (later in the report). A summary of the gross Contingent Resources by PRMS sub-maturity class is presented in Table 1-6. A summary of Chrysaor’s working interest Contingent Resources by PRMS sub-maturity class is presented in Table 1-7.

No economic analyses have been performed on the Contingent Resources and, therefore, their economic status is undetermined.

Table 1-6: Gross Contingent Resources by Sub-Maturity Class as of 30 June 2020

Sub-Class	No. of Projects	Gross Gas (Bscf)			Gross Liquids (MMstb)			Gross (MMboe)		
		1C	2C	3C	1C	2C	3C	1C	2C	3C
DP	10	97.4	190.5	306.1	16.3	27.2	37.7	33.1	60.0	90.5
DOH	20	129.5	280.7	434.0	337.0	477.2	846.8	359.3	525.6	921.6
DUC	27	383.6	745.5	1429.8	170.7	382.0	722.0	236.8	510.5	968.5
DNV	2	1.0	32.7	80.3	2.0	5.2	11.1	2.2	10.8	24.9
Total	**59**	**611.5**	**1249.4**	**2250.2**	**526.0**	**891.6**	**1617.6**	**631.5**	**1107.0**	**2005.6**

Notes

1. Development Pending (DP), Development On Hold (DOH), Development Unclarified (DUC) and Development Not Viable (DNV)
2. Conversion of gas to boe equivalent is based on 5.8 Mscf/bbl
3. These are unrisked Contingent Resources that have not been risked for chance of development
4. Gas resources are based on wellhead volumes prior to shrinkage
5. Totals are added arithmetically which means statistically there is a greater than 90% chance of exceeding the Total 1C and less than a 10% chance of exceeding the Total 3C

Table 1-7: Working Interest Contingent Resources by Sub-Maturity Class as of 30 June 2020

Sub-Class	No. of Projects	Chrysaor Net Gas (Bscf)			Chrysaor Net Liquids (MMstb)			Chrysaor Net (MMboe)		
		1C	2C	3C	1C	2C	3C	1C	2C	3C
DP	10	41.8	86.8	140.8	7.0	12.7	17.5	14.2	27.6	41.8
DOH	20	89.5	193.1	293.5	48.3	72.9	146.5	63.8	106.2	197.1
DUC	27	237.7	480.7	977.2	54.5	156.3	396.1	95.4	239.2	564.6
DNV	2	0.8	22.1	54.2	2.0	4.6	9.6	2.1	8.4	18.9
Total	**59**	**369.8**	**782.8**	**1465.8**	**111.8**	**246.5**	**569.7**	**175.5**	**381.5**	**822.4**

Notes

1. Development Pending (DP), Development On Hold (DOH), Development Unclarified (DUC) and Development Not Viable (DNV)
2. Conversion of gas to boe equivalent is based on 5.8 Mscf/bbl
3. Chrysaor net resources are based on their working interest share of the gross resources
4. Gas resources are based on wellhead volumes prior to shrinkage
5. These are unrisked Contingent Resources that have not been risked for chance of development
6. Totals are added arithmetically which means statistically there is a greater than 90% chance of exceeding the Total 1C and less than a 10% chance of exceeding the Total 3C

Reserves Evaluation

ERCE has carried out an economic evaluation of the Reserves in each field using ERCE forecast commodity prices dated 1 July 2020 (Table 1-8 and Table 1-9). Table 1-10 and Table 1-11 present the before tax and after tax Net Present Values ("NPV") as of 30 June 2020, respectively; the NPVs are presented in millions of US$ at a 10% discount rate and are broken down by asset and Reserves category.

Table 1-8: ERCE Brent crude oil price forecast as of 1 July 2020

Brent ($/bbl)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030+
Real (constant $, 2020)	42	47	52	57	57	58	58	58	58	58	58
Nominal ($ of the day)	42	48	54	61	62	64	66	67	68	70	+2.0% pa

Table 1-9: ERCE UK NBP natural gas price forecast as of 1 July 2020

UK NBP (p/therm)	2020	2021	2022	2023	2024	2025	2026	2027	2028+
Real (constant pence, 2020)	24.4	36.1	40.5	41.9	43.0	43.6	45.7	46.0	+2.0% pa
Nominal (pence of the day)	24.5	37.0	42.3	44.7	46.8	48.4	51.7	53.0	+2.0% pa

Table 1-10: Before Tax Net Present Values of the Reserves as of 30 June 2020

Asset	Before Tax Net Present Value at 10% discount rate ($MM)								
	Developed Reserves			Undeveloped Reserves			Total Reserves		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Armada	-104.4	-71.0	-20.5	0.0	50.1	194.4	-104.4	-20.9	173.9
Beryl	13.9	110.2	215.5	34.7	118.4	305.6	48.6	228.7	521.1
Buzzard	397.2	859.9	1246.4	31.6	138.8	275.7	428.8	998.7	1522.2
Clair Area	61.6	134.1	231.9	525.1	824.0	1126.9	586.7	958.1	1358.8
East Irish Sea	-73.8	-42.8	-19.9	0.0	0.0	0.0	-73.8	-42.8	-19.9
Elgin Area	464.2	647.2	835.9	27.2	76.6	181.0	491.4	723.9	1016.9
Everest Area	-141.8	-2.8	138.5	2.4	8.7	50.6	-139.4	6.0	189.1
Galleon	-0.5	3.2	7.6	0.0	0.4	3.5	-0.5	3.5	11.1
Greater Britannia Area	129.1	474.7	932.9	19.1	97.7	284.2	148.2	572.4	1217.1
J-Area	133.7	308.4	540.6	219.4	376.1	566.6	353.1	684.5	1107.2
Schiehallion	251.2	445.6	580.4	0.0	0.0	0.0	251.2	445.6	580.4
Total	**1130.3**	**2866.7**	**4689.3**	**859.5**	**1691.0**	**2988.4**	**1989.9**	**4557.7**	**7677.7**

Notes

1. The values exclude corporate overheads
2. The NPVs do not necessarily represent fair market value

Table 1-11: After Tax Net Present Values of the Reserves as of 30 June 2020

Asset	After Tax Net Present Value at 10% discount rate ($MM)								
	Developed Reserves			Undeveloped Reserves			Total Reserves		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Armada	-110.3	-95.9	-58.3	0.0	38.8	135.7	-110.3	-57.1	77.3
Beryl	-29.0	17.1	79.9	22.0	84.2	219.3	-7.0	101.4	299.2
Buzzard	238.9	516.5	748.5	21.7	86.1	168.2	260.6	602.6	916.7
Clair Area	36.5	81.6	140.4	323.3	502.9	688.5	359.8	584.5	828.9
East Irish Sea	-79.4	-52.0	-32.4	0.0	0.0	0.0	-79.4	-52.0	-32.4
Elgin Area	279.0	388.9	502.1	19.3	49.3	111.9	298.3	438.2	614.0
Everest Area	-216.2	-136.9	-42.2	1.4	9.2	34.6	-214.8	-127.8	-7.6
Galleon	-1.4	1.4	4.6	0.0	0.5	2.4	-1.4	1.9	7.0
Greater Britannia Area	723.7	723.7	723.7	723.7	723.7	723.7	723.7	723.7	723.7
J-Area	47.6	318.4	600.8	263.0	450.5	681.2	310.6	768.9	1282.0
Schiehallion	150.8	261.6	342.4	0.0	0.0	0.0	150.8	261.6	342.4
Total	**331.6**	**1548.4**	**2830.8**	**667.1**	**1286.1**	**2220.5**	**998.7**	**2834.5**	**5051.3**

Notes

1. The values exclude corporate overheads and tax allowances
2. The NPVs do not necessarily represent fair market value

2. Introduction

Chrysaor has interests in oil and gas fields across the United Kingdom Continental Shelf (UKCS) and an interest in two undeveloped fields on the Norwegian Continental Shelf (NCS). A large proportion of the assets were acquired by Chrysaor following the completion of transactions with Shell in November 2017 (the "Shell Transaction") and with ConocoPhillips in September 2019 (the "ConocoPhillips Transaction").

The Shell Transaction comprised interests in Beryl, Bressay, Buzzard, Elgin-Franklin, Erskine, Everest, the Greater Armada cluster, J-Area, Lomond and Schiehallion; as a result, Chrysaor became Operator of the Armada, Lomond and Everest hubs.

The ConocoPhillips Transaction included interests in Greater Britannia, J-Area, East Irish Sea, Galleon and the Clair area. Chrysaor became Operator of Britannia and J-Area.

A location map illustrating the location of the main assets in the Chrysaor portfolio is presented in Figure 2-1. This excludes the East Irish Sea assets in Morecombe Bay and the Galleon field in the Southern North Sea.

2.1. Data Provided

ERCE has relied upon data and information made available by Chrysaor. These data comprise details of Chrysaor's licence interests, seismic data, basic exploration and engineering data (including well logs, core, PVT and test data), technical reports, interpreted data (including reservoir simulation studies), production and injection data and the field development plans. ERCE has reviewed data made available through to 30 June 2020.

In certain cases, data or information arising after the Effective Date has been incorporated if it was considered material to the CPR:

- Licence blocks awarded to Chrysaor as part of the UK 32nd Offshore Licencing Round
- In October 2020, INEOS issued a revised Final Work Programme and Budget for 2021 for the FPS indicating lower levels of expenditure.
- Buzzard field DC2 drilling results indicating two wells had failed to find sufficient reservoir

No site visit was undertaken in the preparation of this report.

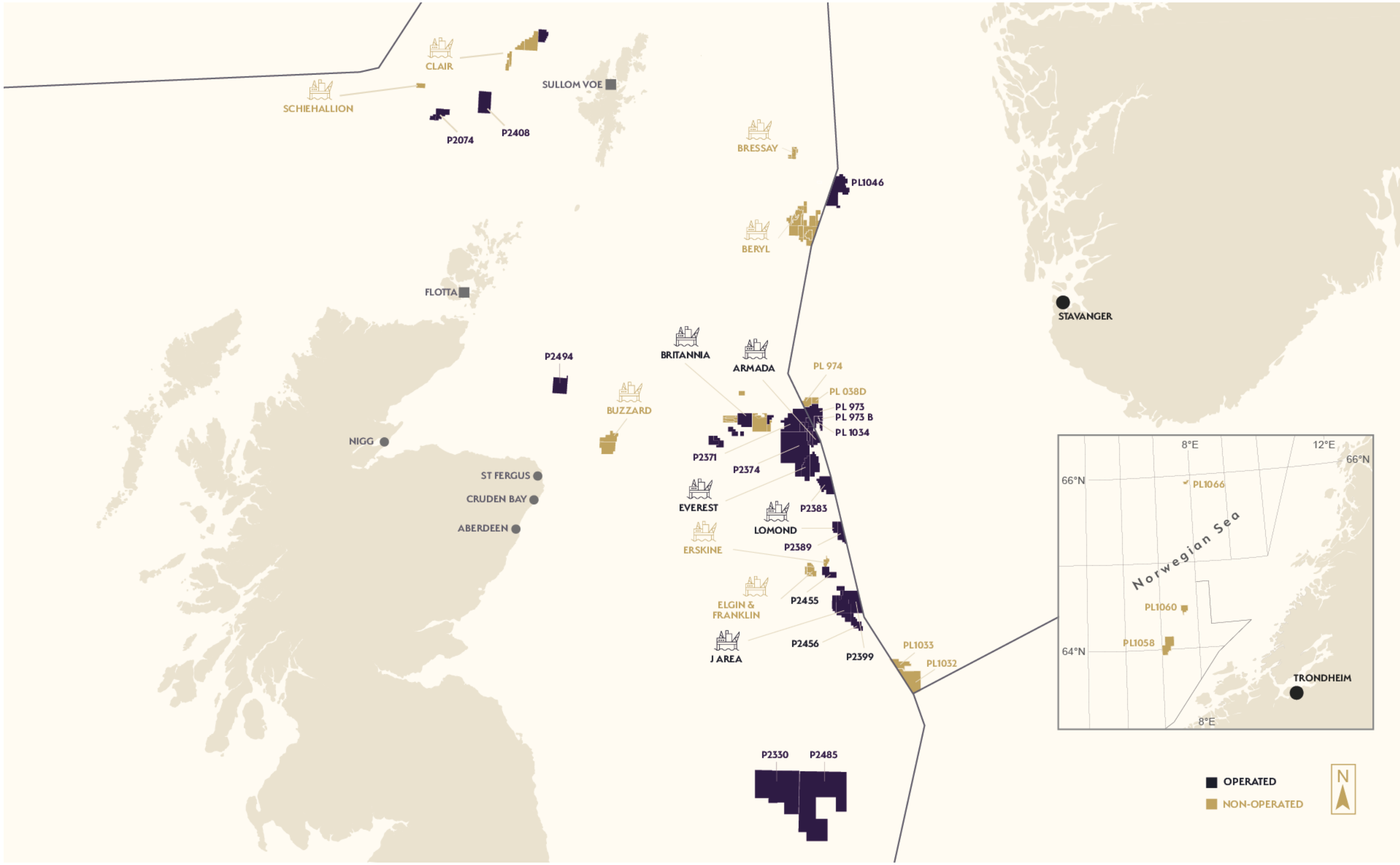


Figure 2-1: Chrysaor Location map showing main assets (source: Chrysaor)[1]

[1] Excludes the East Irish Sea assets in Morecombe Bay and the Galleon field in the Southern North Sea

2.2. Work Completed

ERCE has used standard petroleum evaluation techniques in the generation of this report. These techniques combine geophysical and geological knowledge with assessments of porosity and permeability distributions, fluid characteristics, production performance and reservoir pressure. There is uncertainty in the measurement and interpretation of basic data.

For evaluating Reserves, ERCE did not find it necessary to independently assess the petroleum initially in place ("PIIP"). ERCE has estimated Reserves and their associated uncertainty by using production performance analysis, type curves from analogue wells, calibrated by reviewing studies work undertaken by the Operator. Where appropriate the Operator or Chrysaor PIIP best estimates have been compared to the Reserves estimates to provide relative context. Chrysaor PIIP best estimates have been compared to the Reserves estimates as a cross check of our work to ensure recovery factors are reasonable.

For assessing the Contingent Resources associated with a number of undeveloped discoveries, ERCE has estimated the petroleum initially in place and the degree of associated uncertainty. Estimates of recovery factors were prepared based on consideration of the results of production performance analysis, reservoir simulation models, classical reservoir engineering calculations and the performances of analogue fields.

Production profiles have been generated by ERCE for the Reserves. The forecasts generated have then been used as input to an economic model to undertake an Economic Limit Test ("ELT"). The economic model has been provided to ERCE by Chrysaor, which we have reviewed and have confirmed that the relevant fiscal regimes are correctly represented.

ERCE has evaluated the development plans for the various assets. For each field, ERCE has audited forecasts of capital, operating and abandonment costs from Chrysaor. ERCE has reviewed the costs provided and benchmarked them against its internal database to ensure they are reasonable. Where possible these estimates were compared to historical, actual costs. ERCE has used its own cost estimates where these differed significantly from those presented. ERCE's economic analysis does not take into account any outstanding debt, nor future indirect corporate costs.

3. Producing Fields and Associated Developments

This section includes a description of the various producing fields which Chrysaor has an interest in, their development plans and the associated recoverable resources. The section is subdivided by asset cluster. In addition, if there are undeveloped assets nearby to the asset cluster they are also included in this section. Other undeveloped discoveries which are considered separate are covered in Section 4.

3.1. Armada Asset

The Armada asset comprises a number of gas-condensate/oil fields located 250 km ENE of Aberdeen in the Central North Sea close to the Norwegian border (Figure 3-1). Chrysaor is the Operator and holds a 100% interest in all the Armada assets. The hydrocarbons are trapped in a number of different age reservoirs: Palaeocene, Maureen sands in Fleming; Jurassic, Fulmar sands in Drake, Hawkins and Maria; Jurassic, Fulmar and Pentland sands in SW and NW Seymour; and Triassic, Skagerrak sands in the Seymour Horst.

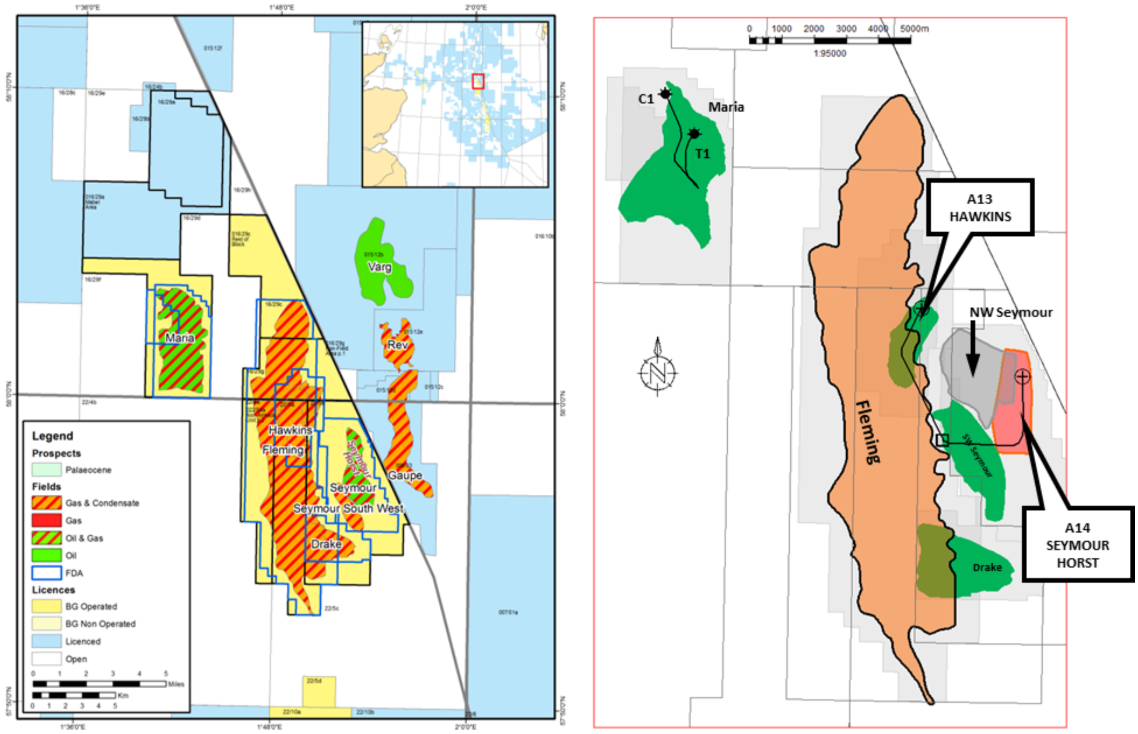


Figure 3-1: Armada Asset Location map

A summary of the fields together with some relevant data is presented in Table 3-1.

Table 3-1: Armada Asset Summary

Field	Reservoir	Depth (m tvdss)	Trap	Fluids	Solution GOR (scf/stb)	Initial CGR (stb/ MMscf)	Porosity	Perm. Thickness (mDft)
Fleming	Maureen	2,700	Stratigraphic/ Dip closure	Gas Cond.	-	31.0	17-22%	5,000
Drake	Fulmar	3,400	Tilted Fault Block	Gas Cond.	-	41.0	24 - 28%	7,000
Hawkins	Fulmar	3,000	Fault/Dip Closure	Gas Cond.	-	49.0	11 - 20%	290
NW Seymour	Pentland	3,100	Fault Bounded Block	Oil	753	-	13 - 17%	2,000
SW Seymour	Fulmar & Pentland	3,100	Fault/Dip Closure	Oil & Gas Cond.	448	63.2	11 - 24%	7,550
Seymour Horst	Skagerrak	3,000	Horst fault blocks	Oil & Gas Cond.	1138	63.1	11 - 17%	n/a
Maria	Fulmar	3,500	Terraced Fault Blocks	Volatile Oil	1621	-	14 - 18%	225 - 5,000

The Fleming, Drake, Hawkins, SW Seymour and Seymour Horst fields have been developed from a fixed 21 slot wellhead and accommodation platform and the NW Seymour and Maria fields have been developed by subsea tie backs. First production occurred in 1997 from the Drake and Fleming fields. Gas and NGLs are transported via CATS and heavier condensate and oil are sent through the Forties pipeline. The platform production plateau was approximately 450 MMscf/d until early 2002 and since then has declined to around 40 MMscf/d. Gas and liquids (oil and condensate) production histories are presented in Figure 3-2 and Figure 3-3 respectively.

Currently there are three wells producing in the Fleming field, one well in the Drake field, one well in the Hawkins field, two wells in the Maria field, and one well in each area of the Seymour field.

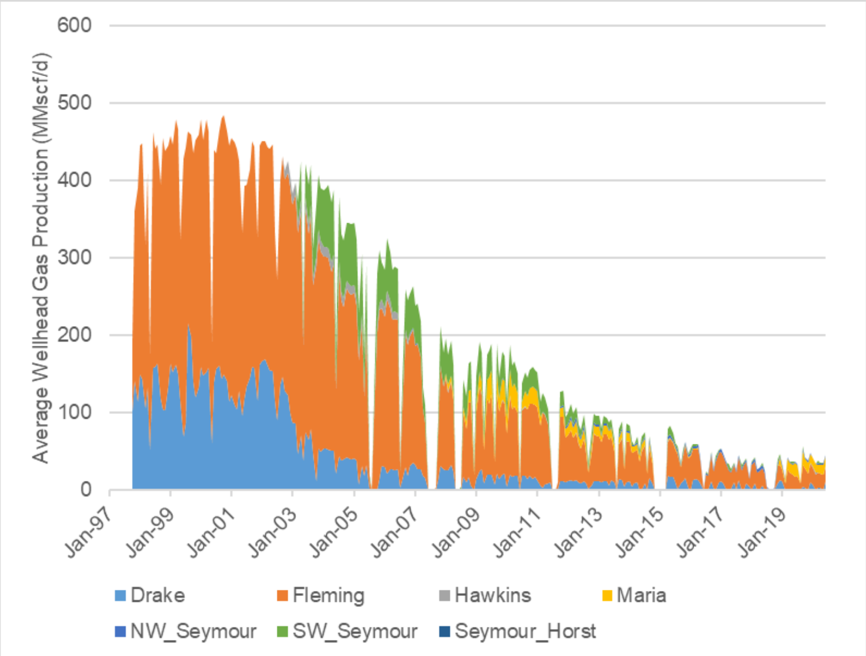


Figure 3-2: Armada Asset gas production history by field

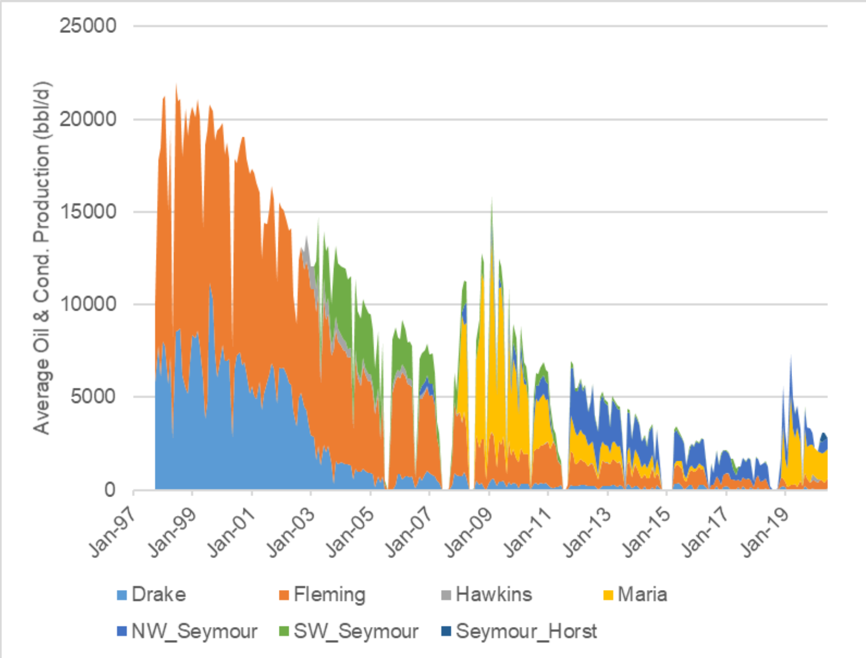


Figure 3-3: Armada Asset oil and condensate production history by field

Recent activity towards the end of 2019 included the sidetracking of Well A13 in the Hawkins field and Well A14 into the Seymour Horst (the first development well in this field).

3.1.1. Fleming Field

The Fleming gas-condensate field originally had seven producers, but now has two currently steady producers (Wells A8 and A10) and one cyclic producer (Well A4). A top structure depth map of the Fleming field, Maureen reservoir is presented in Figure 3-4.

Wells A3, A5 and A9 watered out in 2002, 2007 and 2011, respectively. Water breakthrough is the primary production risk. The potential gas and condensate rates from the field at the end of June 2020 are 20 MMscf/d gas and 500 bopd, respectively, with a CGR of approximately 25 stb/MMscf.

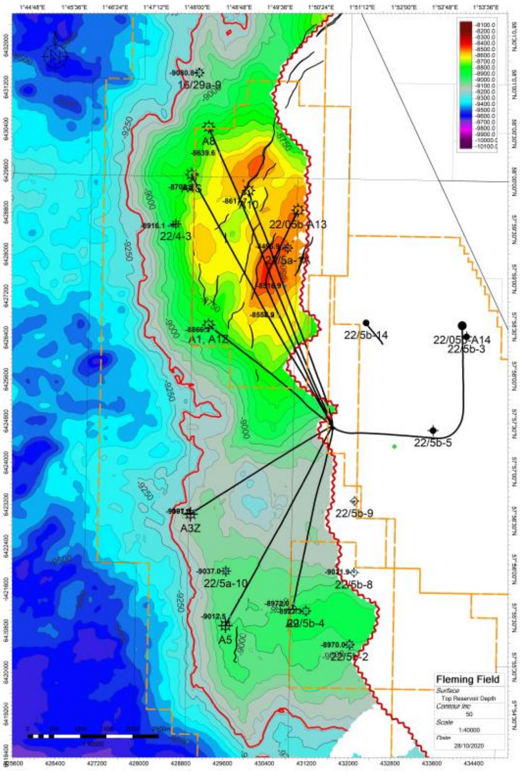


Figure 3-4: Fleming field, Maureen top structure depth map

3.1.2. Drake Field

The Drake gas-condensate field was developed with two producers (Wells A2 and A6). Well A6 watered out in 2003. Well A2 is currently producing at 14 MMscf/d but has a high WGR of about 250 bbl/MMscf; it is occasionally cycled and then requires foam to kick-off. Water handling capacity, sand production and liquid lift are the highest risks to production. A Drake field, Fulmar top structure depth map is presented in Figure 3-5.

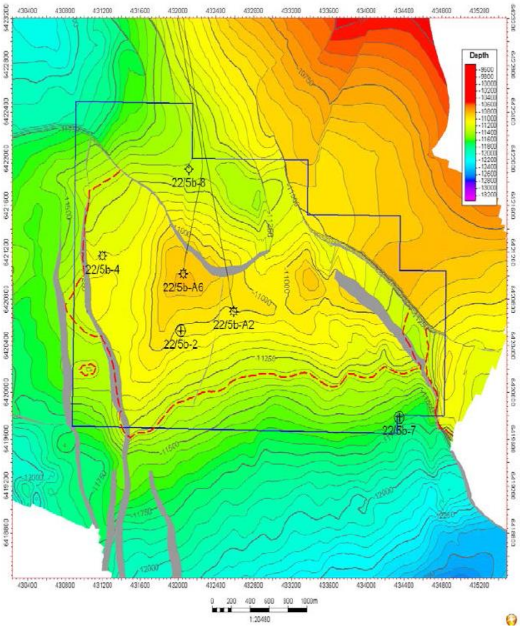


Figure 3-5: Drake field, Fulmar top structure depth map

3.1.3. Hawkins Field

The first Hawkins development Well, 22/5b–A7 (A7), was drilled in 1996 but failed to flow at commercial rates. A top structure map for the Fulmar reservoir is presented in Figure 3-6. The second Well, 22/5b–A11 (A11), came onstream in 2002 at rates up to 16 MMscf/d and a CGR of 90 stb/MMscf. The gas rate declined steadily to 7 MMscf/d in 2006 when productivity suddenly dropped. The well then produced intermittently at low rates before ceasing production in 2018. The limited recovery and observed pressure decline, suggest reservoir compartmentalisation, although condensate banking and associated liquid loading may also be factors.

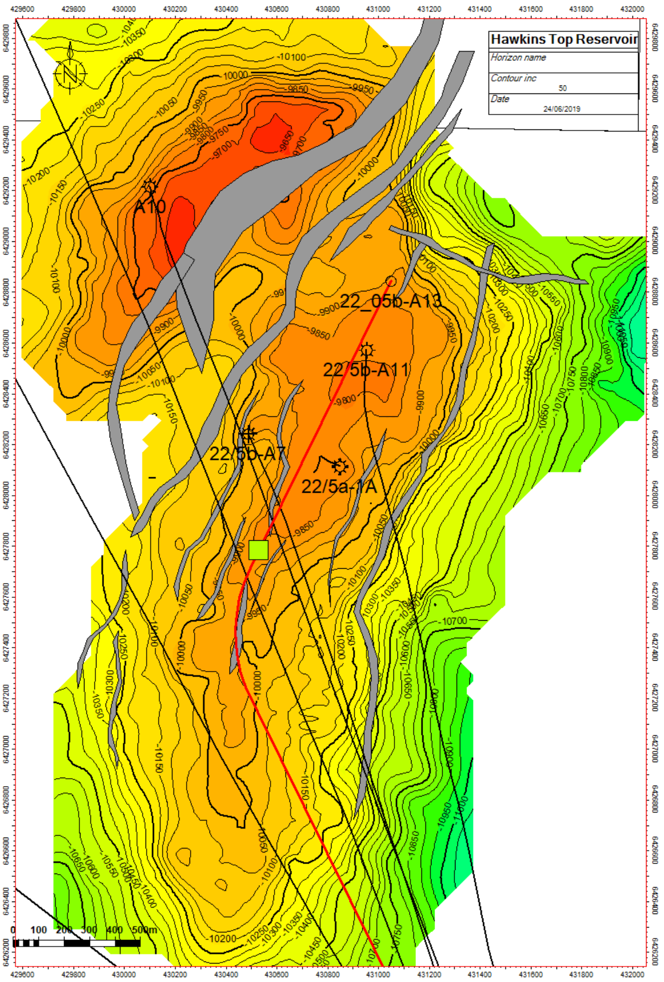


Figure 3-6: Hawkins field, Fulmar top structure depth map

Well A13 was completed in Q4 2019, with six fracs and produced at a maximum clean up rate of 22 MMscf/d, which was below expectations. Since then the well has produced infrequently due to flowline issues but appears to be damaged and poorly connected, perhaps due to limited fracture penetration towards the deeper, and better quality Spiculite reservoir which was produced in Well A11. If further attempts to clean up the well are unsuccessful Chrysaor is likely to try a re-stimulation.

3.1.4. Seymour Fields

The Seymour area fields are located in the triple junction area of the Eastern Central Graben in a series of north-south trending fault blocks and terraces with three distinct hydrocarbon accumulations: NW Seymour (oil), SW Seymour (oil and gas-condensate) and the Seymour Horst (oil and gas-condensate).

The NW Seymour discovery Well 22/5b-14 (NWS14) found black oil in the Jurassic reservoir sands and was completed as a vertical producer in 2006. It produced erratically with a potential around 1,000 stb/d before being suspended in 2011 when it was replaced by horizontal producer Well 22/5b-15 (NWS15). This well continues to produce at around 600 stb/d.

SW Seymour was developed by Well 22/5b-12z (A12) in 2003, encountering gas-condensate bearing reservoir. The well initially produced up to 80 MMscf/d but is now only produced intermittently.

Seymour Horst was discovered in 1983 by Well 22/5b-3 well and appraised by Well 22/5b-5 but never put on production. After considerable subsurface studies, development Well 22/5b-A14 (A14) was drilled at the end of 2019. Seismic mapping is subject to considerable uncertainty due to the poorly imaged faulting and limited stratigraphic control away from the wells.

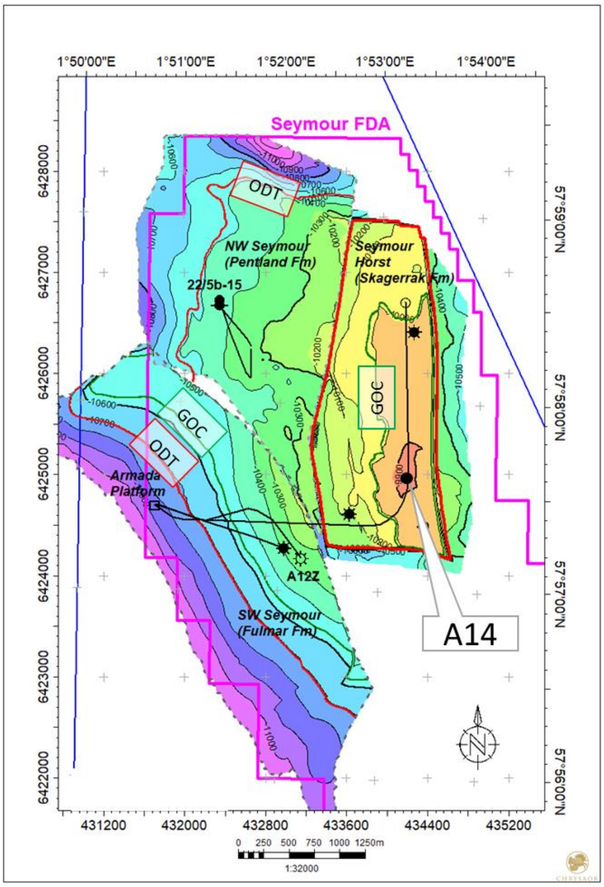


Figure 3-7: Seymour fields Top reservoir Map

3.1.5. Maria Field

The Maria (volatile) oil field lies to the west of the Hawkins field and is located on a structural high over a salt dome comprising a faulted crest, downdip terraces and horst block areas. The field started production in 2008 when two subsea wells were drilled to develop the horst and terrace areas. The horst well was closed in during 2015 due to high water cut and the terrace well was closed in during 2016 due to a pipeline blockage.

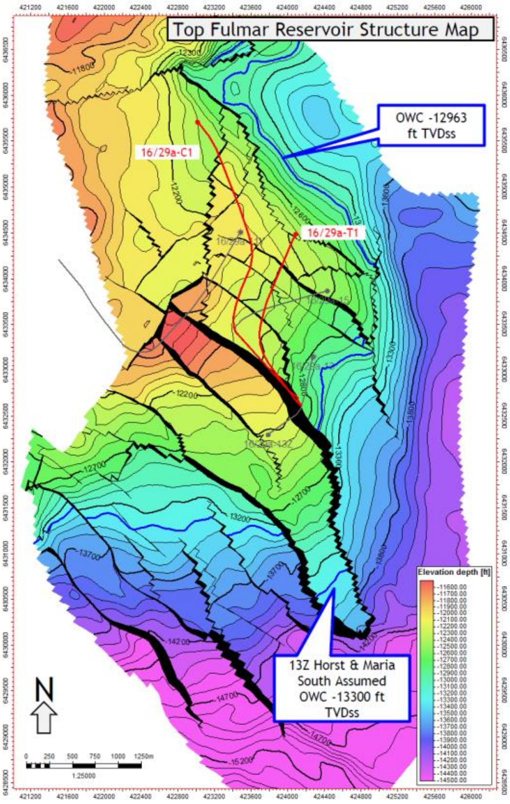


Figure 3-8: Maria field, Fulmar top structure depth map (ft tvdss)

Two infill wells (Wells T1 and C1) were drilled in early 2019 to redevelop the terraces area. The wells initially produced at around 3,000 stb/d before declining to a total rate of 1,500 stb/d. Chrysaor is currently undertaking subsurface studies work to try and understand the relatively poor performance. Field potential at the effective date was 1,700 bopd and 13 MMscf/d, with a GOR being around 8,000 scf/stb.

3.1.6. Development Plans

The Fleming, Drake and SW Seymour fields appear to be fully developed with limited infill opportunities; currently there are no Undeveloped Reserves or Contingent Resources assigned to these fields associated with further drilling.

Chrysaor is proposing to drill a subsea infill well into the NW Seymour area. However, the timing has been delayed from 2021 to 2023. Due to the maturity of the well planning work, the volumes associated with this well have been classified by ERCE as Undeveloped Reserves

Justified for Development. As of the Effective Date, there are no further identified development projects in the other fields (Hawkins, Maria, and Seymour Horst).

Additional Reserves are also associated with lowering wellhead operating pressures either by dropping the wellhead pressure using an eductor pump (likely to be implemented in 2021 and considered Developed Reserves due to low cost involved) or the later lowering of the compressor suction pressure to 4 – 6 bar (considered Contingent Resources).

The Armada area also has potential within the Cretaceous chalk section. A number of wells have encountered hydrocarbon shows whilst drilling this section. In 1982, Well 22/5b-2 tested oil at rates up to 1,230 stb/d but declined to 160 stb/d over an extended flow period with GOR increasing from 600 scf/stb to 3,300 scf/stb. Average permeability from the well test was approximately 1 mD. Well A13 drilled in 2019 to develop the Hawkins field also encountered strong gas shows and evidence of oil in the cuttings. Chrysaor is now considering development options for this reservoir.

3.1.7. Technically Recoverable Resources

ERCE's low, base and high TRR estimates were derived using decline curve analysis (DCA) taking account of the different development well vintages. Estimation of production profiles for the most recent and future wells are based on established type wells or simulation results.

The DCA for existing wells was performed on individual wells based on monthly operating rate versus time. Data were available up to end of June 2020. For all the fields a range of hyperbolic exponents were used to account for the forecast uncertainty. For the recent Hawkins Well A13 the low, base, and high forecasts were based on post-drill simulation work undertaken by Chrysaor. ERCE used Chrysaor's Seymour Horst Well A14 base oil forecast and initial performance indications to estimate low, base, and high cases, assuming some limited further clean-up is possible in a high case. The individual well profiles were aggregated to generate gas/oil potential vs. cumulative gas/oil production curves at field level. These curves were then used to estimate field gas/oil production rate vs. time by applying the Operating Efficiency (OE) factors detailed in Table 3-3.

ERCE's gross Developed plus Undeveloped TRR estimates by field are presented in Table 3-2 and include the cumulative production at 30 June 2020. The recovery factor to date and best estimate technical recovery factor are based on the PIIP volumes reported by Chrysaor as best estimates.

Production forecasts were generated making allowances for operating efficiency including incorporating planned turn arounds ("TAR"s) and for intermittent producers (Table 3-3). The uptime considers the continued cyclic nature of Drake A2 (25% well uptime) and the expected future cyclic nature of Hawkins A13 (50% well uptime) and the Maria T1 & C1 wells after mid 2021 (50% well uptime).

In general, the secondary associated products were forecast based on ratio trends taking account of recent data and accounting for any likely drop out in the reservoir.

Table 3-2: Armada Area TRR Estimates and Recovery Factors

Asset/ Field	Hydrocarbon	PIIP (Chrysaor Best Estimate)	Cum. Prod. at 30 Jun 2020	RF to date	TRR Estimate			TRR best est. RF
					Low	Best	High	
Fleming	Gas (Bscf)	1,296.0	1,060.8	82%	1,087.7	1,110.2	1,122.7	86%
	Cond. (MMbbl)	42.0	32.5	77%	33.0	33.3	33.7	79%
Drake	Gas (Bscf)	410.0	354.0	86%	369.1	374.5	385.8	91%
	Cond. (MMbbl)	16.8	14.6	87%	14.8	14.9	15.0	88%
Hawkins	Gas (Bscf)	64.0	16.7	26%	19.0	21.2	25.7	33%
	Cond. (MMbbl)	4.0	0.8	21%	0.88	0.93	1.02	23%
SW Seymour	Gas (Bscf)	146.8	133.7	91%	133.7	133.7	133.7	91%
	Oil+Cond. (MMbbl)	68.4	4.9	7%	4.9	4.9	4.9	7%
NW Seymour	Gas (Bscf)	53.3	7.3	14%	16.56	27.61	30.13	52%
	Oil+Cond. (MMbbl)	70.8	4.6	7%	6.03	6.35	7.45	9%
Seymour Horst	Gas (Bscf)	50.6	0.05	0%	2.34	3.08	4.79	6%
	Oil+Cond. (MMbbl)	35.4	0.03	0%	0.67	1.04	2.28	3%
Maria	Gas (Bscf)	63.2	36.0	57%	39.4	41.6	46.0	66%
	Oil+Cond. (MMbbl)	39.6	6.9	17%	7.36	7.66	8.08	19%

Table 3-3: Armada area assumed operating efficiency

Field/ Area	Operating Efficiency									
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Armada	78%	84%	79%	75%	75%	75%	75%	75%	75%	75%
Maria	78%	54%	42%	39%	38%	38%	38%	38%	38%	38%
Seymour	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%

Note

1. OE estimates after 2029 remain constant.

3.1.8. CAPEX Assumptions

The CAPEX profile ERCE has used for economic modelling is based upon data provided for review by the Operator. The major CAPEX element in the forecast is the NW Seymour sub-sea well which will be tied-back to the Armada platform through the existing NWS-15 tree. This well is scheduled to be drilled and completed during 2H 2023 and to be on stream Q1 2024. The total cost estimate for this well is $65.4 MM inclusive of rig mobilisation/demobilisation, tie-in and facilities related costs.

There is limited CAPEX expenditure required on the facilities other than sustaining activities with some minor projects such as the installation of an eductor to increase well drawdown, recovery of flash gas and CO_2 efficiency improvements. The total cost requirement during 2H 2020 to 2H 2023 is estimated at $9.6 MM.

3.1.9. OPEX Assumptions

The Operator is planning to reduce the Armada OPEX. These plans have been reviewed by ERCE and incorporated into the forecast where specific detail has been provided and/or the proposals appear reasonable. ERCE estimates an average yearly near term OPEX of approximately $70 MM/year.

The Forties Pipeline System (FPS) OPEX and CAPEX costs have been taken from the latest budget, including a 5-year plan (2020-2025) from INEOS, the FPS operator. A similar level of investment from the Operator is expected to continue after 2025. In 2019 INEOS announced a £500 MM ($650 MM) investment into the FPS, to occur over the next five years. After the Effective Date, in October 2020, INEOS issued a revised Final Work Programme and Budget for 2021 indicating lower levels of expenditure. Due to the materiality of this information it has been incorporated.

3.1.10. Abandonment Assumptions

The Operator provided field abandonment reports and associated estimates. These have been reviewed and facilities decommissioning costs of $200 MM adopted in the economic model.

In addition, well P&A cost for 12 Armada platform wells of $51.4 MM (Operator’s cost adopted), three Seymour/Maria sub-sea wells plus two suspended open-water E&A wells of $40 MM (20% higher than Operator’s cost) are included in the total decommissioning cost included by ERCE.

3.1.11. Facilities and Well Integrity

Since acquiring the Armada assets Chrysaor has invested in improving the integrity of the asset. Operating efficiencies have improved over the course of this investment. However, the latest OCM indicates higher than target backlogs for both safety and non-safety critical activities. ERCE has assumed these are related to the current Covid-19 pandemic and that in time they will be redressed. Plans to address the safety critical backlog were highlighted in the OCM. There are currently no material integrity issues impacting the facilities ability to support the estimated production profiles.

A number of well integrity issues are reported in the OCM meeting in May 2020. Well A1z is suffering from annular communication and a failed wellhead seal. Wells A04 and A07 also both have annular communication, and the latter requires valves on the Xmas tree to be replaced. The wells currently do not need to be shut-in and the repairs will be carried out at an opportune time.

3.1.12. Reserves

The technical production profiles described in the previous section were converted to sales profiles (oil, gas and NGL) by using the sales conversion factors provided by Chrysaor for gas shrinkage, oil shrinkage and NGL yield and accounting for fuel and flare (Table 3-4). Fuel and flare are taken as a constant 6.2 MMscf/d across the Armada area. The gross asset level production forecast (sales) for the Developed plus Undeveloped Reserves categories are included in Appendix 4.

Table 3-4: Armada area sales conversion factors

Field	Gas Shrinkage	Oil Shrinkage	NGL Yield (boe/MMscf)	Fuel & Flare MMscf/d
Armada	10%	0%	25.6	6.2
Maria	5%	11%	28.5	0.0
Seymour	14%	6%	24.5	0.0

Reserves were estimated to the earliest of the economic cut-off dates and the end of the technical profile. For the Armada field all the field low technical profiles were arithmetically summed and input into the economic model to determine the 1P CoP date. Similarly, all the mid-case profiles and all the high case profiles were added and used to determine the 2P and 3P CoP dates. The same procedure was applied for the Maria and Seymour fields.

For all the fields the Developed Reserves were based on the existing well stock. The Seymour Northwest infill well was classified as Undeveloped Reserves.

A summary of the gross on block Reserves by field is presented in Table 3-5 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 3-5: Armada area Gross Reserves by field with CoP dates

Field	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Armada	Developed	0.76	0.94	1.88	12.82	16.66	32.76
	Undeveloped	0.00	0.69	0.39	0.00	10.20	5.39
	Total (Dvpd+Undvpd)	**0.76**	**1.63**	**2.27**	**12.82**	**26.87**	**38.15**
Seymour	Developed	1.90	2.05	4.71	3.18	3.40	8.63
	Undeveloped	0.00	6.19	8.80	0.00	17.27	25.75
	Total (Dvpd+Undvpd)	**1.90**	**8.24**	**13.51**	**3.18**	**20.67**	**34.38**
Maria	Developed	0.39	0.48	0.78	2.41	2.97	4.86
	Undeveloped	0.00	0.24	0.16	0.00	1.43	1.00
	Total (Dvpd+Undvpd)	**0.39**	**0.71**	**0.94**	**2.41**	**4.41**	**5.86**
Total Asset	Developed	3.05	3.47	7.37	18.41	23.04	46.26
	Undeveloped	0.00	7.12	9.36	0.00	28.91	32.14
	Total (Dvpd+Undvpd)	**3.05**	**10.59**	**16.72**	**18.41**	**51.94**	**78.40**
	COP (Total)	Jun-23	Dec-27	Dec-29	Jun-23	Dec-27	Dec-29

Notes

1. Undeveloped Reserves associated with a well in NW Seymour are uneconomic at a 1P level
2. Undeveloped Reserves at the field level are impacted by applying the ELT at hub level (see Section 5 for details). Armada and Maria have no Undeveloped Reserves projects.

3.1.13. Contingent Resources Projects

ERCE has conducted an audit of Chrysaor's Contingent Resources estimates as detailed in Section 6. A number of Contingent Resources projects exist in the Armada asset area as presented in Table 3-6. The Contingent Resources estimates associated with these projects are presented in Table 6-1 of Section 6.

The compression project on Armada will require a re-wheeling on the existing compressors to drop the suction pressure from the current 10 bar (145 psi) down to 4-6 bar (58-87 psi). The project is well defined and is considered to be development pending according to the PRMS sub-maturity class.

Mabel was discovered by Well 16/29-4 in 1975. Chrysaor drilled appraisal Well 16/29e-19 in 2019 with the objective of de-risking volumes in the Palaeocene, Andrew and Maureen sands and justifying a tie-back to the Maria field. The results of the new well suggests the discovery is too small to be commercially developed. Development not viable Contingent Resources have therefore been assigned.

The remaining three projects relate to development of the Armada Chalk. The presence of oil is established in the Lower Chalk within the Armada area, as evidenced by the pay zone encountered in the recent Hawkins field A13 Well. Chrysaor has recently undertaken studies to better understand the complex Chalk geology and to begin to quantify the volumetric ranges which could be developed under various scenarios. There are potentially very large in place hydrocarbon volumes in the structure, and the key challenge for any potential development is to understand and maximise reservoir productivity from the currently ill-defined net reservoir rock. The overall Chalk accumulation is believed to be a combined structural-stratigraphic trap. There are no known analogous developments for this type of Chalk reservoir. At this stage, the projects are all classified under PRMS as development unclarified.

Table 3-6: Armada Area Contingent Resources Project Summary

Field/ Area	Project	Possible Timing	Sub-Maturity Class
Armada	Armada Large Scale Chalk (Hod) Dvpt	To be determined	DUC
Armada	Armada LLP, down to 4-6 bar from 10 bar	Q2 2023	DP
Armada	Well A7 Sidetrack to Chalk	To be determined	DUC
Armada	Well A13 Chalk Perforation	To be determined	DUC
Mabel	Development	To be determined	DNV

3.2. Beryl Area Assets

The Beryl Area assets comprise several oil and gas fields located 335 km NE of Aberdeen in Quad 9 UKCS. Chrysaor acquired an interest in the Beryl Area through the Shell Transaction in 2017. Chrysaor's interest varies across the fields (Section 1, Table 1-1) but in all cases the only other partner is Apache who is also the Operator.

The Beryl embayment lies on the western margin of the Viking Graben, where rotated fault blocks are the dominant trapping style for most of the accumulations. Reservoirs are stacked Jurassic and Triassic sandstones of variable facies, reservoir properties, often with different contacts, pressures and sometimes hydrocarbon types, within a given trap. The entire Beryl embayment is covered by numerous 3D seismic surveys of varying quality, acquired between 1979 and 2013. Apache's recent reprocessing provides a significant imaging improvement in the Beryl area.

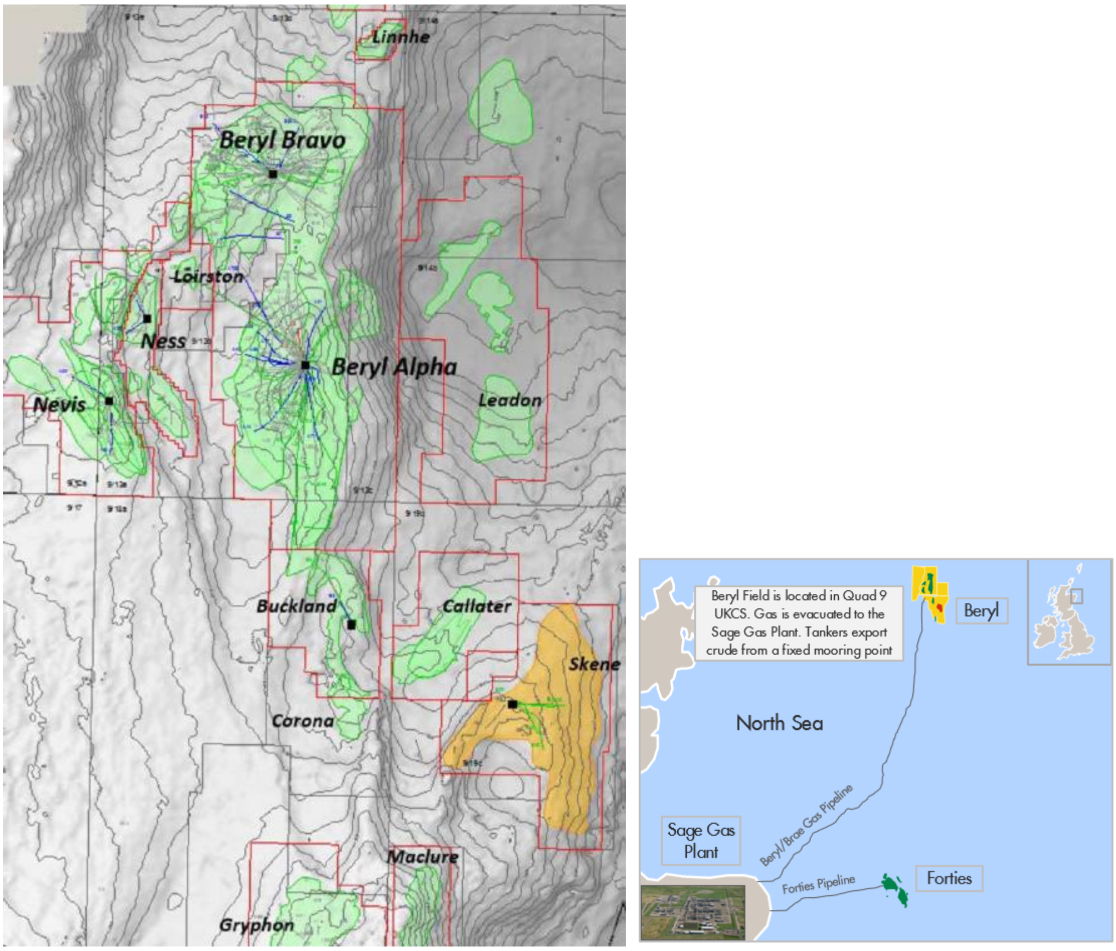


Figure 3-9: Beryl Area Asset Location Map

A summary of the fields together with some relevant data is presented in Table 3-7. A stratigraphic column showing the various reservoirs is presented in Figure 3-10.

The Beryl field is developed via two fixed platforms: Beryl Alpha (built in 1974) and Beryl Bravo (built in 1984). Beryl Alpha is connected via a bridge link to a Riser Access Tower ("RAT"). The Ness-Nevis cluster, Buckland, Skene and Callater fields are developed as subsea tiebacks to either Beryl Bravo or to the Beryl Alpha-RAT. The facilities infrastructure is complex including water injection and gas compression at both platforms and a number of subsea wells. Oil is exported by tanker and gas via the SAGE pipeline to the SAGE gas plant at St. Fergus. Production histories for the oil plus condensate and natural gas are presented in Figure 3-11 and Figure 3-12 respectively.

Table 3-7: Beryl Asset Summary

Field	Reservoir	Top Depth (m tvdss)	Trap	Fluids	Solution GOR (scf/stb)	Initial CGR (stb/ MMscf)	Porosity	Perm. (mD)
Beryl	Beryl, Lewis, Cormorant, Eiriksson, Nansen, Linnhe, Katrine	3,030	Tilted Fault Block	Oil & Gas Cond.	750-1500		12%-23%	10-3,000
Nevis South	Heather, Lewis, Cormorant, Beryl	2,640	Tilted Fault Block	Oil & Gas Cond.	350-1,200		5%-28%	0.1-3,000
Ness & Nevis Central	Heather, Lewis, Cormorant, Beryl	2,640	Tilted Fault Block	Oil & Gas Cond.	520-1,300		5%-28%	0.1-3,000
Nevis West	Heather, Lewis, Cormorant, Beryl	2,640	Tilted Fault Block	Oil & Gas Cond.	1,000		5%-28%	0.1-3,000
Buckland	Beryl	3,340	Fault/Dip Closure	Oil	1,400		13%-22%	10-1000
Skene	Beryl, Lewis	3,300	Fault/Dip Closure	Gas		60-185	5%-18%	0.05-10
Callater	Beryl, Linnhe, Eiriksson, Cormorant	3,555	Fault/Dip Closure	Oil	2,750		6%-17%	0.1-250
Storr	Nansen, Linnhe, Eiriksson, Cormorant	3,125	Fault/Dip Closure	Oil & Gas Cond.	2,050	90	9% - 17%	0.2-130

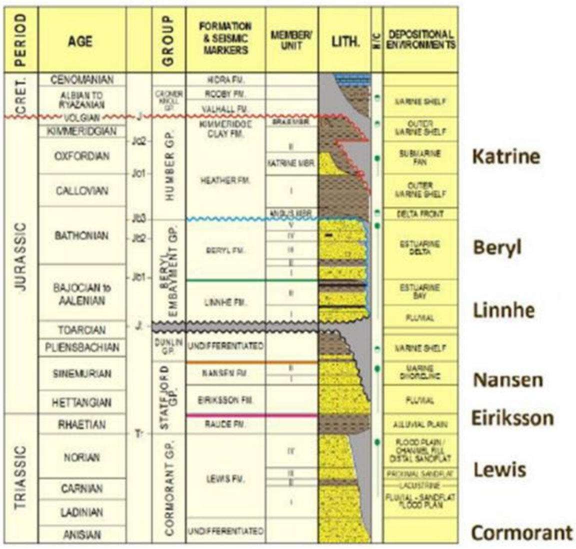


Figure 3-10: Beryl Area Stratigraphic Column

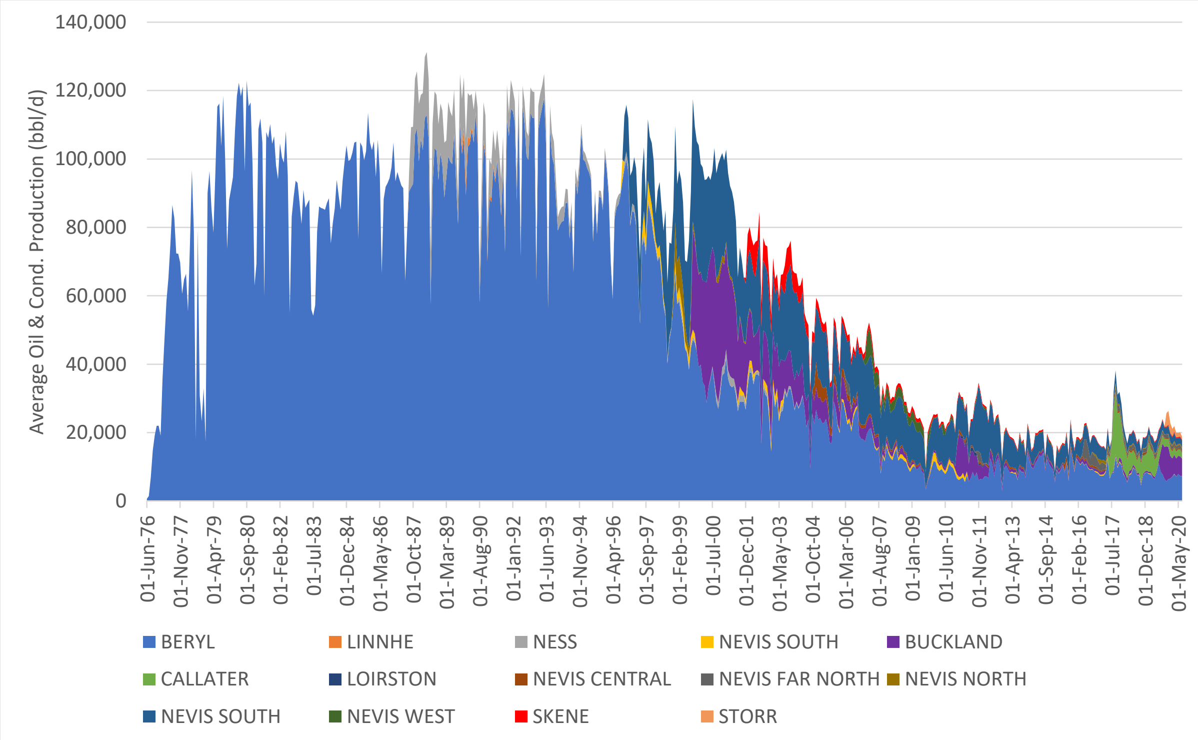


Figure 3-11: Beryl Area oil and condensate production history by field

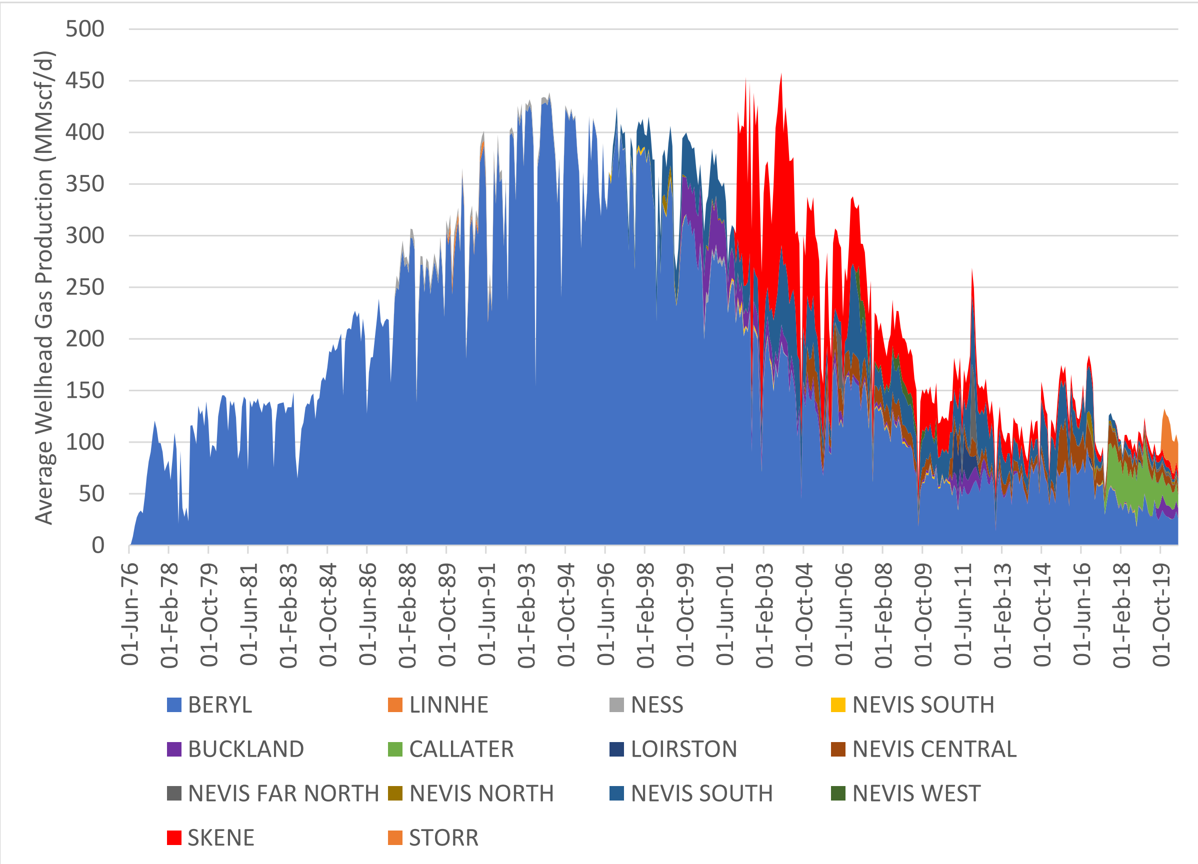


Figure 3-12: Beryl Area gas production history by field

3.2.1. Beryl Field

The Beryl field is broadly divided into the Alpha and Bravo areas as shown in Figure 3-13. Beryl was discovered in 1972 by Well 9/13-1 and development commenced in June 1976 from the Triassic reservoir, produced through the Alpha platform. Production on the Bravo platform began in June 1984 with the development of the Bravo East and Bravo West Fault Block accumulations.

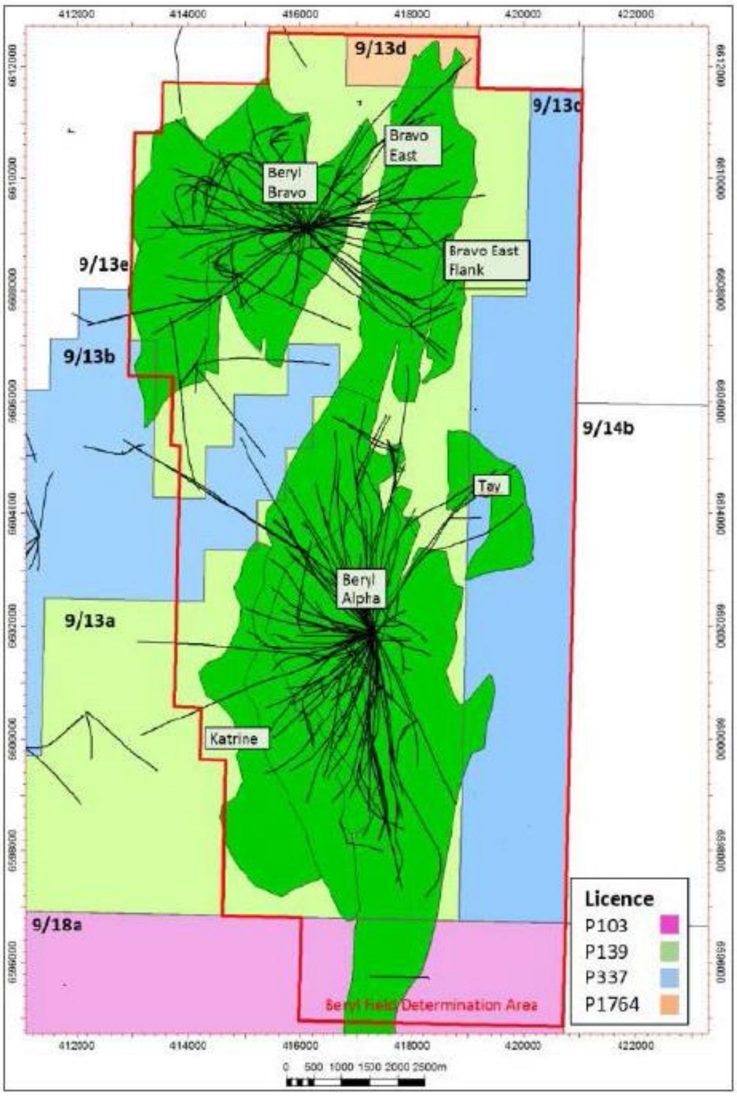


Figure 3-13: Beryl field Map

The reservoir pressure support in the Beryl field has been via water injection and gas injection. There has been variability in the GOR history across the Beryl field. In some areas it has been increasing over the time due to lack of reservoir pressure support or gas injection. However, since 2015 the overall Beryl field GOR shows a steadily decreasing trend with the water cut and the water injection rate increasing.

Historically, production from the various Beryl reservoirs has been comingled. Often production from the high net to gross Beryl formation has been co-mingled with deeper, lower quality reservoirs such as the Linnhe formation.

Since becoming Operator in January 2012 Apache has brought about 29 new production and injection wells on-line in the Beryl field. There are currently 30 oil producing and seven water injection wells (Alpha and Bravo) with 14 wells producing mainly from Triassic and Jurassic reservoirs (Alpha Secondaries) on the Alpha platform and 16 wells producing from Beryl reservoir on the Bravo platform.

During the first half of 2020 three wells were drilled and two wells completed, a producer Well B88Y with an initial production rate of 3,000 bbl/d and an injector Well B89, which started injection at 5,600 bbl/d. A third well (BDA) targeted a down dip eastern flank location but found insufficient reservoir for completion. A fourth infill well (BSA) had been planned but has been deferred to the next drilling campaign as the drilling crew had to leave the platform for the annual TAR.

As of 30 June 2020, the Beryl field (Alpha and Bravo) was producing around 7,500 stb/day (Alpha field 3,700 stb/d and Bravo field 3,800 stb/d) at 76% water cut and 3,700 scf/stb average GOR. Recent production and injection history is presented in Figure 3-14.

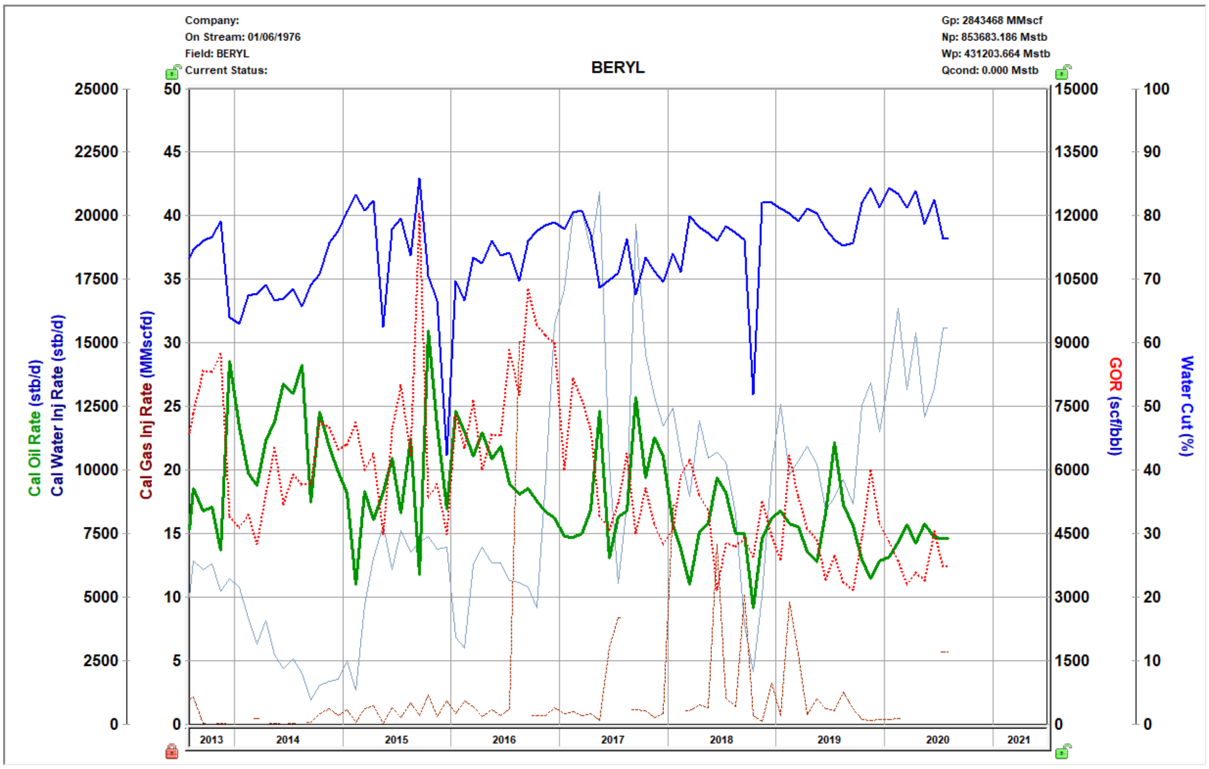


Figure 3-14: Beryl field recent production and injection history

3.2.2. Ness–Nevis, Nevis South, and Nevis West Fields

There are seven distinct oil accumulations in this field cluster: Ness, Ness South, Nevis South, Nevis Central, Nevis West, Nevis North and Nevis Far North (Figure 3-15). The Ness field was the first Beryl subsea satellite to come on stream in 1978. All the fields are tied back to Beryl Bravo apart from Nevis South and Nevis West which are routed to Beryl Alpha-RAT.

Nevis South is currently the main contributor to the production from the overall Ness-Nevis field cluster. Production in Nevis South started in 1996 and at present five wells are producing in the field, Nevis Central has two producing wells and all the other accumulations just one well each. Current production from the fields is summarised in Table 3-8.

Table 3-8: Ness Nevis area fields production at 30 June 2020

Field	Wells capable of producing	Oil Rate stb/d	GOR scf/bbl	Watercut %
Nevis South	N10z, N12, N14, N2, S62z	2,286	2,890	71%
Nevis Central	S64z, S67x	372	17,140	63%
Nevis Far North	S69	1,194	1,232	<5%
Nevis North	S70	400	5,496	83%
Nevis West	S66x	-	-	-
Ness South	S59x	100	2,600	<1%

Note

Well S66X is not currently producing but is to be re-opened in Q3 2022

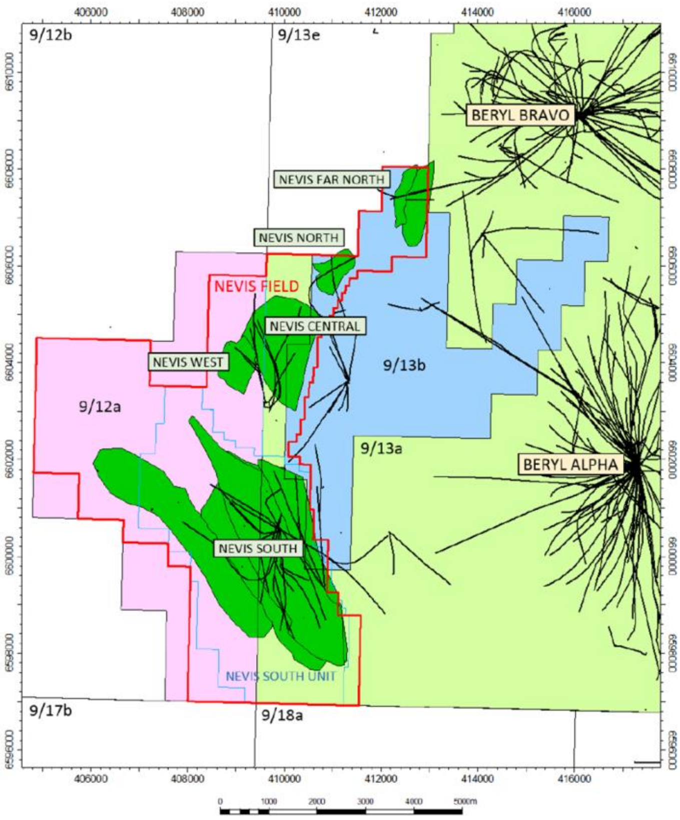


Figure 3-15: Nevis and Ness fields map

Well S59x in the Ness South field was brought back on production in February 2020 at 270 bbl/d for a short while but the well is likely to only be able to produce on an intermittent basis unless a proposed water injector is drilled to provide pressure support. It is expected that Nevis West Well S66x, shut-in due to flowline constraints, will be re-opened again in Q3 2022. This well last flowed in 2016 at 300 bbl/d.

No new wells have been drilled in the Ness and Nevis field since 2016 when Wells S69 (Nevis Far North), S70 (Nevis North) and N14 (Nevis South) were drilled.

Recent production history for the Nevis and Ness fields is presented in Figure 3-16.

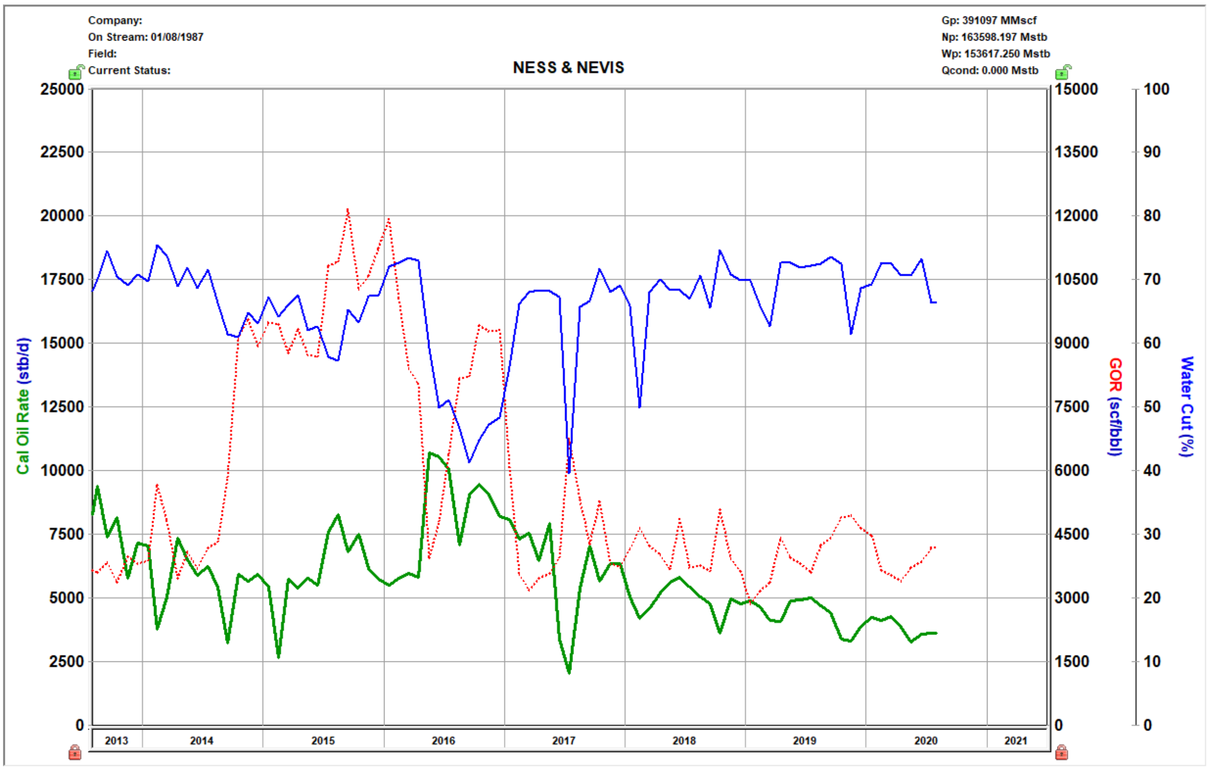


Figure 3-16: Nevis and Ness fields recent production history

3.2.3. Buckland Field

The Buckland oil field lies south of the Beryl field and is a subsea development tied back to Beryl Alpha-RAT. A top structure map for the field is presented in Figure 3-17. The field started production in August 1999. Injection at Well BK3 started in December 1999 and provided efficient support with pressure maintained above the bubble point during most of the field life; injection stopped in 2013 and the GOR is now starting to increase.

Currently two wells (Wells BK6 and BK7B) are active out of a total of seven original development wells. The last well to be drilled was Well BK7B which came online in August 2019. The well is currently producing at 4,820 bbl/d with a GOR of 2,050 scf/stb and a watercut of 24%. The latest production from Well BK5 was in January 2017 with a rate of 690 stb/d of oil. Well BK5 was shut-in to preferentially flow Well BK6 but it may be alternately flowed with Well BK6 as that well declines. As of 30 June 2020, the Buckland field was producing 5,750 bbl/day at 32% water cut and 1,750 scf/stb average GOR. Recent production history is presented in Figure 3-18.

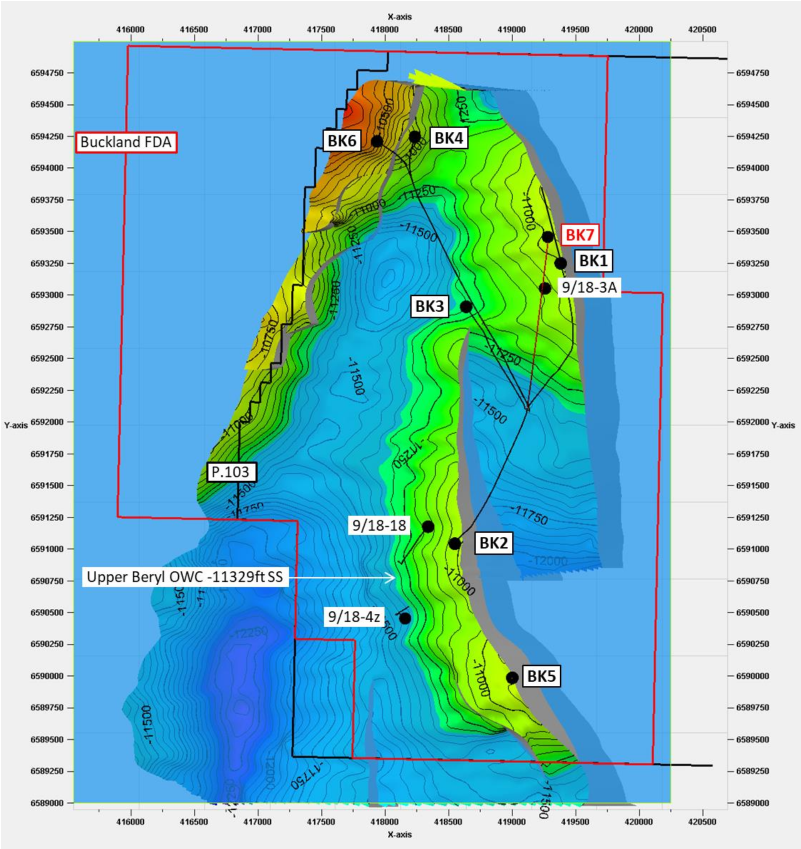


Figure 3-17: Buckland field, Top Beryl Depth Map

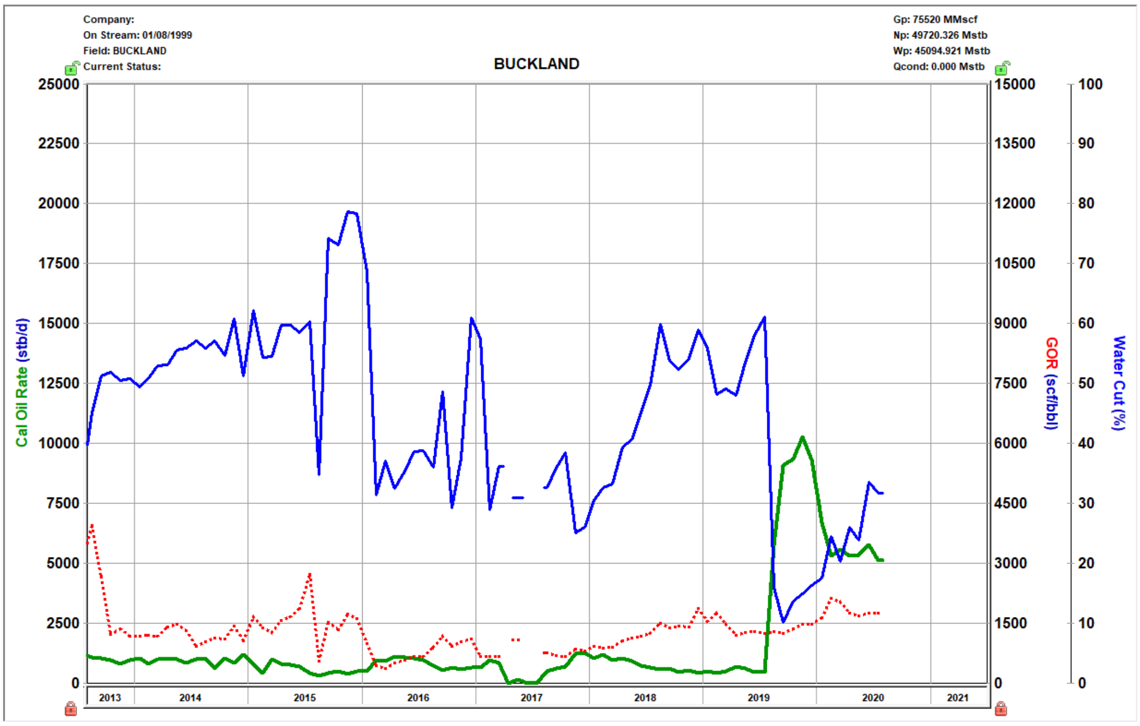


Figure 3-18: Buckland field recent production history

3.2.4. Skene Field

The Skene field located in licence P103, block 9/19c, is a structurally complex gas-condensate field, on the southeast margin of the Beryl embayment, approximately 15 km southeast of the Beryl Alpha production platform. A top structure map for the field is presented in Figure 3-19. Skene is a subsea tie-back to Beryl Alpha-RAT; The Callater and Storr fields were in turn tied-back to Skene in Q2 2017 and Q4 2019, respectively.

The field is subdivided into a number of structural compartments, each of which had different original hydrocarbon water contacts, and in some cases varying fluid types. Further heterogeneities exist due to stratigraphic compartmentalisation between the Upper and Lower Beryl reservoirs.

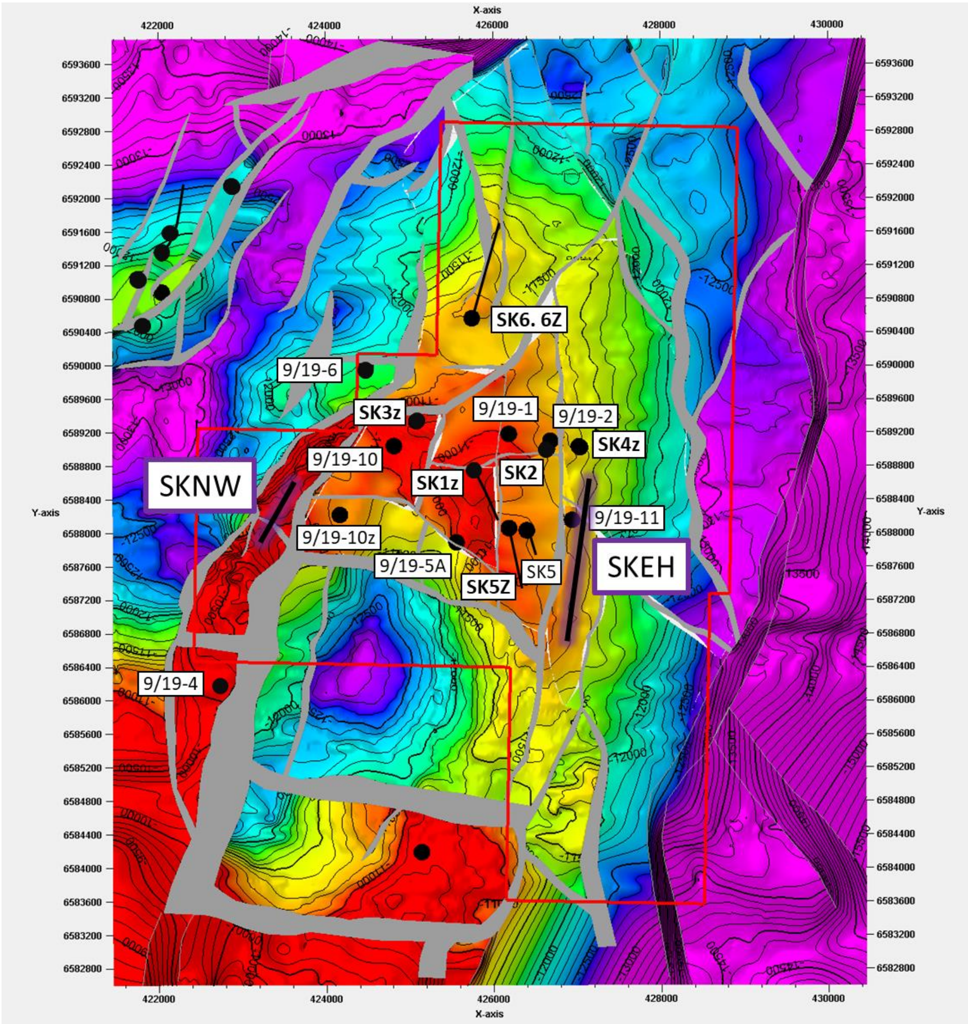


Figure 3-19: Skene field, Top Beryl Depth Map

The Skene field was brought online in 2001. Comingled production from several reservoirs has come from five subsea producers. At present three of the original subsea producers remain active, Wells SK1Z, SK2 and SK4z. No new wells have been completed in Skene since 2001. Skene North was drilled in 2017 but not completed due to the fluid contact depth.

As of 30 June 2020, the Skene field was producing 6.90 MMscf/d at a CGR of 45 stb/MMscf (Figure 3-20).

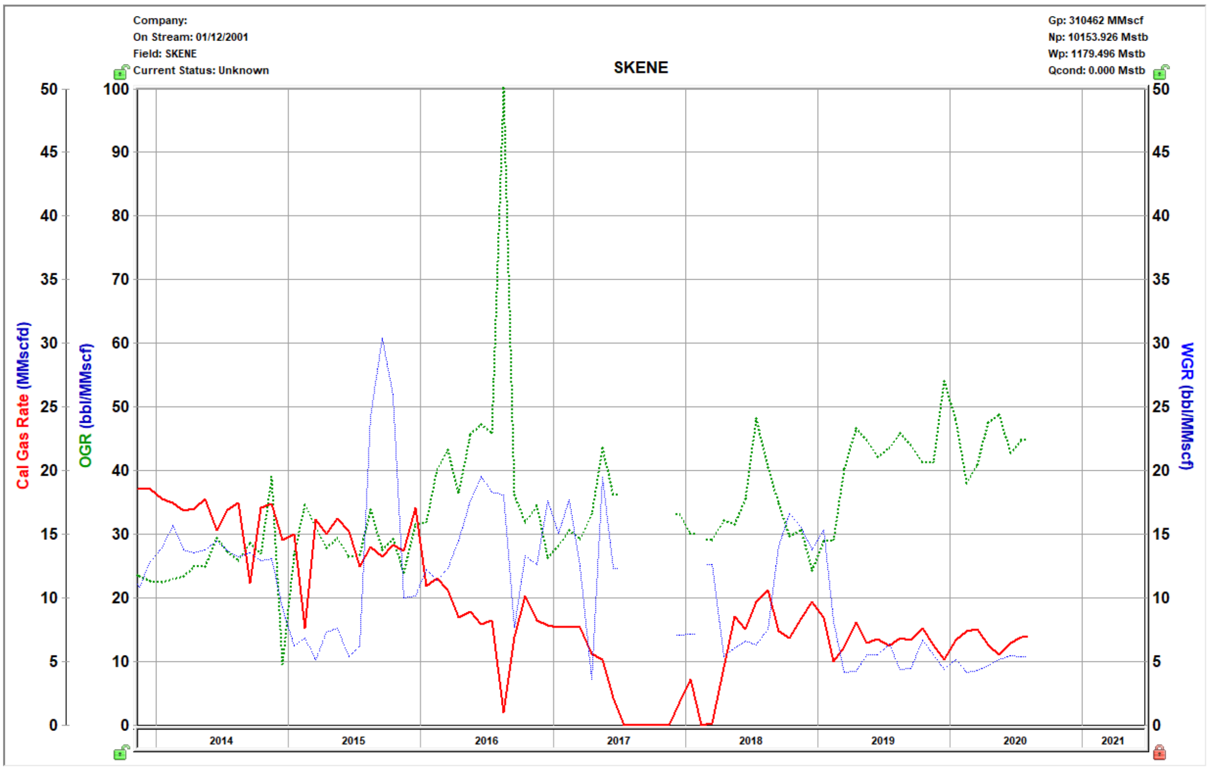


Figure 3-20: Skene field recent production history

3.2.5. Callater Field

The Callater field is a Jurassic and Triassic oil accumulation located 3.9 km west of the Skene field subsea facilities and 12 km southeast from the Beryl Alpha platform (Figure 3-21). The field was discovered in 2015 by the 9/19b-18, 18z and 18x Wells, which encountered net pay in stacked Jurassic and Triassic Cormorant reservoirs.

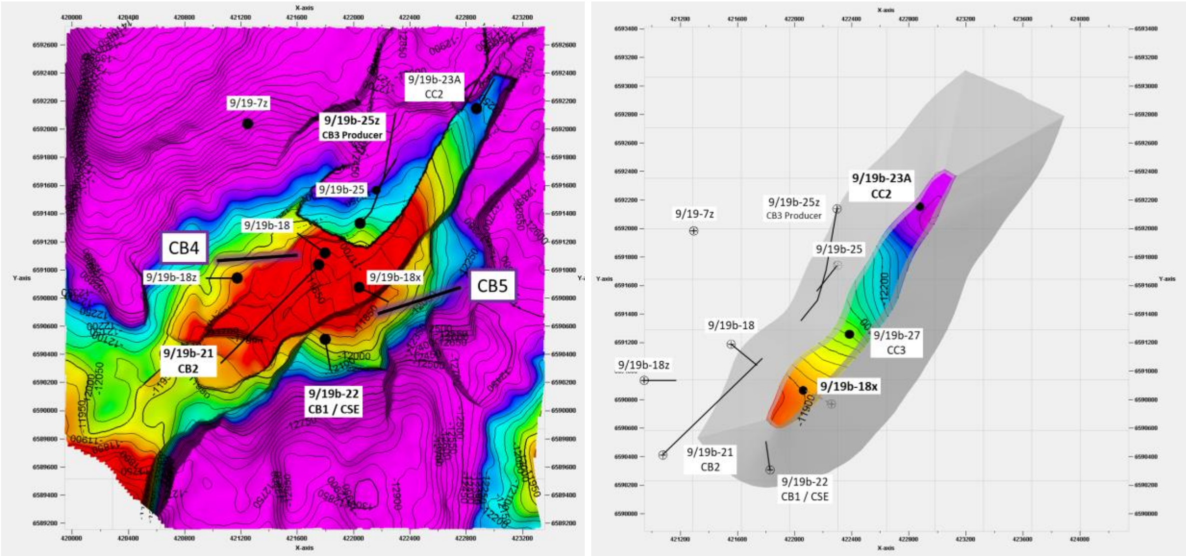


Figure 3-21: Callater field, Top Beryl and Top Cormorant depth map

Well 9/19b-18x (CL18x) was completed as a producer in the Cormorant reservoir and came online April 2017. Four more development wells were drilled during 2017 – 2019. Wells CL21, CL22 and CL25Z were completed in the Beryl sands and Well CL23 was completed as the second well in the Cormorant reservoir.

In Q2 2020 a third Cormorant producer, Well CC3, was drilled between Wells CL18x and CL23, approx. 400m northeast of Well CL18x. This well encountered 188 m tvd of net pay but had lower net-to-gross than prognosed with properties closer to Well CL23 than Well CL18x. No pressure depletion was observed in the well. However, initial rates are below pre-drill expectations and Chrysaor currently prognoses that the well has been completed sub-optimally with investigations ongoing.

As of 30 June 2020, with CC3 not yet on production, the Callater field was producing from four wells at 1,938 bbl/d at 5% water cut and 8,230 bbl/scf average GOR (Figure 3-22).

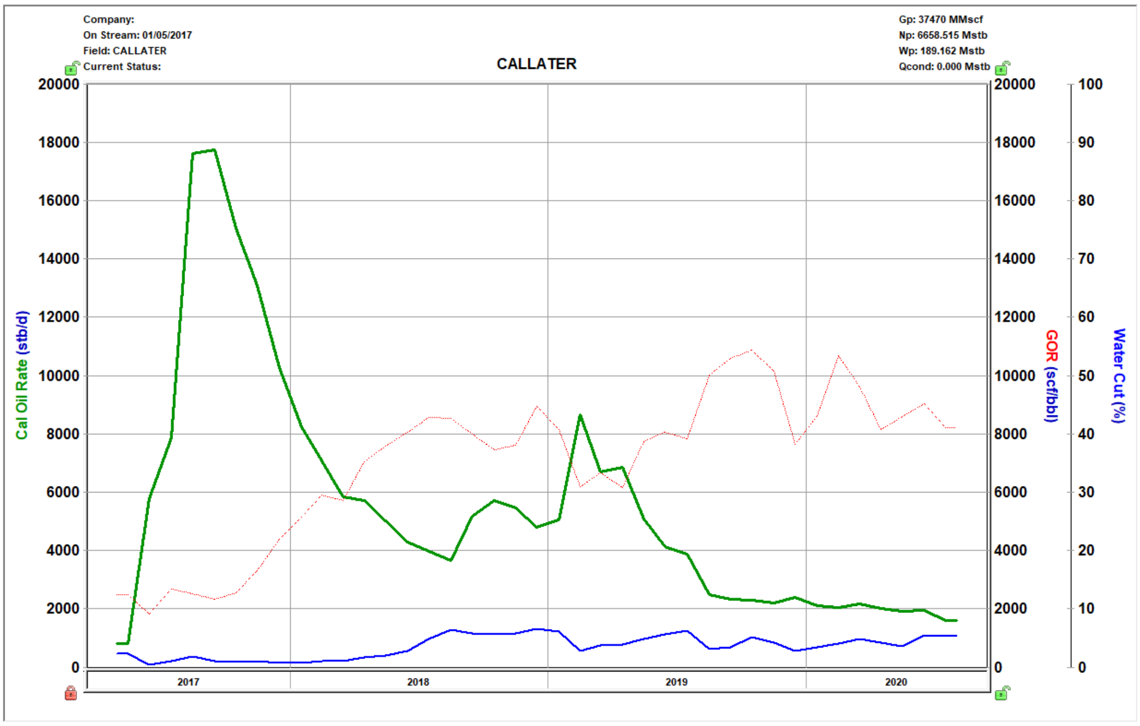


Figure 3-22: Callater field production history

3.2.6. Storr-Brora Fields

The Storr-Brora fields are Jurassic age, gas and oil accumulations located 7 km south of the Skene field subsea facilities on block 9/19. The Brora field was discovered in 1976 by Well 9/19-3, encountering gas condensate in the Lower Beryl reservoir but has not been developed. The Storr East Well 9/19b-19z encountered a minor oil column in the eroded Beryl section, gas condensate in the Nansen formation (primary reservoir), plus oil and gas condensate in the Linnhe and Eiriksson formations. The Storr West Well 9/19b-19y encountered a series of gas and oil columns in the Beryl formation and water-wet underlying secondary reservoirs.

The first phase development Well, 9/19b-ST26B (ST26B) was completed in the Nansen and Eiriksson formations in June 2019; the well was also deepened to the Cormorant which was poorer quality than expected. Production commenced in November 2019, with an initial gas rate of 48 MMscf/d and a CGR of 140 stb/MMscf. In June 2020 the sleeve over the Cormorant was opened and produced comingled with the Nansen and Eiriksson; there was an additional 0.85 MMscf/d and 180 bbl/d of production seen due to opening the Cormorant. As of 30 June 2020, Well ST26B was producing 28 MMscf/d at a CGR of 35 stb/MMscf. This decline is faster than expected and indicates more compartmentalisation or baffling within the Jurassic reservoir than originally prognosed, leading to accelerated planning for 2021 infill drilling to the South (targets SCNS & SSWC in Figure 3-23). An early p/z analysis from June 2020 suggests in a low case Well ST26B may only be connected to a GIIP of 19 Bscf which was used to guide ERCE's low case resources estimate.

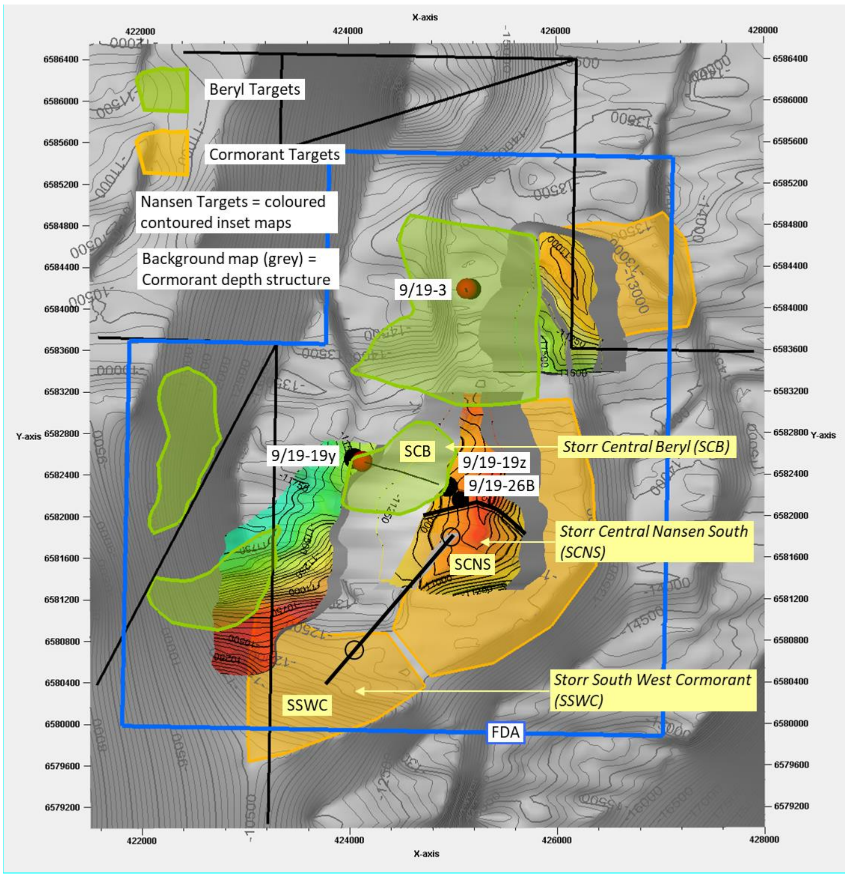


Figure 3-23: Storr field Top Nansen Depth Map

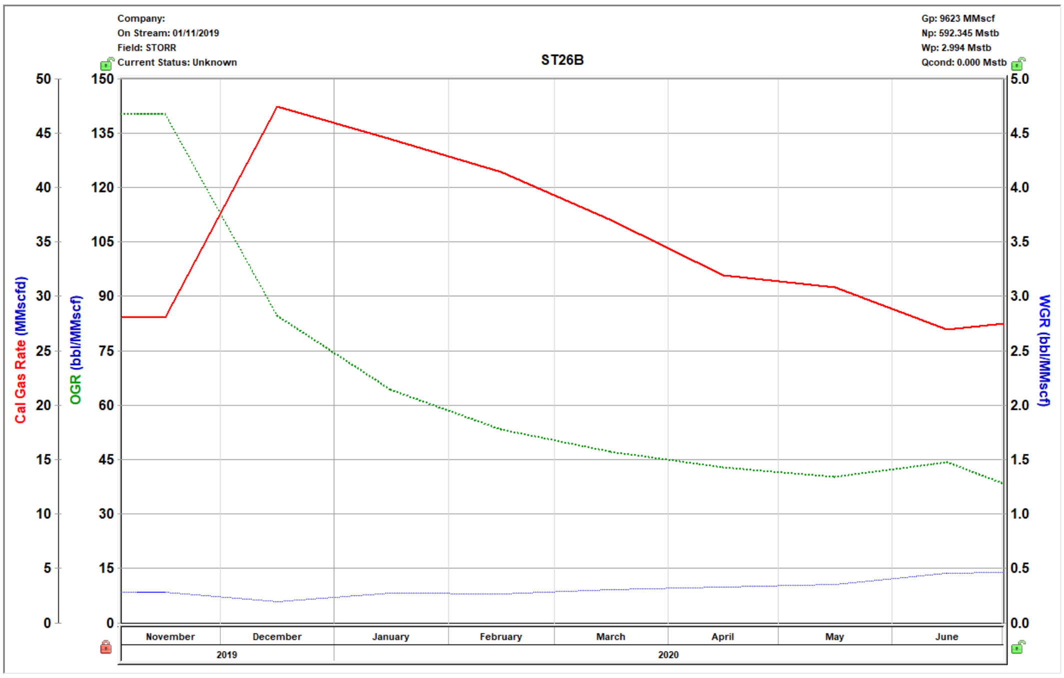


Figure 3-24: Storr field, Well ST26B production history

3.2.7. Development Plans

Apache is an active Operator. The general approach for the Beryl field is to maintain production from the existing well stock, work over old low rate wells and drill infill locations from the Beryl Alpha and Beryl Bravo platforms.

The current Beryl infill drilling programme runs until the end of 2023. Drilling is in two phases from the Alpha platform. There is a 6-month drilling break when the rig crew will be temporarily redeployed to another field. While explicit subsurface targets are not represented on the Apache drill schedule, Chrysaor assumes the programme will include 12 infill wells (six wells in each phase), including three approved wells, Well AL6 (currently drilling, targeting Linnhe oil left by Well S06A), Well ALI (water injector to enhance pressure support in Alpha Main and Bravo East areas) and Well ANC (targeting Well A50 attic Nansen oil) plus an approved workover on the Well A21 water injector (to support Well ANC). Chrysaor names the other targets as ASQ, ANA, TP9, TI3, ACP, ACO, AIB, T5 and ACF.

Chrysaor also assumes a "Phase 3" of Beryl drilling, including a further nine Beryl infill wells beyond 2023 based on the remaining portfolio of targets identified by Apache. ERCE considers resources associated with the Phase 3 campaign to be Contingent Resources.

The three satellite field wells on Apache's subsea drilling schedule (Ocean Patriot semi-sub rig) which are considered by ERCE to be Undeveloped Reserves are:

- Well SCNS-SSWC in the Storr field – a multi-target infill, southwest of Well ST26B targeting both the Nansen/Eiriksson and Cormorant reservoirs scheduled for Q3 2021 (Figure 3-23);

- Well NSHW in Nevis South - an infill well in the Heather reservoir, northwest of the existing Well N12 well drilled in 2011 scheduled for Q1 2022 (Figure 3-25);
- Well SKEH targeting Beryl, Lewis and Cormorant in the appraised but undeveloped eastern horst block in the Skene field (Figure 3-19).

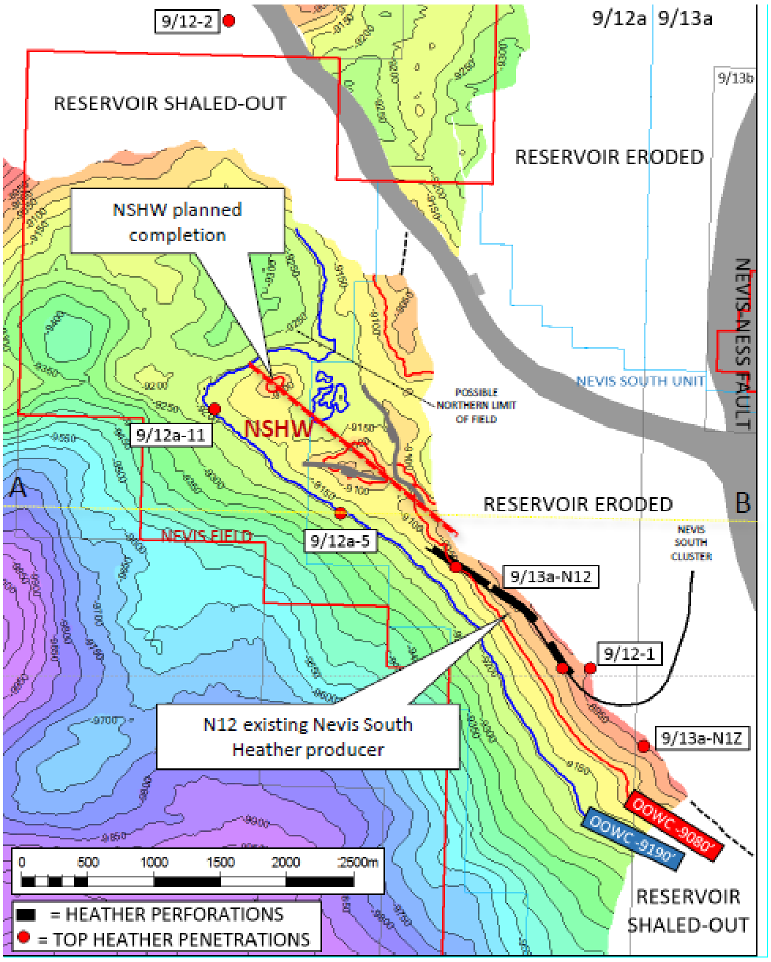


Figure 3-25: Nevis South Well NSHW infill target

The remaining Beryl Area targets included, except for Well NSI, on the 2021-2023 Apache subsea drilling schedule, and considered by ERCE as potential development wells, are:

- Well CC4 a Cormorant infill in the Callater field,
- Well CB4 a Beryl infill in the Callater field and designated as a water injector in the FDP)
- Well NSI a water injector in Ness South.

Well NSI has originally been considered as a potential subsea well; but according to Chrysaor recently been reconsidered as a potential Beryl Alpha platform ERD well.

Based on the available material, ERCE does not consider these wells to be mature enough in the planning/approval process yet to be considered Undeveloped Reserves and are instead classified as Contingent Resources.

Two wells on the Apache schedule are considered by ERCE to have exploration risk and so were not included in this evaluation: Storr field Well SNNBC (targeting an unpenetrated Northern fault block); and Nevis West Well NWB6 (targeting an unpenetrated fault block to the East of the block developed by Well S66x).

3.2.8. Technically Recoverable Resources

ERCE's low, base, and high TRR estimates for existing wells were mostly derived using decline curve analysis (DCA). Estimation of production profiles for the most recent and future wells were based on established type wells or simulation results where available.

The DCA for existing production was performed on individual wells based on monthly operating rate versus time. Data were available up to end of June 2020. From the review of production performance and based on waterflood recovery in the majority of the oil reservoirs, a range of hyperbolic exponents were used to account for the forecast uncertainty.

For the wells more recently on production, such as Beryl Wells B88Y (BEB) and B89 (BTI) water injector, Callater Well CC3 and Storr Well ST26B, the Operator's simulation and analytical work was taken into account in our estimates of low, base and high cases.

The assessment of the Undeveloped Reserves in a mature field like Beryl is challenging. Incremental production will reduce as more and more wells are drilled, due to reduced well spacing and production interference. This is compounded by the comingling of production and uncertainty in the allocation of injected volumes to reservoir(s). ERCE has not been given access to the Operator's simulation model(s) but we understand the proposed well locations and their predicted recovery are guided by these models and analytical techniques. As a check, plots of the forecast recovery by well over time can be used to estimate future recoveries (a creaming curve approach) provided the wells drilled in the past are considered representative of the wells to be drilled in the future. Chrysaor has adopted this approach and estimates future "Phase 1" infill wells will recover circa 0.6 MMstb/well, "Phase 2" wells circa 0.5 MMstb/well and "Phase 3" wells circa 0.35 MMstb/well. For the 12 Beryl Alpha infill targets, half are considered Phase 1 wells and half Phase 2 wells. ERCE has reviewed this work and believes it to be reasonable for determining best estimate TRR (where the Operator estimates were available these were slightly higher on average than the Chrysaor estimates). ERCE's low and high case estimates were based on 50% and 167% of the best estimate case respectively with the wide range reflecting the inherent uncertainty. For forecasting the associated gas ERCE has used the average current GOR of 3,800 scf/stb for all the infill wells.

For the Undeveloped Reserves associated with the Storr Well SCNS-SSWC, ERCE has reviewed the Operator's updated simulation work completed post the drilling of Well ST26B. Based on simulation work a recoverable volume of circa. 8 MMboe was estimated for this dual target well. ERCE has further scaled the volumes because of the complex nature of combining targets, the apparent structural complexities and the additional compartmentalization seen in Well ST26B. For a base case it is assumed only one target is completed, or two targets sub-optimally.

The Nevis South Well NSHW has been considered for drilling over several years. Further study work including simulation modelling in 2019 and a new pre-stack seismic inversion interpretation done during 2020 (which has slightly increased the in-place volume) appears to be the catalyst for drilling the well. Simulation work is ongoing however ERCE now believes there is a firm intent to drill the well and has assigned Undeveloped Reserves. ERCE has based the TRR range on the previous well proposal with some further scaling to account for water/gas production in the low case given the deferral of the well (aligned to the lower recoverable from the 2019 simulation work).

The Skene SKEH well has also been assessed as an infill target for many years. The Eastern Horst block was appraised by well 9/19-11 in 1993 before production started in the field. The subsequent drilling and production of S2 and S4z indicated the horst block was not connected to the main field. The SKEH target lies south of another fault from the S4z horst producer and the assumption is it is isolated from it based on S4z performance. ERCE has based the TRR range for SKEH on the previous well proposal, having reviewed the risked volumetric analysis, which is felt to sufficiently account for the risk of compartmentalisation and potential depletion by existing wells. The production profile associated with SKEH uses S4z as an analogue.

ERCE’s gross Developed plus Undeveloped TRR estimates are presented in Table 3-9 and include the cumulative production to date. The recovery factor to date and best estimate technical recovery factor are based on the PIIP volumes reported by the Operator as best estimates.

Table 3-9: Beryl Area TRR Estimates

Asset/ Field	Hydrocarbon	PIIP (Operator Best Estimate)	Cum. Prod. at 30 Jun 2020	RF to date	TRR Estimate			TRR best est. RF
					Low	Best	High	
Beryl	Gas (Bscf)*	2,806.0	2,842.6	101%	2,903.5	2,945.2	2,987.3	105%*
	Oil+Cond. (MMbbl)	2,295.0	853.5	37%	869.5	880.5	891.5	38%
Nevis South	Gas (Bscf)	414.5	248.7	60%	268.1	274.1	280.0	66%
	Oil+Cond. (MMbbl)	360.8	113.5	31%	121.9	124.5	127.1	35%
Ness & Nevis Central	Gas (Bscf)	215.3	129.7	60%	151.6	160.0	167.2	74%
	Oil+Cond. (MMbbl)	158.9	45.9	29%	49.5	50.9	52.1	32%
Nevis West	Gas (Bscf)	17.4	12.2	70%	13.1	13.3	13.7	77%
	Oil+Cond. (MMbbl)	5.7	4.1	72%	4.41	4.48	4.6	79%
Buckland	Gas (Bscf)	168.0	58.4	35%	61.7	64.3	66.8	38%
	Oil+Cond. (MMbbl)	120.0	38.1	32%	39.9	38.4	42.7	32%
Skene	Gas (Bscf)	508.0	310.25	61%	320.9	333.7	369.3	66%
	Oil+Cond. (MMbbl)	38.9	10.14	26%	10.62	11.20	12.80	29%
Callater	Gas (Bscf)	179.0	37.06	21%	58.61	67.46	78.11	38%
	Oil+Cond. (MMbbl)	77.0	6.61	9%	9.48	10.66	12.08	14%
Storr	Gas (Bscf)	276.9	8.8	3%	39.0	64.2	95.7	23%
	Oil+Cond. (MMbbl)	45.4	0.6	1%	1.5	2.2	3.2	5%

Note

* 1,040 Bscf of gas had been injected in Beryl up to 30 June 2020

Production forecasts were generated making allowances for operating efficiency including incorporating planned turn arounds (TARs) and for intermittent producers (Table 3-10).

Table 3-10: Beryl assumed operating efficiency

Field	Operating Efficiency									
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Beryl	84%	84%	80%	84%	84%	84%	84%	84%	84%	84%

Note

1. OE estimates after 2029 remain constant.

In general, the secondary associated products were forecast based on ratio trends taking account of recent data and accounting for any likely drop out in the reservoir.

3.2.9. CAPEX Assumptions

The CAPEX profile used for the economic modelling is based upon cost data provided to partners such as AFEs, budgets and forecasts from partner meetings. These data have been reviewed and profiles developed accordingly. The major CAPEX expenditure in the forecast is on 12 Beryl Alpha platform-based infill wells planned to be drilled during the period 2H 2020 through to 2023. The total cost considered for these 12 wells is $195.3 MM inclusive of platform hook-up activities.

Additional CAPEX is associated with three subsea development wells, one on Nevis South (Well NSHW), one on Skene (Well SKEH) and one on Storr (Well SCNS-SSWC). The total cost estimate for each of these wells is $53.4 MM inclusive of hook-up costs.

There is limited CAPEX expenditure on the Beryl facilities other than sustaining activities. The annual cost included for these activities is some $8 to 8.5 MM/ year until the end of 2028.

3.2.10. OPEX Assumptions

The OPEX profile estimated by ERCE, makes use of similar data to the CAPEX profile. A 3-year forecast for OPEX in the order of $150 MM per year was provided by the Operator and is considered by ERCE to be reasonable.

The profiles suggest that Beryl will be gas deficient around 2025 and hence, an allowance is included in the OPEX to "buy-back" fuel-gas from the pipeline thereafter.

3.2.11. Abandonment Assumptions

The Operator provided field abandonment reports and associated estimates. These have been reviewed and the costs adopted in the economic model.

The facilities decommissioning and well P&A costs are listed in Table 3-11.

Table 3-11: Beryl Area Decommissioning Costs

Field	ERCE Decommissioning Costs $MM (Developed + Undeveloped)		
	Facilities	Wells(1)	Total - Dev & Undev
Beryl	767	339	1,106
Ness_Nevis Central	54	167	220
Nevis_South	39	144	183
Nevis_West	5	15	20
Skene	48	86	134
Buckland	34	82	117
Callater	21	75	95
Storr	5	46	51
Total	**972**	**954**	**1,926**

Note

1. Well count covers Developed & Undeveloped wells plus several open-water E&A wells

ERCE has included a total Beryl field well P&A cost of $339 MM which covers 39 Alpha platform wells, 21 Bravo platform wells, nine subsea wells and six suspended open-water E&A wells. The Operator's estimated well P&A costs were benchmarked against average 2019 Oil and Gas UK costs and while the cost for subsea wells was considered reasonable, the P&A

cost of the platform wells was considered too low. ERCE has increased the platform well P&A cost to be aligned with the Benchmark costs.

3.2.12. Facilities and Well Integrity

The TCM in May 2020 indicates that the backlog in safety critical maintenance has risen above the UK average. The Operator is developing a strategy to address the issue. The Covid-19 pandemic has also impacted the maintenance being carried out. The review suggests that the highest priority issues are still being addressed, and it is not envisioned that this would prevent the facilities being able to handle the forecast production.

3.2.13. Reserves

The technical production profiles described in the previous section were converted to sales profiles (oil, gas and NGL) using the sales conversion factors provided by Chrysaor for gas shrinkage, oil shrinkage and NGL yield and accounting for fuel and flare (Table 3-12). Fuel and flare are assumed to be a constant 21 MMscf/d across the Beryl area and is split between the fields based on their percentage of 1H2021 gas production forecast. ERCE has used oil equivalent conversion factors as presented in Appendix 3 to calculate barrels of oil equivalent (Bscf to MMboe). The gross asset level production forecast (sales) for the Developed plus Undeveloped Reserves categories are included in Appendix 4.

Table 3-12: Beryl sales conversion factors

Field	Gas Shrinkage	Oil Shrinkage	NGL Yield (boe/MMscf)	Fuel & Flare MMscf/d
Beryl	7%	2%	36	7.6
Buckland	10%	3%	74	1.1
Nevis South	12%	2%	75	0.9
Ness_Nevis	9%	0%	75	1.9
Callater	11%	0%	74	4.0
Storr	10%	0%	34	4.4
Skene	7%	2%	76	1.1

Reserves were estimated to the earliest of the economic cut-off dates and the end of the technical profile. For the Beryl field, all the field low technical profiles were arithmetically summed and input into the economic model to determine the 1P CoP date. Similarly, all the best-case profiles and all the high case profiles were added and used to determine the 2P and 3P CoP dates.

A summary of the gross on block Reserves by field is presented in Table 3-13 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 3-13: Beryl Area Gross Reserves by field with CoP dates

Field	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Beryl	Developed	8.21	12.75	17.24	14.69	22.26	30.81
	Undeveloped	0.00	9.15	15.91	0.00	23.29	41.31
	Total (Dvpd+Undvpd)	**8.21**	**21.89**	**33.15**	**14.69**	**45.54**	**72.12**
Ness-Nevis	Developed	2.39	3.45	4.53	6.70	9.37	12.27
	Undeveloped	0.50	0.54	0.89	0.97	0.91	1.55
	Total (Dvpd+Undvpd)	**2.88**	**3.99**	**5.42**	**7.67**	**10.27**	**13.82**
Nevis South	Developed	2.70	4.20	5.46	3.50	5.38	6.97
	Undeveloped	2.09	3.46	5.63	3.17	5.45	8.90
	Total (Dvpd+Undvpd)	**4.79**	**7.66**	**11.09**	**6.67**	**10.83**	**15.87**
Nevis West	Developed	0.22	0.38	0.55	0.48	0.85	1.23
	Undeveloped	0.11	0.09	0.06	0.24	0.20	0.14
	Total (Dvpd+Undvpd)	**0.33**	**0.48**	**0.62**	**0.72**	**1.05**	**1.36**
Buckland	Developed	1.88	3.09	4.09	1.57	2.34	2.98
	Undeveloped	0.00	0.16	0.32	0.00	0.00	0.00
	Total (Dvpd+Undvpd)	**1.88**	**3.26**	**4.41**	**1.57**	**2.34**	**2.98**
Skene	Developed	0.51	0.84	1.20	2.92	4.90	7.04
	Undeveloped	0.00	1.34	3.81	0.00	9.12	26.26
	Total (Dvpd+Undvpd)	**0.51**	**2.19**	**5.01**	**2.92**	**14.02**	**33.31**
Callater	Developed	2.70	3.98	5.49	7.46	10.65	14.96
	Undeveloped	0.28	0.31	0.56	0.00	0.00	0.00
	Total (Dvpd+Undvpd)	**2.98**	**4.29**	**6.05**	**7.46**	**10.65**	**14.96**
Storr-Brora	Developed	0.63	1.23	1.71	6.22	12.25	17.13
	Undeveloped	0.00	1.44	2.55	0.00	18.21	33.07
	Total (Dvpd+Undvpd)	**0.63**	**2.67**	**4.26**	**6.22**	**30.46**	**50.20**
Total Asset	Developed	19.24	29.93	40.27	43.55	67.99	93.40
	Undeveloped	2.98	16.49	29.74	4.37	57.18	111.23
	Total (Dvpd+Undvpd)	**22.22**	**46.42**	**70.01**	**47.92**	**125.17**	**204.63**
	COP (Total)	Jun-27	Dec-30	Dec-34	Jun-27	Dec-30	Dec-34

Notes

1. Undeveloped Reserves associated with Beryl infill programme and an infill well in the Storr field are uneconomic at a 1P level
2. Undeveloped Reserves at the field level are impacted by applying the ELT at hub level (see Section 5 for details). Buckland and Nevis West have no Undeveloped Reserves projects.

3.2.14. Contingent Resources Projects

ERCE has conducted an audit of Chrysaor's Contingent Resources estimates as detailed in Section 6. A number of Contingent Resources projects exist in the Beryl area as presented in Table 3-14. The Contingent Resources estimates associated with these projects are presented in Table 6-1 of Section 6.

As described in Section 3.2.7, the Contingent Resources include a further nine possible infill wells for Beryl Alpha and Bravo which are not expected to be drilled before 2024 and do not yet have firm targets associated with them, however a portfolio of possible remaining targets exists.

Contingent Resources are assigned to several wells on the current Apache subsea drilling schedule: NSI, CC4, CB4 and an additional Storr field development well targeting the central block. In addition, several targets not on the current Apache drilling schedule, Nevis West (NCS), Ness Nevis Central (NSP), another Callater well (CSE-2, CB5), Loriston SW (LSW) and two Leadon targets (SE & CS).

Potential volumes associated with the Nevis West NWB6, NWK and Skene SWHN infill targets are categorized as Prospective Resources due to the significant geological risk associated with these opportunities.

Corona and Solar are two recent discoveries within a Tertiary injectite play. Corona was discovered in 2015 by Well 9/18a-39A. The Solar discovery well and sidetrack, Wells 9/18e-42A and 42Z, were completed in February 2020. The Operator is also planning to drill a number of other similar Tertiary prospects which were outside the scope of this CPR as they would be classified as Prospective Resources.

Table 3-14: Beryl Area Contingent Resources Project Summary

Field	Project	Possible Timing	Sub-Maturity Class
Beryl	Beryl further infills (9 wells)	2024-2025	DOH
Beryl	Corona	To be determined	DUC
Beryl	Solar	To be determined	DUC
Ness South	NSI -injector	Q4 2021	DP
Callater	CC4	Q3 2021	DP
Callater	CB4	Q2 2023	DOH
Callater	CB5	2025->	DOH
Callater	CSE-2	Q3 2024	DOH
Storr	Central Beryl SCB	Q3 2022	DOH
Nevis Central	NSP	Q2 2024	DOH
Nevis West	NCS	2025->	DOH
Loirston	SW LSW	2025->	DUC
Leadon	Leadon SE	2025->	DUC
Leadon	Leadon CS	2025->	DUC

3.3. Buzzard Field

The Buzzard field is located in the Outer Moray Firth of the North Sea (Figure 3-26). Chrysaor holds a 21.73% interest and CNOOC is the Operator with a 43.21% interest. Other partners are Suncor and ONE Dyas. Chrysaor obtained its interest through the Shell Transaction in 2017.

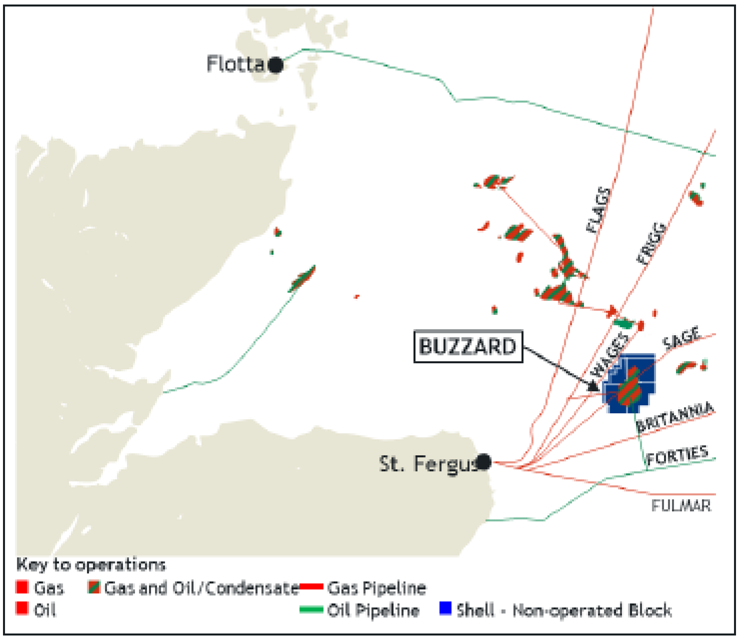


Figure 3-26: Buzzard field location map (source: Shell)

A summary of some key field data is presented in Table 3-15.

Table 3-15: Buzzard field summary data

Field	Reservoir	Depth (m tvdss)	Trap	Fluids	Initial Res. Pressure (psia)	Solution GOR (scf/stb)	NTG	Por.	Perm (mD)
Buzzard	B2 & B4	2,660	Stratigraphic	Oil - 32 API	4628	270	65%	25%	2,500

The Buzzard reservoir consists of turbidite sandstone members of the Upper Jurassic, Kimmeridge Clay formation. A stratigraphic column showing the Buzzard stratigraphy is presented in Figure 3-27. The figure shows the principal reservoir units: the B4 (further subdivided into LB4, UB4-4 and UB4-5), characterised as a laterally extensive massive sand; and the B2 a laterally extensive unit of variable reservoir quality. The B4 reservoir contains the majority of the STOIIP. A B4 top structure map is presented in Figure 3-28.

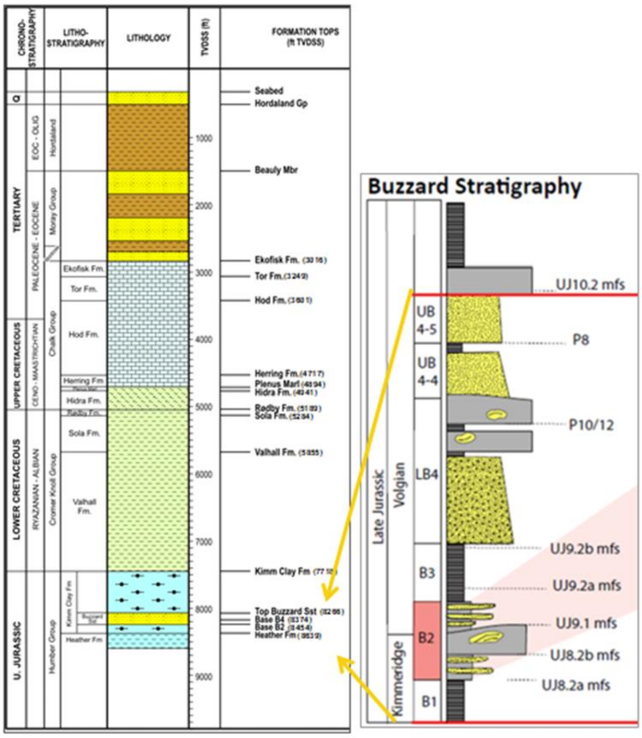


Figure 3-27: Buzzard field stratigraphic column (source: Operator)

The field was discovered in 2001 and first produced in 2007. The initial development consisted of three bridge linked platforms (wellhead, production and accommodation/utilities) with steel jackets. A fourth platform was installed in 2012 to handle hydrogen sulphide in the produced oil. Phase 1 drilling was completed in 2014 with 38 wells drilled from 36 platform slots. Oil is exported via the Forties Pipeline System (FPS) to the Kinneil Terminal at Cruden Bay, and gas via the Frigg pipeline system to the St. Fergus gas terminal.

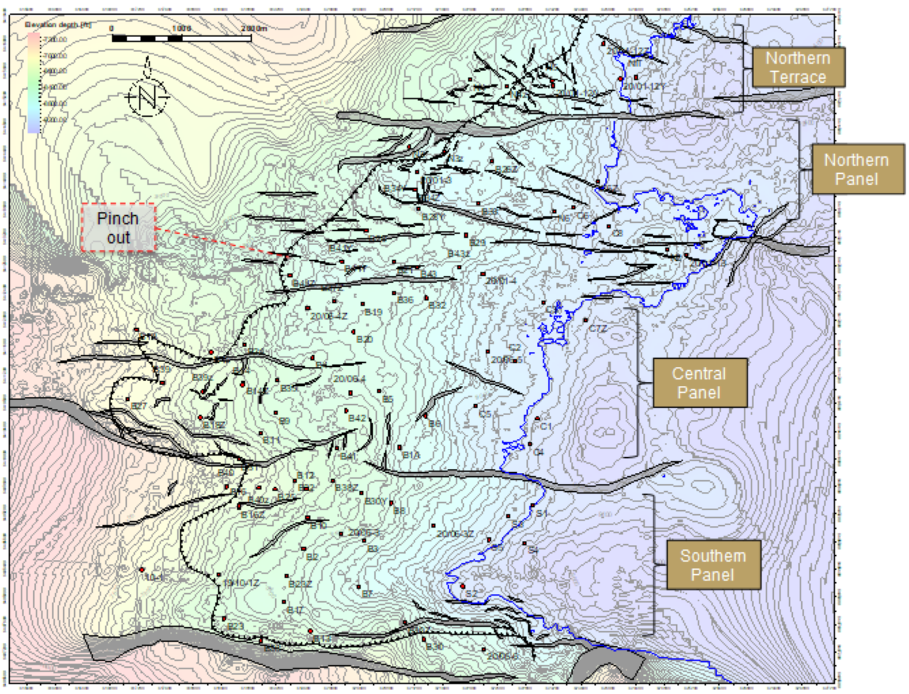


Figure 3-28: Buzzard field B4 top structure map (source: Chrysaor)

There are currently 32 producing wells. The cumulative production to end of June 2020 was 754.6 MMstb of oil and 165 Bscf of gas, and the field has been under water injection since the beginning of production. The oil and gas production rates at end June 2020 were approximately 83,000 bopd and 21 MMscf/d respectively, with GOR being around 260 scf/stb and water cut above 70%. The production and injection history for the Buzzard field is presented in Figure 3-29.

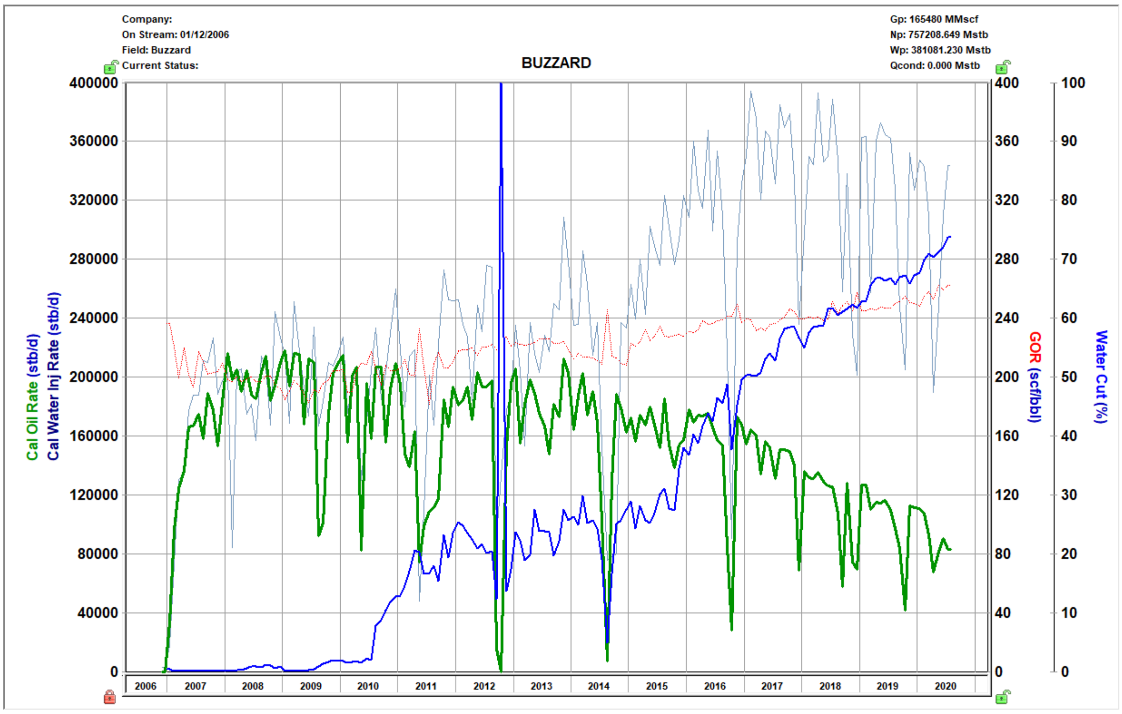


Figure 3-29: Buzzard field production and injection history

Voidage replacement and reservoir pressure are linked and the reservoir pressure had declined by 1,000 psia by 2014. Since then the oil rate has come off plateau, water injection rates have increased and cumulative voidage replacement is now closer to 100%.

3.3.1. Development Plans

The Buzzard field initial development was completed by 2014. The next stage of development started in 2018 with infill drilling from two centres.

The wellhead platform was designated Drilling Centre One ("DC1") and drilling started in September 2018. The DC1 campaign was originally associated with drilling six infill wells from which four producers were drilled during 2019 as Wells B39z, B40, B41y and B42; one injector Well PRC6 was drilled in 1H2020 and Well NP3 was cancelled.

A subsea manifold is used for the Drilling Centre Two ("DC2") campaign which targets development of the Northern Terrace and Central Panel areas (Figure 3-28). DC2 drilling started in April 2019 with the plan to drill four producers and two injectors. By September 2020:

- two wells had been successfully drilled and completed (Wells N1-inj and N5-prod)
- two wells (Wells N3 and N4 plus side-tracks) had failed to find sufficient reservoir; and
- two wells remained to be completed (Wells N2-prod and N6-inj)

As a result, there are two fewer wells planned to come on stream, which will impact future production. Although this information became available after the Effective Date of this report, ERCE considers this material and has incorporated this information in our evaluation.

The Operator is at an early stage of evaluating three further infill wells.

3.3.2. Technically Recoverable Resources

ERCE's TRR estimates for the current producing wells were derived using decline curve analysis (DCA) on a well level. Estimation of production profiles for the recent DC1 and the DC2 infill wells are based on established type wells and simulation results provided by Chrysaor.

ERCE has performed DCA to estimate future performance of the current producing wells. The DCA was performed on individual wells based on monthly operating rate versus time. Data were available up to end of June 2020. A range of hyperbolic exponents were used to account for the forecast uncertainty. Secondary phase production volumes were estimated using constant GOR derived from historic production data at the well level.

The individual well profiles were aggregated to field production forecasts making allowances for operating efficiency ("OE") including planned turn arounds (TARs). The Buzzard OE estimates as determined by ERCE are presented in Table 3-16.

Table 3-16: Buzzard assumed operating efficiency

Field	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Buzzard	88%	75%	88%	88%	83%	88%	88%	83%	88%	88%

Note

1. OE estimates after 2029 repeat on the same three-year cycle.

ERCE's gross Developed plus Undeveloped TRR estimates for the Buzzard field presented in Table 3-17 compares technically recoverable resources until end of 2045 and includes the technical recovery factors.

Table 3-17: Buzzard TRR Estimates and Recovery Factors

Asset/ Field	Hydrocarbon	PIIP[1] (Operator Best Estimate)	Cum. Prod. at 30 Jun 2020	RF to date	TRR Estimate			TRR best est. RF
					Low	Best	High	
Buzzard	Oil (MMstb)	1,664	755	45%	876	993	1,107	60%

1) PIIP is from the 2018 FDP Update.

3.3.3. CAPEX Assumptions

The CAPEX profile used for the economic modelling is based upon cost data provided to partners such as AFEs, budgets and forecasts from partner meetings. These data have been reviewed and profiles developed accordingly.

The major CAPEX expenditure in the forecast are costs related to drilling the remaining DC2 Phase 2 sub-sea wells during 2H 2020 ($52 MM) and tie-back and hook-up at the Buzzard platform of four out of six of the DC2 drilled wells ($163.9 MM).

There is limited CAPEX expenditure on the facilities other than sustaining activities of $44.1 MM until end of 2021.

3.3.4. OPEX Assumptions

The OPEX profile developed made use of similar data to the CAPEX profile. Average OPEX over the near term is some $135 MM / year.

The Forties Pipeline System (FPS) OPEX and CAPEX costs have been taken from the latest budget, including a 5-year plan (2020-2025) from INEOS, the FPS operator. A similar level of investment from the Operator is expected to continue after 2025. In 2019 INEOS announced a £500 MM ($650 MM) investment into the FPS, to occur over the next five years. After the Effective Date, in October 2020, INEOS issued a revised Final Work Programme and Budget for 2021 indicating a lowering of expenditures of some 24% over the next 5-year period. Due to the materiality of this information it has been incorporated.

3.3.5. Abandonment Assumptions

The Operator provided field abandonment reports and associated estimates. These have been reviewed and the costs adopted in the economic model. Total facilities decommissioning cost of $482 MM has been considered.

The Operator's well P&A costs compare well with the Oil and Gas UK guideline and benchmark costs and have been adapted by ERCE. The total Buzzard field well P&A cost considered by ERCE of $454 MM covers 36 Buzzard platform wells, 19 subsea wells and 1 open-water E&A well.

3.3.6. Facilities and Well Integrity

TCM meetings indicate there is a significant backlog of maintenance work being built up. At this time the number of safety critical issues is small and is being prioritised and managed. ERCE considers that nothing should prevent the facilities being able to handle the forecast production.

Wells B20 and B11 have integrity issues and a well intervention in 2020 is planned together with other interventions on other wells.

3.3.7. Reserves

The technical production profiles described in Section 3.3.2 were converted to sales profiles (oil, gas, LPG and NGL) using shrinkage and yield factors, which were based on data provided by Chrysaor. A summary of these factors is presented in Table 3-18. Wellhead gas was corrected for fuel and flare consumption, estimated at 13.3 MMscf/d flat. ERCE has used oil equivalent conversion factors as presented in Appendix 3. The gross asset level production forecast (sales) for the Developed plus Undeveloped Reserves categories are included in Appendix 4.

Table 3-18: Buzzard field wellhead to sales conversion factors

Field	Oil Shrinkage (frac)	LPG Yield (bbl/Mstb)	Gas Shrinkage (frac)	Fuel and Flare (MMscf/d)	NGL Yield (stb/MMscf)
Buzzard	0.964	1.4	0.908	13.3	56.8

Reserves were estimated to the earliest of the economic cut-off dates and the end of the technical profile. For Buzzard field the low technical profiles were used as input into the economic model to determine the 1P CoP date. Similarly, all the mid-case profiles and all the high case profiles were used to determine the 2P and 3P CoP dates.

The Developed Reserves were based on the existing well stock. Four DC2 infill wells were classified as Undeveloped Reserves due to their status at the Effective Date.

A summary of the gross on block Reserves is presented in Table 3-19 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 3-19: Buzzard Field Gross Reserves with CoP dates

Field	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Buzzard	Developed	87.59	183.24	265.63	0.26	0.57	0.85
	Undeveloped	7.80	21.03	44.23	0.04	2.02	4.40
	Total (Dvpd+Undvpd)	**95.39**	**204.27**	**309.86**	**0.30**	**2.59**	**5.26**
	COP (Total)	Dec-31	Dec-41	Jun-45	Dec-31	Dec-41	Jun-45

3.3.8. Contingent Resources Projects

There are currently no Contingent Resources projects identified in the Buzzard area.

3.4. Greater Clair Area

The Greater Clair Area assets are located on the UKCS, some 70 km West of Shetland (WoS) (Figure 3-30). Chrysaor holds a 7.5% interest and BP is the Operator with a 45.1% interest. Other partners are Shell (28.0%) and Chevron (19.4%). Chrysaor obtained their interest through the ConocoPhillips Transaction in 2019.

The Greater Clair area, operated by BP, contains the Clair Phase 1 development with its integrated drilling and production platform, the Clair Ridge development with its two bridge linked platforms which ties into the Phase 1 pipelines to the Sullom Voe Terminal, and the Clair South and Clair North discoveries.

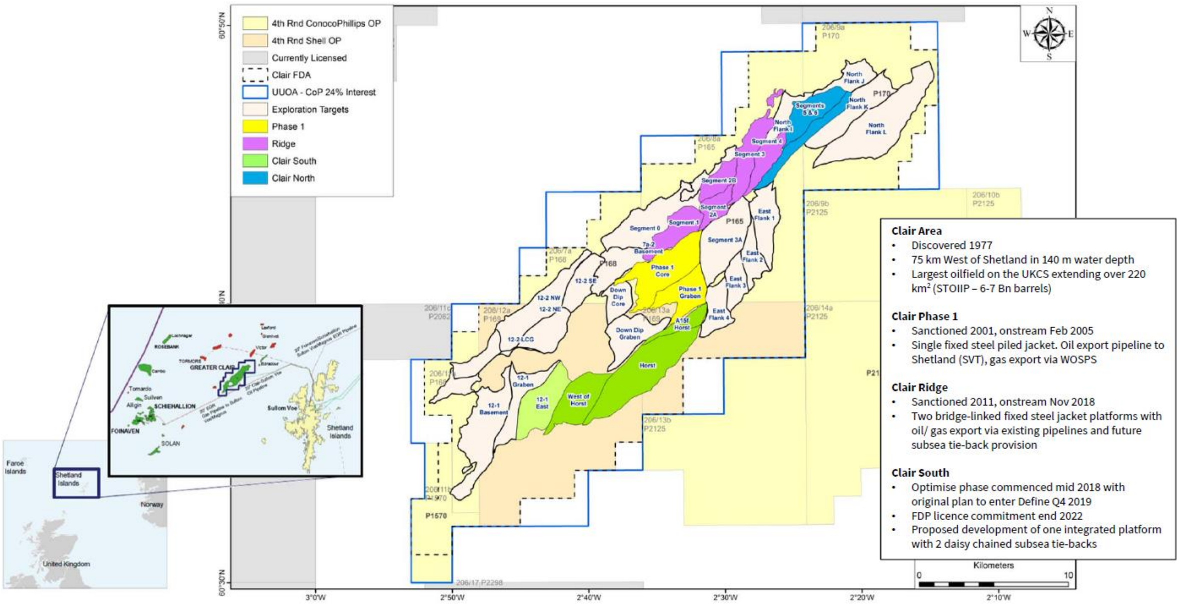


Figure 3-30: Clair Field Location (source: Chrysaor)

The terrestrial Upper Clair Group ("UCG") and Lower Clair Group ("LCG") of Devonian and Carboniferous age predominantly comprise fluvial and lacustrine sediments overlain unconformably by marine clastics of Cretaceous age that provide an effective top seal. These have been classified into ten units based on depositional characteristics. Units III, V and VI of the LCG form the main reservoir intervals. A second major unconformity separates the LCG from the Lewisian Basement. A stratigraphic column is presented in Figure 3-31.

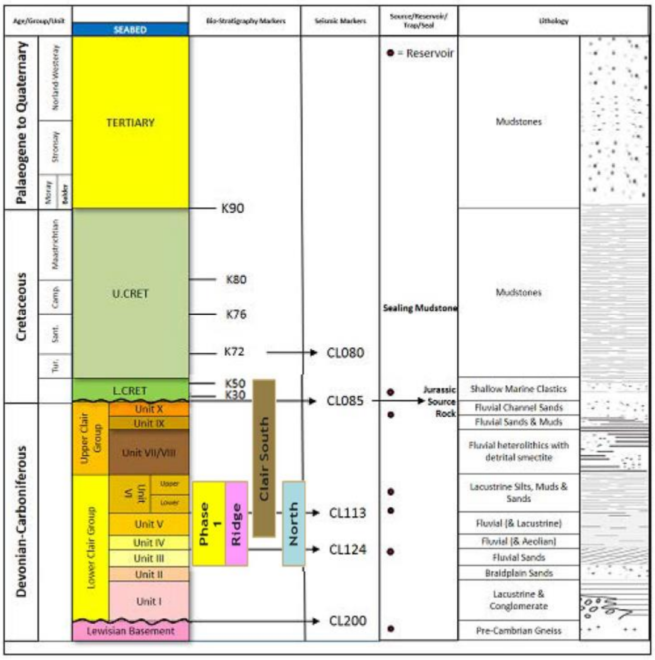


Figure 3-31: Clair Field Stratigraphy (source: Operator)

The structural evolution of the Clair area is complex, and the field comprises over 30 heavily faulted segments, overlying an elongated basement horst (Figure 3-26). The Operator is carrying out extensive studies work with continuous model builds as more data are gathered. There are multiple 3D seismic datasets and 4D seismic surveys are also being acquired.

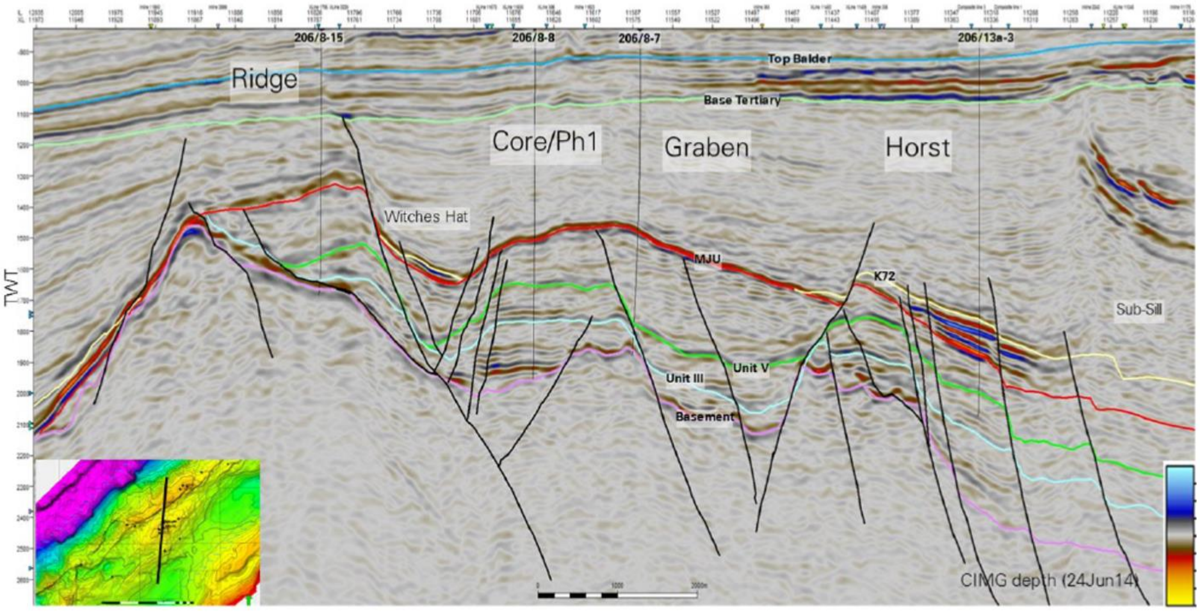


Figure 3-32: Clair Field Seismic and Structure (source: Operator)

The Phase 1 area came on stream in 2005, producing from four different reservoir segments with different characteristics. Currently 21 wells are active producers and water injectors. As of 30 June 2020, average oil production was 32,000 stb/d with 12 MMscf/d gas and a water cut of 45%.

The Clair Ridge development achieved first oil in November 2018 from two wells, followed in 2019 by two further producers plus one water injector. Initial performance has been lower than prognosed with wells producing at lower than expected rates and three wells (B2, B4 and B6) already seeing water breakthrough. As of 30 June 2020, average oil production was 34,000 stb/d with 12 MMscf/d gas and a water cut of 27%.

Production history by field area is presented in Figure 3-33.

Acquisition and processing of a 4D Ocean Bottom Node ("OBN") seismic survey is planned for the Phase 1 and Ridge areas (80 km^2), with processing completion targeted for Q1 2022. This will be the first repeat survey of the initial 2017 OBN dataset. Imaging uplift is expected to assist in finding targets for future infill development wells.

In Phase 1, future plans include five infill wells targeting Segment 3A, Core, and Basement areas of the field. The infill well campaign is scheduled to start 2H 2021 and be finished towards the end of 2023.

The Ridge sanctioned development plan consists 25 producers, 10 water injectors and one cuttings disposal well; at the Effective Date four producers, one water injector and the cuttings disposal well had been drilled.

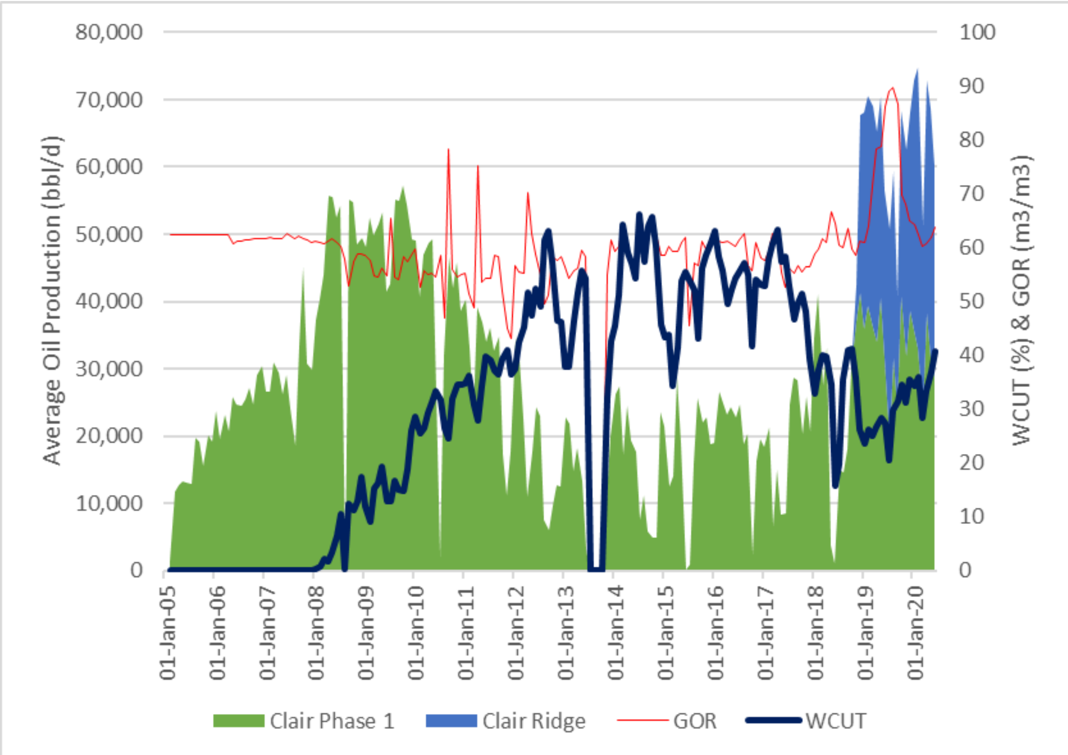


Figure 3-33: Clair production history by area

3.4.1. Clair Phase 1

The Clair Phase 1 area is producing from four different segments with different characteristics.

The reservoirs have extensive vertical and lateral heterogeneities and considerable lithology variations within the sandstones. An open fracture network controls productivity in the Phase 1 area; the northern Core tends to be fracture dominated, whilst permeability in the Graben and Horst are matrix dominated.

The main producing horizon in the Phase 1 development is Unit V, interpreted as a mixture of fluvial channel and damp aeolian deposits with average permeabilities in the order of 100 mD with some high permeability beds up to several Darcy. Unit VI; up to 200m thick has also been a production target; but this unit generally has poorer reservoir quality than Unit V.

Oil fluid properties are 24° API, 4 - 5 cP viscosity and initial solution gas-oil ratio of some 350 scf/stb. There may be a slight compositional gradient with depth and some variation between segments.

A common free water level (FWL) of 2,122 m tvdss is interpreted across the Phase 1 area, except for the Horst which has a FWL of 2,145 m tvdss. Initial pressure and temperature are 2,776 psia and 157°F, respectively at a datum depth of 1,820 m tvdss.

3.4.2. Clair Ridge

The Clair Ridge development, which targets the area NE of Phase 1, achieved first oil in November 2018. The initial phase of the Ridge development targets two main units (Units III and V) within five segments (1, 2A, 2B, 3 & 4).

Unit III is volumetrically the most significant reservoir on the Clair Ridge field with average thickness of 130m; but variable due to basement onlap. Lower Unit III is composed of very fine sandstone and siltstone while Upper Unit III is very fine sandstone. The latter can have excellent reservoir properties by Clair standards (porosity 14% and permeability on average 119 mD and with individual core plug permeabilities up to 7 Darcy).

Unit IV is largely non-reservoir and forms a vertical baffle.

Unit V is the main reservoir in the Clair Phase 1 area and in parts of the Ridge area, where it has an average permeability of 20 mD with some high permeability beds up to several Darcy.

Oil fluid properties are 24° API, 3.2 cP viscosity and initial solution gas-oil ratio of some 380 scf/stb. There may be a slight compositional gradient with depth and some variation between segments.

The FWL is shallower in the Ridge at 2,060 m tvdss. Initial pressure and temperature are 2,776 psia and 157 °F, respectively at a datum depth of 1,820 m tvdss.

The sanctioned development consists of 25 producers, 10 injectors and one cuttings re-injection well. Six of the development wells (four producers, one injector and the cuttings re-injection well) had been drilled at the Effective Date.

3.4.3. Development Plans

Future plans for Clair Phase 1 include five infill wells targeting the Segment 3A, Core, and Basement areas. The infill well campaign is scheduled to start 2H 2021 and be finished towards end of 2023. Undeveloped Reserves are assigned to this infill well campaign project.

Drilling continues on Clair Ridge toward fulfilment of the sanctioned 36 development wells as per the approved FDP. As of 30 June 2020, another 30 wells (21 producers and nine water injectors) remain to be drilled and completed. Drilling of water injection Well B07 had to be temporarily suspended in March-April 2020 due to Covid-19. In May 2020, producer B08 was spudded and is expected to be completed after the Effective Date. Drilling activities will resume on Well B07 after B08. Wells B09 through to B36 are planned to be drilled on a continuous basis over the nest many years. Undeveloped Reserves are assigned to these sanctioned remaining 28 development wells.

3.4.4. Technically Recoverable Resources

3.4.4.1. Clair Phase 1 Developed

Phase 1 Developed Reserves have been derived by extrapolating the historical rise in water production, using a linear relationship between the logarithm of water-oil ratio (WOR) and cumulative oil produced (WOR versus Cumulative oil method) for the Phase 1 area as a whole. A linear trend was well-defined prior to the addition of four new wells in 2016-17, since when a lower and less steep WOR trend has been established.

Examination of historical field liquid rates per producing well shows a very slight decline, 1.2% per annum, which is imposed on ERCE's forecast of liquid throughput for the developed wells. Combining this with the WOR trend gives a forecast for oil production from these wells. As the throughput forecast is based on actual historical rates, the combined operating efficiency of the Phase 1 wells, facilities and export route is already incorporated into the oil forecast, on the assumption of no substantial change to these individual efficiency factors.

The main uncertainty lies in the prediction of water-cut. By using different trends low and high case profiles were estimated.

The estimated oil Developed Technically Recoverable Resources (TRR) for Clair Phase 1 to a presumed technical life of 2038 are 221 MMstb (low), 245 MMstb (best), and 268 MMstb (high). These compare with the Operator's Q2 2020 long term plan ("LTP") forecast of 248 MMstb.

3.4.4.2. Clair Phase 1 Undeveloped

The five infill wells targeting Segment 3A, the Core and Basement areas are classified as Undeveloped Reserves by ERCE. Adapting the WOR versus Cum method used for the Developed TRR by associating with each new well an increase to the liquid throughput, low, mid and high case profiles for the combined Developed plus Undeveloped forecast have been calculated using the same uncertainty approach for the WOR extrapolation.

Field gross TRR estimates for the combined Developed plus Undeveloped are presented in Table 3-20 and include the cumulative production to date. The recovery factor to date and best estimate technical recovery factor are based on the Operator PIIP. The estimates are to a presumed technical life of 2038. The best estimate oil TRR of 285 MMstb compares to 288 MMstb from the Operator's Q2 2020 LTP forecast for Clair Phase 1.

3.4.4.3. Clair Ridge Developed

The sanctioned development consists of 25 producers, 10 injectors and one cuttings re-injection well. All these wells are classified by ERCE as Reserves. Clair Ridge Developed Reserves are from the existing well stock of B01, B02, B04 and B06, supported by water injection into B05. Wells B01, B02 and B05 are in Unit III of Segment 2; Well B04 is in Unit V of Segment 3, and Well B06 is in the same unit but in Segment 4.

Unfortunately, there is insufficient production history and there are too few wells online to perform any meaningful field decline analysis or water trend analysis as a basis for prediction. Instead, ERCE has based its view on: the field development plan (FDP), which was updated in 2017, prior to production; the Q2 2020 LTP; and on the simulations more recently performed as a TDRM (Top Down Reservoir Management) exercise by the Operator using their updated static model.

ERCE has taken account of the higher than expected water cuts in Wells B04 and B06 by rescaling the water cut versus cumulative oil relationship for each well as defined in the 2017 FDP. ERCE's resulting view of the Developed TRR to 2057 for Clair Ridge is 70 MMstb (low), 88 MMstb (mid) and 126 MMstb (high).

3.4.4.4. Clair Ridge Undeveloped

The bulk of the Clair Ridge Reserves lie in the Undeveloped category. Undeveloped Reserves include the next seven wells, B08 through to B17, for which revised completion dates were provided at the May 2020 TCM; plus the remaining 14 of the 25 sanctioned producers outlined in the FDP.

The drilling track record on Clair Ridge shows that early wells suffered non-productive time events with rig equipment failures being the major cause and waiting on weather. In addition, formation fractures have caused drilling fluid losses resulting in a requirement to install a Managed-Pressure-while-Drilling ("MPD") system to support the drilling operations. Covid-19 has additionally placed limitations on persons on board the platforms and other logistical requirements for drilling. Hence, the Operator's original FDP drilling schedule is now considered by ERCE to be too optimistic. The Operator's 2020 LTP reflects continued drilling operations on Clair Ridge to last through to the end of 2026. ERCE estimates that drilling operations may well have to continue into 2027 before all remaining 28 wells have been completed.

Having made a revised estimate of the recovery to be expected from Wells B04 and B06, ERCE has made downward revisions to the TRR for other wells in their segments, namely Segments 3 and 4. ERCE notes that the FDP carries forecast for two yet-to-be drilled wells, Wells B09 and B019, to recover 195 MMstb of oil, which amounts to 30% of the total planned TRR. Since these two wells are also in Segments 3 and 4, the likelihood of them achieving such high recovery can reasonably be questioned. The experiences from Wells B04 and B06 raise the possibility both that reservoir quality may be poorer than expected in Unit V in those segments, and also that the nature of the fracturing in those areas may lead to earlier water breakthrough and poorer sweep than expected.

The Operator's 2020 LTP shows a reduced full development TRR. This is corroborated in its CDP6 Simulation Report where the average TRR from its six 'Key Deterministic Cases' is 530 MMstb.

To estimate the total, Developed plus Undeveloped TRRs and the corresponding production profiles, ERCE has built a model comprising two 'type' wells, with parameters representing the average initial rates and expected recovery from the best 12 (in the one case) and the worst 13 wells (in the other) as estimated in the FDP – with downward revision to the TRR for Wells B04, B06, B09 and B019 for the reasons stated above. The type profiles were then sequenced in accordance with the assumed, revised drilling schedule leading to ERCE's best estimated Developed plus Undeveloped TRR for Clair Ridge of 527 MMstb (Table 3-20).

To evaluate an appropriate uncertainty range, ERCE considered two views from the Operator: One, pre-production, from the original FDP back in 2011 (the 2017 update does not describe uncertainties), and another more recent from the recent reservoir simulation. In the former, the range of TRRs is expressed as 424 (low), 610 (best) and 811 (high) MMstb. In the latter, the cumulative probability plot presented indicates corresponding numbers of 432, 537 and 650 MMstb.

The simulation uncertainty (above) is ± 20%, which ERCE regards as too narrow. Noting that Clair Ridge is still in a very early stage of development, ERCE considers a wider range of uncertainty to be appropriate. ERCE has therefore applied a range of -30% to +40% to our best estimate giving a low case TRR of 378 MMstb and a high case TRR of 732 MMstb (Table 3-20).

Corresponding low and high case production profiles were calculated by introducing progressively decreasing (or increasing) multipliers onto the best estimate profile, while – in the high case – respecting platform liquid handling capacity. (The same multipliers were used to estimate the low and high Developed profiles from the best estimate Developed profile.)

Table 3-20: Clair Phase 1 and Clair Ridge TRR and RF estimates

Asset/ Field	Hydrocarbon	PIIP (Operator Best Estimate)	Cum. Prod. at 30 Jun 2020	RF to date	TRR Estimate			TRR best est. RF
					Low	Best	High	
Clair Phase 1	Oil (MMbbl)	1,442.0	148.4	10%	244.7	285.4	330.6	20%
	Gas (Bscf)	408.1	49.4	12%	76.7	88.2	101.0	22%
Clair Ridge	Oil (MMbbl)	2,214.0	17.9	1%	378	527	732	24%
	Gas (Bscf)	823.6	7.8	1%	141.6	197.3	273.6	24%

3.4.5. CAPEX Assumptions

The CAPEX profile used for the economic modelling is based upon cost data provided to partners such as AFEs, budgets and forecasts from partner meetings. This data has been reviewed and profiles developed accordingly.

The major CAPEX expenditure associated with Undeveloped Reserves projects on Clair Phase 1 in the forecast is on the five infill wells and a work-over planned to take place during Oct-21 to Jan-24 ($ 257 MM). Further facilities cost including costs related to hook-up of new wells and rig re-certification to support future workover activities is considered at a cost of $121 MM.

The major CAPEX expenditure associated with Undeveloped Reserves projects on Clair Ridge in the forecast is on the drilling of the remaining 28 development wells (Wells B09 through to B36) to take place until 2027+ and on the MOL pump and water injection remediation projects. Forward considered well costs are $1,257 MM and facilities cost including hook-up of new wells, rig re-certification and the remediation projects on the MOL pump and water injection facilities are $365 MM. ERCE note that the Operator currently has approved long lead expenditures for all wells up to and including Well B13.

Table 3-21 and Table 3-22 provide listings of the estimated forward CAPEX and ABEX elements for both Clair Phase 1 and Clair Ridge.

Table 3-21: Clair Phase 1 & Clair Ridge CAPEX and ABEX - Developed

Clair Phase 1 & Clair Ridge CAPEX and ABEX Costs $MM - Developed Case					
Field	Cost element	Facilities dev $MM	Dev Wells	Dev. Wells $MM	Total - Dev $MM
Clair Phase 1	CAPEX	116			116
	ABEX	172	18	233[1]	405
Clair Ridge	CAPEX	321			321
	ABEX	250	8	60	310

Note
1. Includes additional P&A cost of three suspended open-water E&A wells

Table 3-22: Clair Phase 1 & Clair Ridge CAPEX and ABEX – Developed + Undeveloped

Clair Phase 1 & Clair Ridge CAPEX and ABEX Costs $MM – Developed + Undeveloped Case						
Field	Cost element	Facilities dev+Und $MM	Undeveloped Wells	Dev+Und. Wells	Dev+Und. Wells $MM	Total - Dev & Undev $MM
Clair Phase 1	CAPEX	121	5+1w/o	24	257	378
	ABEX	172	5+1w/o	24	263[1]	435
Clair Ridge	CAPEX	365	28	36	1,257	1,622
	ABEX	250	28	36	271	521

Note

1. Includes additional P&A cost of three suspended open-water E&A wells

3.4.6. OPEX Assumptions

The Operator provides detailed long-term plans with annual updates. These have been reviewed against historic out-turn costs and adopted going forward. 2H 2020 costs have been taken from the latest provided full year estimate. The Operator (BP) is currently restructuring and anticipates cost reductions arising from this. No detail has been made available in respect of this, however, it is credible that OPEX may fall in the medium term relative to the profile taken from the 2020 LTP.

Clair Phase 1 and Clair Ridge are predicted to become fuel gas deficient before the CoP date. Although the Operator in their LTP does not provide separate breakout of energy costs for power generation by fuel gas and later diesel, the emissions sheets do show that they plan to use diesel when the fields becomes fuel gas deficient. Hence, ERCE considers that the Operator in their 2020 LTP has included the incremental cost when having to switch to using diesel for power generation in their OPEX forecasts.

Average OPEX over the near term for Clair Phase 1 is some $135 MM to $150 MM per year and similar for Clair Ridge.

3.4.7. Abandonment Assumptions

The Operator provided field abandonment reports and associated estimates. These have been reviewed and the costs adopted in the economic model.

The data on wells decommissioning provided by the Operator have been reviewed and considered acceptable. The well stock for the Clair Phase 1 platform at the time of decommissioning including the incremental Undeveloped Reserves projects is 24 platform wells and three suspended open-water subsea E&A wells. The total amount considered for well P&A is $263 MM.

The Clair Ridge platform will have a well stock of 36 platform wells at decommissioning. The total well P&A cost estimated by the Operator and adopted by ERCE is $271 MM which gives an average platform well P&A cost similar to the average OGUK benchmark cost. However, ERCE highlight, that this well P&A cost are at risk of being significantly higher given the harsh West of Shetland operational environment.

ABEX cost data considered are listed in Table 3-21 and Table 3-22

3.4.8. Facilities and Well Integrity

The Clair Operator provides limited data to its partners in terms of maintenance backlog and associated issues at the OCM/TCMs. As a result, ERCE has been unable to develop a clear understanding of the facilities integrity. ERCE is aware that the reservoir fluids are sourer than the facilities were initially designed for however there is no reason why this cannot be managed safely. ERCE has assumed that the facilities will be able to handle the forecast production.

3.4.9. Reserves

The technical production profiles described in Section 3.4.4 were converted to sales profiles for oil and gas using the conversion factors provided by Chrysaor for oil and gas shrinkage, and accounting for fuel and flare (Table 3-23). In this case, no shrinkage is applied for oil or gas as the allocation is in sales/export volumes. Similarly, no further correction is required for uptime as the profiles were developed on the basis of historical and current actual throughput performances. The gross asset level production forecast (sales) for the Developed plus Undeveloped Reserves categories are included in Appendix 4.

Table 3-23: Clair Area sales conversion parameters

Field	Oil Shrinkage	GOR (scf/stb)	Gas Shrinkage	Fuel & Flare MMscf/d
Clair Phase 1	0%	283	0%	4.5
Clair Ridge	0%	372	0%	13.5

Reserves were estimated to the earlier of the economic cut-off date and the end of the technical profile. These CoP dates were determined separately for Clair Phase 1 and Clair Ridge. In each case (Developed, or Developed plus Undeveloped; P90, P50 or P10), the corresponding technical profiles were input to the economic model to determine the 1P, 2P and 3P CoP dates, respectively.

For both fields, the Developed Reserves were based on the existing well stock. Clair Phase 1 Undeveloped Reserves comprise the incremental recovery from five planned wells targeting Segment 3A, Basement and Core infill areas. For Clair Ridge, where the larger part of reserves are so far undeveloped, the Undeveloped Reserves cover the expected recovery from completion of the remaining 21 producing wells and seven supporting water injectors that were sanctioned in the Clair Ridge FDP (2011), updated details of which are included in the Operator’s Clair Ridge Depletion Plan (2017).

A summary of the gross on block Reserves is presented in Table 3-24 together with CoP dates.

Table 3-24: Clair Field Gross Reserves with CoP dates

Field	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Clair Phase 1	Developed	71.21	95.57	118.27	1.11	2.49	4.79
	Undeveloped	23.43	40.07	62.69	2.95	7.78	16.01
	Total (Dvpd+Undvpd)	**94.63**	**135.64**	**180.96**	**4.07**	**10.28**	**20.80**
	COP (Total)	Dec-38	Dec-38	Dec-38	Dec-38	Dec-38	Dec-38
Clair Ridge	Developed	29.47	43.39	78.91	0.00	0.15	0.41
	Undeveloped	330.23	466.56	637.01	27.91	62.62	108.77
	Total (Dvpd+Undvpd)	**359.70**	**509.95**	**715.93**	**27.91**	**62.77**	**109.18**
	COP (Total)	Dec-57	Dec-57	Dec-57	Dec-57	Dec-57	Dec-57
Total Asset	Developed	100.68	138.96	197.18	1.11	2.64	5.21
	Undeveloped	353.65	506.63	699.71	30.86	70.41	124.77
	Total (Dvpd+Undvpd)	**454.33**	**645.59**	**896.89**	**31.98**	**73.05**	**129.98**

3.4.10. Contingent Resources Projects

ERCE has conducted an audit of Chrysaor's Contingent Resources estimates as detailed in Section 6. A number of Contingent Resources projects are associated with the Greater Clair Area as presented in Table 3-25. The possible timings are in line with the first oil dates from the Operator's June 2020 long term plan. The Contingent Resources estimates associated with these projects are presented in Table 6-1 of Section 6.

Table 3-25: Greater Clair Area Contingent Resources Project Summary

Field	Project	Possible Timing	Sub-Maturity Class
Clair South	Development	2028	DOH
Clair South	Further targets (West & Unfract. Phase 1 Core)	To be determined	DUC
Clair North	Development	To be determined	DUC
Clair Phase 1	Further Infill	2025	DUC
Clair Ridge	Infill, incl. 15 shared conductors	2027	DUC
Clair Ridge	Further Infill (8 wells)	2030	DUC

The further infill projects in the Clair Phase 1 and Ridge areas are detailed in the Operator long term plans. The shared conductor project in Clair Ridge involves using wellhead splitter technology to increase the number of wells that can be drilled from the existing platform slots.

The development plan for Clair South dates from 2017 and involves either the installation of a dedicated platform with some subsea wells or a subsea development tied back to a bridge linked platform next to the Clair Ridge platform. The oil is slightly more viscous (7-10 cP) compared to the Phase 1 (4-5 cP) and Ridge (3 cP). As with the other areas waterflooding will be required. The plans involve drilling up to 41 wells (23 producers and 18 injectors).

The Clair North development covers the NE extension of the ridge area. The area is complex and suffers from poor seismic quality and extensive faulting. Further appraisal and seismic may be required to reduce the uncertainty.

3.5. East Irish Sea Assets

Chrysaor's East Irish Sea ("EIS") assets are located in quadrants 110 and 113 offshore of the north-west coast of England, near the developed North and South Morecambe fields. The EIS Area consists of the Millom and Dalton fields and the Rivers Complex, which comprises one field, Calder and four discoveries (Figure 3-34). Chrysaor acquired a 100% interest in the fields as part of the ConocoPhillips Transaction in 2019. As part of a service agreement, Spirit Energy, which is the Operator of the North Morecambe Platform, operates the EIS Area fields.

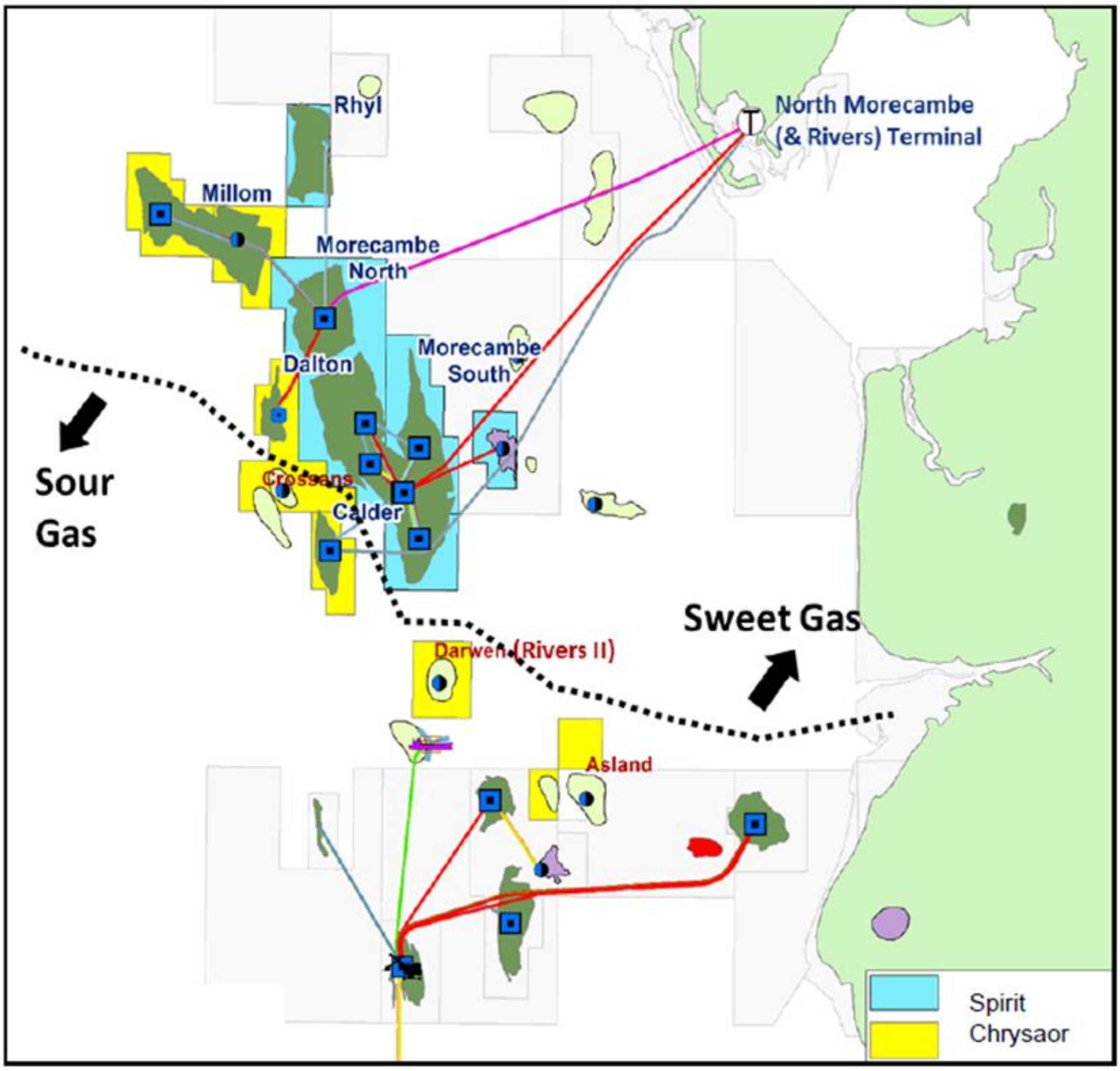


Figure 3-34: East Irish Sea assets location map (source: Chrysaor)

The primary reservoir in the EIS Area is the upper most sandstone of the Lower Triassic Sherwood Group, the Ormskirk Sandstone. The reservoirs are a mixture of aeolian, fluvial and sabkha deposits circa 1,200 m thick. The reservoir is at a depth of 600 – 1,200 m tvdss. Original reservoir pressures are low, between 500 - 2,500 psia. The reservoir fluid is dry gas containing different amounts of inert gases.

Most of the EIS Area production comes from two fields, Millom (sweet gas) and Calder (sour gas), which are still on production.

The Millom gas field is located in blocks 113/26a (Millom West) and 113/27a and 110/2c (Millom East) in water depths of approximately 36 m. The Calder field, part of the Rivers Complex, is located 10 to 15 km southwest of the Morecambe South gas field. The field structure is a NNW - SSE tilted fault block. The Millom and Calder fields are produced under natural depletion; there is no evidence of aquifer support.

A summary of the two fields, together with some relevant data, is presented in Table 3-26.

Table 3-26: Millom and Calder Summary

	Millom	Calder
Fluid	Dry Gas (N_2: 10%, H_2S: 0%)	Dry Gas (N_2:16%, H_2S: 0.4%)
Main Reservoir	Triassic Sherwood Sandstone	Triassic Sherwood Sandstone
Depth	1200 m	760 m
Pressure, Temperature	2100 psia 40ºC	1300 psia 27ºC
Column Height	36 m	45 m

A third producing field, the Dalton gas field, located in block 110/2b, is 40 km from Barrow-in-Furness and approximately 10 km NW of the North Morecambe gas field. The water depth is approximately 35 m. Production from the field is backed out by Millom production and so the two Dalton Wells, R1 and R2, can only flowed be flowed when Millom is shut-in and/or the line pressure is less than 8.5 bar (123.3 psi). The recoverable resources associated with the Dalton field are not considered material. However, the field is included as an abandonment liability.

At the end of June 2020, 153 Bscf of gas has been produced from the Calder field, 249 Bscf of gas from the Millom field and approximately 50 Bscf from the Dalton field. Gas production histories are presented by field in Figure 3-35.

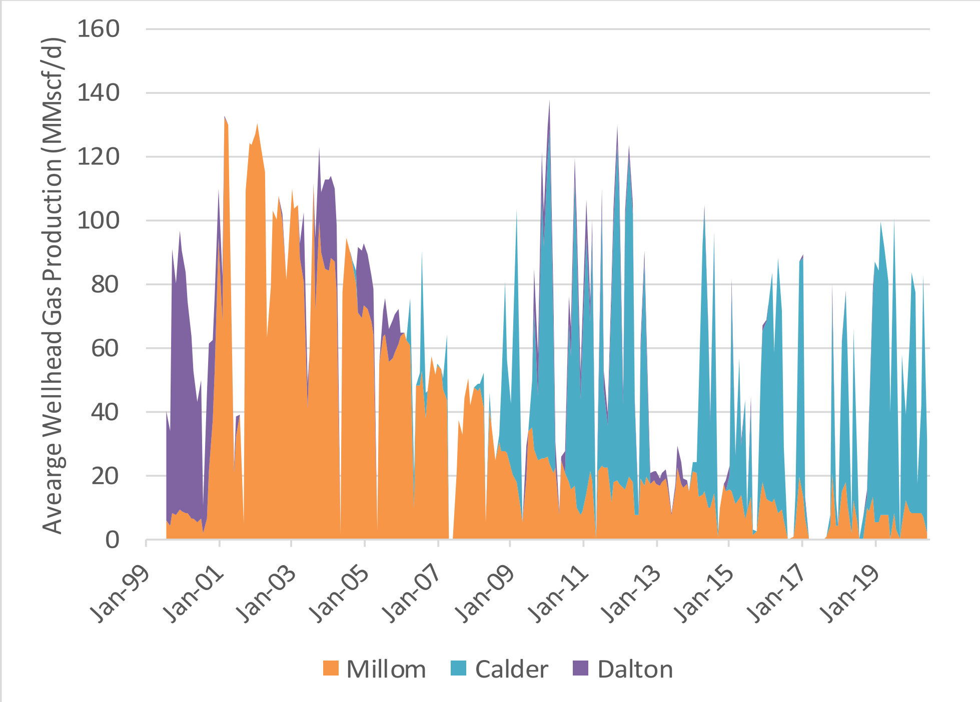


Figure 3-35: East Irish Sea Assets gas production history by field

The Millom field has been developed via a Normally Unmanned Installation ("NUI") platform, with Millom East connected as a subsea tieback. Millom gas is evacuated via a 12", 15 km tie-back to North Morecambe where gas is processed to remove nitrogen. The Calder field has been developed utilising a NUI platform with three single completion wells. Production from the Calder platform is exported to the Rivers Terminal via a dedicated 24", 49 km pipeline. Here the gas is treated to remove the hydrogen sulphide and then transferred to the North Morecambe Terminal where nitrogen and carbon dioxide are removed, and the gas further treated to comply with the National Transmission System ("NTS") sales gas specifications.

3.5.1. Millom Field

The Millom field is divided into two accumulations. The western accumulation was discovered in 1982 by Well 113/26-2 and the eastern accumulation was discovered in 1987 by Well 113/27-3. Structural connection between the two accumulations was proven in 1992 by Well 13/26a-2. In-place volumetric estimates were updated in March 2015 using a revised static model that superseded previous estimates. Uncertainty was based on varying the FWL assumptions in Millom East.

The field has been on production since 1999 with four platform wells draining the western area. The wells suffer from salt impairment and require regular water wash programmes. Two of the wells are produced on a cyclic basis. The eastern area has been developed with three subsea wells (Figure 3-36) of which only one, Well Q3, is an active producer. As of the Effective Date, Well Q3 was not online, but is expected to restart production at the beginning of 2021. A total of 219 Bscf and 30 Bscf of gas have been recovered from Millom West and Millom East respectively.

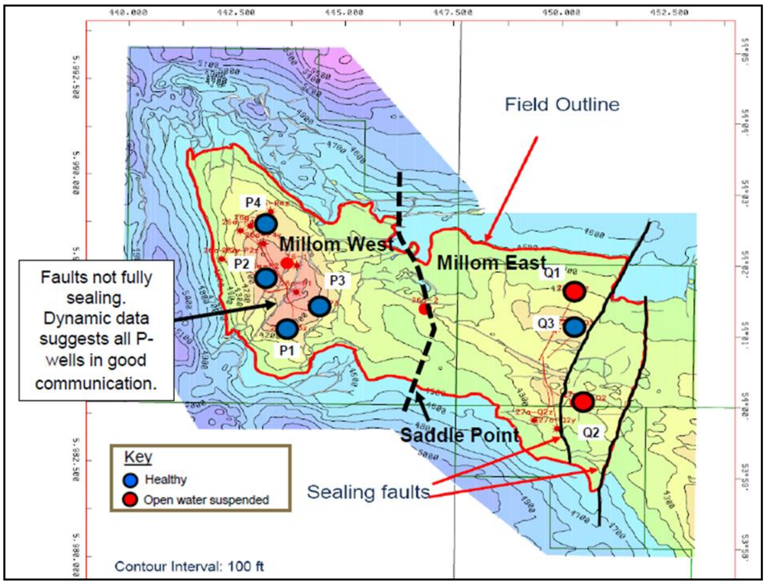


Figure 3-36: Millom Subsurface Overview (source: Chrysaor)

3.5.2. Calder Field

The Calder sour gas field was discovered in 1983 by Well 110/7a-3 and appraised by two subsequent wells. The gas is underlain by a thin 4 m oil rim. The field was developed with three wells establishing first gas production in 2004. Production is via a dedicated 24", 49 km pipeline to the Rivers gas terminal at Barrow. At the end of June 2020, the cumulative gas production from the field was 153 Bscf. Total field level production data were provided but without allocation to the well level. Chrysaor reports that Wells T1z and T3 are continuous producers, but Well T2 is shut-in because of a methanol metering issue. The well locations are displayed in Figure 3-37.

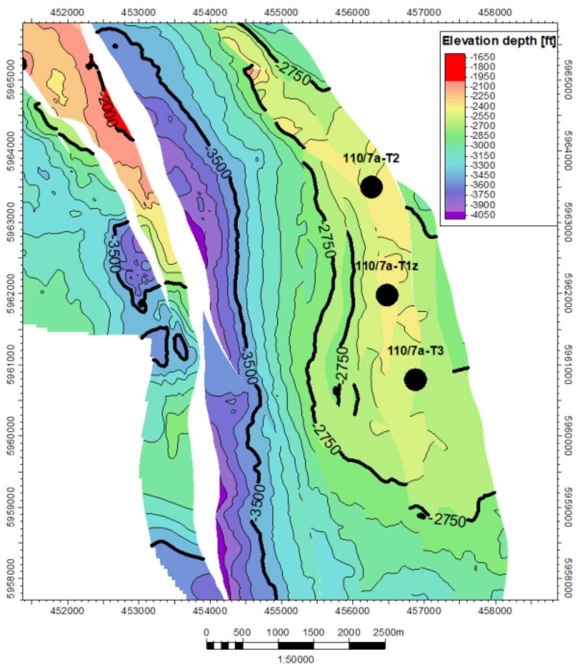


Figure 3-37: Calder Well Locations (source: Chrysaor)

3.5.3. Development Plans

There are no firm plans to drill further wells in the EIS Area. Additional Reserves are associated with a compression project at Calder which is planned to reduce the suction pressure in order to extend production life. There are two existing Calder compressors (“FGCs”) operating with different suction pressures. The Operator has investigated various configurations of the FGCs with running the compressors in series the currently preferred option. The costs involved are relatively low and are included in the business plan for 2022 and 2023. ERCE has assigned Developed Reserves to the incremental resources recoverable through this project.

3.5.4. Technically Recoverable Resources

ERCE has not prepared an independent volumetric estimate of the gas initially in place (“GIIP”) for the Millom and Calder fields. ERCE has compared Chrysaor’s mapped in-place volumes with the hydrocarbon volumes interpreted using p/z analysis. There is good alignment between mapped and p/z-derived volumes. More uncertainty exists in the Millom field where the degree of reservoir communication and hence the connected volume is less well defined.

ERCE’s TRR estimates were derived by estimating the recovery using the p/z plot extrapolated to the expected abandonment pressures. These estimates were then reconciled with the results of independent forecasts generated by ERCE using decline curve analysis. The DCA was performed on operating rate versus cumulative gas and versus time. The analysis was carried out by well for the Millom field and at a field level for the Calder field.

For Millom West, ERCE has analysed Chrysaor well by well forecasts at 100% operating efficiency and accepted Chrysaor’s low and best forecasts. The high case forecasts were adjusted to create a wider range of uncertainty in ultimate recovery. For Millom East, ERCE has analysed the single Well Q3 forecast proposed by Chrysaor. This was generated using a Gap network model accounting for production system pressure interactions and constraints. ERCE sees these forecasts as reasonable and has accepted the recovery (including operating efficiency) proposed at all levels of confidence. New production profiles (at 100% operating efficiency) were generated by ERCE to match our view on TRR. Gas recoveries from Millom West and Millom East were also reconciled with estimates from the p/z methodology (at 160 psia abandonment pressure).

For the Calder field, ERCE has estimated a potential range of uncertainty based on the p/z analysis prepared by Chrysaor which shows minimal scatter. Recoveries at different abandonment pressures (corresponding to different compressor configurations) were estimated and a range of uncertainty defined. The estimates were reconciled with ERCE’s forecasts generated using DCA.

ERCE’s forecasts for Millom West and East were aggregated to field level and, as for Calder, allowances were made for production efficiency incorporating planned turn arounds (TARs) and for intermittent, cyclic producers. For the Millom field, ERCE has assumed operating efficiencies (OE) of 30% for years 2020 and 2021, and of 60% afterwards. For Calder ERCE has assumed operating efficiencies of 50% and 40% respectively for years 2020 and 2021, and of 60% afterwards (Table 3-27). At a well level additional efficiency factors were accounted for in Millom, where cyclic Wells P2 and P3 are forecasted respectively at 40% and 70% operating efficiencies.

Table 3-27: East Irish Sea Assets assumed operating efficiency

Asset	Operating Efficiency									
	2020 H2	2021	2022	2023	2024	2025	2026	2027	2028	2029
Millom	30%	30%	60%	60%	60%	60%	60%	60%	60%	60%
Calder	50%	40%	60%	60%	60%	60%	60%	60%	60%	60%

Note

1. OE estimates after 2029 remain constant.

ERCE's gross Developed plus Undeveloped TRR estimates are presented in Table 3-28 and include the cumulative production to date. The recovery factor to date and best estimate technical recovery factor are based on the mapped GIIP reported by Chrysaor as best estimates.

ERCE has not identified a technical Cessation of Production (CoP) associated with the design life of the facilities as past studies indicated that life extension of the facilities could be achieved with moderate remediation outlays. As such, technical profiles were not curtailed at a specific date and all TRR are reported, for comparison purposes, at year 2050.

Table 3-28: East Irish Sea Assets TRR Estimates and Recovery Factors

PIIP	Chrysaor Best Estimate GIIP (Bscf)	Cumulative Production at 30 Jun 2020 (Bscf)	RF to date	TRR (Bscf)			Estimated Technical RF (best)
				Low	Best	High	
Millom	440	249	57%	271	283	298	64%
Calder	325	153	47%	270	283	296	87%

3.5.5. CAPEX Assumptions

Limited data was provided to support the assessment. The current year's budget and an estimate for the deferred 2020 Calder barge campaign were used to support the CAPEX profile. A technical report was provided that showed that reduced suction pressure compression can be achieved by placing the existing compressors in series at minimal cost. Total CAPEX considered for the East Irish Sea assets Miller, Calder and Rivers II over the next eight years is $87.3 MM.

3.5.6. OPEX Assumptions

Limited data was provided to support the assessment. The latest and previous years budgets were used as the basis for the forecast. Annual OPEX for the East Irish Sea assets is some $43.8 MM per year.

3.5.7. Abandonment Assumptions

Limited data was provided to support the ABEX estimate. ERCE has considered a facilities decommissioning cost of some $90MM and well P&A costs of $118 MM.

3.5.8. Facility and Well Integrity

The contracted Operator (Spirit Energy) has raised significant integrity concerns around the condition of both the Millom and Calder platforms. Work is required to bring the helideck at Millom into compliance with CAP-437. The Civil Airline Authority (CAA) has limited landings at the facility until this work is completed, which limits the maintenance work that can be carried out. There are plans to address the issues with a walk-to-work barge campaign at both locations during 2021. There would be a significant risk to the production profiles should this planned campaign not be carried out.

Millom wells are impaired by salt deposition downhole and a water wash program is recommended and carried out typically twice a year. The Millom East producing Well Q3 is shut-in due to upper and lower master valves issues.

The Calder field suffers from odour related issues (H_2S at 2,500ppm) and the Rivers terminal's restricted gas throughput.

The two Dalton intermittent producers R1 and R2 flow opportunistically when the line pressure is below 8.5 bar. The wells are currently shut-in due to topside integrity issues.

3.5.9. Reserves

The technical production profiles described in Section 3.5.4 were converted to sales profiles using shrinkage and yield factors, which were based on data provided by Chrysaor. Wellhead gas was corrected for fuel and flare consumption; estimated at 2 MMscf/d and 5 MMscf/d for Millom and Calder respectively at full operating efficiencies (100%). Fuel consumption was pro-rated on the basis of the OE factor estimated by ERCE. The Millom field quickly becomes fuel gas deficient at all levels of confidence curtailing the technical profiles. As advised by Chrysaor, gas shrinkage factors of 5% and 10% have been used for Millom and Calder respectively. ERCE has used oil equivalent conversion factors as presented in Appendix 3 to calculate barrels of oil equivalent (Bscf to MMboe). The gross asset level production forecast (sales) for the Developed plus Undeveloped Reserves categories are included in Appendix 4.

Reserves were estimated to the earliest of the economic cut-off dates and the end of the technical profile. For the EIS area fields all the field low technical profiles were arithmetically summed and input into the economic model to determine the 1P CoP date. Similarly, all the mid-case profiles and all the high case profiles were added and used to determine the 2P and 3P CoP dates.

A summary of the gross on block Reserves by field is presented in Table 3-29 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 3-29: East Irish Sea Area Gross Reserves by field with CoP dates

Field	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Calder	Developed	0.00	0.00	0.00	80.08	91.96	99.26
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total (Dvpd+Undvpd)	**0.00**	**0.00**	**0.00**	**80.08**	**91.96**	**99.26**
Millom	Developed	0.00	0.00	0.00	10.24	14.73	18.05
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total (Dvpd+Undvpd)	**0.00**	**0.00**	**0.00**	**10.24**	**14.73**	**18.05**
Total Asset	Developed	0.00	0.00	0.00	90.32	106.69	117.31
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total (Dvpd+Undvpd)	**0.00**	**0.00**	**0.00**	**90.32**	**106.69**	**117.31**
	COP (Total)	Jun-27	Jun-28	Dec-28	Jun-27	Jun-28	Dec-28

3.5.10. Contingent Resources Projects

ERCE has conducted an audit of Chrysaor's Contingent Resources estimates as detailed in Section 6. A number of Contingent Resources projects are associated with the East Irish Sea Assets as presented in Table 3-30. The Contingent Resources estimates associated with these projects are presented in Table 6-1 of Section 6.

Table 3-30: EIS Area Contingent Resources Project Summary

Field / Area	Project	Possible Timing	Sub-Maturity Class
Rivers II	Darwen	Q1 2025	DOH
Rivers II	Crossans	Q1 2029	DOH
Calder	Compression - pressure reduction from 10 bar to 5 bar	To be determined	DOH

The Calder Contingent Resources compression project is a follow up to an existing planned project to implement series compression at Calder (Section 3.5.3).

Contingent Resources are attributable to the Rivers Phase II project. This comprises the development of two sour gas discoveries: Darwen; and Crossans. The plan is to drill one subsea development well at each discovery tied back to the Calder NUI platform. Development will be phased in line with the sour gas facility constraints at the Rivers Terminal. Darwen would be tied back to the existing 12" Calder riser and Crossans would be tied back to the existing 10" Calder riser. Darwen, the largest discovery, was drilled in 1991 by Well 110/8A-4 and flow tested with a DST, with a reported rate of 27.1 MMscf/d and a CGR of 5-10 stb/MMscf.

3.6. Elgin Hub Area

The Elgin Hub is located in the Central Graben Area, UK Central North Sea, approximately 240 km east of Aberdeen, across Blocks 22/29b, 22/30c, 29/4d, 29/5b and 29/5c, in a water depth of approximately 92 m (Figure 3-38).

Chrysaor acquired a 14.11% working interest in Elgin, Franklin and West Franklin and a 14.7% working interest in Glenelg through the Shell Transaction in 2017. The hub is operated by Total E&P Ltd and includes four producing fields: Elgin; Franklin; West Franklin; and Glenelg. The fields were discovered between 1985 and 2003; first production was achieved in 2001.

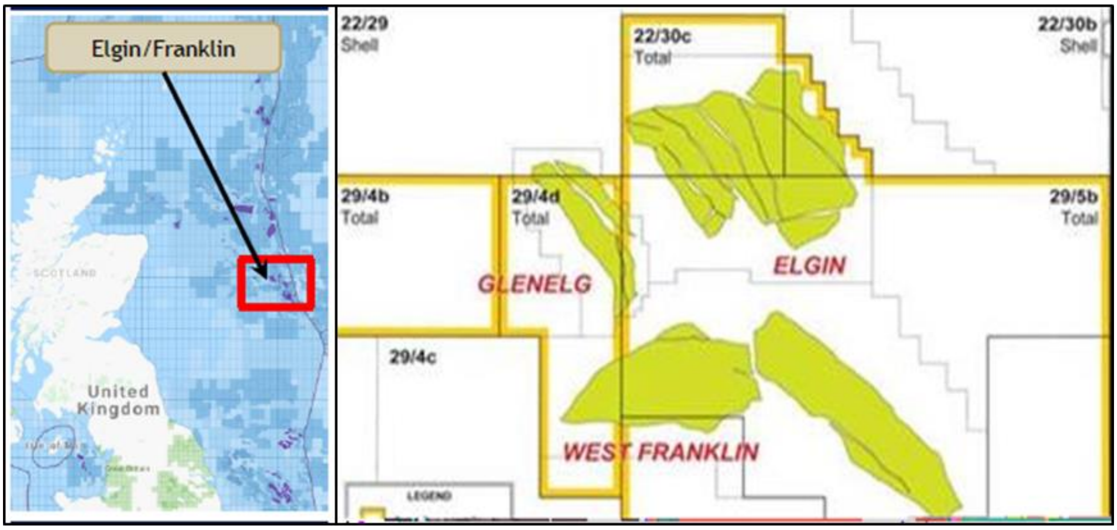


Figure 3-38: Location Map (Source: Chrysaor and Shell IM)

The fields are High Pressure, High temperature (HPHT) accumulations and produce from reservoirs at depths of between 5,000 and 6,000 m tvdss. Initial pressures were between 16,000 psia and 17,000 psia and initial temperatures from 380°F to 420°F.

The principal reservoir is the Upper Jurassic Fulmar formation, deposited as shallow marine shoreface sandstones. The hydrocarbons are sourced from the Upper Jurassic, Kimmeridge Clay formation and are structurally trapped within tilted fault blocks.

The Elgin Hub fields all contain initially highly over-pressured gas condensate. Initial pressure gradients from surface were approximately 0.93 psi/ft. Properties of the fluids vary between and, to some extent, within the fields. A summary of the fields together with some relevant data is presented in Table 3-31.

Table 3-31: Elgin Hub Summary

Typical Reservoir Properties	Elgin	Franklin	West Franklin	Glenelg
Reservoir Area (sq. km)	16	11	7	2
Reservoir Depth (m)	5,230	5,090	5,590	5486
Reservoir Temperature (ºC)	195	200	215	196
Initial Reservoir Pressure (bar)	1,100	1,100	1,150	1,129
Reservoir Pressure (bar)	250	250	550	700
Condensate Gravity (ºAPI)	50	45	45	50.1
Gross Reservoir Thickness (m)	250	320	260	290
Net Reservoir Thickness (m)	200	256	182	255
Hydrocarbon Saturation (%)	83	85	80	75
Porosity (%)	20	18	18	16
Permeability (mD)	>100	>10	>10	10
CGR (stb/MMscf)	320	170	150	160

As the fields have been produced and reservoir pressures have fallen, the formation above the reservoir (the overburden) has settled. This has resulted in deformation of casing strings within wells and consequent well integrity issues. Several wells have been affected and some wells have failed in the past. In March 2012, loss of integrity in the casing strings of Well G4 resulted in a gas leak to surface and the fields were closed in. The leak was stopped in May 2012 and production from the fields resumed in March 2013. Since the incident, the Elgin, Franklin, and West Franklin well designs have been changed to accommodate any further subsidence.

Currently production is via 15 gas wells including a cyclic well in the Glenelg field. This well stock also includes the recent Wells EIF (B4) and FIC (F12) brought on stream in August 2019 and December 2019, respectively. The cumulative production as of 30 June 2020 was 2,584 Bscf of gas and 530 MMstb of condensate. The H1 2020 average gas production rate from the hub was around 450 MMscf/d. Gas and condensate production histories are presented in Figure 3-39 and Figure 3-40 respectively.

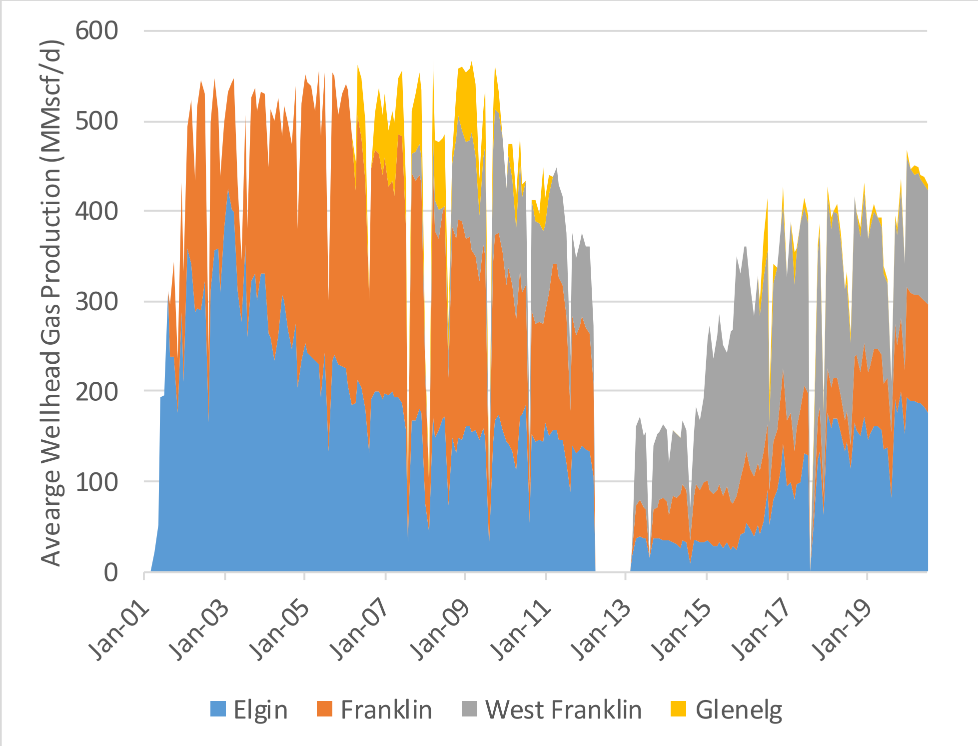


Figure 3-39: Elgin Hub gas production history by field

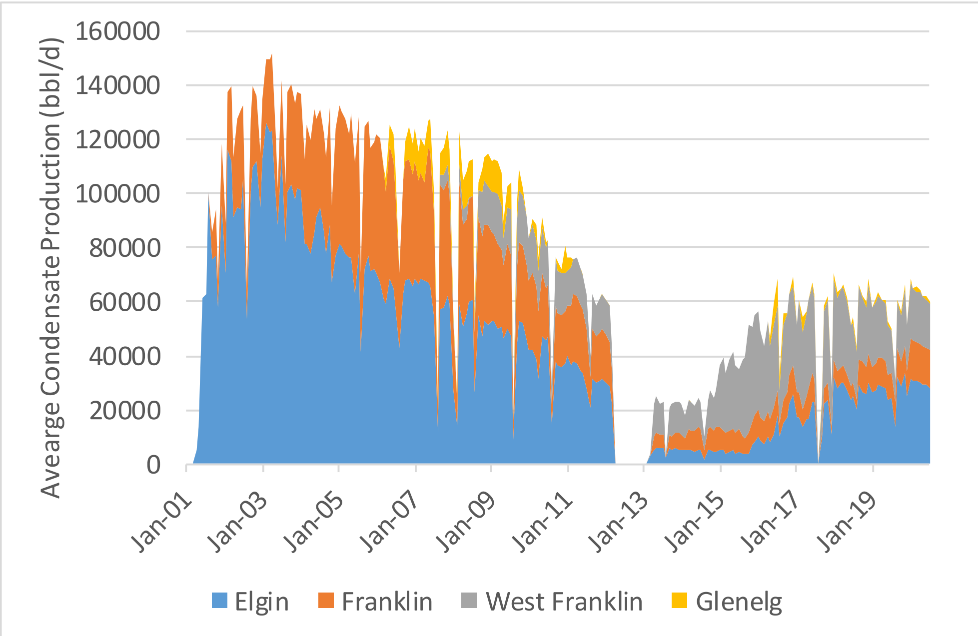


Figure 3-40: Elgin Hub condensate production history by field

A schematic of the production facilities is presented in Figure 3-41. The Elgin facilities comprise a jack-up with process, utilities and living quarters (PUQ). The Elgin A Wellhead Platform is bridge linked to the PUQ and has eight well slots. A second wellhead platform, Elgin B is bridge linked to Elgin A and has nine slots. Well drilling is conducted by a jack-up rig and includes extended reach drilling to the Glenelg field.

The Franklin facilities comprise a nine-slot remote NUI wellhead platform at Franklin and a twelve-slot remote NUI wellhead platform at West Franklin. Both platforms are remotely operated from the Elgin PUQ.

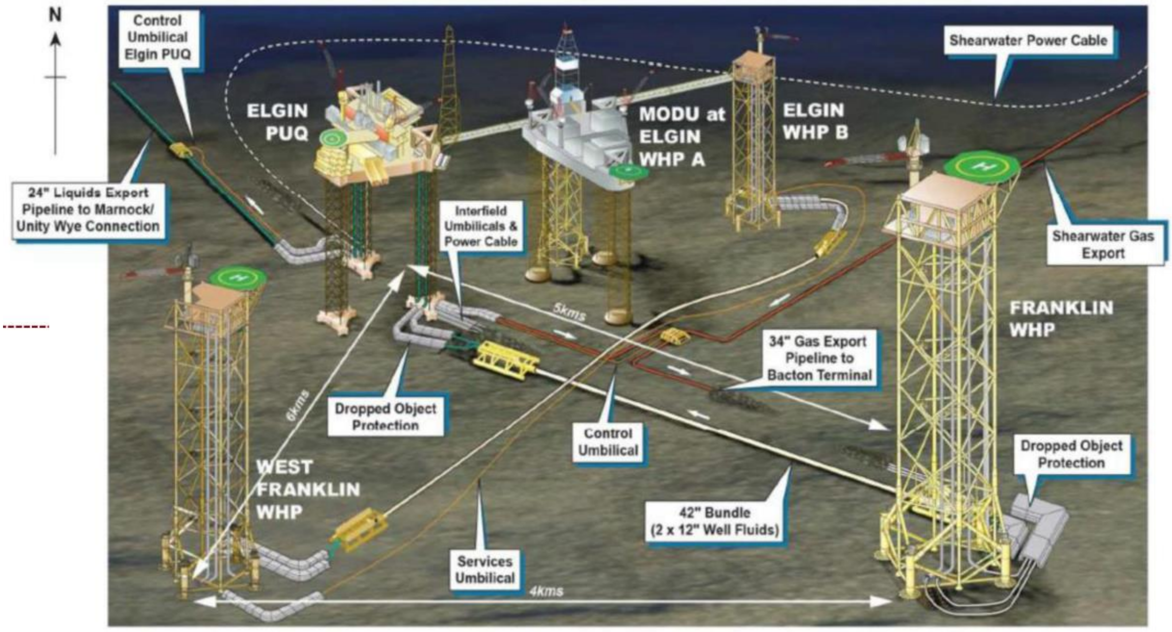


Figure 3-41: Elgin Franklin facilities layout (source: Operator)

Sales gas is exported via the Shearwater Elgin Area Line (SEAL) to the Shell Bacton Terminal and condensates and NGLs via the Marnock Platform, the Gannet Area Export Line ("GAEL") and the Forties Pipeline System (FPS) to Cruden Bay and Kinneil.

3.6.1. Elgin Field

The Elgin field was discovered in March 1991 by Well 22/30c-8 with production starting in March 2001. The Elgin wells produce to two platforms. The Elgin A Wellhead Platform is bridge linked to the PUQ and has eight well slots. A second wellhead platform, Elgin B is bridge linked to Elgin A and has nine slots. Well drilling is conducted by jack-up rig. A total of 1,054 Bscf of gas and of 295 MMstb of condensate were produced from the Elgin field as of 30 June 2020. Currently a total of six Elgin wells are producing at an average rate of 184 MMscf/d (six months average). Elgin well locations at top Fulmar are presented in Figure 3-42.

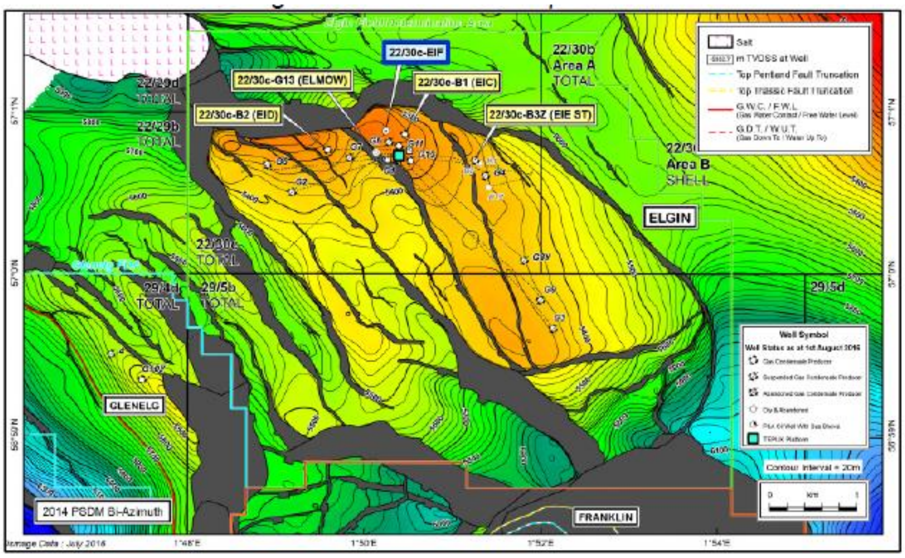


Figure 3-42: Elgin field, Fulmar top structure depth map m tvdss (source: Operator)

3.6.2. Franklin Field

The Franklin field was discovered by Well 29/05b-4 in October 1986 and production from the field started in September 2001. The Franklin wells produce to a normally unmanned wellhead platform (NUI) tied back approximately 5 km to the Elgin platform. The Franklin facilities comprise a nine-slot remote NUI wellhead platform at Franklin and a twelve-slot remote NUI wellhead platform at West Franklin. Both platforms are remotely operated from the Elgin PUQ. A total of 927 Bscf of gas and of 143 MMstb of condensate were produced from the Franklin field as of 30 June 2020. Currently a total of nine Franklin wells are producing at an average rate of 120 MMscf/d (6 months average). Franklin well locations at top Fulmar are presented in Figure 3-43.

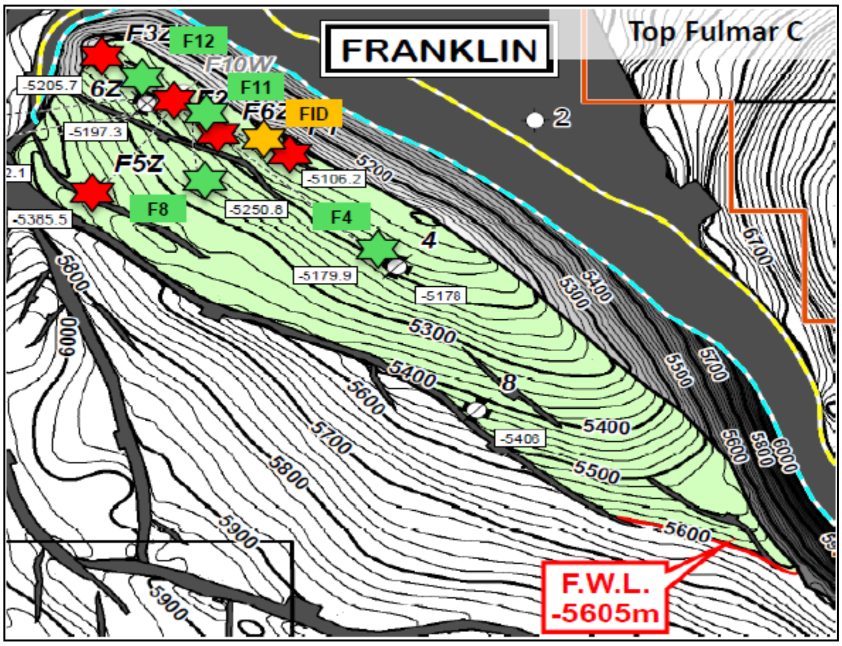


Figure 3-43: Franklin field, Fulmar C top structure depth map m tvdss (source: Operator)

3.6.3. West Franklin Field

The West Franklin field was discovered in 2003 and put on production in September 2007. The field was initially developed through extended reach drilling from the Franklin wellhead platform. In January 2015, the West Franklin Phase 2 development came on stream with an additional wellhead platform, the West Franklin wellhead platform.

A total of 508 Bscf of gas and of 76 MMstb of condensate were produced from the West Franklin field as of 30 June 2020. Currently a total of four West Franklin wells are producing at an average rate of 134 MMscf/d (six months average). West Franklin well locations, at top Fulmar C, are presented in Figure 3-44.

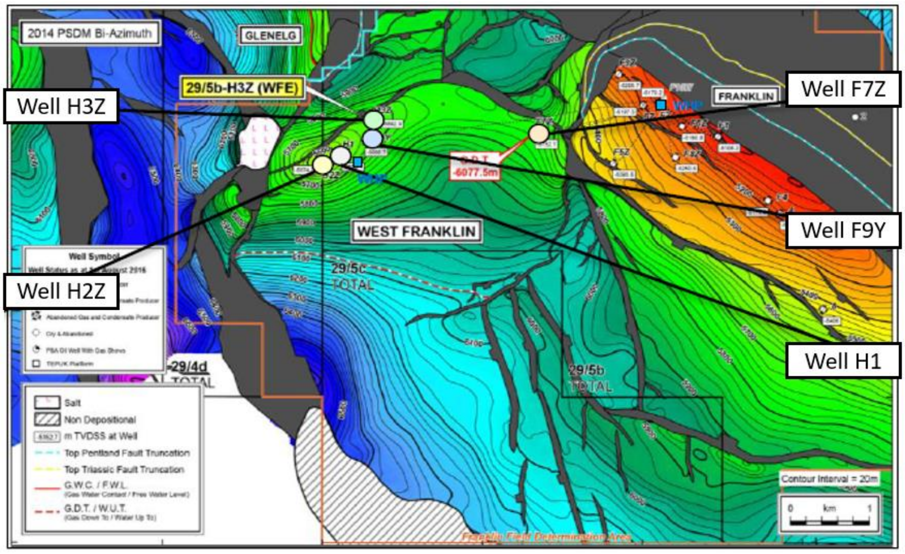


Figure 3-44: West Franklin field, Fulmar C top structure depth map m tvdss (source: Operator)

3.6.4. Glenelg Field

The Glenelg field is located approximately 4 km to the west of the Elgin development. It is produced to the Elgin wellhead platform via a single extended reach well, Well G10. The well (Figure 3-45) came onstream in 2006. In addition to being HPHT, the reservoir fluids are also sour and significant scaling has occurred in the well since water breakthrough and it now produces only intermittently. A total of 92 Bscf of gas and of 15 MMstb of condensate were produced from the Glenelg field as of 30 June 2020

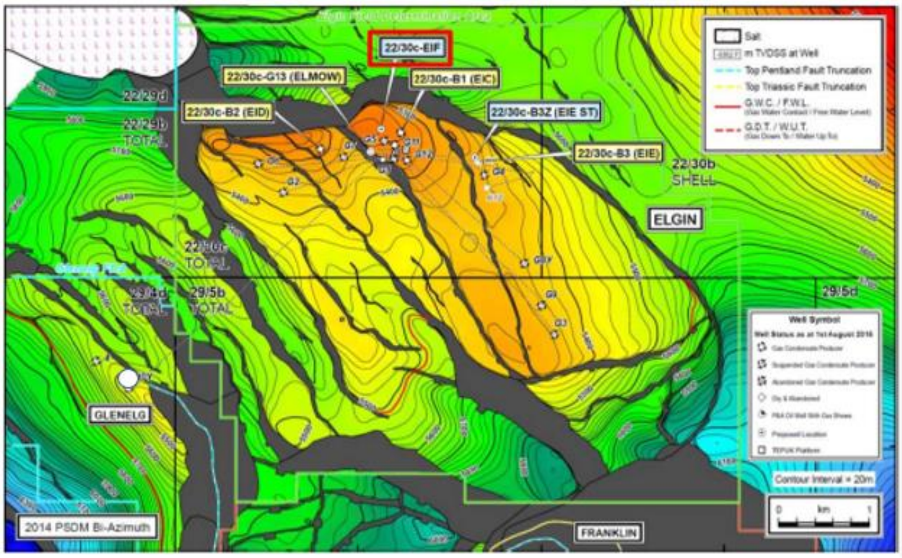


Figure 3-45: Glenelg (bottom left) on Fulmar top structure depth map m tvdss (source: Operator)

3.6.5. Development Plans

The development of the Elgin Hub is documented by the Operator in a Long-Term Plan (LTP), where development opportunities are reported, along with their technical maturities and associated resource estimates. ERCE has reviewed the future activities presented in the document and cross checked them against drilling schedules proposed by the Operator and Chrysaor with the expected future expenditure. ERCE has classified the projects according to their maturity as Developed Reserves (both producing and non- producing), Undeveloped Reserves and Contingent Resources.

Developed Reserves are attributable to the current stock of 15 producing wells. These Reserves are calculated at the earliest of the economic limit and the technical Cessation of Production of the Elgin Hub; tied to the current facilities design life, which the Operator has specified as year-end 2033. Developed Reserves are limited to this cut-off date as the cost of extending the life of the facilities is not insignificant (see later).

Developed non-producing Reserves were assigned to the incremental recoverable resources associated with the interventions planned for Wells F4 and F7. In addition, Developed non-producing Reserves were assigned to a medium (MP) to low pressure (LP) compressor project at the Elgin PUQ.

Undeveloped Reserves were assigned to several projects: The new Franklin Well FID, which was spudded in March 2020 and was still being drilled at the Effective Date; Well EIG, an infill well in Elgin originally approved in 2019 but subsequently delayed by the ongoing Covid-19 pandemic; and finally a project to extend the facilities life from 2034 to 2040.

There are also a number of less mature projects which are discussed in the section on Contingent Resources (Section 3.6.12).

3.6.6. Technically Recoverable Resources

ERCE has not prepared an independent volumetric estimate of the GIIP for the Elgin Hub fields. The fields have produced approximately 50% of their estimated TRR and all four fields can be reliably assessed based on their dynamic data. The TRR estimates were mostly derived using decline curve analysis (DCA) taking account of different development well vintages.

For the current well stock of producing wells, DCA was the preferred methodology as a reasonably long production history was generally available. ERCE's DCA was performed on individual wells based on operating rate versus cumulative gas and versus time. For more recent wells with no clear decline established (e.g. Well F12), ERCE has tried to capture the uncertainty related to the duration of the production plateau and ultimate recovery, based on past well performance.

Integrity workovers are assumed on some of the older producing wells drilled prior to the Well G-4 incident. The workover costs have been spread over several years in line with Operator estimates, as their timing will depend on the results of continued integrity monitoring. Whilst there will be a delay in production associated with carrying out any workovers, this was not included as any impact will be minor when spread over several years to reflect the timing uncertainty. A similar approach was also adopted in the case of Well WFF which may never be drilled but is included in the CAPEX requirements as an insurance in case one of the existing wells fails.

The Operator currently estimates Glenelg, Well G-10 is likely to fail during 2023. The economic viability of working over the well is in doubt and so the Glenelg production forecasts terminate at this point.

ERCE has accepted the Operator's best estimate of incremental resources associated with the MP to LP compression project and the production forecasts. ERCE has then made allowances for uncertainty to generate the low and high estimates.

For the future wells (including those being drilled at the Effective Date) and well interventions, ERCE has reviewed and accepted the best estimate incremental resources proposed by the Operator, largely based on simulation results. For each project ERCE has then generated low and high cases to account for the likely uncertainty.

Secondary phase production volumes were estimated using constant CGR ratios, derived from historic production data for the different accumulations. Different future trends were extrapolated at different levels of confidence.

The individual well and project profiles were aggregated to field production forecasts making allowances for production efficiency including allowing for planned turn arounds (TARs) and for intermittent producers. ERCE assumed average operating efficiencies are listed in Table 3-32 and reflect years with planned TAR's.

Table 3-32: Elgin Hub area operating efficiency estimates (ERCE)

Asset	Operating Efficiency									
	2020 H2	2021	2022	2023	2024	2025	2026	2027	2028	2029
Elgin Hub	93%	79%	91%	91%	88%	91%	91%	88%	91%	91%

ERCE's gross Developed plus Undeveloped TRR estimates for the Elgin Hub fields are presented in Table 3-33 and include the cumulative production to date. TRR estimates are reported to year-end 2040 (2023 for Glenelg), which is the expected technical CoP of the facilities after life extension.

Table 3-33: Elgin Hub area TRR Estimates and Recovery Factors

Asset/Field	Hydrocarbon	PIIP (Chrysaor Best Estimate)	Cumulative Production at 30 Jun 2020	RF to date	TRR			Estimated Technical RF (best)
					Low	Best	High	
Elgin	Gas (Bscf)	1,986	1,054	53%	1,525	1,661	1,766	84%
	Cond. (MMbbl)	661	295	45%	362	387	418	59%
Franklin	Gas (Bscf)	2,174	927	43%	1,201	1,280	1,370	59%
	Cond. (MMbbl)	377	143	38%	171	183	201	48%
West Franklin	Gas (Bscf)	1,042	508	49%	675	755	829	73%
	Cond. (MMbbl)	164	76	46%	100	112	125	68%
Glenelg	Gas (Bscf)	285	95	33%	102.9	103.2	103.4	36%
	Cond. (MMbbl)	44	15	35%	15.4	15.4	15.4	35%

3.6.7. CAPEX Assumptions

ERCE has based the CAPEX for the Elgin Hub on the Operator's Long-Term Plan and accepted the CAPEX for new wells and sanctioned projects. These include well costs for the FID well, which is currently being drilled, along with the WFF insurance well and EIG well. Costs for workovers and a compression campaign to be carried out in 2025 have also been incorporated within ERCE's estimates. An additional planned CAPEX is included within the Operator's Long-Term Plan for the 2034+ to 2040 Life of Field Extension works, which the Operator has already started to implement. Total forward well related costs considered for the above activities are $298 MM and total facilities related costs are $284 MM.

3.6.8. OPEX Assumptions

ERCE has based its OPEX forecast on the Operator's Long-Term Plan forecast. The OPEX estimates presented within the Long-term plan have been reviewed against historic costs and are considered reasonable. The near term OPEX averages some $160 to 200 MM per year.

The OPEX estimates exclude costs associated with tariffs, cost share or corporate overheads.

ERCE has relied on Chrysaor for third party throughput via the Forties Pipeline System; these are based on WoodMac estimates up until 2033 and then kept constant until 2040. The late life OPEX costs are highly sensitive to third party production which ERCE is unable to independently verify.

The Forties Pipeline System (FPS) OPEX and CAPEX costs have been taken from the latest budget, including a 5-year plan (2020-2025) from INEOS, the FPS operator. A similar level of investment from the Operator is expected to continue after 2025. In 2019 INEOS announced a £500 MM ($650 MM) investment into the FPS, to occur over the next five years. After the Effective Date, in October 2020, INEOS issued a revised Final Work Programme and Budget for 2021 indicating a lowering of expenditures of some 24% over the next 5-year period. Due to the materiality of this information it has been incorporated.

3.6.9. Abandonment Assumptions

ERCE has based its ABEX forecast for all Elgin Hub wells and facilities, including the SEAL and GAEL pipelines, on the Operator's Long-Term Plan forecast. The latest cost estimate is considered a reasonable estimate of implementing all future decommissioning works. The total decommissioning cost considered is $969 MM.

3.6.10. Facility and Well Integrity

The Elgin Hub does not seem to have any significant facilities integrity concerns. Production efficiency is high, and maintenance seems to be managed properly.

Historically, there have been well integrity issues with the early well designs e.g., the Elgin Well G4 gas leak in 2012 caused by casing corrosion and influx of gas from the Hod chalk above the main reservoir into the C annulus.

Since the G4 gas leak, the Operator has redesigned the HPHT well architecture. First and second-generation type 1 and type 2 wells respectively have had integrity issues. The latest third generation type 3 wells have improved well architecture and special cement. None of the third-generation wells have had integrity issues.

Well F4 has sustained high annulus pressure and a well workover is planned for 2H 2020.

The Operator has budgeted for a contingent "insurance" well in case Well F9 and/or Well H2z may fail.

3.6.11. Reserves

The technical production profiles described in Section 3.6.6 were converted to sales profiles (oil, gas and NGL) using shrinkage and yield factors, which were based on data provided by the Chrysaor and other Operator documentation.

Wellhead gas is reduced by fuel and flare consumption, assumed to be of 14 MMscf/d flat until year 2033 and of 16 MMscf/d afterwards. Export gas is sent to Bacton at NTS specification with negligible shrinkage. Wellhead oil is exported via the liquids export line and with any associated gas and NGL separated out from the oil phase at the Kinneil Terminal. To calculate the oil stream products ERCE has used the NGL yield provided by Chrysaor (0.23 boe/bbl) and has estimated from the Operator's documentation the stabilisation GOR and shrinkage to Stabilised Crude Oil ("SCO"), of 0.23 Mscf/bbl and of 0.69 stb/bbl respectively. ERCE has used oil equivalent conversion factors as presented in Appendix 3 to calculate barrels of oil equivalent (Bscf to MMboe). The gross asset level production forecast (sales) for the Developed plus Undeveloped Reserves categories are included in Appendix 4.

Reserves were estimated to the earliest of the economic cut-off dates and the end of the technical profile. For the Elgin area fields all the field low technical profiles were arithmetically summed and input into the economic model to determine the 1P CoP date. Similarly, all the mid-case profiles and all the high case profiles were added and used to determine the 2P and 3P CoP dates.

A summary of the gross on block Reserves by field is presented in Table 3-34 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 3-34: Elgin Hub area Gross Reserves by field with CoP dates

Field	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Elgin-Franklin	Developed	90.16	120.61	153.93	712.08	901.08	1047.87
	Undeveloped	9.25	33.83	57.45	67.14	236.31	372.63
	Total (Dvpd+Undvpd)	**99.41**	**154.44**	**211.38**	**779.21**	**1137.39**	**1420.50**
Glenelg	Developed	0.12	0.12	0.13	7.32	7.56	7.81
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total (Dvpd+Undvpd)	**0.12**	**0.12**	**0.13**	**7.32**	**7.56**	**7.81**
Total Asset	Developed	90.28	120.73	154.05	719.40	908.65	1055.68
	Undeveloped	9.25	33.83	57.45	67.14	236.31	372.63
	Total (Dvpd+Undvpd)	**99.53**	**154.56**	**211.50**	**786.53**	**1144.95**	**1428.31**
	COP (Total)	Dec-32	Dec-40	Dec-40	Dec-32	Dec-40	Dec-40

3.6.12. Contingent Resources Projects

ERCE has conducted an audit of Chrysaor's Contingent Resources estimates as detailed in Section 6. A number of Contingent Resources projects are associated with the Elgin Hub area as presented in Table 3-35. The Contingent Resources estimates associated with these projects are presented in Table 6-1 of Section 6.

Table 3-35: Elgin Hub Contingent Resources Project Summary

Field	Project	Possible Timing	Sub-Maturity Class
Elgin	Well G6 sidetrack	Q2 2022	DP
Elgin	Infill Well EIH	Q2 2023	DP
Glenelg	Well G-10 workover	Q1 2024	DOH

The Contingent Resources projects are based on the plans of the Operator. These identify a number of different projects at different maturity levels and include a sidetrack of Well G-6 in Elgin, a workover in Well G-10 in Glenelg and a new infill, Well EIH, in Elgin.

3.7. Everest Area Assets

The Everest Area comprises the Everest, Lomond and Erskine gas-condensate fields located 240 km east of Aberdeen in the UK Central North Sea. A location map showing the relative location of the fields is presented in Figure 3-46. Chrysaor holds a 100% interest in the Everest and Lomond fields and is the Operator and a 32% interest in the Erskine field operated by Ithaca. Chrysaor obtained its interest through the Shell Transaction in 2017.

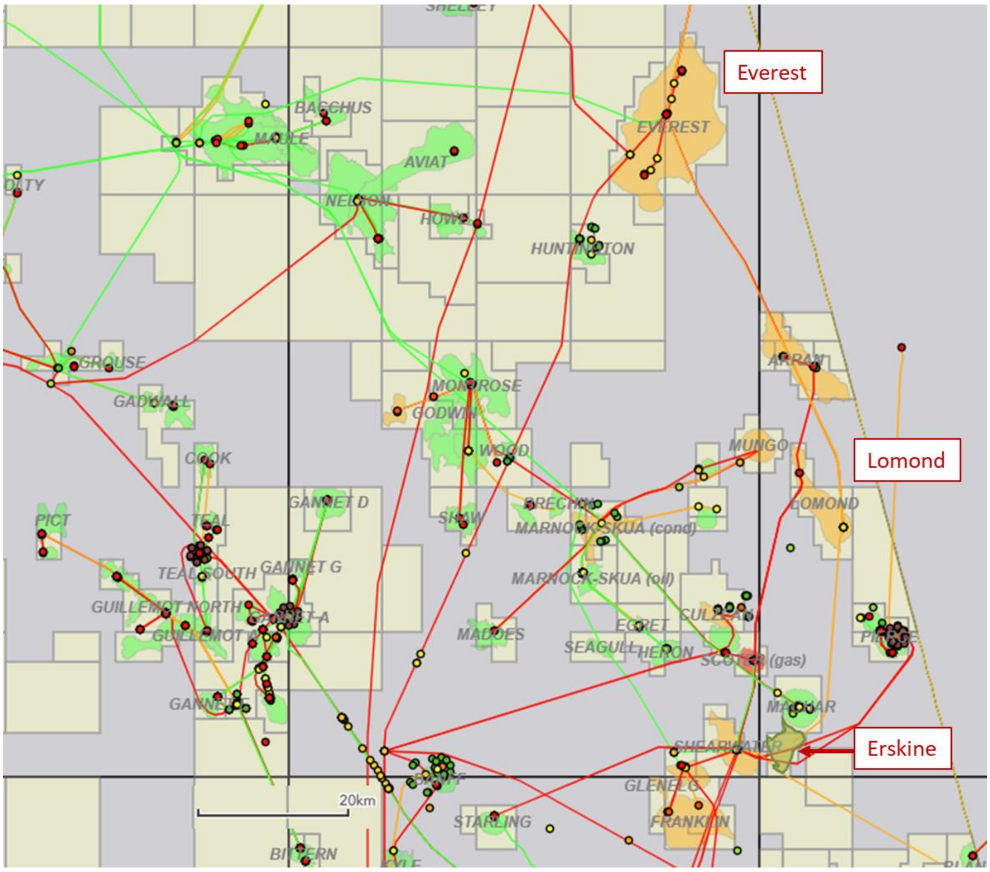


Figure 3-46: Everest, Lomond and Erskine fields location map (source: OGA)

The various fields are connected by pipeline to the CATS riser tower which is bridge linked to the Everest platform. Natural gas is transported via the Central Area Transmission System (CATS) to Teesside. Condensate is transported via the Forties Pipeline System to the Kinneil refinery at Cruden Bay.

Multiphase fluids from the Normally Unattended Installation ("NUI") Erskine are transported by a 30 km pipeline to the Lomond platform, which hosts the Erskine production module. Gas and condensate from Lomond and Erskine are sent to the CATS riser tower through dedicated gas and condensate pipelines.

3.7.1. Everest Field

The Everest field is located in blocks 22/9, 22/10a and 22/14a in the Central North Sea, 240 km east of Aberdeen in water depths of circa 90 m. It was discovered by Amoco in 1982 and first produced in 1993.

The reservoirs are in the Forties, Mey and Maureen sandstones of Tertiary age. The trapping mechanism has a structural and a stratigraphic component. Twelve wells were drilled during phase 1 and it started producing in 1993. Five further wells were drilled between 2001 and 2012 (Figure 3-47).

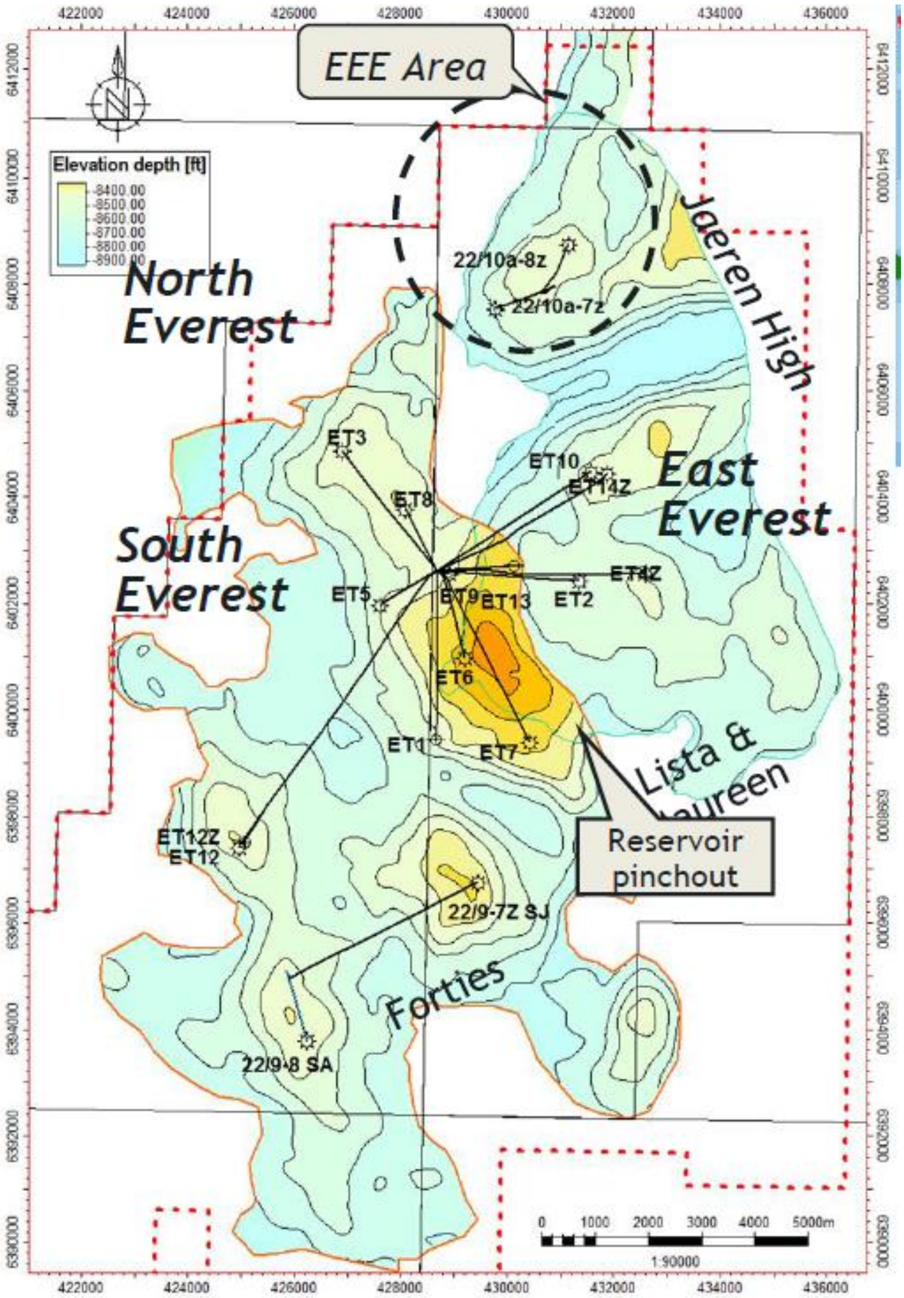


Figure 3-47: Everest field top reservoir map (source: Chrysaor)

There are currently ten producing wells. The cumulative production to end of June 2020 was 1,044 Bscf of gas and 38.7 MMstb of condensate. The gas and condensate production rates at the end June 2020 averaged 63 MMscf/d and 2,245 bopd respectively, with the CGR being around 37 stb/MMscf. Figure 3-48 shows the production history of the Everest field.

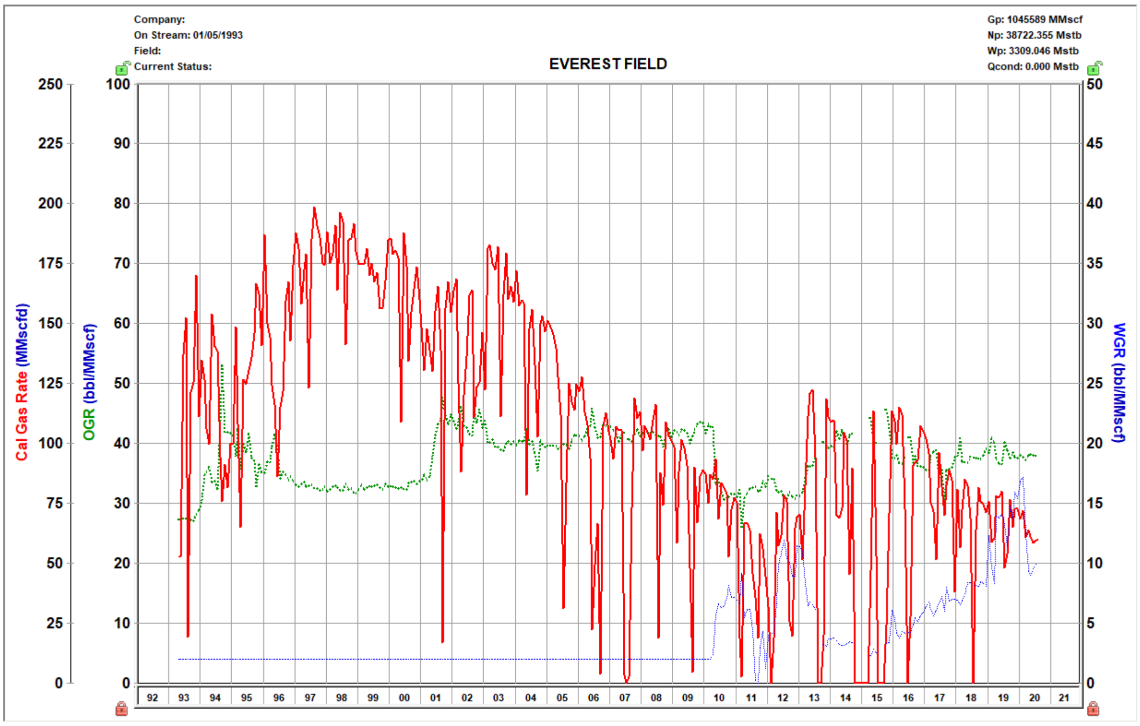


Figure 3-48: Everest field production history

3.7.2. Lomond Field

The Lomond field is located in block 23/21a in the Central North Sea, 50 km SSE of the Everest field in water depths of circa 85 m (Figure 3-49). It was discovered in 1972 and first produced in 1993.

The trap is a diapir induced anticline and the main reservoir is in the Forties turbiditic sandstones. Eight wells were drilled during Phase 1 in 1993 and two further wells were drilled in 2000 (Figure 3-49).

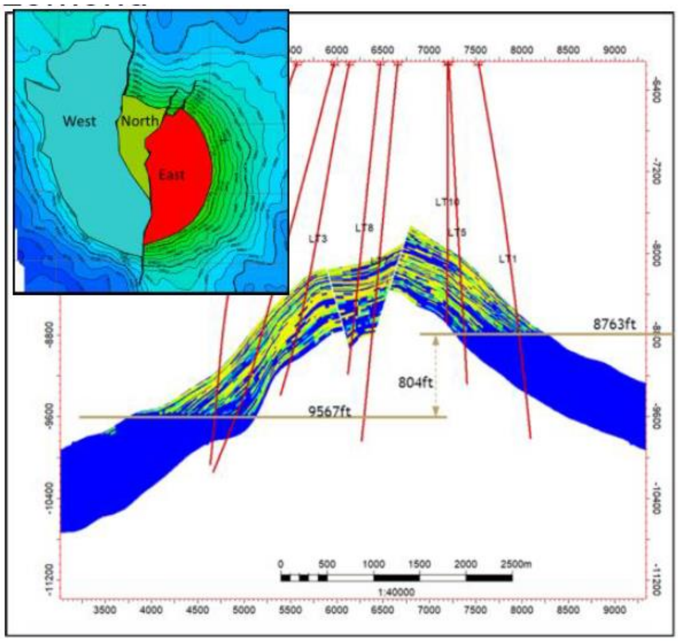


Figure 3-49: Lomond field map and cross section (source: Chrysaor)

There are currently five producing wells (Wells LT2, LT3, LT8, LT9 and LT10) out of a total of ten development wells originally drilled. The cumulative production to end of June was 900 Bscf of gas and 22.53 MMstb of condensate. The gas and condensate production rates at the Effective Date averaged 31 MMscf/d and 630 bopd respectively, with CGR being around 18 stb/MMscf. Figure 3-50 presents the production history of the Lomond field.

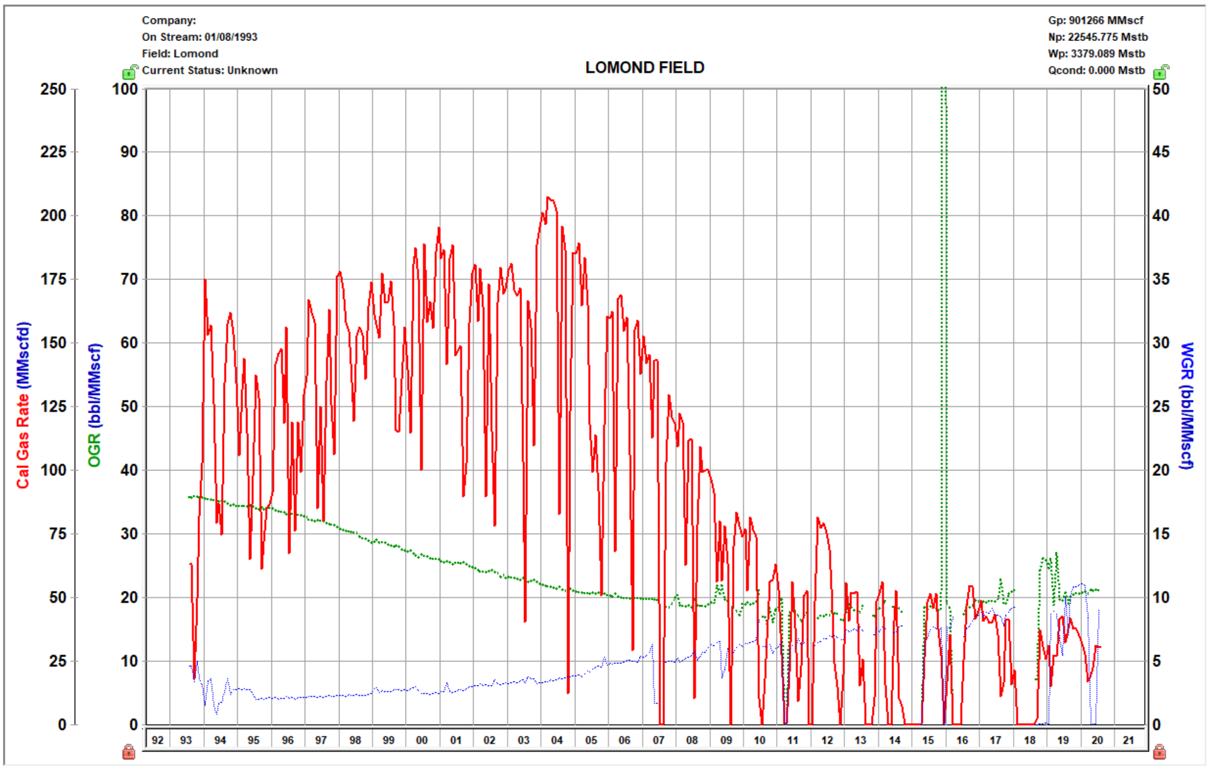


Figure 3-50: Lomond field production history

3.7.3. Erskine Field

The Erskine field is located in block 23/26b in the East Central Graben some 30 km south of the Lomond field in water depths of circa 90m (Figure 3-51).

The field was discovered in 1981 and started producing in 1998. The development consists of three exploration wells, five appraisal wells and five development wells (Figure 3-51). The field is HPHT.

The main reservoir is at a depth of 1,485 m tvdss and is Late Oxfordian in age. The Erskine field is a combination of a dip and fault bounded trap.

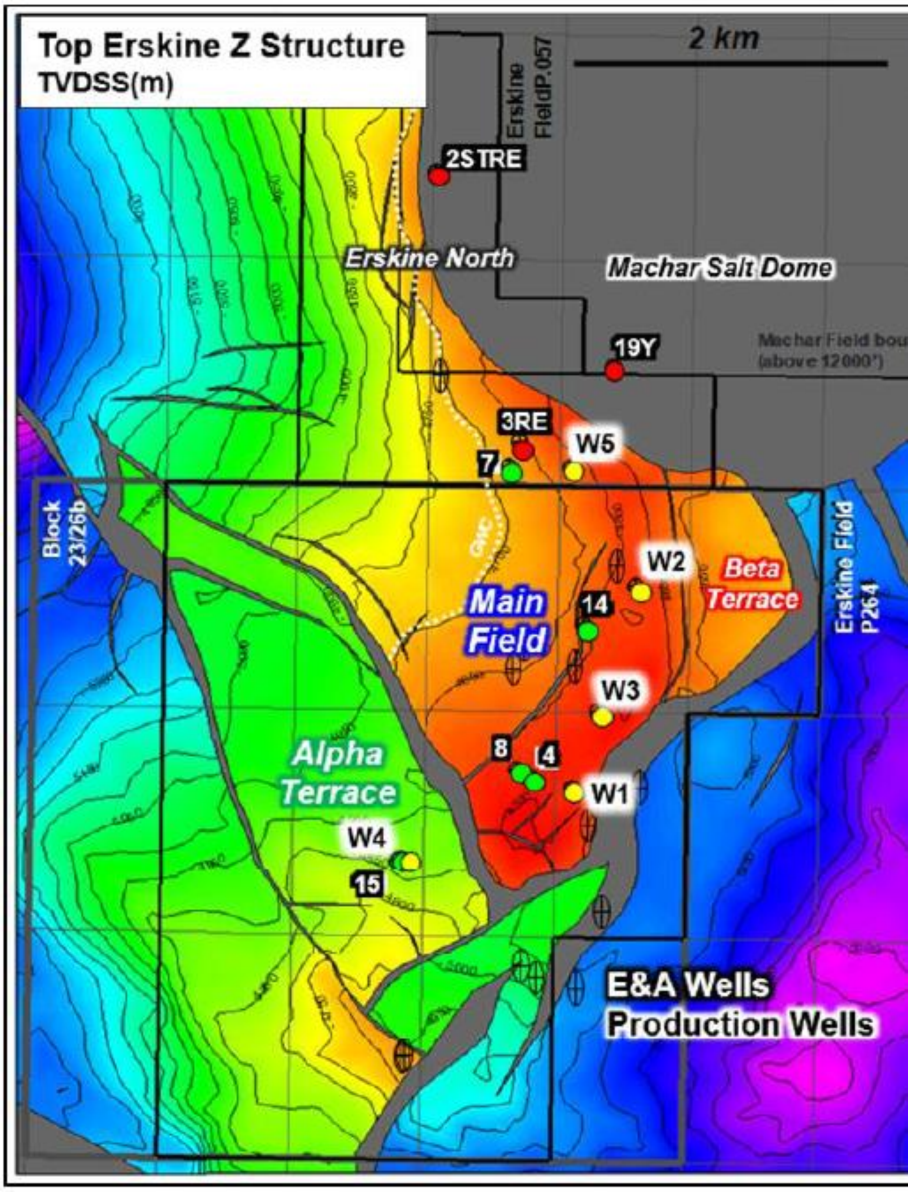


Figure 3-51: Erskine field top reservoir (source: Chrysaor)

All five development wells (Wells W1, W2, W3, W4 and W5) are still producing. The peak gas production of 105 MMscf/d was achieved in 2002. The cumulative production to end June 2020 was 369 Bscf of gas and 68.6 MMstb of condensate. At the same date the gas and condensate production averaged 51 MMscf/d and 6,300 bopd respectively, with the CGR being around 127 stb/MMscf. Figure 3-52 presents the production history of the Erskine field.

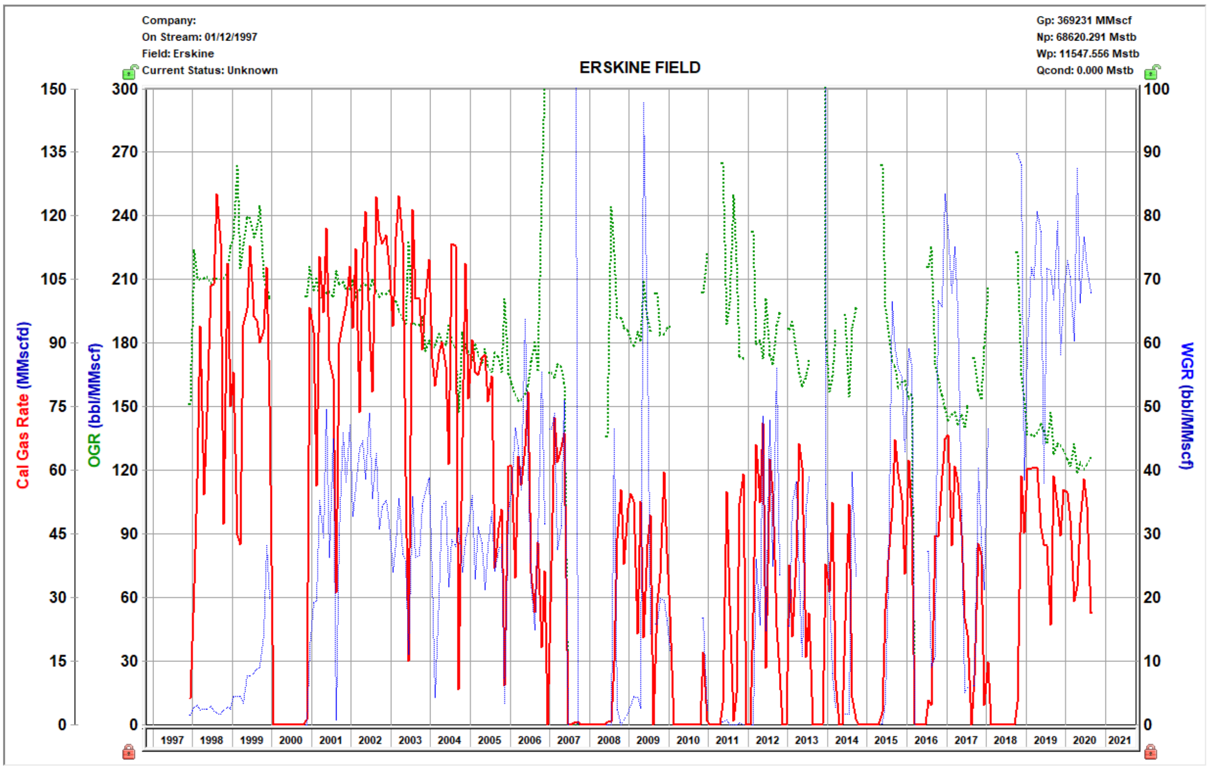


Figure 3-52: Erskine field production history

3.7.4. Development Plans

Additional Undeveloped Reserves are associated with one infill well opportunity in the Everest field, the subsea Well LAD which is scheduled to be drilled 2H 2021 with first gas in January 2022. Additionally, the Operator plans a late life field lower compression project to reduce the separator pressure from 11 barg (159 psig) to 7 barg (102 psig). This project has been assessed as Developed Non-Producing Reserves.

The Lomond and Erskine fields appear to be fully developed with limited infill opportunities; there is a firm late life field compression project on Lomond which is expected to be commissioned for first gas in 3Q 2021, a year delayed due to Covid-19. Recoverable volumes associated with this project are classified as Developed Non-Producing Reserves. There is similar consideration of a late life compression project on the Erskine field, but this project is still at an early design stage and is considered as Contingent Resources.

3.7.5. Technically Recoverable Resources

ERCE's TRR estimates for the current producing wells were derived using decline curve analysis (DCA) on a well by well level. A minimum technical gas flow rate limit was applied due to liquid holdup. Estimation of production profiles for Everest Well LAD are based on established type wells and simulation results. The incremental recovery for the compression projects associated with lowering the suction pressure were derived from the production profiles provided by Chrysaor.

Low, best, and high DCA's were generated to capture the estimated Reserves uncertainty range. Secondary phase production volumes were estimated using a constant CGR ratio in the Lomond field and a declining CGR ratio in the Everest and Erskine fields based on historic production data at the well level.

ERCE performed DCA to estimate future performance of the current producing wells. The DCA was performed on individual wells based on monthly operating rate versus time. Production data were available up to end of June 2020. A range of hyperbolic exponents were used to account for the forecast uncertainty. The individual well profiles were aggregated to generate gas potential versus cumulative gas production forecasts at the field level. These forecasts were then used to estimate the field gas production rate versus time by applying the operating efficiency (OE) factors presented in Table 3-36.

Table 3-36: Everest Area assumed operating efficiencies (ERCE)

Field	Operating Efficiency									
	2020 H2	2021	2022	2023	2024	2025	2026	2027	2028	2029
Lomond	76%	74%	83%	82%	75%	80%	80%	75%	80%	80%
Everest	77%	75%	84%	83%	75%	80%	80%	75%	80%	80%
Erskine	71%	69%	78%	77%	70%	75%	70%	75%	70%	75%

Note

1. OE estimates after 2029 remain constant.

ERCE's gross Developed plus Undeveloped TRR estimates are presented in Table 3-37. The technical recovery factors are based on the Chrysaor best estimate GIIP value. TRR forecasts were to the end of 2044.

Table 3-37: Everest Area TRR Estimates and Recovery Factors

Asset/ Field	Hydrocarbon	GIIP (Chrysaor Best Estimate)	Cum. Prod. at 30 Jun 2020	RF to date	TRR Estimate			TRR best est. RF
					Low	Best	High	
Everest	Gas (BCF)	1,466	1,046	71%	1,196	1,258	1,300	86%
Lomond	Gas (BCF)	1,030	900	87%	928	953	984	92%
Erskine	Gas (BCF)	800	369	46%	435	493	539	62%

3.7.6. CAPEX Assumptions

The CAPEX profiles used for the economic modelling are based upon data provided for review by the Operator. The major CAPEX elements included in the forecast are for drilling the LAD well and for carrying out the late life compression projects on the Everest and Lomond fields. The total CAPEX consideration covering these activities is $141 MM.

3.7.7. OPEX Assumptions

The Operator has tabled proposals to reduce OPEX considering the current economic environment. These have been reviewed and incorporated into the forecast where specific detail has been provided and/or the proposals appear reasonable. The Everest Hub OPEX considered is some $145 MM per year.

The Forties Pipeline System (FPS) OPEX and CAPEX costs have been taken from the latest budget, including a 5-year plan (2020-2025) from INEOS, the FPS operator. A similar level of investment from the Operator is expected to continue after 2025. In 2019 INEOS announced a £500 MM ($650 MM) investment into the FPS, to occur over the next five years. After the Effective Date, in October 2020, INEOS issued a revised Final Work Programme and Budget for 2021 indicating a lowering of expenditures of some 24% over the next 5-year period. Due to the materiality of this information it has been incorporated.

3.7.8. Abandonment Assumptions

The Operator provided field abandonment reports and associated estimates. These have been reviewed and the costs adopted in the economic model. The estimated total decommissioning cost for the Everest Hub facilities is $415 MM and for well P&A $ 213 MM.

3.7.9. Facilities and Well Integrity

Since the Shell Transaction, the Operator has invested in improving the integrity of the Everest and Lomond facilities. Operating efficiencies have improved over the course of this investment. All the assets have safety critical maintenance backlogs that are reasonably close to target. There are specific integrity issues identified on each of the assets, but these are being managed and are not believed to pose a significant threat to the production profiles.

On Everest, Well ET02 has an A-annulus to reservoir communication and is colour coded in orange with one barrier failure identified. Wells ET03 and ET06 have annulus and wellhead seals degraded (yellow colour code). A wireline campaign in Q4 2019 replaced the WRSSV in Well ET07 and the well was reperforated. Well ET02 had a fish removed to bring the well back on stream but failed due to liquid loading.

On Lomond, Well LT08 has been shut-in following well intervention activity in Q1 2020 where repair and re-perforation were completed but a PLT got stuck downhole with a radioactive source and requires remediation work. Well LT09 is also shut-in due to a leaking SSSV. Well LT02 was repaired and re-perforated but the well ceased to flow due to liquid loading after a short while.

On Erskine, produced formation water is causing scaling issues. Furthermore, there is a high risk of sand production in most of the producers. Well integrity may be an issue as all wells have liner deformation (from weak to moderate) which will limit well workover opportunities.

3.7.10. Reserves

The technical production profiles described in Section 3.7.5 were converted to sales profiles (oil, gas and NGL) using shrinkage and yield factors, which were based on data provided by the Operator. For Everest, Lomond and Erskine the wellhead gas was corrected for fuel and flare consumption estimated at 4.48 MMscf/d, 3.62 MMscf/d and 2.36 MMscf/d respectively.

ERCE has used the oil equivalent conversion factors as presented in Appendix 3 to calculate barrels of oil equivalent. The gross asset level production forecast (sales) for the Developed plus Undeveloped Reserves categories are included in Appendix 4.

Reserves were estimated to the earliest of the economic cut-off dates and the end of the technical profile. For the Everest, Lomond, and Erskine fields the low technical profiles were used as input into the economic model to determine the 1P CoP date. Similarly, all the mid-case profiles and all the high case profiles were used to determine the 2P and 3P CoP dates.

For all the fields the Developed Reserves were based on the existing well stock and the low-pressure compression projects for Everest and Lomond. The Everest Well LAD was classified as Undeveloped Reserves.

A summary of the gross on block Reserves by field is presented in Table 3-38 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 3-38: Everest Area Gross Reserves by field with CoP dates

Field	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Everest	Developed	5.04	7.49	9.25	73.23	111.01	140.48
	Undeveloped	0.00	1.04	1.68	0.00	15.85	26.19
	Total (Dvpd+Undvpd)	**5.04**	**8.52**	**10.93**	**73.23**	**126.86**	**166.66**
Lomond	Developed	1.12	2.28	3.40	17.88	37.63	56.30
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total (Dvpd+Undvpd)	**1.12**	**2.28**	**3.40**	**17.88**	**37.63**	**56.30**
Erskine	Developed	7.64	13.41	18.68	45.51	81.03	114.80
	Undeveloped	0.20	0.00	0.27	0.97	0.00	1.55
	Total (Dvpd+Undvpd)	**7.83**	**13.41**	**18.95**	**46.48**	**81.03**	**116.35**
Total Asset	Developed	13.80	23.18	31.33	136.63	229.67	311.58
	Undeveloped	0.20	1.04	1.95	0.97	15.85	27.73
	Total (Dvpd+Undvpd)	**13.99**	**24.21**	**33.28**	**137.60**	**245.52**	**339.31**
	COP (Total)	Jun-27	Jun-31	Jun-35	Jun-27	Jun-31	Jun-35

Notes

1. Undeveloped Reserves associated with an infill well in the Everest field are uneconomic at a 1P level
2. Undeveloped Reserves at the field level are impacted by applying the ELT at hub level (see Section 5 for details). Erskine has no Undeveloped Reserves projects.

3.7.11. Contingent Resources Projects

ERCE has conducted an audit of Chrysaor's Contingent Resources estimates as detailed in Section 6. Several Contingent Resources projects exist in the Everest asset area as presented in Table 3-39. The Contingent Resources estimates associated with these projects are presented in Table 6-1 of Section 6.

The Everest field Contingent Resources are associated with an infill well in the eastern part of the field (Well LAC) and the workover and possible sidetrack of a subsea well in the southern area of the field (Well SJ).

A number of Contingent Resources projects have been identified in the Erskine field. Options are being investigated to lower the backpressure at the Erskine producers most likely by lowering the suction pressure on the Erskine Production Module located on the Lomond platform. Other projects include a behind pipe perforation of the Erskine sand in Well W1, currently producing from the Pentland reservoir, and the drilling of an additional infill well.

Chrysaor is studying appraisal/development options for the Faraday and Ockley discoveries. Chrysaor acquired the licence which contains both discoveries in 2018 as part of the UK 30th Offshore Licencing Round.

Faraday is a Heather sand, HPHT gas condensate discovery which needs further appraisal; possible tie-back to Erskine or the J-Area is being considered.

Ockley is a Hod Chalk formation, HPHT gas condensate discovery which has been appraised by a number of wells. The field was discovered in 1983 by Well 30/1c-2A. Maersk Oil drilled a horizontal well in 2007-2008 and a further well and sidetrack in 2012. The sidetrack was completed as a multi-stage, fracture stimulated horizontal well. The well flowed for several short periods over a 26-day test with rates around 4 to 5 MMscf/d. Chrysaor believes that through advancements in fracture stimulation they could be able to successfully develop the field using eight horizontal wells.

The remaining two opportunities (Mortimer and Teme) are single well, fallow discoveries close to the Chrysaor infrastructure; they were picked up in the recent UK 32nd Offshore Licencing Round. The award announcement was made in September 2020, which is after the Effective Date, but as the event was considered material the fields have been included in the CPR.

Table 3-39: Everest Area Contingent Resources Project Summary

Field / Area	Project	Possible Timing	Sub-Maturity Class
Everest	Well SJ	2021/2022	DOH
Everest	LAC infill well	2021/2022	DOH
Erskine	LLP Compression - 37 bar to 20-25 bar	2025	DP
Erskine	6th well infill well	2023	DUC
Erskine	ERS1 perf Erskine sand in W1(P1) Pentland	2023	DP
Mortimer	Development - 1994 discovery	To be determined	DUC
Teme	Development - 1988 discovery	To be determined	DUC
Faraday	Development - 2011 discovery	2024-2025	DUC
Ockley	Chalk Development	2024	DUC

3.8. Galleon Field

The Galleon gas field is located within the Sole Pit area of the Southern Gas Basin (Figure 3-53). Chrysaor acquired an 8.4% working interest in the field through the ConocoPhillips Transaction. The field is operated by Shell.

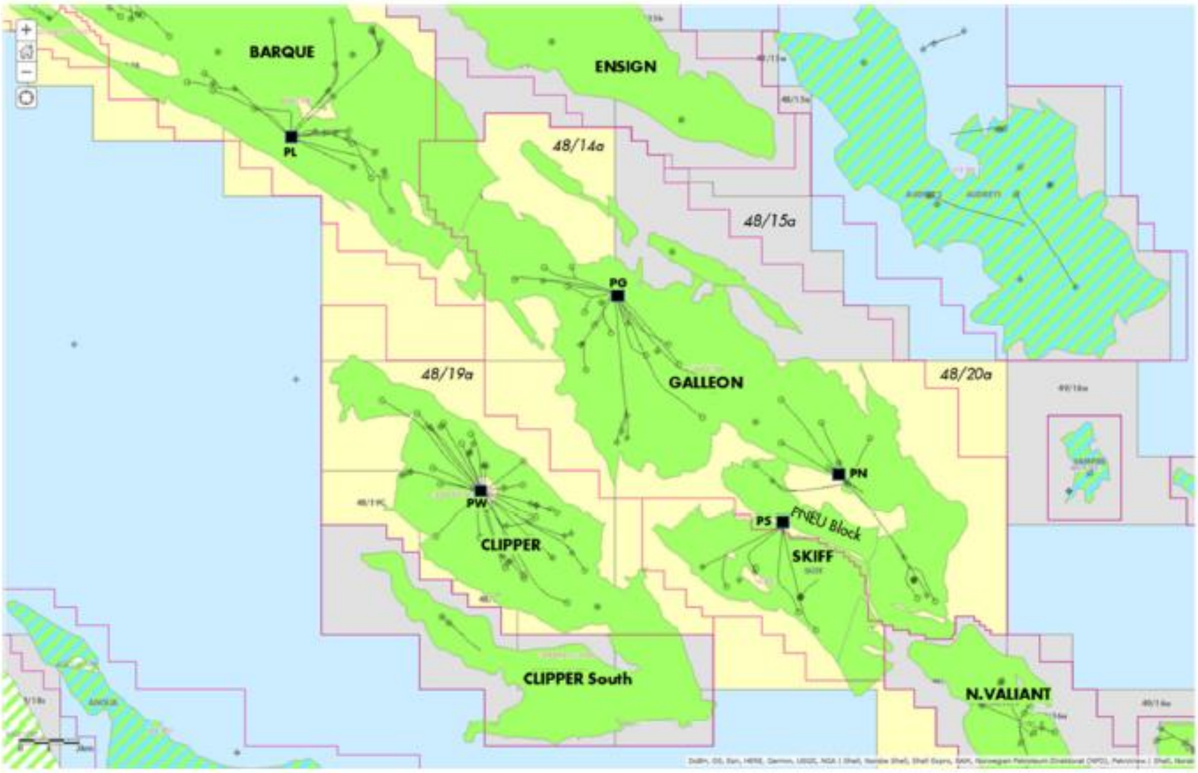


Figure 3-53: Galleon field location map (source: Chrysaor)

The field has an average top reservoir depth of 2,580 m tvdss and produces lean gas from the Permian aged Leman Sandstone formation (Rotliegend equivalent). The reservoir was deposited in an aeolian environment and is sub-divided into the Leman A, B and C sands. The reservoir rock is heterogeneous and poor-medium quality with average porosities and permeabilities of 7-8% and 0.1 mD respectively. The gas has a CGR of 0.5 stb/MMscf.

The field was developed in two stages. Phase I of the development, completed in mid-1994, involved the installation of a minimal facilities platform, Galleon 'PN', in the southeast part of the field. Production from Phase I started on schedule in October 1994. Development approval for Phase II of Galleon was granted in December 1996 and first gas from this part of the project commenced in November 1998. The second phase accessed the northwest area of the field via a new wellhead platform, Galleon 'PG'. Both platforms are tied back to the Barque and Clipper facilities via dedicated pipelines. Gas is exported to Bacton via the Sole Pit gas export line.

The Galleon field has been developed with ten wells on the PG platform and eight wells on the PN platform. As of 30 June 2020, cumulative gas production was 771 Bscf and six wells were flowing from the PG platform and three from the PN platform. Average production for

2020 (six months average) was circa 35 MMscf/d of dry gas. Galleon production history is displayed in Figure 3-54. Very small amounts of condensate are recovered but these were not considered material in terms of the Reserves.

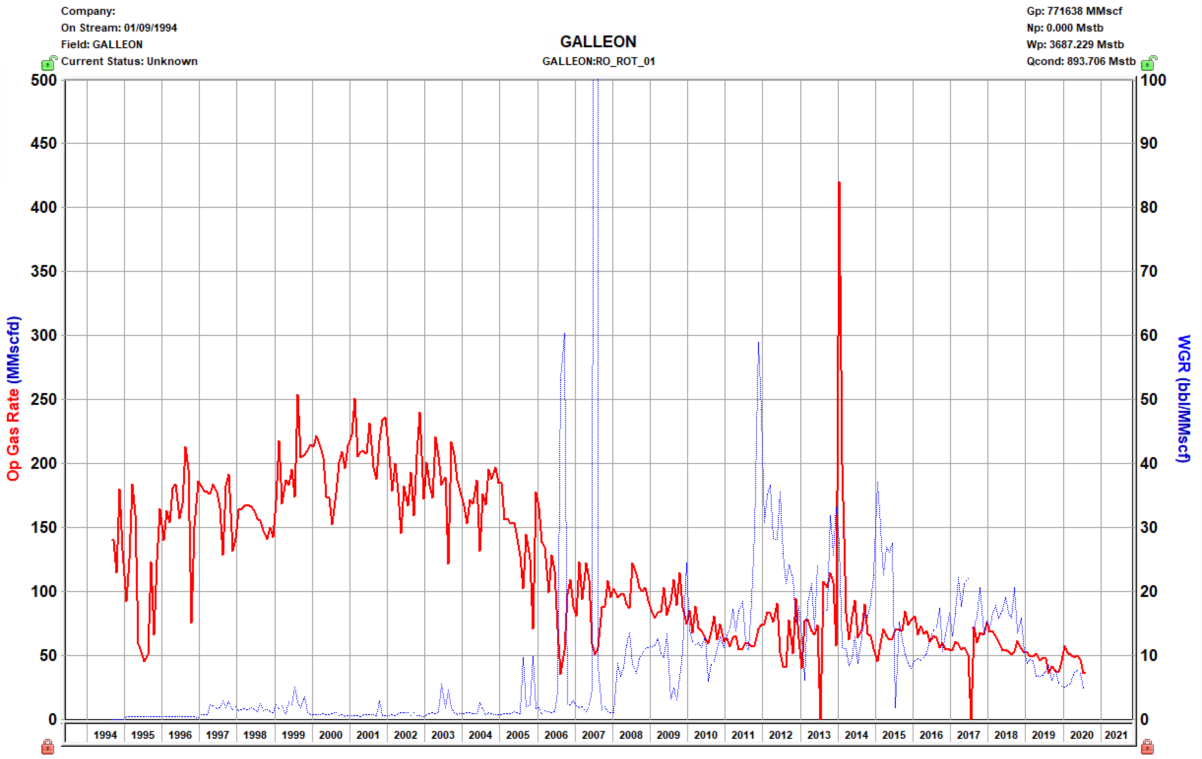


Figure 3-54: Galleon field gas production history

The well with the largest production on the PN platform (PN04) had a SSSV control line failure during 2019; following a successful workover the well was returned to production in January 2020 with a significant positive impact on production. Another Well, PG05, was reported to be down in mid-June and is under study for future intervention.

3.8.1. Development Plans

The Operator reports multiple future development opportunities which ERCE has reviewed to assess commercial maturity.

The re-drill or repair of Well PN09 has an approved AFE with intervention scheduled for 2021. During 2019 this well was drilled into the low permeability area of the field and was due to be fracked prior to producing. However, several problems occurred, which have led to the well being suspended before fracking. The well is to be worked over and first gas is forecast for September 2021. ERCE has assigned Undeveloped Reserves to this well given the costs are considered significant relative to the cost of a new well.

Additional interventions, expected to impact production to various degrees, are included in the well and reservoir facility management ("WRFM") operations and frac campaigns.

A possible re-drill of Well PN02 is considered less mature and is discussed in the Contingent Resources projects in Section 3.8.8.

3.8.2. Technically Recoverable Resources

ERCE has not prepared an independent volumetric estimate of the GIIP for the Galleon field. Given the maturity of the field, the dynamic data is considered to provide good estimates of connected GIIP.

ERCE's TRR estimates were mostly derived using decline curve analysis (DCA) and reconciled with the PIIP proposed by the Operator. The DCA was performed on operating rate versus cumulative gas and versus time. The analysis was carried out on a platform basis where platforms are forecasted to have different operating efficiencies.

For the re-drill/repair of Well PN09, ERCE was provided with different production forecasts from the Operator and Chrysaor. The profiles displayed an ultimate recovery varying between 29 and 36 Bscf, at the best level of confidence. Based on the performance of the existing wells and the trends over time as new wells have been added, ERCE has estimated a best estimate TRR of 27 Bscf. A range of uncertainty was created to generate estimates of recovery at high and low levels of confidence.

Some interventions are planned by the Operator as a part of the WRFM activity, mostly to maintain production levels and offset field decline. ERCE has not explicitly modelled these workovers in its production forecasts although they are accounted for in its decline analysis.

The individual platform forecast profiles were aggregated to field production forecasts making allowances for operating efficiency (OE) including incorporating planned turn arounds (TARs) and for intermittent producers. ERCE has assumed constant factors for the future OE, expected to be of 85% for the PN platform and of 94% for the PG platform (Table 3-40).

Table 3-40: Galleon field operating efficiency estimates by platform

Platform	Operating Efficiency									
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PN	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
PG	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%

Note

1. OE estimates after 2029 repeat on the same three-year cycle.

ERCE's gross Developed plus Undeveloped TRR estimates for the Galleon field are presented in Table 3-41. The technical recovery factors given in the table below are based on a number of different PIIP estimates reported by Chrysaor.

Table 3-41: Galleon TRR Estimates and Recovery Factors

PIIP	Best Estimate (Bscf)	Cumulative Production at 30 Jun 2020	RF to date	TRR (Bscf)			Estimated Technical RF (best)
				Low	Best	High	
Full Static GIIP	3,250	771	24%	845	871	895	27%
Developed Static GIIP	1,750	771	44%	845	871	895	50%
Dynamic GIIP	945	771	82%	845	871	895	92%

3.8.3. CAPEX Assumptions

The main CAPEX element on Galleon is for Well PN09. CAPEX of $101 MM including well hook-up is based upon AFE data provided by the Operator.

3.8.4. OPEX Assumptions

The OPEX forecast of $9 MM per year is based upon budget data from the last three years.

3.8.5. Abandonment Assumptions

A facilities ABEX estimate was provided by the Operator which has been reviewed and adopted. ERCE consider the total decommissioning cost of facilities and P&A of wells to be $134 MM.

3.8.6. Facilities and Well Integrity

Limited data was made available to assess specific integrity issues, however the facilities have good reliability and availability, so it is considered unlikely they will have material integrity issues.

Despite the many lessons learned while attempting to drill the now suspended Well PN09, there is a risk of not being able to repair the well. The next option it to re-drill a well that proved to be challenging. Well PN04 suffers from salt scaling and requires periodic water washes. Well PG06 produces a significant amount of sand.

3.8.7. Reserves

The technical production profiles described in Section 3.8.2 were converted to sales profiles based on data provided by the Chrysaor. Wellhead gas was corrected for fuel consumption, estimated at 2 MMscf/d flat. ERCE has used oil equivalent conversion factors as presented in Appendix 3. The gross asset level production forecast (sales) for the Developed plus Undeveloped Reserves categories are included in Appendix 4.

Reserves were estimated to the earliest of the economic cut-off dates and the end of the technical profile. For the Galleon field all the low technical profiles were arithmetically summed and input into the economic model to determine the 1P CoP date. Similarly, all the mid-case profiles and all the high case profiles were added and used to determine the 2P and 3P CoP dates.

A summary of the gross on block Reserves is presented in Table 3-42 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 3-42: Galleon Reserves with CoP dates

Field	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Galleon	Developed	0.00	0.00	0.00	38.50	56.59	80.55
	Undeveloped	0.00	0.00	0.00	0.00	30.16	40.67
	Total (Dvpd+Undvpd)	**0.00**	**0.00**	**0.00**	**38.50**	**86.75**	**121.22**
	COP (Total)	Jun-27	Jun-34	Jun-38	Jun-27	Jun-34	Jun-38

Notes

1. Undeveloped Reserves associated with Well PN09 are uneconomic at a 1P level
2. The 2P Undeveloped Reserves are greater than the ERCE's best estimate TRR for the PN09 well due to the CoP deferral impact on the developed reserves

3.8.8. Contingent Resources Projects

ERCE has conducted an audit of Chrysaor's Contingent Resources estimates as detailed in Section 6.

The Galleon field contains one project which has been assigned Contingent Resources as summarised in Table 3-43. The Contingent Resources estimates associated with this project are presented in Table 6-1 of Section 6.

Well PN02 has experienced liquid hold-up issues over the last two years preventing the well flowing. The Operator is evaluating an intervention on the well which could be re-drilled and hydraulically fracked. The project is considered by the Operator to be in the project define phase. At the end of June 2020, the project was still pending negotiations for the rig and the frac vessel.

Table 3-43: Galleon Contingent Resources Project Summary

Project	Possible Timing	Sub-Maturity Class
PN02 re-drill	Q3 2021	DP

3.9. Greater Britannia Area Assets

The Greater Britannia Area ("GBA") includes the Britannia field and four subsea tiebacks: Brodgar, Callanish, Enochdhu, and Alder. The fields are located in quadrants 15, 16 and 21 in the Central North Sea (Figure 3-55) some 210 km northeast of Aberdeen. An asset summary is presented in Table 3-44. Chrysaor acquired its interest in the fields through the ConocoPhillips Transaction; as shown in Table 3-44 the working interest (WI) varies across the fields. In the case of the Brodgar field the current WI is 87.5% but will increase to 93.75% when the cumulative production since Well H4 came on production is 10 MMboe; at the Effective Date, 6.13 MMboe had been produced from Brodgar since Well H4 started producing.

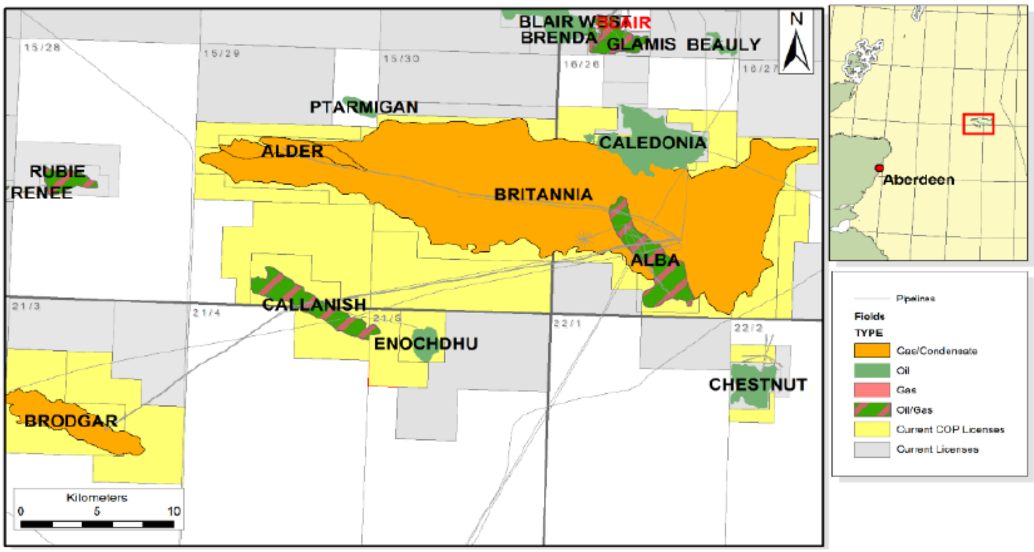


Figure 3-55: Greater Britannia location map (source: Chrysaor)

The reservoirs comprise sandstones of Palaeocene, Cretaceous and Jurassic age. The Callanish and Enochdhu fields contain light oil, whereas the other fields contain relatively rich gas-condensates. Except for Alder, the fields are normally pressured (Alder is HPHT with an initial reservoir pressure of 12,284 psia at 4,500 m tvdss).

Table 3-44: GBA asset summary

Field	Chrysaor WI%	Reservoir	Depth (m tvdss)	Trap	Fluids	Solution GOR (scf/stb)	Initial CGR (stb/MMscf)	Avg. Porosity	Perm. Thickness (mDft)
Britannia	58.65	Britannia SST	3,600	Strat / Struct	Gas Cond.	-	90	15%	< 60,000
Brodgar	87.5[1]	Britannia SST	3,300	Strat / Struct	Gas Cond.	-	70	20%	27,000
Callanish	83.5	Forties SST	2,000	Four-way closure / Pinch out	Oil	670	-	24%	50,000
Enochdhu	50	Forties SST	2,100	Four-way closure	Oil	840	-	24%	28,500
Alder	26.32	Galley SST	4,500	Strat / Fault seal	HPHT Gas Cond.	-	110-185	20%	7,000

Note

1. Brodgar current WI is 87.5% but will increase to 93.75% when 10 MMboe has been produced since Well H4 start-up.

Production started from the Britannia field in 1998 using a steel production and wellhead platform, and a subsea template. Gas is evacuated via a dedicated pipeline to the SAGE terminal at St. Fergus. Hydrocarbon liquids are transported via the Forties Pipeline System (FPS) to the Cruden Bay terminal. In 2008 a new bridge linked platform was installed to process fluids from the Callanish and Brodgar fields. A schematic showing an overview of the facilities is presented in Figure 3-56.

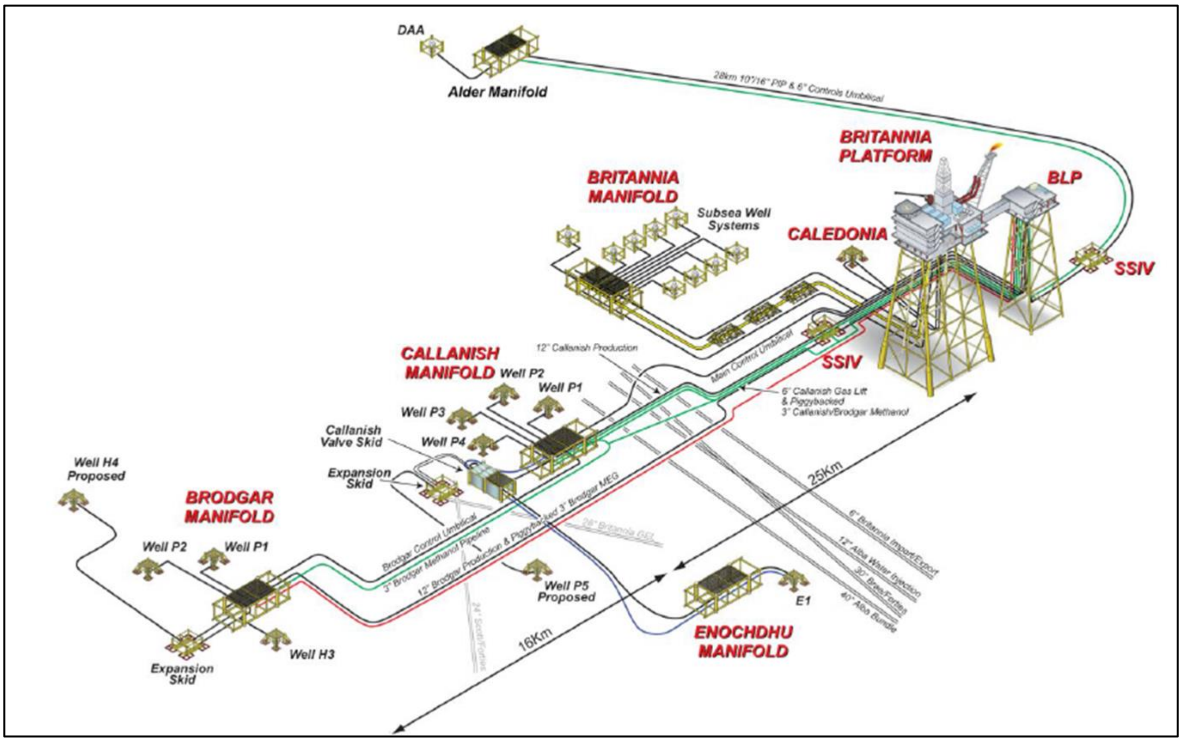


Figure 3-56: GBA facilities schematic (source: Chrysaor)

Overall gas and liquid (oil and condensate) production histories by field are shown in Figure 3-57 and Figure 3-58 respectively.

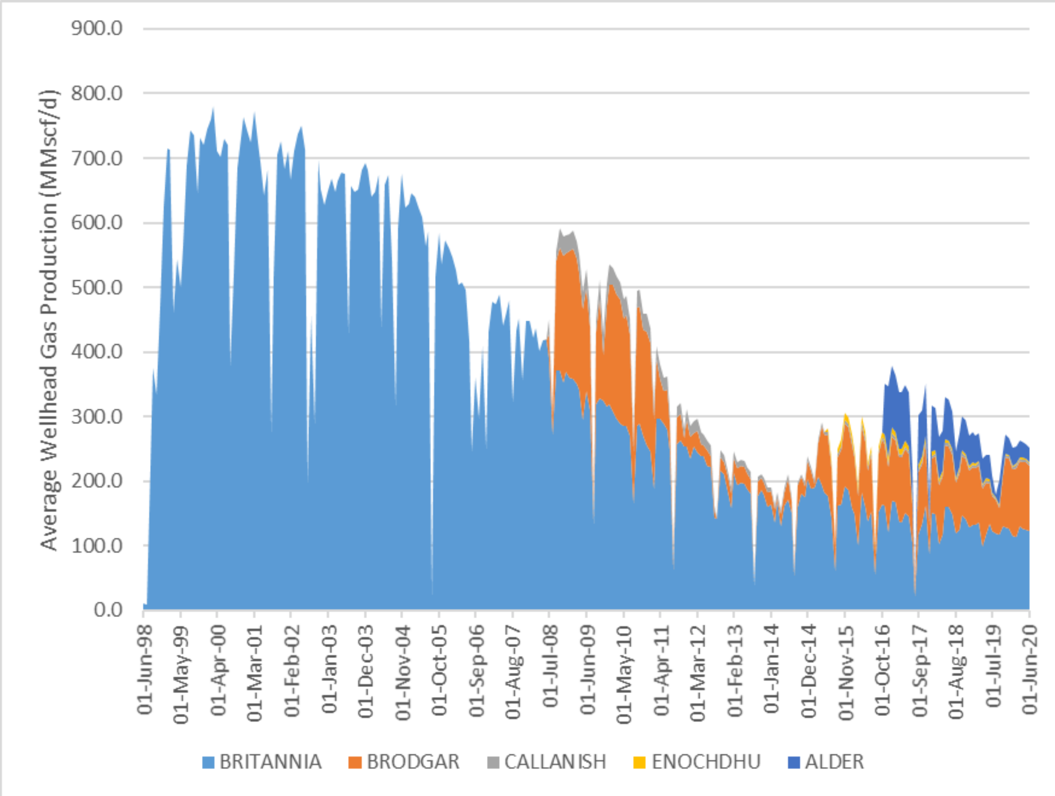


Figure 3-57: GBA gas production history

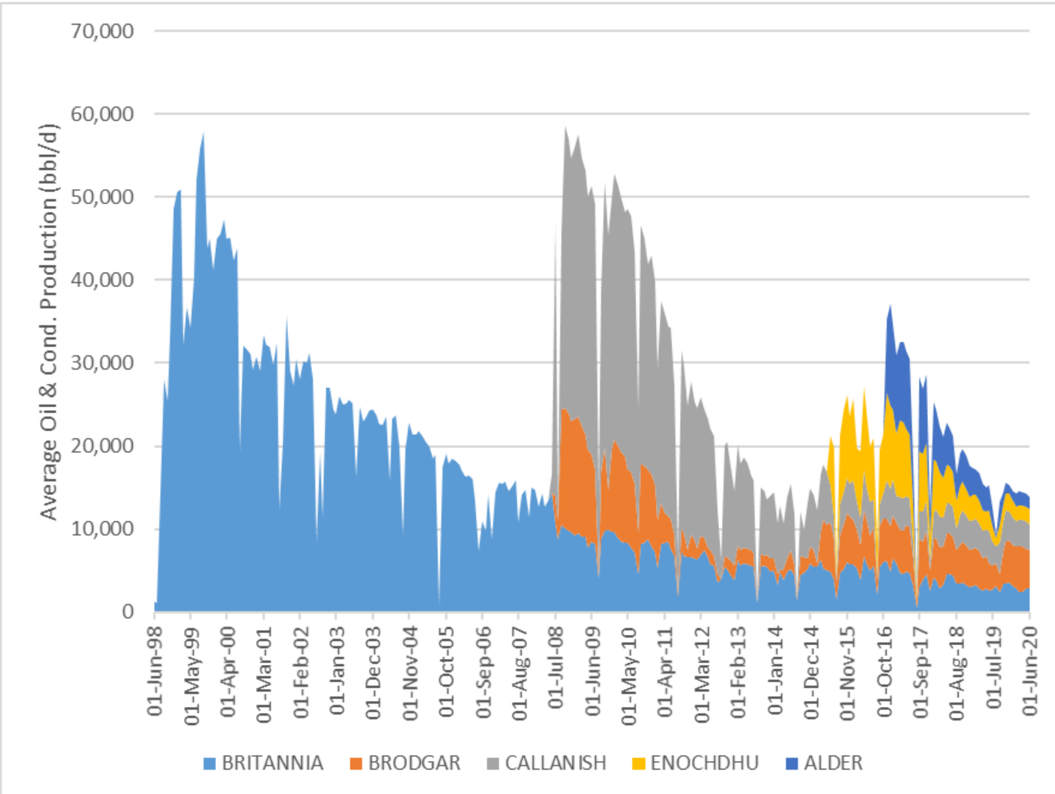


Figure 3-58: GBA liquids production history

3.9.1. Britannia Field

The Chrysaor operated Britannia field is located approximately 210 km east of Aberdeen in the Central North Sea. The field is a large structural-stratigraphic trap some 40 km in length. The field extends over several blocks but most of the platform wells are in block 16/26 (Figure 3-59). The field was discovered in 1975 by Well 15/30-1 drilled by Conoco. After an extended appraisal phase the field was developed during the 1990s and production began in 1998.

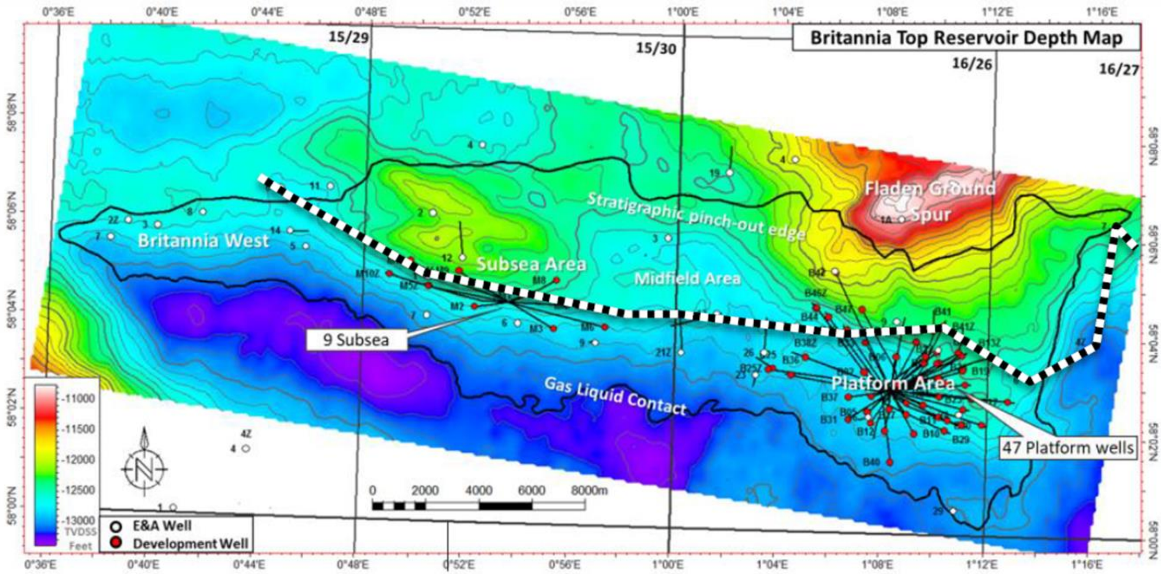


Figure 3-59: Britannia top reservoir depth map (source: Chrysaor)

A total of 55 wells have been drilled across Britannia (Figure 3-59 well numbers include one well in the Alder field). At the Effective Date, 28 of the wells were flowing continuously while ten wells were cyclic producers to manage liquid loading. The remaining 17 wells are suspended or shut-in. Water breakthrough is the primary production risk and is the focus of recent and future workover activity.

Production history for the field is presented in Figure 3-60. The gas and condensate rates of the field at the end of June 2020 were 125 MMscf/d and 2,900 bbl/d, respectively. The CGR has declined from an initial 90 stb/MMscf to 24 stb/MMscf at end June 2020.

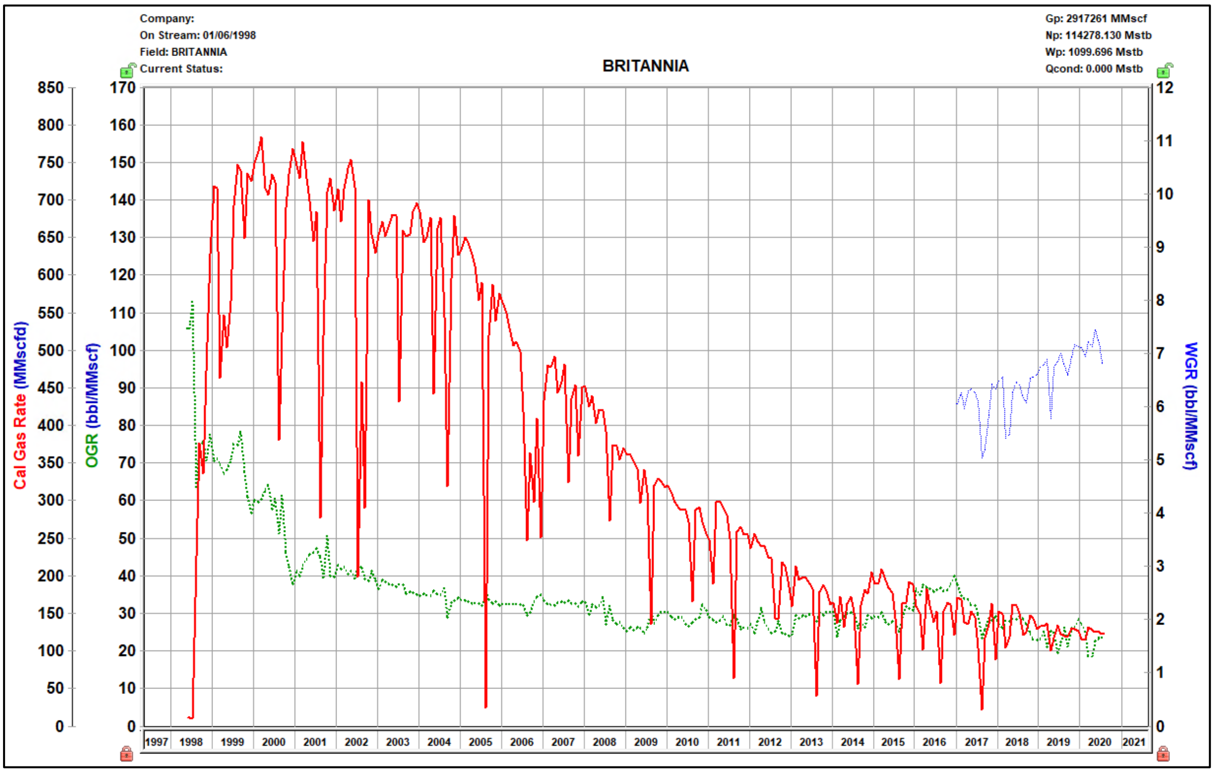


Figure 3-60: Britannia field production history

3.9.2. Brodgar Field

Brodgar is a gas condensate accumulation situated in block 21/3a (Figure 3-62). Chrysaor is the field Operator.

The field was discovered in 1985 by Well 21/3a-4 and appraised in 2000 by Well 21/3a-7. Production started in 2008 with Wells H1 and H2 drilled from the Brodgar subsea template. Water breakthrough occurred in both wells in 2011 and for a period the field operated at a reduced offtake rate. Well H3 was brought on stream in 2015 as H1 and H2 came offline, and similarly broke water in 2019. Well H4 came on-stream in 2019. All wells started up at similar rates of 90-100 MMscf/d. Production history for the field is presented in Figure 3-61. At end June 2020 the field was flowing at 100 MMscf/d and 4,600 bbl/d of gas and condensate respectively. The CGR has declined from 70 stb/MMscf to 44 stb/MMscf. The timing of water breakthrough is the primary risk to well performance.

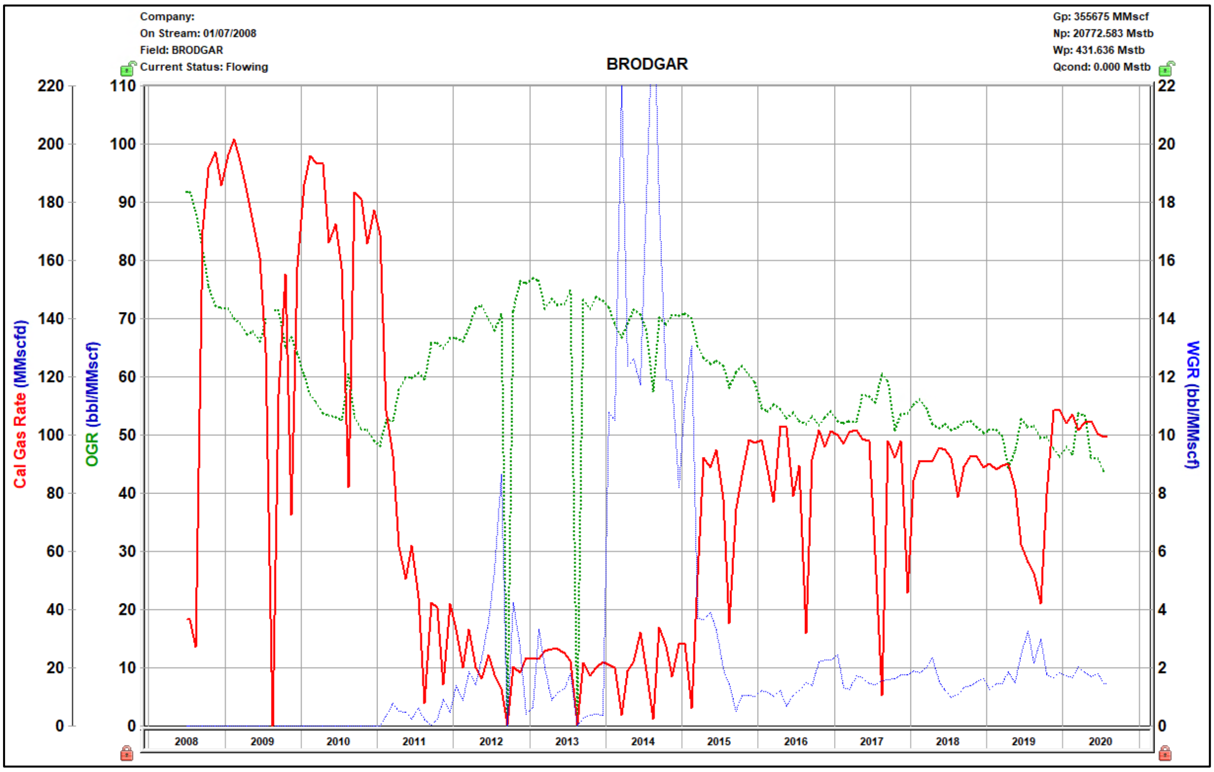


Figure 3-61: Brodgar field production history

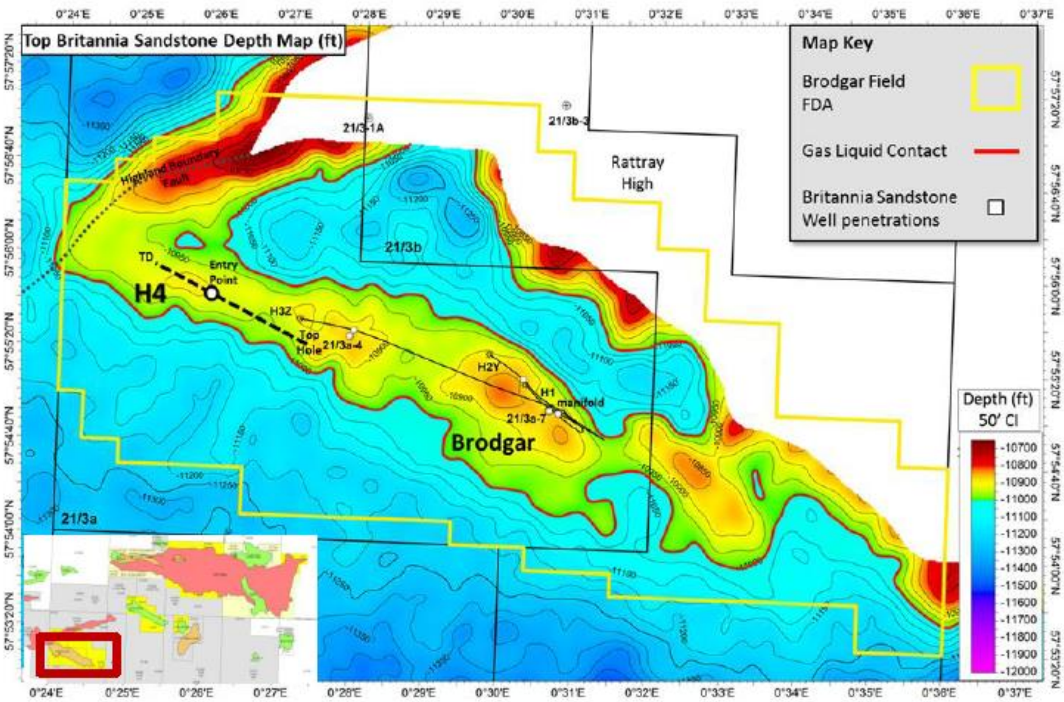


Figure 3-62: Brodgar top reservoir depth map ft tvdss (source: Chrysaor)

3.9.3. Callanish Field

The Chrysaor operated Callanish oil field is located in blocks 15/29b and 21/4aN (Figure 3-63). The field was discovered in 1999 by Well 15/29-12 and appraised in 2000 by Well 15/29b-13. Production started together with the Brodgar field in 2008. Three wells are currently online, Wells F01, F03 and F04. Well F02 was suspended in 2019 to optimise the liquid rate of the field. The field is underlain by a strong aquifer and all the wells are producing water. The field liquid rate has remained steadily around 25-30,000 stb/d for the last two years. By end June 2020, the field water cut was around 90% and oil rate around 2,900 stb/d (Figure 3-64).

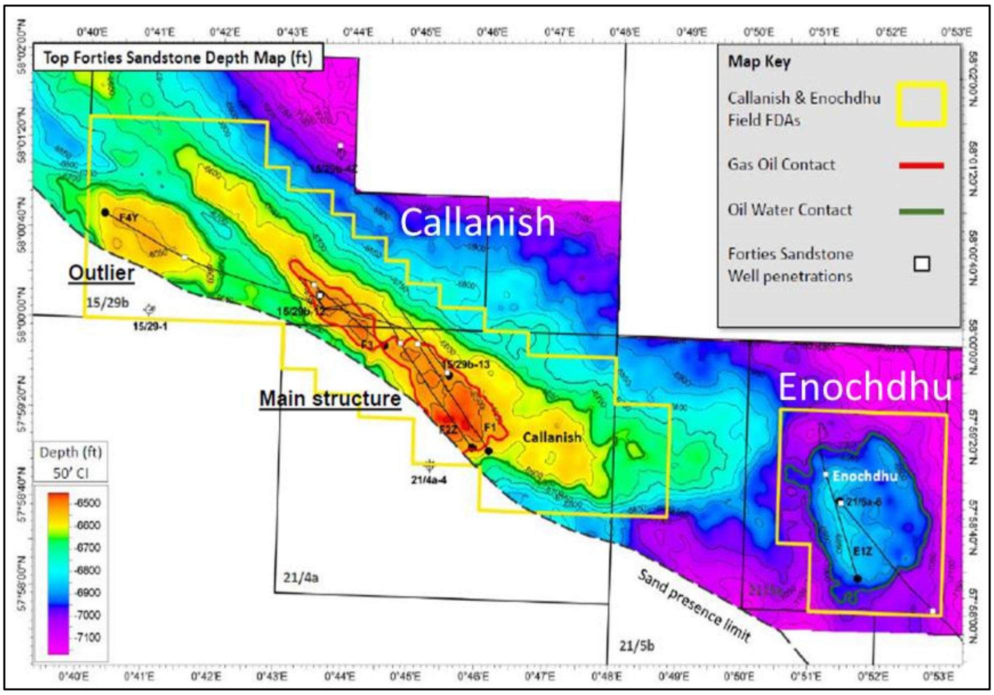


Figure 3-63: Callanish and Enochdhu top reservoir depth map tvdss (source: Chrysaor)

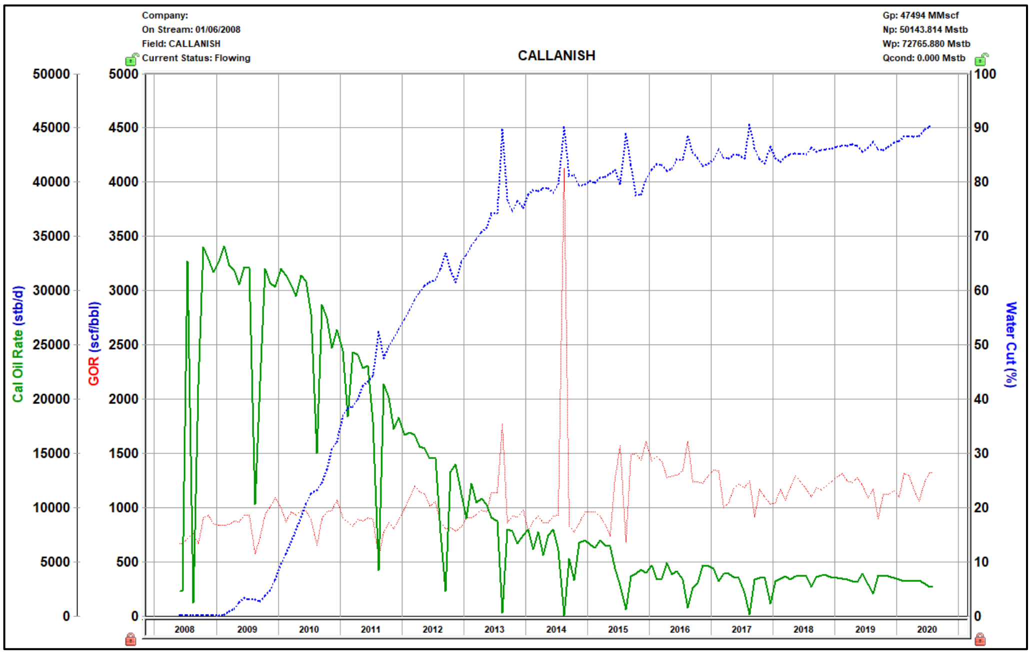


Figure 3-64: Callanish field production history

3.9.4. Enochdhu Field

The Enochdhu oil field is located in block 21/5a to the southeast of the Callanish field (Figure 3-63). The field was developed and appraised by Well 21/5a-6 and 6z in 2015. Production started in 2015 with similar performance to Callanish in terms of water cut development.

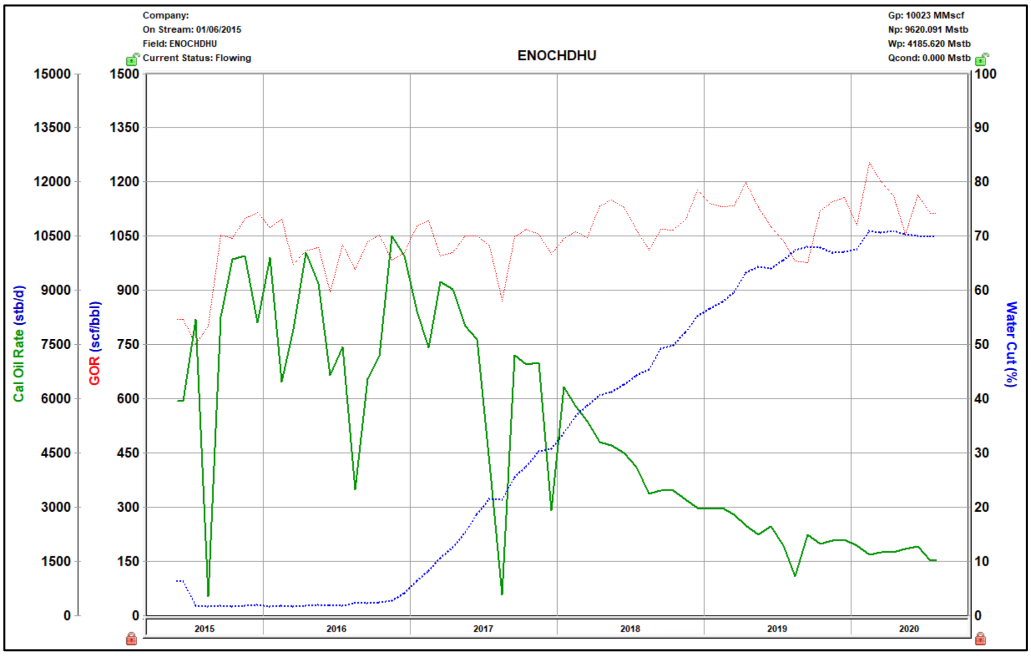


Figure 3-65: Enochdhu field production history

3.9.5. Alder Field

The Alder, HPHT gas-condensate field is located in blocks 15/29 and 15/29a (Figure 3-66) and underlies the main Britannia field. The field is operated by Ithaca.

The field was discovered in 1976 by Well 15/29-2 and appraised by a further four wells. A subsea single-well 28 km tie-back was sanctioned in 2012 with first production in 2016.

A top structure map is presented in Figure 3-66 showing the various well locations including the A1 producer in the DAA block. As of end June 2020, the gas rate was 23 MMscf/d and the condensate rate was 1,500 bbl/d. The CGR has declined from an initial producing CGR of 115 stb/MMscf to 65 stb/MMscf.

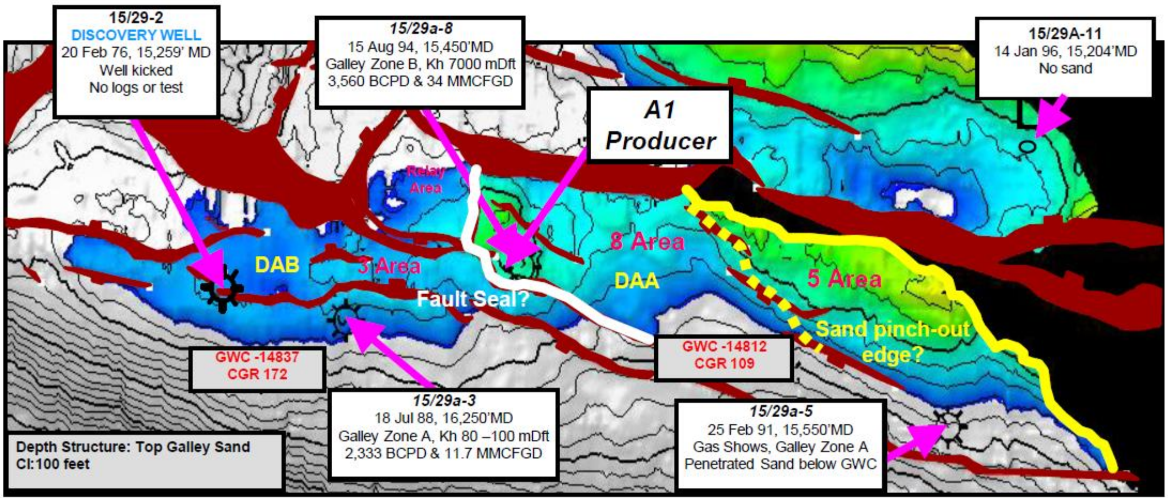


Figure 3-66: Alder top reservoir depth map (source: Chrysaor)

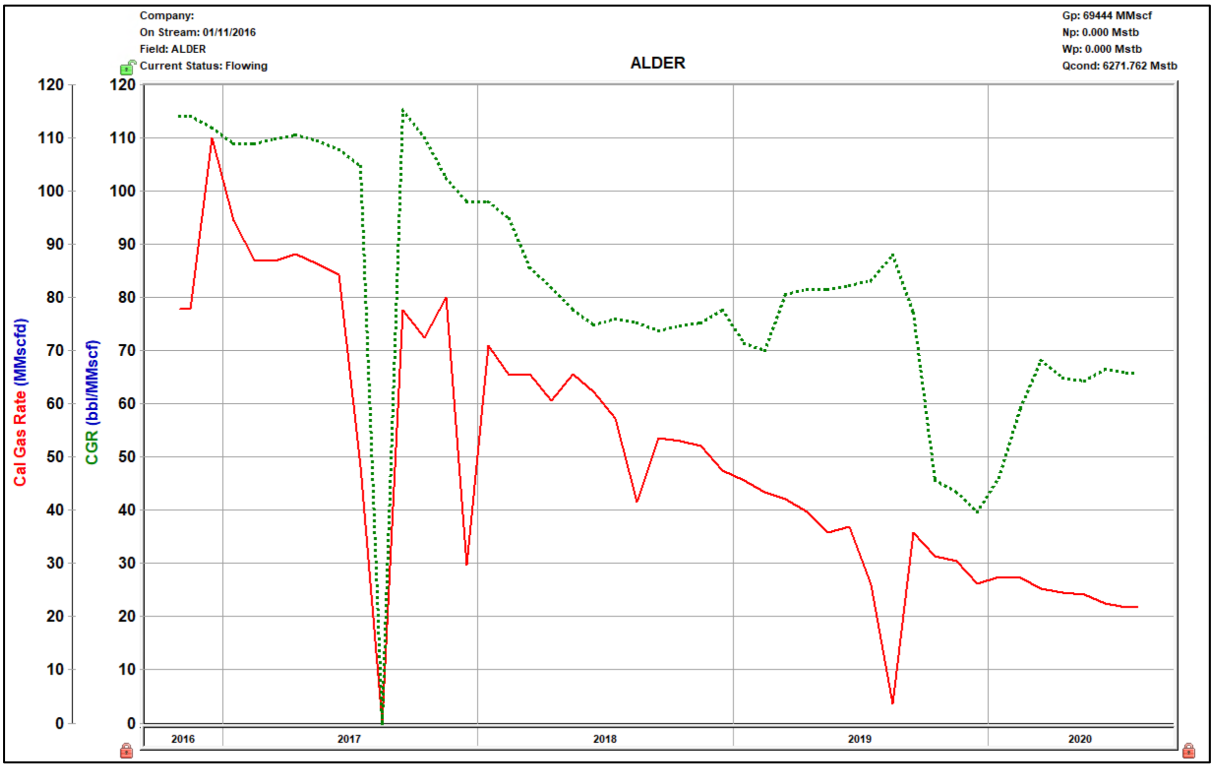


Figure 3-67: Alder field production history

3.9.6. Development Plans

There is relatively little planned drilling activity in the GBA area. The only new well on the drilling schedule and considered firm enough to assign Reserves, is Well F05 in the Callanish field. This subsea well is to be drilled in Q4 2020 and should be hooked up by April 2021.

For Britannia, there are a number of planned workovers to restart or enhance production performance of existing wells.

Future non-drilling projects include compressor optimization (re-wheeling) as part of a long-term compression (LTC) project. This was originally planned for September 2020 but has been deferred to Q1 2021 due to the Covid-19 pandemic. The objective is to reduce suction pressure at the Britannia platform from 5.2 barg (90 psia) to 3.9 barg (71 psia). This will benefit wells with liquid lift problems and allow a lowering of the abandonment pressure.

The general deferral of development plans means that the TAR which occurs every 3 years is now realigned, starting in 2021.

3.9.7. Technically Recoverable Resources

For the Britannia field, ERCE performed a well by well decline curve analysis. An exponential decline was fitted using an operating rate versus cumulative gas basis and varied to give low, best and high cases. Minimum gas rates were used taking account of modelled well liquid loading limits and the lower LTC suction pressure. Some wells are assumed to go cyclical once they fall below the liquid loading limit and this is characterised by a drop in their average production rate. Chrysaor plan several workovers and documentation shows a workover portfolio to at least 2024. Several workovers have been performed in the first half of 2020 with better than anticipated results helping to offset the field decline. As the workover benefits are present in the production history, the DCA forecasts are assumed to implicitly allow for similar workover levels in the future.

In 2018, the Operator (ConocoPhillips) implemented a compressor suction pressure reduction test from 6.0 to 5.6 barg (102 – 96 psia) and concluded there was a benefit of between 4 and 6.5 MMscf/d per bar of suction pressure reduction. Based on this, ERCE has estimated the benefits of the next LTC compressor optimization will be between 5.2 and 8.5 MMscf/d. In addition, this will allow a lowering of the abandonment pressure which, based on p/z analysis, gives a 14.3 Bscf best estimate incremental recovery; this was then varied by +/-30% to derive low and high case estimates. Based on Chrysaor's schedule, ERCE has assumed the LTC re-wheel will occur in Q1 2021. For forecasting condensate, the CGR was taken to be constant at 24 stb/MMscf (the current stable CGR).

For the Brodgar field, Chrysoar has recently undertaken reservoir simulation modelling and obtained a good history match of the water cut development. ERCE has accepted Chrysaor's simulation forecast for Well H4 as the best estimate case. Recent production is dominated by Well H4 and the field's longevity is dependent on the timing of water breakthrough in this well. The low and high cases were estimated based upon observations of the well stock historical performance. The Chrysaor forecast for Well H3 predicted the well would have been shut-in which has not yet occurred; ERCE has therefore estimated the likely future performance of this well at different confidence levels. For forecasting condensate, the CGR is assumed to decline from its current 45 stb/MMscf to 25 stb/MMscf over the profile life.

For the Callanish field, production forecasts were generated for the existing well stock using a WOR versus cumulative oil extrapolation assuming constant liquid rates representative of the last few years performance. For the planned new Well, F05, ERCE has reviewed work undertaken by Chrysaor and determined a low, best, and high case TRR of 0.5 MMstb, 4.1 MMstb and 10.2 MMstb respectively. Initial rates were varied from 3,000 to 8,000 stb/d and the decline was assumed to be hyperbolic with a b exponent of 0.5. For forecasting associated gas, a constant GOR of 1,200 scf/stb was used in all cases based on the current average field GOR.

For the Enochdhu field, production forecasts were estimated using a WOR versus cumulative oil analysis. When Well F05 starts up in Callanish, production from Enochdhu will be backed out; based on Chrysaor production network modelling. Thus, an additional 23% deferment was applied in all cases. For forecasting associated gas, a constant GOR of 1,050 scf/stb was used in all cases based on the current average field GOR.

Production forecasts for the Alder field were based on an operating rate versus cumulative gas extrapolation. Minimum flow rates of 11, 10 and 5 MMscf/d in the low, best and high cases respectively were used based on hydrate limitations. The forecasts include the benefits of the planned Alder to LTC project in Q1 2022 which will allow the Alder wells to benefit from the lower LTC suction pressure at Britannia. For forecasting condensate, the CGR is assumed to decline from its current 65 stb/MMscf to 20 stb/MMscf over the well life.

All the production forecasts were adjusted to take account of forecasted operating efficiency (OE) including incorporating planned turn arounds (TARs) and for intermittent producers; the OE forecasts are presented in Table 3-45.

ERCE's gross Developed plus Undeveloped TRR estimates for the Greater Britannia Area fields are presented in Table 3-46. The production forecasts make allowances for production efficiency including incorporating planned turn arounds (TARs) and for intermittent producers. Operating efficiency assumptions are shown in Table 3-45.

Table 3-45: GBA operating efficiency forecasts (ERCE)

Asset	Operating Efficiency									
	2020 H2	2021	2022	2023	2024	2025	2026	2027	2028	2029
Britannia	86%	72%	86%	86%	79%	86%	86%	79%	86%	86%
Brodgar	86%	72%	86%	86%	79%	86%	86%	79%	86%	86%
Callanish	86%	79%	81%	77%	79%	81%	81%	79%	81%	81%
Enochdhu	86%	64%	58%	55%	56%	58%	58%	56%	58%	58%
Alder	86%	72%	86%	86%	79%	86%	86%	79%	86%	86%

Note

1) OE estimates after 2029 repeat on the same three-year cycle.

Table 3-46: Greater Britannia Area TRR Estimates and Recovery Factors

Asset/ Field	Hydrocarbon	PIIP (Chrysaor Best Estimate)	Cum. Prod. at 30 Jun 2020	RF to date	TRR Estimate			TRR best est. RF
					Low	Best	High	
Britannia	Gas (Bscf)	4,180.0	2,913.5	70%	3,188.8	3,280.5	3,387.9	78%
	Cond. (MMbbl)	376.2	114.2	30%	120.8	123.0	125.9	33%
Brodgar	Gas (Bscf)	567.0	352.6	62%	397.0	429.8	477.8	76%
	Cond. (MMbbl)	39.7	20.6	52%	22.1	23.3	24.8	59%
Callanish	Gas (Bscf)	87.1	47.4	54%	57.5	66.3	76.6	76%
	Oil (MMbbl)	130.0	50.1	39%	58.8	66.5	75.5	51%
Enochdhu	Gas (Bscf)	19.7	10.0	51%	12.5	13.7	15.0	69%
	Oil (MMbbl)	23.4	9.6	41%	12.0	13.1	14.3	56%
Alder	Gas (Bscf)	217.0	68.8	32%	75.5	78.5	85.7	36%
	Cond. (MMbbl)	28.0	6.2	22%	6.5	6.7	6.9	24%

3.9.8. CAPEX Assumptions

The main CAPEX forecast is for drilling Callanish Well F05 and execution of the Britannia platform compressor re-wheeling project, which has been deferred to 2021.

CAPEX cost across the Greater Britannia area fields are listed in Table 3-47.

Table 3-47: Greater Britannia Area CAPEX, OPEX and ABEX

GBA CAPEX and ABEX Costs $MM - Developed+Undeveloped Case						
Field	Cost element	Facilities dev+Und $MM	Dev+Und. Wells	Wells $MM	Total - Dev & Undev $MM	OPEX $MM/yr
Britannia	CAPEX	103			103	122
	ABEX	477	47 pltf, 10 SS, 3 E&A	395	872	
Brodgar	CAPEX	0			0	2
	ABEX	23	4 SS	55	79	
Callanish	CAPEX	42		54	97	3
	ABEX	36	5 SS	55	92	
Enochdhu	CAPEX				0	2
	ABEX	23	1 SS	15	39	
Alder	CAPEX				0	2
	ABEX	15	4 SS	65	80	

3.9.9. OPEX Assumptions

The OPEX profile is based upon a long-term plan provided by the Operator which has been evaluated against the historic performance over the previous few years. A cost reduction program has been premised by the Operator some elements of which have been included in the forecast. Some elements of the cost reduction proposals were found to be too immature to be adopted, whilst accepting that as the Operator works them in more detail there is a reasonable probability, they will lead to further OPEX reductions. The near-term yearly OPEX considered for operating the Britannia, Brodgar, Callanish, Enochdhu and Alder fields is some $145 MM.

The Forties Pipeline System (FPS) OPEX and CAPEX costs have been taken from the latest budget, including a 5-year plan (2020-2025) from INEOS, the FPS operator. A similar level of investment from the Operator is expected to continue after 2025. In 2019 INEOS announced a £500 MM ($650 MM) investment into the FPS, to occur over the next five years. After the Effective Date, in October 2020, INEOS issued a revised Final Work Programme and Budget for 2021 indicating a lowering of expenditures of some 24% over the next 5-year period. Due to the materiality of this information it has been incorporated.

3.9.10. Abandonment Assumptions

The ABEX estimate is based upon a detailed study provided by the Operator. ABEX costs considered are listed in Table 3-47.

3.9.11. Facilities and Well Integrity

The latest OCM/TCM meeting showed that the safety critical maintenance backlog is small. The overall backlog has been increasing in the year to date due to the limitations imposed by Covid-19. However, there are no major integrity issues that cannot be managed and so the facilities should be able to handle the production profiles. Some specific points are noted below:

Brodgar: Remotely Operated Vehicle (“ROV”) survey in May 2019 identified an intermittent stream of clear gaseous bubbles emanating from the seabed at the SE guidepost at the Brodgar Well H1 location. A Diver Support Vessel (“DSV”) investigation is planned for July 2020.

Callanish: A continuous stream of bubbles seen emanating around the NE corner of the roof panel. The bubbles are believed to be coming up outside of the conductor. DSV investigation planned for July 2020.

Enochdhu: A low insulation resistance measurement was identified at Enochdhu at the end of December 2019. Breakdown in the integrity of the insulating material suggests sea water is entering the electrical distribution system.

3.9.12. Reserves

The technical production profiles were converted to sales profiles based on data provided by Chrysaor. Wellhead gas was corrected for fuel and flare consumption and for processing shrinkage. NGL yields were applied to the wellhead gas volumes. A summary of these factors is presented in Table 3-48. ERCE has used oil equivalent conversion factors as presented in Appendix 3. The gross asset level production forecast (sales) for the Developed plus Undeveloped Reserves categories are included in Appendix 4.

Reserves were estimated to the earliest of the economic cut-off dates and the end of the technical profile. For the Greater Britannia Area Assets all the field low technical profiles were arithmetically summed and input into the economic model to determine the 1P CoP date. Similarly, all the mid-case profiles and all the high case profiles were added and used to determine the 2P and 3P CoP dates, respectively.

A summary of the gross on block Reserves by field is presented in Table 3-49 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 3-48: Greater Britannia Area wellhead to sales conversion factors

Field	Gas Shrinkage (frac)	Fuel and Flare (MMscf/d)	NGL (stb/MMscf Sales Gas)
Britannia	0.977	11.5	7.1
Brodgar		4.3	12.0
Callanish		1.4	62.8
Enochdhu		0.8	64.4
Alder		1.5	11.6

Notes

1. Britannia gas shrinkage accounts for total GBA shrinkage
2. Britannia single train fuel and flare excludes Alba (estimated at 1.75 MMscf/d)

Table 3-49: Greater Britannia Area Gross Reserves by field and CoP dates

Field	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Britannia	Developed	6.12	8.21	11.36	160.54	216.91	301.57
	Undeveloped	0.24	0.62	0.71	7.71	16.69	21.26
	Total (Dvpd+Undvpd)	**6.36**	**8.83**	**12.07**	**168.25**	**233.60**	**322.83**
Brodgar	Developed	2.01	3.54	5.58	40.29	69.83	113.73
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total (Dvpd+Undvpd)	**2.01**	**3.54**	**5.58**	**40.29**	**69.83**	**113.73**
Callanish	Developed	5.14	7.55	10.90	1.06	1.96	3.36
	Undeveloped	0.00	4.49	10.16	0.00	4.29	10.65
	Total (Dvpd+Undvpd)	**5.14**	**12.04**	**21.07**	**1.06**	**6.25**	**14.01**
Enochdhu	Developed	1.60	2.46	3.66	0.16	0.21	0.29
	Undeveloped	0.00	0.09	0.06	0.00	0.00	0.00
	Total (Dvpd+Undvpd)	**1.60**	**2.55**	**3.72**	**0.16**	**0.21**	**0.29**
Alder	Developed	0.41	0.58	0.90	5.89	8.40	14.22
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total (Dvpd+Undvpd)	**0.41**	**0.58**	**0.90**	**5.89**	**8.40**	**14.22**
Total Asset	Developed	15.27	22.33	32.39	207.95	297.31	433.17
	Undeveloped	0.24	5.21	10.94	7.71	20.98	31.91
	Total (Dvpd+Undvpd)	**15.51**	**27.54**	**43.33**	**215.66**	**318.29**	**465.08**
	COP (Total)	Jun-30	Jun-34	Jun-38	Jun-30	Jun-34	Jun-38

Notes

1. Callanish Undeveloped Reserves associated with Well F05 are uneconomic at a 1P level
2. Undeveloped Reserves at the field level are impacted by applying the ELT at hub level (see Section 5 for details). Enochdhu has no Undeveloped Reserves projects.

3.9.13. Contingent Resources Projects

ERCE has conducted an audit of Chrysaor's Contingent Resources estimates as detailed in Section 6. A number of Contingent Resources projects exist in the Greater Britannia Area as presented in Table 3-50. The Contingent Resources estimates associated with these projects are presented in Table 6-1 of Section 6.

Table 3-50: GBA Contingent Resources Project Summary

Field	Project	Possible Timing	Sub-Maturity Class
Britannia	Infill (5 Wells)	To be determined	DUC
Brodgar	Brodgar to LTC	To be determined	DP
Callanish	Well F06	To be determined	DOH
Alder	Infill (DAB)	To be determined	DUC
MacLeod	Development - 1983 discovery	To be determined	DUC
Shirley	Development - 1981 discovery	To be determined	DUC
Leverett	Development - 1975 discovery	To be determined	DOH

The infill project on the Britannia field involves drilling five extended reach platform wells. A number of target areas have been identified and Chrysaor has estimated Contingent Resources based on type well and creaming curve analysis.

The Brodgar to LTC project would allow the Brodgar field wells to benefit from the lower suction pressure on the Britannia platform and requires a number of facility modifications. A decision on the project also depends on resolving some issues with the provision of MEG to suppress hydrates.

The infill Well F06 on the Callanish field is dependent upon the success of the upcoming F05 Well to be drilled in April 2021. Well F06 would target potential stranded oil in the north-western flank of the Callanish field. The area being targeted has a 12-15 m stand off from the OWC.

The Alder infill well would target a compartment not currently drained by the Alder-1 producer. An HPHT subsea well would be required tied-back to the Britannia platform.

The remainder of the Contingent Resources are associated with three undeveloped discoveries.

The Leverett gas discovery lies immediately to the north of the Brodgar field within Chrysaor blocks 21/3a and 21/3b and extending west into Zennor Petroleum's block 21/2d. The discovery has not yet been unitised. Leverett was discovered by Well 21/2-2 drilled in 1975 and subsequently appraised by three wells in 1977, 2013 and 2015. The area is structurally complex, and it remains to be established whether the drainage area and connected volume associated with future wells will be large enough to be commercial.

The acreage containing the MacLeod and Shirley discoveries was awarded to Chrysaor as part of the recent UK 32nd Offshore Licencing Round. The award announcement was made in September 2020, which is after the Effective Date, but as the event was considered material the discoveries have been included in the CPR. Both discoveries are close to the Britannia field.

Macleod was discovered by Well 22/2-2 in 1983 southeast of the Britannia field. The well encountered a 10 m hydrocarbon column in the Jurassic Piper/Fulmar sands. The reservoir will be challenging to develop as it contains ultra HPHT gas condensate at 15,500 psia and

350°F. One option would be to develop MacLeod using a subsea well tied back 25 km to the Britannia platform, however, pressures at this level are above the normal operating envelope for North Sea subsea developments. Chrysaor intends to acquire new 3D seismic over the discovery and the adjacent MacLeod West prospect before drilling.

Shirley was discovered by Well 16/27a-3 drilled in 1981. The well found a gas column in the Early Cretaceous, Britannia sand. Three well tests were attempted but none of them flowed. There is evidence that the tests were compromised by sand production, but the reservoir quality is also relatively poor (core data suggests the permeability is around 1 mD). Chrysaor believe that by using modern hydraulic fracturing technology they will be able to produce at commercial rates.

3.10. J-Area Assets

The J-Area fields are located in Quad 30 in the UK Central North Sea, 240 km southeast of Aberdeen (Figure 3-68). The cluster comprises four producing oil and gas-condensate fields named Judy, Joanne, Jade and Jasmine. All four fields are operated by Chrysaor.

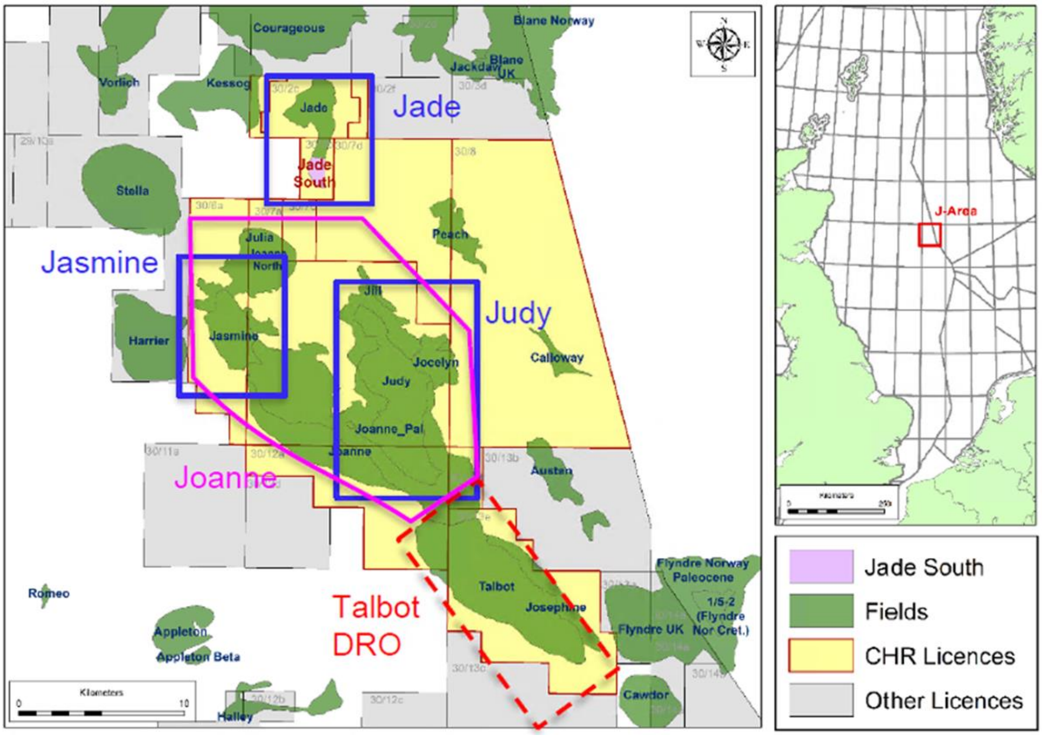


Figure 3-68: J-Area fields location map (source: Chrysaor)

The J-Area fields have multiple stacked reservoirs of Palaeocene, Cretaceous, Jurassic, and Triassic age (Figure 3-69). The fields contain resources at multiple stratigraphic levels and care is required to avoid confusion between the different naming conventions used for the field names, reservoir targets, well names and platforms (Figure 3-70). This report is generally consistent with Figure 3-70 and Table 3-51 provides the designated field, reservoir and well names used by ERCE.

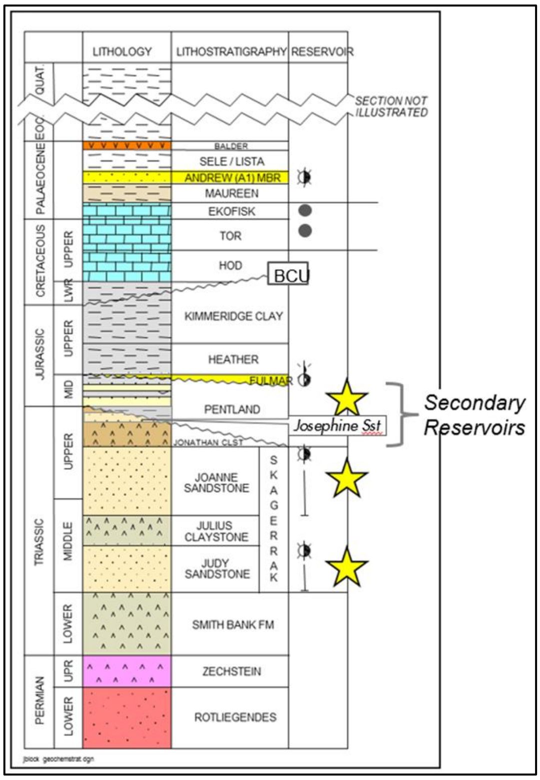


Figure 3-69: J-Area stratigraphic column (source: Shell)

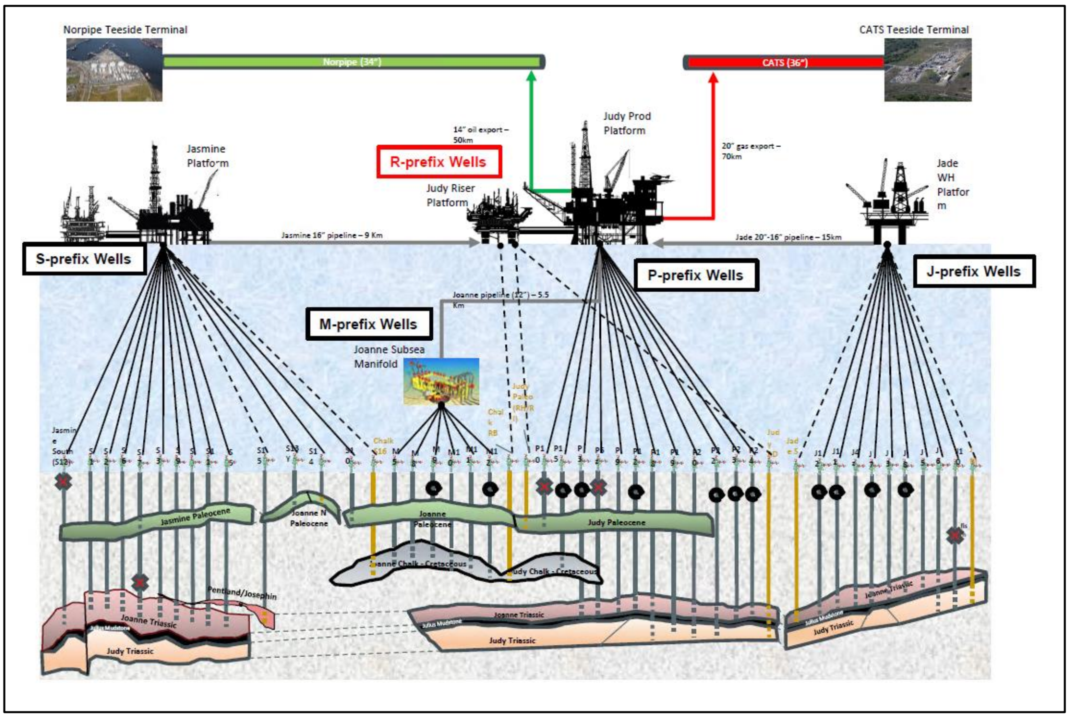


Figure 3-70: J-Area fields and facility nomenclature (source: Chrysaor)

Table 3-51: J-Area – ERCE Naming Convention

Field	Well Prefix	Reservoir	Well Names	Total Gas Wells	Total Oil Wells	Flowing Gas Wells	Flowing Oil Wells
Jade	J	Joanne Triassic	J3-4Z-5-6-7-8-11-12Z	8		8	
		Josephine Pentland	J9	1		0	
		Judy Triassic	J10	1		0	
Jasmine	S	Joanne Triassic	S1-2-3-4-5Z-6Z-7o-9-11	9		8	
		Josephine Pentland	S15	1		1	
Joanne	(Mostly) M	Jasmine Palaeocene	S7		1		1
		Joanne Chalk	M1Z-3Y-4-5-7X-8-10-11Z-12		10		5
		Joanne N Palaeocene	S13Y-14		2		2
		Joanne Palaeocene	M2Z-S10		2		1
		Judy North Chalk	P15-15o		2		1
		Judy Palaeocene	P2Z-4Z-6Z-8-10-11-13Z-14Z		8		0
Judy	P	Joanne Triassic	P1-3-5Z-7-9-12-17-23-24	9		5	
		Judy Triassic	P16Z-18-19-20Z-21-22	6		4	
Total				**35**	**25**	**26**	**10**

A summary of the different reservoirs and their fluids is presented in Table 3-52.

Table 3-52: J-Area – Reservoir and Fluids Summary

Field	Reservoir	Depth (m tvdss)	Fluids	Initial Pressue (psia)	Initial GOR (scf/stb)	Initial CGR (stb/MMscf)
Jade	Joanne & Judy Triassic	4,360	HPHT Gas Cond.	12,350		60-100
Jasmine	Joanne & Judy Triassic	3,990	HPHT Gas Cond.	11,650		300
Joanne	Judy Palaeocene (Lista L2 SST)	2,800	Oil - 47 API	6,550	4000	
	Joanne Palaeocene (Lista L2 SST)	2,800	Oil - 47 API	6,550	3,000-9,000	
	Joanne & Judy Chalk (Ekofisk & Tor)	2,990	Oil - 41 API	7,000	2200	
	Joanne N Palaeocene (Lista L2 SST)	2,800	Oil - 41 API	6,550	1000	
Judy	Joanne & Judy Triassic	3,350	Gas Cond.	8,750		200-400

Production commenced from the area in 1995 from the Joanne and Judy fields. A plot of the gas production history by field is presented in Figure 3-71 and includes the total liquid to gas ratio which is a mixture of oil and condensate.

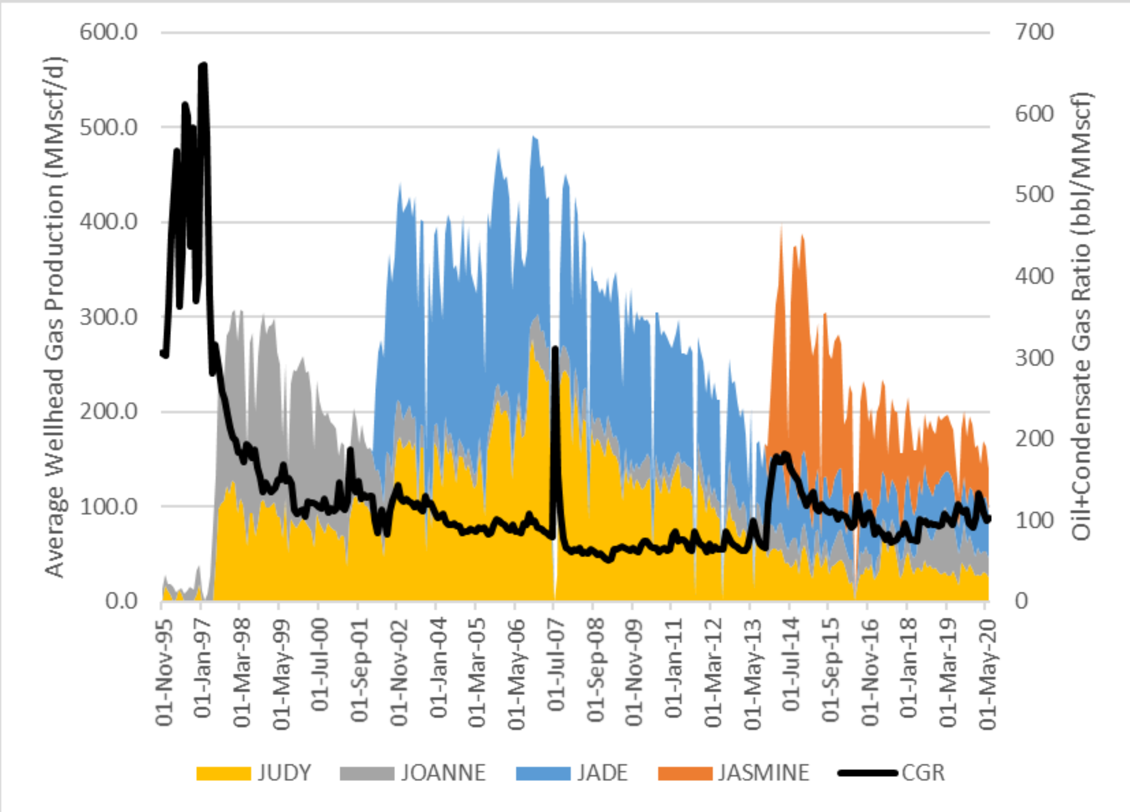


Figure 3-71: J-Area production history by field

Export from the J-Area is via two routes; the rich gas is transported through the Central Area Transmission system (CATS) to the Teesside Gas Processing Plant ("TGPP") while the oil is transported through the Norpipe system to the Teesside Oil Terminal as shown in Figure 3-72.

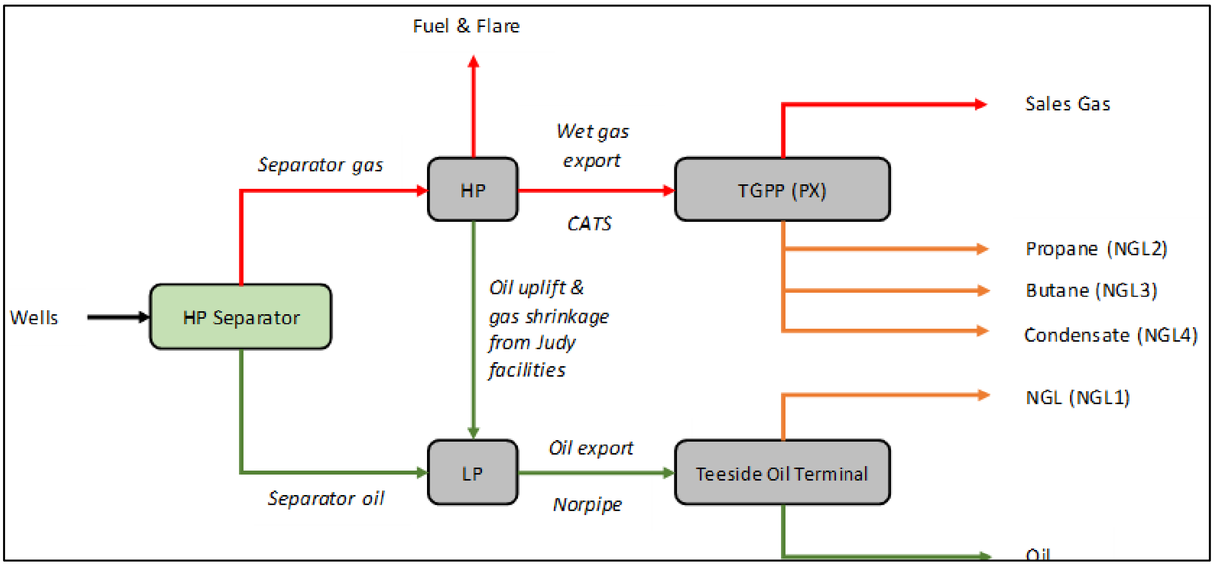


Figure 3-72: Fluid Processing for the J-Area (source: Chrysaor)

With respect to area-wide operations, in 2019 it was proposed to reprocess 586 km^2 of 1992/93 Phillips streamer 3D seismic data and produce 4D results incorporating recently acquired OBN survey data. This should provide a consistent and improved seismic dataset across the whole of the J-Area. The time-lapse 4D seismic is expected to help reduce uncertainty when estimating the FWL and reservoir behaviour. The June 2020 TCM indicates the results should be available in November 2020.

3.10.1. Judy Field

The Judy field is located in blocks 30/7a and 30/12a in the UK Central North Sea. Chrysaor is the Operator and holds a 67% interest in the block. ENI holds the remaining 33% interest. The Judy field was discovered in 1985 and has been producing since 1995.

The Judy field is a fault compartmentalised and eroded Triassic horst (Figure 3-73). The main reservoirs are the rich gas-condensate bearing Triassic Joanne and Judy sandstones. There are localized oil-bearing Jurassic Fulmar formation sands, which also contribute to production in some wells. The field is compartmentalised with progressively deeper hydrocarbon contacts away from the crest, but with a common aquifer.

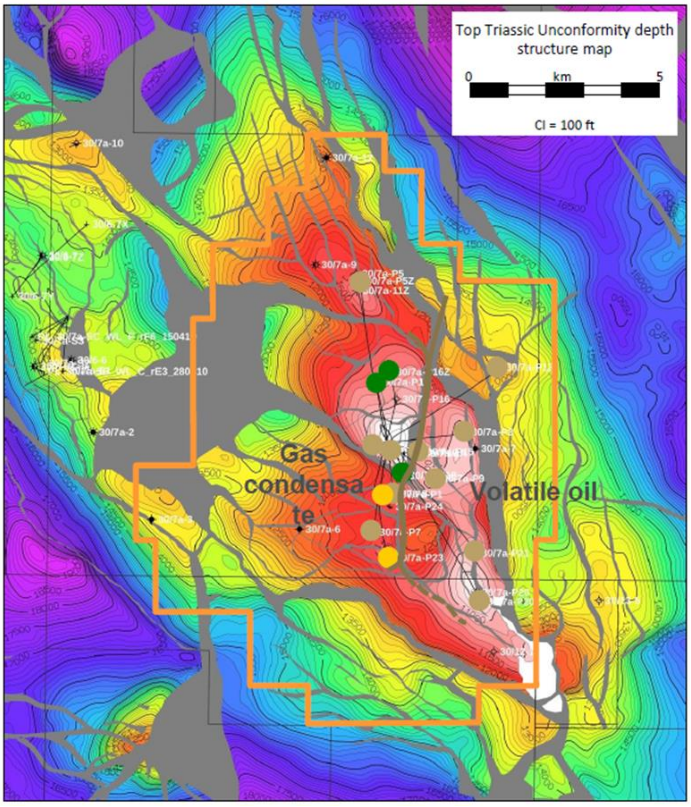


Figure 3-73: Judy field top reservoir (source: Chrysaor)

The Judy field is overlain by a low relief Palaeocene oil accumulation, which appears to be separate from the Joanne field Palaeocene oil reservoir, although they share the same aquifer. However, historically the production from the Judy Palaeocene is allocated to the Joanne field (there are currently no wells active in this area).

The field has been in production since 1995. The compartmentalised nature of the field has required a considerable number of wells (24) to be drilled during three main development phases. There has been no recent drilling activity. The latest well drilled was Well P24 which was put on production in 2010. Only nine wells are still on production from the Triassic reservoir and five of them are on cyclic production due to water loading problems. As a result, the Judy field produces at variable rates that depend on the flowing of individual wells and on allocation between Judy and Joanne fields. The last three months with available production data (April to June 2020), show average gas and condensate rates of 29 MMscf/d and 3,078 stb/d, respectively (avg. CGR of 106 stb/MMscf). The historical performance of the field is presented in Figure 3-74.

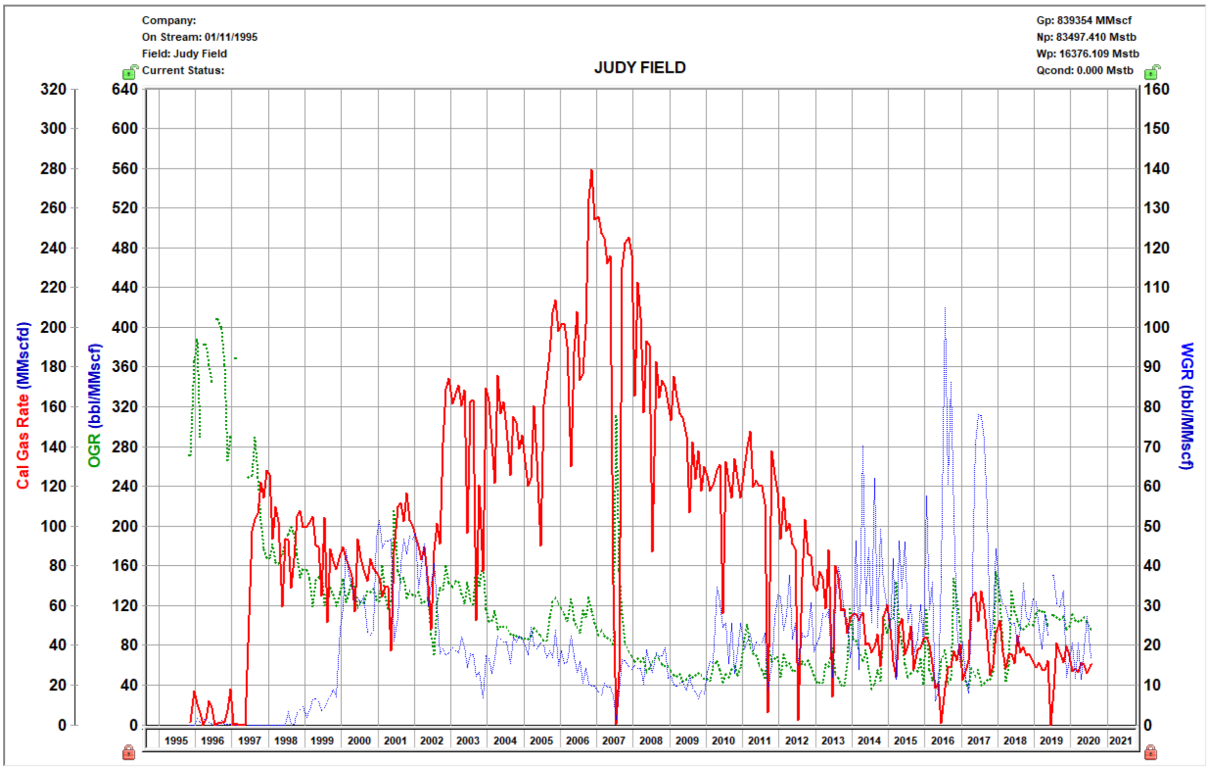


Figure 3-74: Judy field production history

In April 2017, re-wheeling of the compression system took place, which reduced the suction pressure to 15 barg (232 psia). This enabled some previously shut-in wells such as P12 to start flowing again. As a result, field production increased in the first months after the suction pressure reduction.

Work undertaken by the previous Operator (ConocoPhillips) demonstrated the benefits of a further reduction in suction pressure to around 10 barg (160 psia). This project, termed JACS, is scheduled for execution in 2025, with incremental production from mid-2025 onwards.

3.10.2. Joanne Field

The Joanne field is a subsea development located in blocks 30/7a and 30/12a in the UK Central North Sea. Chrysaor is the Operator and holds a 67% interest in the block. ENI holds the remaining 33% interest. The Joanne field was discovered in 1981 and it has been producing since 1995.

The Joanne field is a four-way dip closure domed structure overlying an incipient salt diapir, with oil bearing Lista formation L2 sandstones and Ekofisk Chalk (both Palaeocene) and Tor Chalk (Cretaceous) reservoirs. The Ekofisk and Tor chalks are referred to as the 'Joanne Chalk'. The L2 sandstones of the Lista formation are referred to as 'Joanne Palaeocene'. The Joanne Chalk and Joanne Palaeocene accumulations have separate tilted hydrocarbon contacts.

The Joanne Palaeocene forms part of a relatively thin (8-9 m thickness) extensive (mega) channelized turbidite sand system, deposited across the Central North Sea. The channelised system is orientated NWSE. There is extensive regional well and production data from both the J-Area wells and surrounding area to support the regional continuity of the aquifer. This results in a general NW-SE orientated hydrodynamic gradient in the J-Area, locally modified by pressure release at salt diapirs. The hydrodynamic gradient may account for the oil-prone accumulations being 'off-crest' to the north of the J-Area around the Joanne North and Jasmine accumulations as opposed to the more buoyant gas accumulations being at the crest in both the Joanne and Judy accumulations.

Joanne North (previously known as the Julia Palaeocene) is a Palaeocene Lista formation, L2 sandstone oil reservoir discovery (1991) in a faulted four-way dip closure separated from the main Joanne field to the southwest by a saddle (Figure 3-75). The reservoir is below seismic resolution; but mapped based on interpretation of the shallower Top Balder and deeper Top Ekofisk levels.

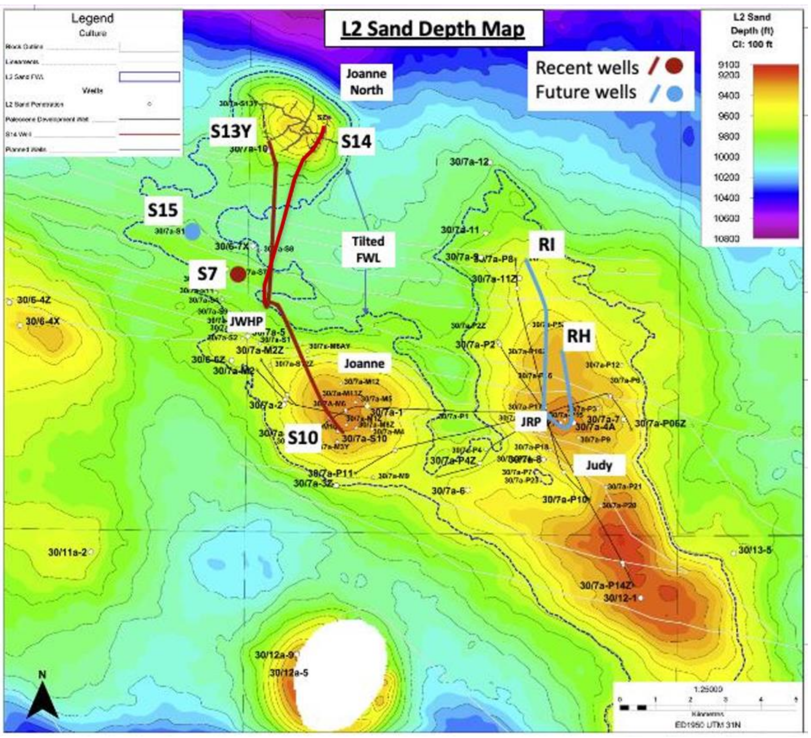


Figure 3-75: Joanne field L2 sand reservoir ft tvdss

The discovery had remained undeveloped due to its distance to the surrounding infrastructure. However, advances in drilling technology combined with new J-Area hub facilities, allowed two wells to be drilled during 2019 (Wells 30/7a-13Z and 30/7a-14Z). Unfortunately, both wells appear to be producing from small compartments with limited connected volume.

The Joanne Chalk reservoirs reside in three contiguous accumulations namely: Joanne Main, Judy North Chalk and Judy South Chalk. Although the Judy North and Judy South Chalk overlie the Judy field's Triassic reservoir, both accumulations are considered part of the Joanne field (Figure 3-76). Fracturing of the Joanne Main Chalk over the buried salt feature improves the connectivity and producibility between the chalk layers.

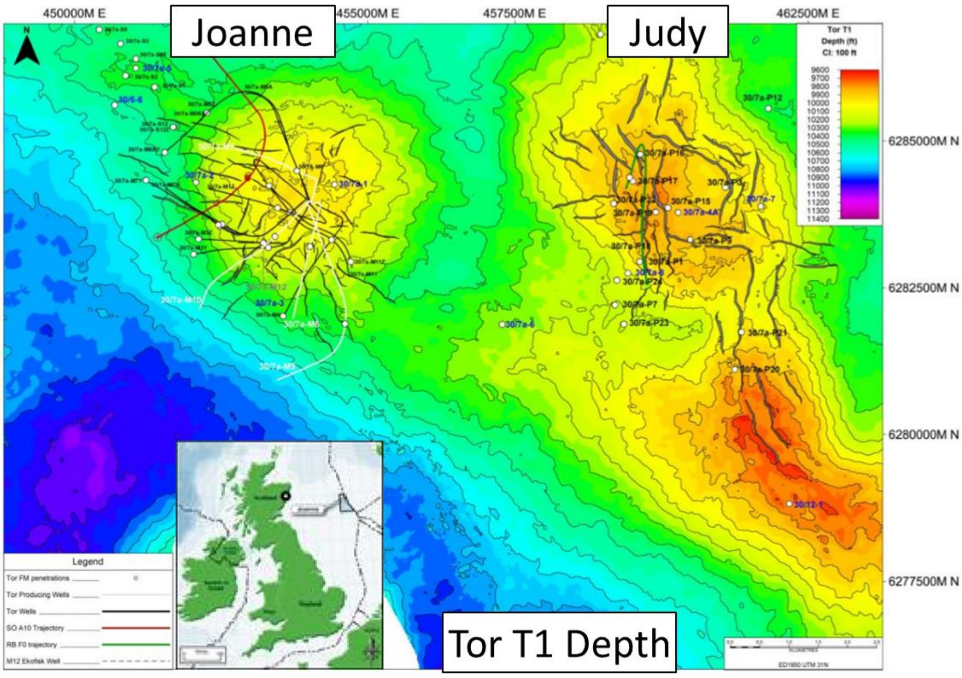


Figure 3-76: Joanne field Chalk reservoir ft tvdss (source: Chrysaor)

Several J-shaped wells have been drilled and completed into the Joanne chalk with an acid fracture stimulation i.e., Wells M1Z, M3Y, M4, M5, M7x, M8, M9, M10, M11z, and M12 (a dedicated horizontal well landed within the Ekofisk chalk formation). Most of the active wells are cyclic producers under current flow conditions. The last three months with available production data (April to June 2020), show average gas and condensate rates of 22 MMscf/d and 7,150 stb/d, respectively (avg. CGR of 327 stb/MMscf). The historical performance of the field is shown in Figure 3-77.

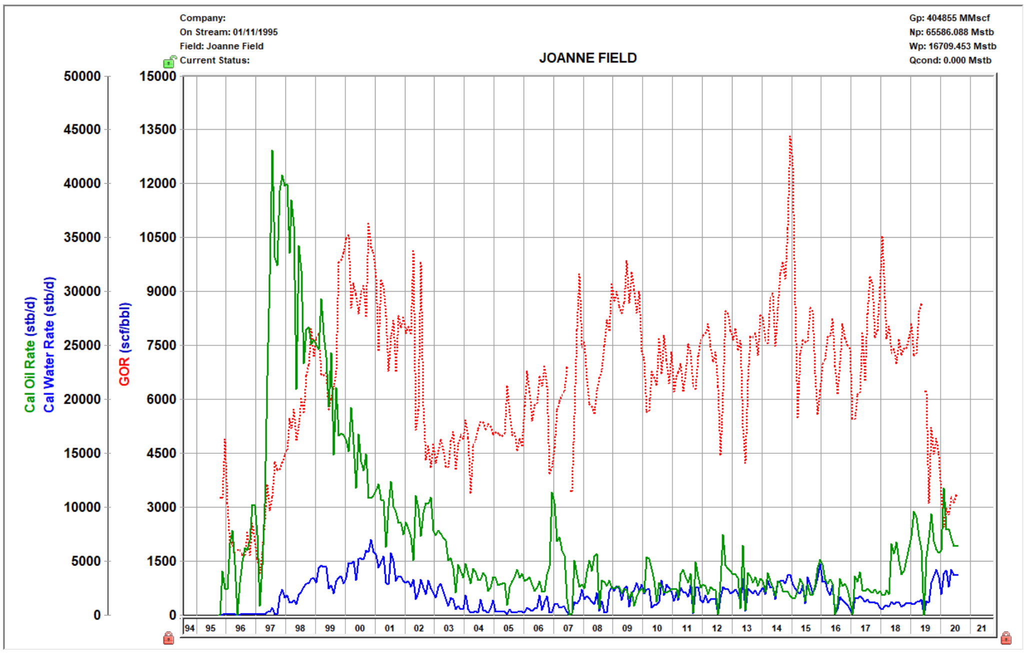


Figure 3-77: Joanne field production history

3.10.3. Jade Field

The Jade field is located in block 30/2c in the UK Central North Sea. Chrysaor is the Operator and holds a 67.5% interest in the block. The remaining interests are held by Ithaca (19.93%), ENI UK Ltd (7%) and Siccar Point Energy 5.57%. The Jade field was discovered in 1997 and it has been producing since 2002.

The Jade field is an HPHT Triassic gas-condensate reservoir. The main reservoirs are the rich gas-condensate bearing Joanne and Judy Triassic sandstones. The field was the first separate HPHT accumulation brought on stream in the J-Area. The field is compartmentalised with 200 to 1,200 psi pressure difference between the various compartments (Figure 3-78).

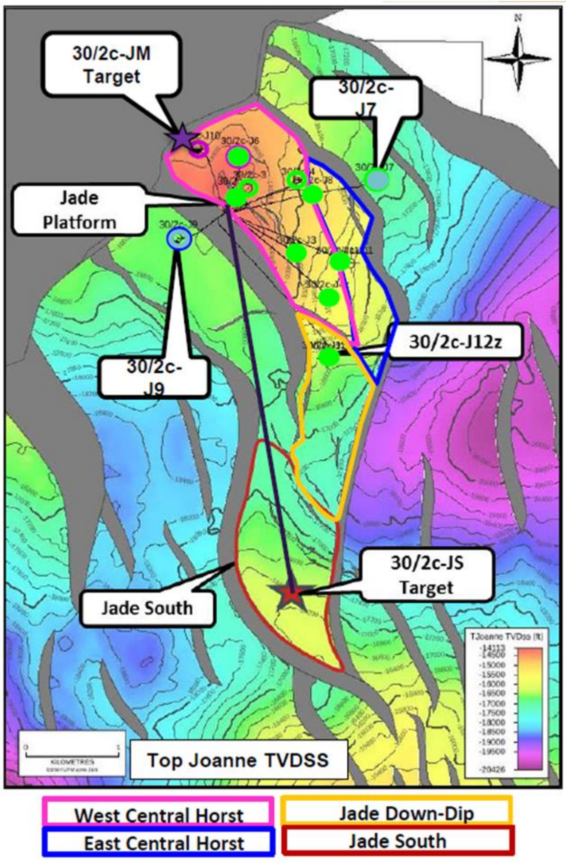


Figure 3-78: Jade top reservoir depth map ft tvdss (source: Chrysaor)

Most of the wells produce from the Joanne sandstone reservoir in Jade field Central Horst area. The exceptions are Well J10 (Judy sandstone) and Well J6 (commingled Joanne and Judy sandstone). The most recent well in the field was Well J12Z drilled in 2014, downdip of the main Central Horst, into a separate fault block. The well encountered a depleted reservoir and confirmed communication across the field. Wells J07 and J09 were drilled in separate fault blocks on the flanks of the field. Both wells had low productivity and Well J09 has been abandoned. Well J07 is still in operation as a cyclic well.

Production liner deformation has been observed in most of the wells using calliper campaigns during the early development stage (2003 and 2007). This caused Well J10 to be shut-in during 2017 and a subsequent workover failed to repair the well; it remains shut-in.

The last three months with available production data (April to June 2020), show average gas and condensate rates of 54 MMscf/d and 2,052 stb/d, respectively (avg. CGR of 38 stb/MMscf). The historical performance of the field is shown in Figure 3-79.

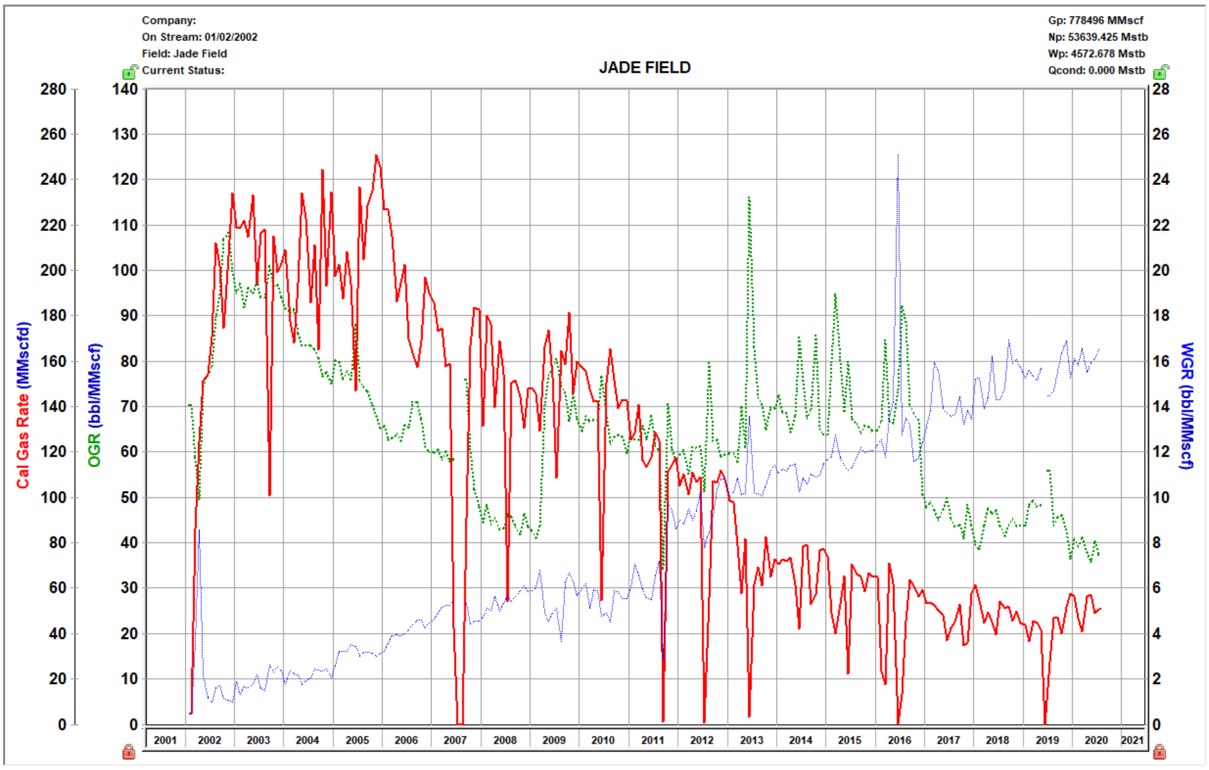


Figure 3-79: Jade field production history

3.10.4. Jasmine Field

The Jasmine field is located in blocks 30/7a and 30/6a in the UK Central North Sea. Chrysaor is the Operator and holds a 67% interest in the field. ENI holds the remaining 33% interest. The Jasmine field was discovered in 2006 and it has been producing since 2013.

The Jasmine field was the second Triassic HPHT rich gas-condensate field to be brought on stream in the J-Area. The bulk of the accumulation lies in the Joanne sandstone on the West Limb of the field (Figure 3-80).

Nine wells are completed in the Triassic reservoirs and, as in the Jade field, some liner deformation is being observed. Several well intervention campaigns have been successfully completed including re-perforating and running PLTs.

Well S15 was drilled in 2019 to target the Triassic within the Merida fault block (Figure 3-80). The well found a gas bearing interval in the Triassic but reservoir quality was poorer than expected. A decision was taken to complete the well in this zone and the overlying Jurassic Pentland formation, which was also hydrocarbon bearing. Production commenced in October 2019 but at low rates and the well appears to have limited remaining resources.

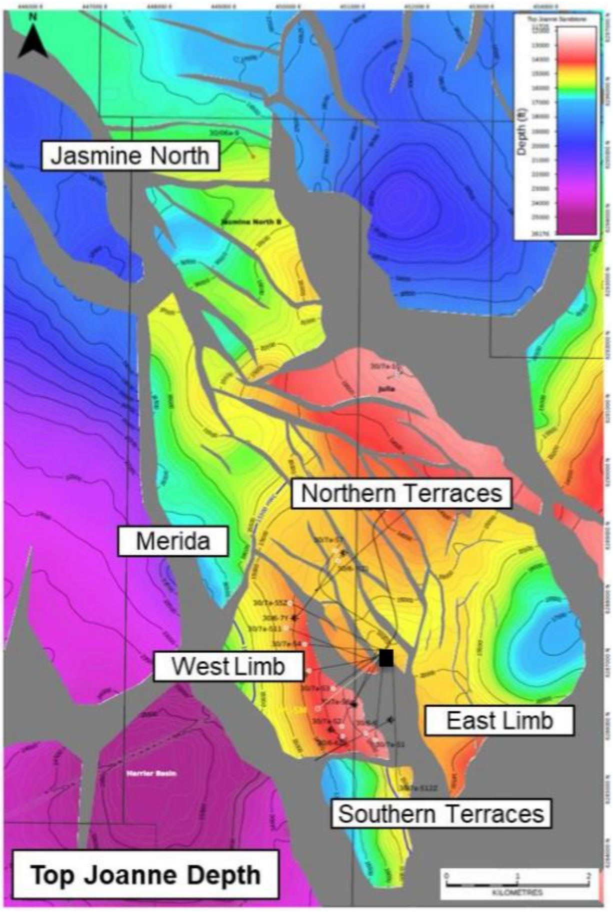


Figure 3-80: Jasmine top reservoir ft tvdss (source: Chrysaor)

The historical performance of the field is shown in Figure 3-81. The last three months with available production data (April to June 2020), show average gas and condensate rates of 53 MMscf/d and 4,019 stb/d, respectively (avg. CGR of 76 stb/MMscf).

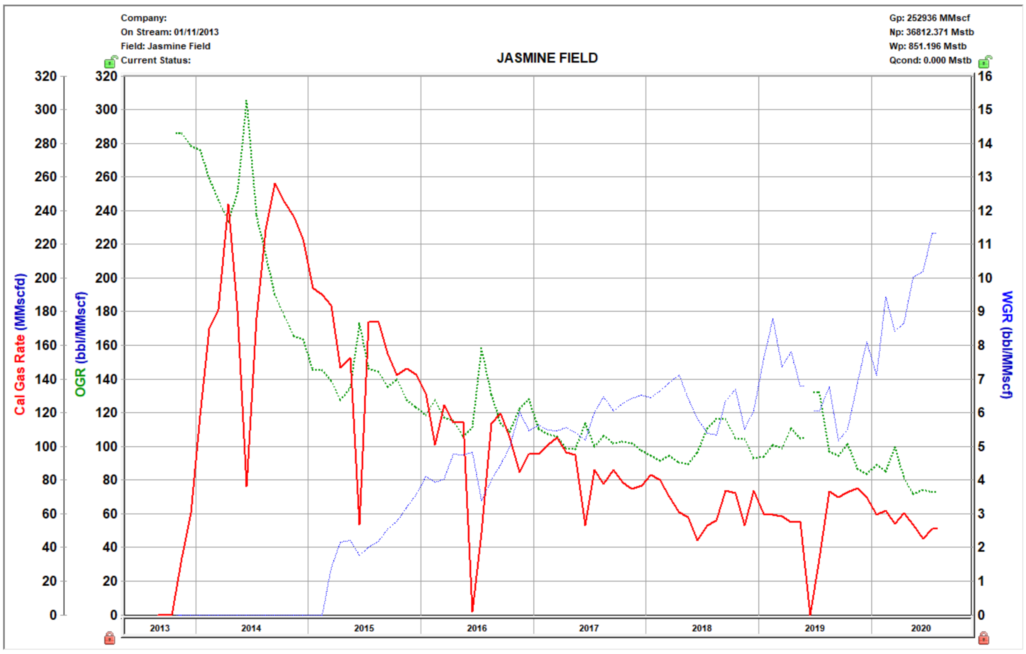


Figure 3-81: Jasmine field production history

3.10.5. Development Plans

The Operator's planned development opportunities in the J-Area comprise:

- Joanne S16 well. Drilling of this multi-stage acid frac chalk well from the Jasmine platform restarted in September 2020 following a delay due to COVID19
- Jasmine West Limb infill well (SM). Well targeting under-depleted volumes in the Jasmine West Limb oil leg
- S15 recompletion to the Palaeocene, providing further offtake to the OIIP in the Jasmine saddle area
- Jade JM, a replacement well for the failed J10 well targeting the remaining GIIP in the Judy reservoir at the Jade field
- Judy RD, an extended reach well from the Jasmine riser platform (JRD) at Judy targeting the accumulation discovered and tested by Well 30/7a-12
- Joanne RB, a horizontal multi-stage acid frac chalk well to be drilled in the Judy Area from the Judy Riser Platform adding to the limited P15 offtake in the area
- Joanne RH and RI wells. Targeting under-swept volume in the Palaeocene reservoir at the Crest and Northern end of the Judy Area
- Jade JS a well targeting Jade South to be drilled in 2022
- JACS, a project to further reduce the suction pressure at Judy, means to reach <10 bar (145 psi) identified, intention to work further towards target of 5 bar (72.5 psi)
- Well Intervention – regular intervention is premised for the J-Area platform wells. Future plans to focus on liquid loading mitigations (velocity strings, foam)

3.10.6. Technically Recoverable Resources

ERCE's TRR estimates were mostly derived using decline curve analysis (DCA) taking account of the mix of different development well vintages. Estimation of production profiles for the most recent and future wells are based on established type wells or simulation results.

The recovery associated with the Jade Well JS was based on ERCE volumetric analysis. Table 3-53 presents the resultant wet gas GIIP and forecast gross TRR for the well. The forecast start date for this well is September 2022.

Table 3-53: Jade South Gross Wet Gas GIIP and Wellhead TRR

ERCE	GIIP (Bscf)			Gas TRR (Bscf)			Condensate TRR (MMstb)		
	P90	P50	P10	P90	P50	P10	P90	P50	P10
Upper Joanne	27.8	35.9	45.6	7.4	11.9	17.6	0.5	0.8	1.2
Middle Joanne	1.6	2.4	3.6	0.5	0.8	1.3	0.0	0.1	0.1
Lower Joanne	99.5	142.8	202.7	27.8	47.3	75.6	1.8	3.2	5.1
Total	137.5	181.7	242.5	40.3	60.6	89.1	2.7	4.0	6.0

Low, best, and high DCA's were generated to capture the estimated reserves uncertainty range. Secondary phase production volumes were estimated using constant GOR or CGR ratios, derived from historic production data at the well level.

ERCE has performed DCA to estimate future performance of the producing wells. The DCA was performed on individual wells based on monthly operating oil rate versus time. Data were available up to end of June 2020. The individual well profiles were aggregated to generate the production forecasts at a field level. Future operating efficiencies were estimated for each of the fields in the J-Area (Table 3-54) and applied to the production forecasts. Where the historical operating efficiencies are lower, ERCE has applied the historical OE values.

Table 3-54: J-Area operating efficiency estimates

Asset	Operating Efficiency									
	2020 H2	2021	2022	2023	2024	2025	2026	2027	2028	2029
Judy	86%	86%	76%	86%	76%	86%	86%	76%	86%	86%
Jade	85%	85%	75%	85%	75%	85%	85%	75%	85%	85%
Joanne	84%	84%	74%	84%	74%	84%	84%	74%	84%	84%
Jasmine	85%	84%	72%	84%	74%	84%	84%	74%	84%	84%

Note

1. OE estimates after 2029 repeat on the same three-year cycle.

ERCE's gross Developed plus Undeveloped TRR estimates for the J-Area fields are presented in Table 3-55.

Table 3-55: J-Area TRR Estimates and Recovery Factors

Asset/ Field	Reservoir	Hydrocarbon	PIIP (Chrysaor Best Estimate)	Cum. Prod. at 30 Jun 2020	RF to date	TRR Estimate Low	TRR Estimate Best	TRR Estimate High	TRR best est. RF
Judy		Gas (Bscf)	1,362.0	838.4	62%	942.7	990.6	1,027.7	73%
		Cond. (MMbbl)	331.0	83.4	25%	94.0	98.5	101.9	30%
Joanne	Joanne Palaeocene	Gas (Bscf)	120.0	57.8	48%	59.2	61.1	63.6	51%
		Oil/Cond. (MMbbl)	30.0	7.4	25%	7.5	7.7	8.0	26%
	Judy Palaeocene	Gas (Bscf)	262.0	168.3	64%	183.1	198.4	213.6	76%
		Oil/Cond. (MMbbl)	65.0	17.4	27%	19.3	21.3	23.3	33%
	Julia Palaeocene (Joanne North)	Gas (Bscf)	40.0	1.4	3%	2.9	4.6	7.0	12%
		Oil/Cond. (MMbbl)	36.0	1.3	4%	2.9	4.4	6.4	12%
	Jasmine Palaeocene	Gas (Bscf)	18.0	0.6	4%	1.0	1.4	1.8	8%
		Oil/Cond. (MMbbl)	22.0	0.6	3%	1.1	1.6	2.1	7%
	Joanne Chalk	Gas (Bscf)	757.0	171.3	23%	205.9	227.2	245.3	30%
		Oil/Cond. (MMbbl)	353.0	37.9	11%	42.5	45.5	48.0	13%
	Judy North Chalk	Gas (Bscf)	99.0	4.8	5%	10.8	16.4	21.9	17%
		Oil/Cond. (MMbbl)	47.0	0.8	2%	1.8	2.9	3.9	6%
Jade		Gas (Bscf)	1,241.0	776.9	63%	1050.1	1106.3	1179.1	89%
		Cond. (MMbbl)	150.0	53.6	36%	67.9	71.9	77.6	48%
Jasmine	Jasmine Triassic	Gas (Bscf)	1,057.0	251.3	24%	355.8	406.6	454.9	38%
		Cond. (MMbbl)	331.0	36.7	11%	44.7	49.9	55.6	15%
	Josephine (Merida well only)	Gas (Bscf)	22.0	0.1	0%	0.1	0.1	0.1	1%
		Cond. (MMbbl)	8.0	0.0	0%	0.1	0.1	0.1	1%

3.10.7. CAPEX Assumptions

The main CAPEX forecast is for the ongoing development drilling infill well activities. There are also projects to increase the available accommodation at Judy, to reduce TAR costs and to enable Jasmine to operate with reduced manpower. CAPEX forecasts, AFEs and OCM slides / minutes were all provided to support the cost estimates.

The CAPEX considered by ERCE is listed Table 3-56.

Table 3-56: J-Area CAPEX, OPEX and ABEX

J-Area CAPEX and ABEX Costs $MM - Developed+Undeveloped Case							
Field	Cost element	Facilities Dev & Undev $MM	Undeveloped Wells	Dev & Undev Wells	Wells $MM	Total - Dev & Undev $MM	OPEX $MM/yr
Judy	CAPEX	107	4		241	348	104
	ABEX	390		13 platform	218	608	
Joanne[(1)]	CAPEX					0	
	ABEX			10 sub-sea	200	200	
Jade	CAPEX	7	2		168	175	17
	ABEX	91		11 platform	147	238	
Jasmine[(2)]	CAPEX	14	3		124	138	45
	ABEX	265		11 platform	123	388	

Notes
1. Joanne OPEX & ABEX included in Judy Facilities OPEX & ABEX
2. Inclusive of Judy Riser Platform

3.10.8. OPEX Assumptions

The OPEX profile is based upon the long-term plan provided by the Operator which has been evaluated against the historic performance over the previous few years.

A cost reduction program has been premised by the Operator, some elements of which have been included in the forecast. Some elements of the cost reduction proposals were found to be too immature to be adopted, whilst accepting that as the Operator works them in more detail there is a reasonable probability, they will lead to further OPEX reductions.

Total near-term OPEX for the J-Area is some $165 MM per year.

3.10.9. Abandonment Assumptions

The facilities ABEX estimate is based upon a detailed study provided by the Operator. Table 3-56 lists the considered facilities decommissioning and well P&A costs for all the fields.

3.10.10. Facilities and Well Integrity

The June 2020 TCM highlights that there is a growing maintenance backlog across J-Area facilities of which close to 400 hours are safety critical. The overall backlog has grown YTD largely due to the limitations imposed by Covid-19. The critical activities are being prioritised and managed. There has been a recent issue with solids production impacting the Jasmine production and test separators. Options for management of the issue are still being reviewed. However, none of these issues should prevent the facilities from being able to handle the production profiles.

The integrity status of the wells in the J-block as per end of April 2020 are as follows:

- Jasmine: Jasmine wells have high gas content in annuli; Well S15 has gas ingress to the DHSV CL; Well S01 TAC; Well S10 gas in DHSV control line; Well S14 VR plug leak.

- Judy/Joanne: Well P17 sustained annulus pressure; Well P15 control line communication with TH void; Judy wells high gas content in annuli; Well P3, Well P9, Well P10, and Well P18 has control line pressure build up; Well P23 has annulus A-B communication; Well P10 also has annulus A-B communication and gas ingress in DHSV control line; Well M02 has bubbles at subsea tree cap.

Depleted reservoirs are a challenge to drill. In extreme cases this is usually addressed with a contingency casing which increases the cost of the wells.

3.10.11. Reserves

The technical production profiles were converted to sales profiles based on data provided by Chrysaor. Wellhead gas was corrected for fuel and flare consumption and for processing shrinkage. NGL yields were applied to the wellhead gas volumes. A summary of these factors is presented in Table 3-57. ERCE has used oil equivalent conversion factors as presented in Appendix 3. The gross asset level production forecast (sales) for the Developed plus Undeveloped Reserves categories are included in Appendix 4.

Table 3-57: J-Area wellhead to sales conversion factors

Field	Oil Yield (bbl/Mstb)	Gas Shrinkage	Fuel and Flare (MMscf/d)	Teesside NGL Yield	TGPP NGL Yield (stb/MMscf)
Judy	14.3	95%	1.5	7%	37.4
Joanne	14.3	95%	1.1	7%	37.4
Jade	5.3	98%	2.8	7%	37.4
Jasmine	11.4	98%	2.6	7%	37.4

Reserves were estimated to the earliest of the economic cut-off dates and the end of the technical profile. For the J-Area assets all the field low technical profiles were arithmetically summed and input into the economic model to determine the 1P CoP date. Similarly, all the mid-case profiles and all the high case profiles were added and used to determine the 2P and 3P CoP dates, respectively.

A summary of the gross on block Reserves by field is presented in Table 3-58 together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 3-58: J-Area Gross Reserves by field with CoP dates

Field	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Judy	Developed	10.38	16.44	23.00	56.22	89.75	126.30
	Undeveloped	0.00	4.57	4.44	0.00	30.94	34.17
	Total (Dvpd+Undvpd)	**10.38**	**21.02**	**27.44**	**56.22**	**120.69**	**160.46**
Joanne	Developed	5.98	10.81	16.46	19.17	34.92	53.56
	Undeveloped	6.16	12.32	17.57	26.26	52.86	76.24
	Total (Dvpd+Undvpd)	**12.13**	**23.13**	**34.04**	**45.43**	**87.78**	**129.79**
Jade	Developed	9.76	14.10	20.49	112.74	154.90	215.83
	Undeveloped	11.81	15.85	19.47	87.80	120.03	140.39
	Total (Dvpd+Undvpd)	**21.57**	**29.95**	**39.96**	**200.54**	**274.93**	**356.23**
Jasmine	Developed	8.78	14.78	23.11	61.10	96.95	144.17
	Undeveloped	0.00	4.36	4.73	0.00	24.04	26.21
	Total (Dvpd+Undvpd)	**8.78**	**19.13**	**27.83**	**61.10**	**120.99**	**170.38**
Total Asset	Developed	34.90	56.13	83.06	249.22	376.51	539.86
	Undeveloped	17.96	37.10	46.21	114.06	227.88	277.01
	Total (Dvpd+Undvpd)	**52.86**	**93.23**	**129.28**	**363.28**	**604.39**	**816.86**
	COP (Total)	Dec-35	Dec-41	Dec-44	Dec-35	Dec-41	Dec-44

Notes

1. Undeveloped Reserves at the Jasmine and Judy fields are uneconomic at a 1P level
2. Undeveloped Reserves at the field level are impacted by applying the ELT at hub level (see Section 5 for details).

3.10.12. Contingent Resources Projects

ERCE has conducted an audit of Chrysaor's Contingent Resources estimates as detailed in Section 6. A number of Contingent Resources projects exist in the J- Area as presented in Table 3-59. The Contingent Resources estimates associated with these projects are presented in Table 6-1 of Section 6.

Table 3-59: J-Area Contingent Resources Project Summary

Field / Area	Project	Possible Timing	Sub-Maturity Class
Joanne	Judy South Chalk	To be determined	DUC
Talbot	Development - 1972 discovery	Q4 2021 - Q1 2022	DP
Peach	Development - 1995 discovery	To be determined	DNV
Appleton	Development - 1993 discovery	To be determined	DUC
Romeo	Development - 2012 discovery	To be determined	DUC

The Contingent Resources are associated with a number of undeveloped discoveries.

Talbot is a south-easterly extension in block 30/13e of the Palaeocene, Lista formation L2 sandstones encountered in the Joanne field (Figure 3-68). The area was first drilled by Well 30/13-2 in 1972 and then appraised in 2011 by Well 30/13a-9 and in 2013 by Wells 30/13a-11 and 30/13a-11z. The discovery has two distinct four-way dip closures at Talbot North (Well 30/13-2) and Talbot South (Well 30/13a-9). In addition, the southeast flank area drilled in 2013 may be a separate accumulation or part of a larger culmination including both the north and south closures. The larger culmination would imply a tilted FWL to explain the fluid distribution seen in the wells, which would be consistent with other fields in the area. Seismic amplitude extractions provide further evidence for a single large culmination. Chrysaor is planning to drill an appraisal well during Q4 2021 to Q1 2022 to confirm the nature of the closure before optimising the development plan.

As discussed in Section 3.10.2 the Judy South Chalk is considered part of the Joanne field. The Chalk development to date has mostly been in the Joanne Main area where there are currently five active wells producing at 1,600 stb/d and 12.5 MMscf/d (cumulative oil and gas production are 37.9 MMstb and 171 Bscf respectively). A top structure map of the Tor Chalk is presented in Figure 3-76 (Section 3.10.2) with the Judy South Chalk towards the southeast. The development of the Judy South Chalk would likely follow on from development of the Judy North Chalk. Currently the Judy North Chalk is produced from just Well P15 at low rates; further development is planned for Q4 2022 when the Joanne RB Well will be drilled as a dedicated horizontal well. Any development of the Judy South Chalk will depend on a successful development in the north and require extended reach drilling or a subsea development with timing still to be determined.

Peach was discovered by Well 30/8-2 drilled in 1995. The discovery lies in block 30/8 which was awarded to Chrysaor as part of the UK 30th Offshore Licencing Round in 2018. Well 30/8-2 found a 13 m gas column in the Forties sand with a GWC. On test, the sand flowed gas condensate at 1.19 MMscf/d and 117 stb/d. The Peach trapping mechanism is stratigraphic. A possible extension exists to the south which if present could provide sufficient volume for a subsea co-development with the nearby Dunnottar prospect which is planned for exploration drilling in 2H 2021. As such the development of Peach will likely require exploration success at both Peach and Dunnottar.

The blocks containing the Appleton and Romeo discoveries were awarded to Chrysaor as part of the recent UK 32nd Offshore Licencing Round. The award announcement was made in September 2020, which is after the Effective Date, but as the event was considered material the discoveries have been included in the CPR. Both discoveries are to the west of the J-Area developments.

Romeo was discovered by Well 30/11c-6c drilled in 2012. The well penetrated HPHT oil in Jurassic, Heather and Fulmar sands and Triassic, Skagerrak sands. Wireline pressure data was taken but no well test was performed. The Operator at the time concluded a commercial development would not be possible due to poor reservoir quality and limited volumes.

Chrysaor believe that as small pool development concepts evolve there may be a justification to drill a downdip appraisal well to target better quality sands.

Appleton is made up of two culminations Alpha and Beta with gas-condensate in the Jurassic, Fulmar sand. Appleton Alpha was discovered in 1993 by Well 30/11b-3. Appleton Beta was discovered in 1997 by Well 30/11b-4. Both Alpha and Beta structures relate to underlying Triassic salt withdrawal which produced a turtle back anticline. Appleton Alpha is on the north side associated with a growth fault which produced a local four-way dip closure. Appleton Beta is to the south and is a larger more complex structure in a separate pressure regime from Alpha. Well 30/11b-3 tested HPHT gas condensate over a cleaner, lower sand at 19.5 MMscf/d gas and 4,500 stb/d condensate. An upper more shaley section flowed at 3 MMscf/d and 790 stb/d. Well 30/11b-4 encountered gas-condensate at approximately 1,000 psia lower pressure than in Alpha but in what appear to be better quality sands; however, pressure depletion during the test suggested a limited connected volume (the previous Operator interpreted 4.5 MMstb). Uncertainty over the size of the connected volumes to development wells remains the biggest risk for any development. Chrysaor is hoping to use recently re-processed seismic data to better understand the structural complexity before deciding on whether to drill further wells.

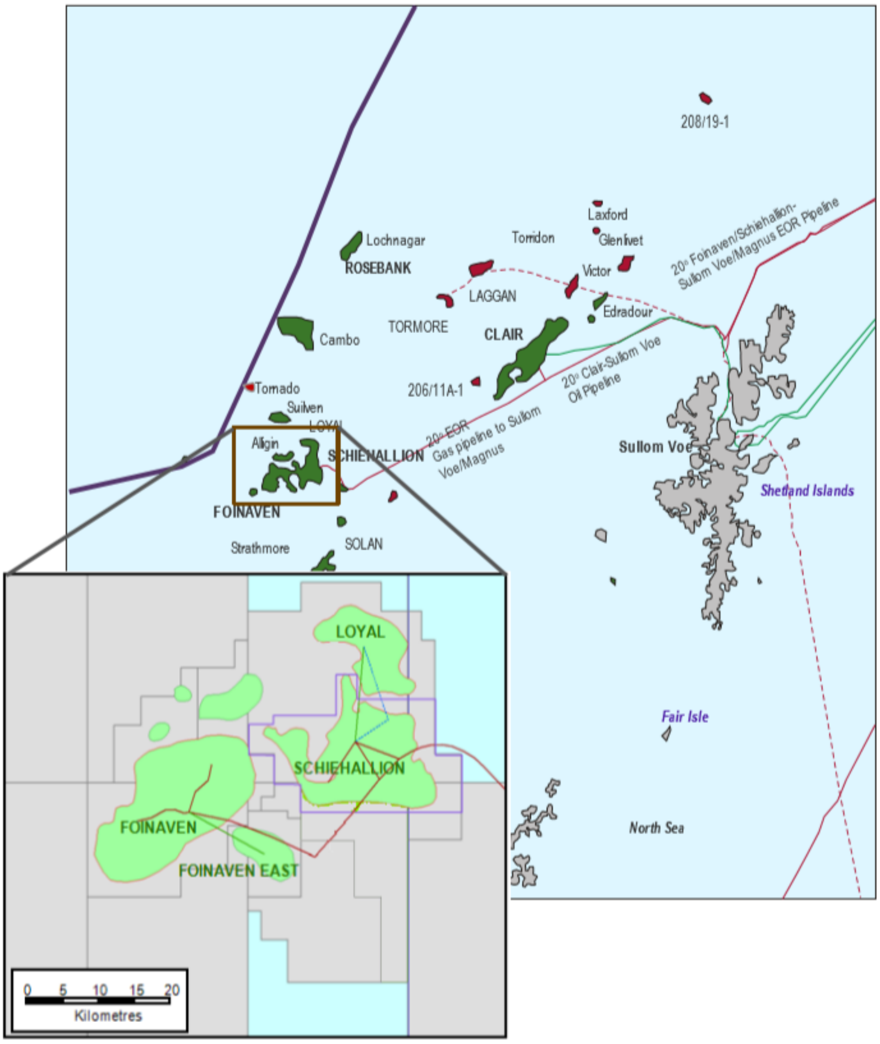
3.11. Schiehallion Field

The Schiehallion field is located in blocks 204/20 and 204/25, 130 km west of the Shetland islands in water depths of approximately 300 to 500 metres (Figure 3-82). The field is operated by BP on behalf of the joint venture partners which include Chrysaor, Shell and Siccar Point. Chrysaor acquired their 10% working interest from Shell as part of the Shell Transaction in 2017.

The field was discovered in 1993 and started producing in 1998. During the period between 1998 and 2013 the field produced 323 MMstb from 21 producers supported by 23 water injectors. The FPSO suffered from integrity issues throughout this period and a decision was taken to carry out a major redevelopment. A new FPSO (the Glen Lyon) was built and production re-started in May 2017. The FPSO production capacity is shared between the Schiehallion and Loyal fields. Chrysaor does not have a working interest in the Loyal field and as such the field has not been included in this evaluation other than to take account of the likely OPEX share. Oil is exported by tanker, and gas via the West of Shetlands Pipeline ("WOSP") to the Sullom Voe terminal on the Shetland Islands.

Drilling of the 17 planned Phase 1 redevelopment wells commenced in 2016 and has now been completed with the last two producers (Wells CP29 and CP31) brought onstream in May 2020. A Phase 2 drilling campaign is still under consideration with four wells likely to be drilled in the first tranche and further wells in a subsequent tranche.

Since 2017 the FPSO water injection system has presented commissioning challenges which have continued into 2020. The average injection rate over the first half of 2020 was 140,000 bbl/d against a target of approximately 200,000 bbl/d.



Notes:
(1) Excludes Loyal.
(2) Denotes operator.
(3) Includes Schiehallion and Loyal shares.

Figure 3-82: Schiehallion field location map (source: Chrysaor)

The Schiehallion reservoirs are of Palaeocene age and are comprised of deep water turbidites. There are three key reservoir sections:

- T34/35 which was deposited in a confined canyon system.
- T31 which was deposited as a combination of confined channelised systems and semi-confined lobe fairways. This reservoir has high NTG and extensive lateral distribution.
- T28/25 which was deposited as a semi-confined channelised fairway. It has high NTG within a semi-confined basin.

The field is being developed in segments/areas with combinations of producers and injectors. The producers tend to be reservoir specific, whereas the injectors are completed across multiple reservoirs. The reservoirs mostly contain slightly undersaturated oil (although there are localised primary gas caps) and reservoir voidage is being managed, where possible, to maintain reservoir pressure above the bubble point; there is insignificant aquifer support. A summary of some key data is presented in Table 3-60. A development schematic showing the segments and wells is presented in Figure 3-83. The use of tracers, 4D seismic and extensive reservoir modelling have helped the understanding of reservoir connectivity and helped locate the wells.

Table 3-60: Schiehallion Summary Data

Reservoir	Depth (m tvdss)	Fluids	Initial Reservoir Pressue (psia)	Bubble Pt. Pressure (psia)	Insitu Oil Viscosity (cP)	Initial GOR (scf/stb)	Bo (rb/stb)	Average Porosity	Horizontal Permeability (mD)
T31, T34/35, T25/28	1,940	Oil (26 API)	2907	2677	1.5-3.5	350	1.16	27%	400-1000

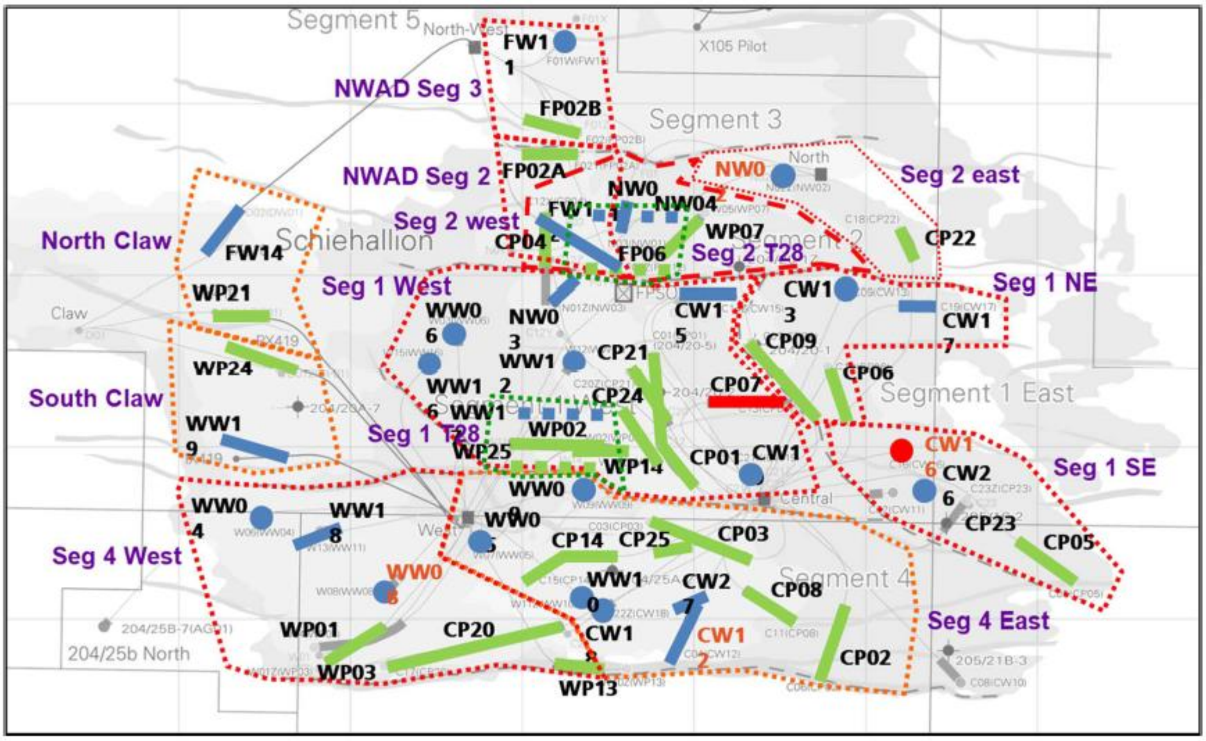


Figure 3-83: Schiehallion field subsurface development schematic (source: Operator)

Field production and injection histories are presented in Figure 3-84 together with an approximate production split by reservoir. Historically the T31 reservoir has been the most important. The field has underperformed lately; during the first half of 2020 the average oil production was 52,000 stb/d versus a 2020 budget estimate of 71,000 stb/d. Production facility deferrals have been caused by several issues with the most significant being related to compression, separation and produced water handling. In addition, some wells are being choked back due to sand production issues. At the end of June 2020 there had been an improvement in the operational efficiency with the field producing 70,000 stb/d. Production history since the redevelopment is presented in Figure 3-85.

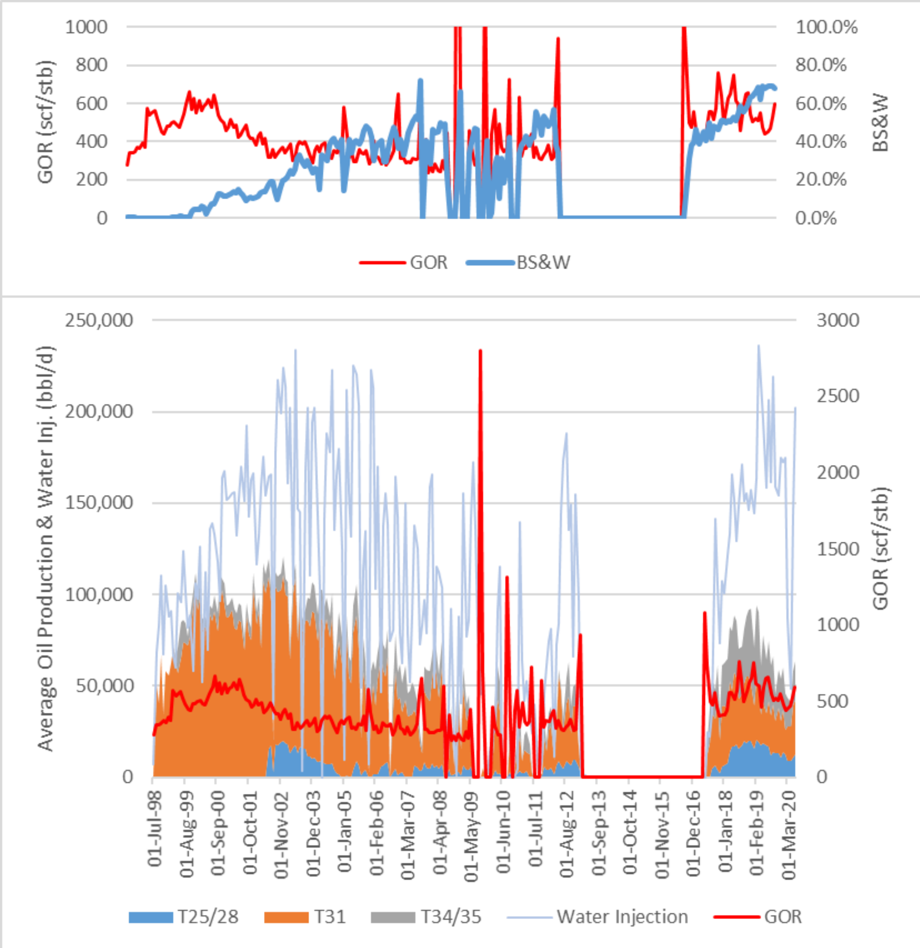


Figure 3-84: Schiehallion field production history by reservoir with total GOR and water injection

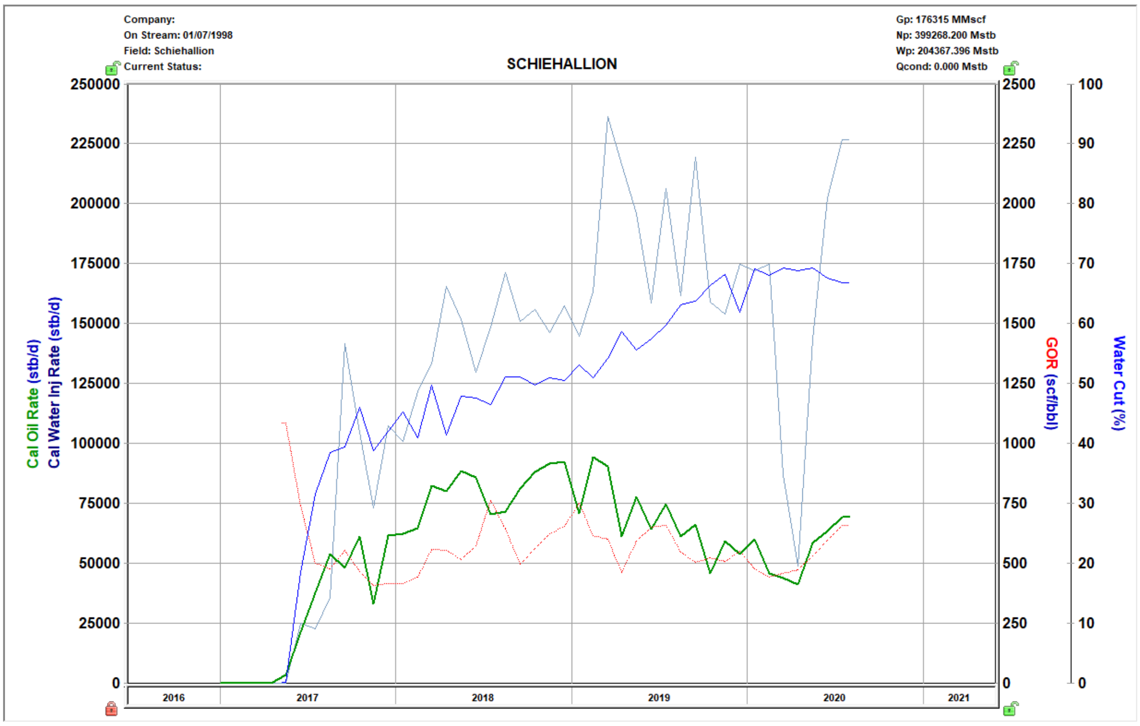


Figure 3-85: Schiehallion field production history post redevelopment

3.11.1. Development Plans

The Operator has previously identified infill locations targeting either attic or 'behind the flood front' bypassed oil. Tranche 1 of the phase 2 drilling programme had been expected to occur during 2020 with the drilling of four new wells. For a variety of commercial reasons, BP took the decision to release the drilling rig and defer the drilling of the wells by two years. It is now unclear when the Tranche 1 wells will be drilled and, given they may be contingent on improved operational performance, ERCE has classified all future drilling as Contingent Resources. Consequently, the Reserves presented in this CPR are based on the current developed producing wells with no Undeveloped Reserves.

3.11.2. Technically Recoverable Resources

The TRR estimates for Schiehallion were estimated using DCA analysis. Reservoir level, water oil ratio ("WOR") versus cumulative oil trends are reasonably well defined and less influenced by the fluctuating offtake rate and could be used to define a range of recovery estimates. Oil production forecasts were generated for different liquid (oil and water) rates to account for possible production increases associated with improvements to water injection. Wells CP29 and CP31 which started production in May 2020 were forecast separately based on the range of incremental recovery predicted by the Operator (these estimates were considered reasonable). Associated gas production forecasts were based on a constant GOR of 650 scf/stb. The production forecasts also take account of predicted operational efficiency (OE) following a review by ERCE and extend to mid-2050. OE is expected to be 70% for the remainder of 2020 and then improve to 80% in 2021 onwards. Production TARs are assumed to occur every five years based on information from the Operator, with the next one due in 2022; this results in an annual average OE of 73% in the TAR years. The resulting forecasts are presented in Table 3-61. ERCE's TRR estimates, which include the cumulative production to date, are presented in Table 3-62 together with RFs based on the Operator PIIP estimates.

Table 3-61: Schiehallion assumed operating efficiency

Field	Operating Efficiency									
	2020 H2	2021	2022	2023	2024	2025	2026	2027	2028	2029
Schiehallion	70%	80%	73%	80%	80%	80%	80%	73%	80%	80%

Note

1. OE estimates after 2029 repeat on the same three-year cycle

Table 3-62: Schiehallion Field TRR Estimates and Recovery Factors

Asset/ Field	Hydrocarbon	PIIP (Operator Best Estimate)	Cum. Prod. at 30 Jun 2020	RF to date	TRR Estimate			TRR best est. RF
					Low	Best	High	
Schiehallion	Oil (MMbbl)	1,839	397.1	22%	567.3	633.2	685.9	34%
	Gas (Bscf)	821	174.9	21%	189.4	199.8	211.2	24%

Notes

1. TRR estimates include the cumulative production to date and represent the total technical recovery prior to economic cut-off

3.11.3. CAPEX Assumptions

The CAPEX profile used for the economic modelling is based upon cost data provided to partners such as AFEs, budgets and forecasts from partner meetings. This data has been reviewed and profiles developed accordingly. The major CAPEX expenditure in the forecast is on the Glen Lyon FPSO, specifically life extension activities required to support the long production profile.

Considered CAPEX, OPEX and ABEX are listed in Table 3-63.

Table 3-63: Schiehallion CAPEX, OPEX and ABEX

Schiehallion CAPEX and ABEX Costs $MM - Developed+Undeveloped Case							
Field	Cost element	Facilities dev+Und $MM	Undev. Wells	Dev+Und. Wells	Wells $MM	Total - Dev & Undev $MM	OPEX $MM/yr
Schiehallion	CAPEX	78				78	300-400
	ABEX	350		61 SS	982	1,332	

3.11.4. OPEX Assumptions

The Operator provides detailed long-term plans with annual updates. These have been reviewed against historic out-turn costs and adopted going forward. 2H 2020 costs have been taken from the latest provided full year estimate. The Operator (BP) is currently restructuring and anticipates cost reductions arising from this. No detail has been made available in respect of this, however it is credible that OPEX may fall in the medium term relative to the profile taken from the 2020 LTP.

ERCE predicts that Schiehallion becomes fuel gas deficient between 2026 and 2032, subject to reservoir performance of the current well stock and/or future contingent drilling activities.

In the Operator’s 2019 LTP, OPEX provisions were made for assumed fuel gas import from 2026 to 2030 and post 2030 diesel import to cover the power requirements.

The Operator has included a placeholder for three fuel gas wells in 2027 in the 2020 LTP to meet fuel gas requirements, however, also states that this is under review. There is no further information provided and hence, ERCE judge this project to be at a too immature stage to underpin Reserves booking once Schiehallion goes fuel gas deficient.

ERCE has instead assumed gas import from the WoS gas system by reversing the stream in the current gas export line to compensate for fuel gas deficiency. ERCE has applied an import gas price 20% above ERCE’s NBP gas price assumption to estimate the incremental OPEX.

3.11.5. Abandonment Assumptions

The Operator provided field abandonment reports and associated estimates. These have been reviewed and the costs adopted in the economic model. The Operator’s proposed well P&A cost of some $16 MM each is above the Benchmark Oil and Gas UK average of some $11 MM and was considered reasonable as the harsh WoS weather conditions can impact on supply and logistics. The ABEX costs are presented in Table 3-63 and include the decommissioning and well P&A costs.

3.11.6. Facilities and Well Integrity

At the June 2020 TCM it was highlighted that there were 15,854 hours of maintenance backlog on the Glen Lyon FPSO. There was no breakdown to determine how much of this was safety critical, but a prioritisation system is in place and so ERCE would expect it to be minimal. Covid-19 was shown as contributing to an increase in the backlog, but plans were in place to increase resources and reduce the backlog.

Schiehallion's post redevelopment FPSO (Glen Lyon) installed in 2016, has apart from in 2018 failed to achieve the efficiency that would be expected from a new facility. At the most recent 2020 OCM the Operator acknowledged they were unlikely to make their operating efficiency target (73%). There are several facilities related issues e.g sand production, erosion, separation, gas compressor, water injection pumps – all of which can impact on longer term production and cost and have been accounted for in ERCE's cost and OE estimates.

3.11.7. Reserves

The technical production profiles were converted to sales profiles based on data provided by Chrysaor. Wellhead gas was corrected for fuel and flare consumption and for processing shrinkage. NGL yields were applied to the wellhead gas volumes. A summary of these factors is presented in Table 3-64. ERCE has used oil equivalent conversion factors as presented in Appendix 3. The gross asset level production forecast (sales) for the Developed plus Undeveloped Reserves categories are included in Appendix 4.

Table 3-64: Schiehallion wellhead to sales conversion factors

Field	Oil Shrinkage	Fuel and Flare (MMscf/d)	NGL Yield (stb/MMscf)
Schiehallion		14	

Reserves were estimated to the earliest of the economic cut-off dates and the end of the technical profile. A summary of the gross on block Reserves is presented in Table 3-65. together with CoP dates applicable to the total (i.e. Developed plus Undeveloped) Reserves cases.

Table 3-65: Schiehallion Gross Reserves with CoP dates

Field	Status	Oil+Cond+NGL Reserves (MMstb)			Gas Reserves (Bscf)		
		1P	2P	3P	1P	2P	3P
Schiehallion	Developed	146.48	236.12	288.74	22.26	37.90	54.76
	Undeveloped	0.00	0.00	0.00	0.00	0.00	0.00
	Total (Dvpd+Undvpd)	**146.48**	**236.12**	**288.74**	**22.26**	**37.90**	**54.76**
	COP (Total)	Jun-40	Jun-50	Jun-50	Jun-40	Jun-50	Jun-50

3.11.8. Contingent Resources Projects

ERCE has conducted an audit of Chrysaor's Contingent Resources estimates as detailed in Section 6. Contingent Resources were assigned to two projects in the Schiehallion field as presented in Table 3-66. The Contingent Resources estimates associated with these projects are presented in Table 6-1 of Section 6.

Table 3-66: Schiehallion field Contingent Resources Project Summary

Field	Project	Possible Timing	Sub-Maturity Class
Schiehallion	Tranche 1 Infill - 4 Wells	2022	DOH
Schiehallion	Tranche 2 Infill - 7 Wells	To be determined	DUC

The Tranche 1 infill project comprises four Phase 2 infill wells (two producers and two water injectors). The project was to have been executed in 2021 but has been postponed. The timing will depend on partner agreement and securing a rig contract most likely in 2022.

The Tranche 2 infill project contains a notional seven further infill wells and as such is considered development unclarified.

4. Additional Undeveloped Discoveries

This section covers a number of other undeveloped discoveries which are independent of the producing areas detailed in Section 3.

4.1. Bressay Field

The Bressay field is an undeveloped discovery located within licences P234, P493, P920 and P977, blocks 3/27B, 3/28A, 3/28B, 9/2A and 9/3A in the Northern North Sea (Figure 4-1). The area is operated by Equinor who hold an 81.625% working interest. The remaining 18.375% interest is held by Chrysaor; acquired as part of the Shell Transaction in 2017.

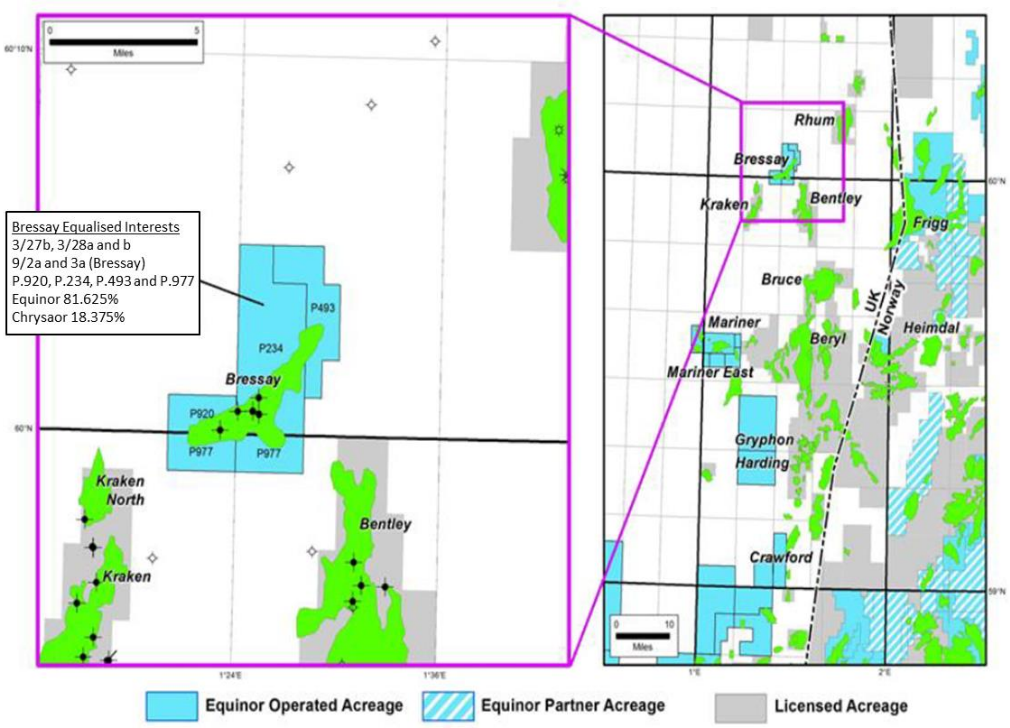


Figure 4-1: Bressay Field Location (source: Equinor)

The Bressay field was discovered in 1976 by Well 3/28-1 and has since been appraised by a further five wells, the most recent in 2008. The field contains 11°API heavy oil, with high in-situ viscosity (~550 cP) and low GOR (~150 scf/bbl). The oils are biodegraded due to the shallow depth and low reservoir temperature (99°F) and there is a primary gas cap. Initial reservoir pressure is hydrostatic (1,570 psia at 1,067 m tvdss). The OWC is at 1,116 m tvdss and the GOC is at 1,036 m tvdss.

The reservoir is interpreted as a late Palaeocene/early Eocene deep water turbiditic fill of an existing seabed canyon. Subsequently, shallower water, deltaic sediments of the Dornoch formation prograded and onlapped over the Bressay canyon. The Bressay reservoir consists of clean sands with excellent reservoir properties, heterolithic rich sands, shale/mudstones and carbonate cemented sands. The top reservoir can be mapped with good confidence from the seismic (Figure 4-2 and Figure 4-3).

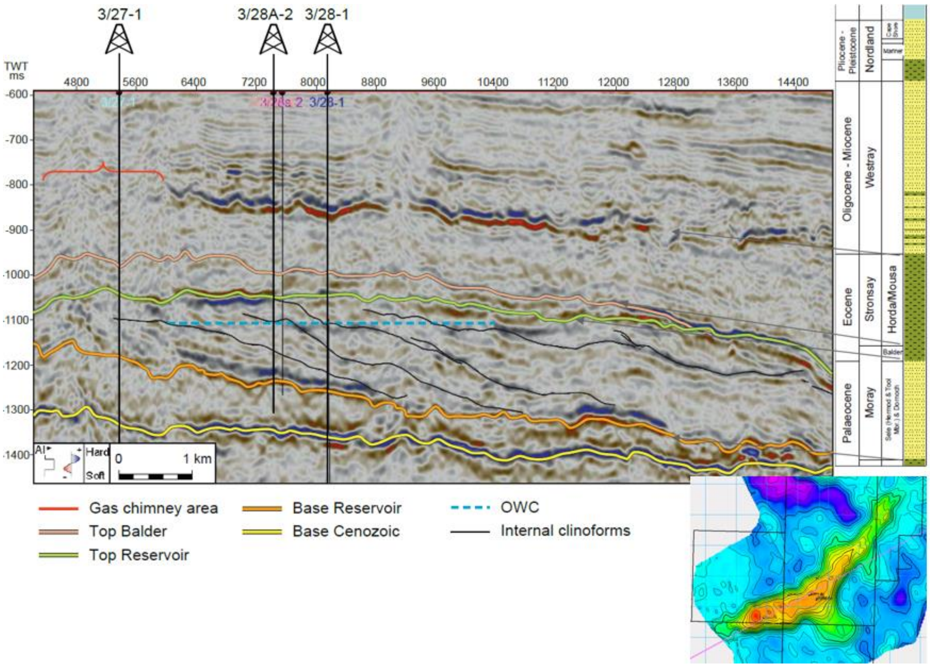


Figure 4-2: 3D Random Seismic Line Along Field Axis (source: Equinor)

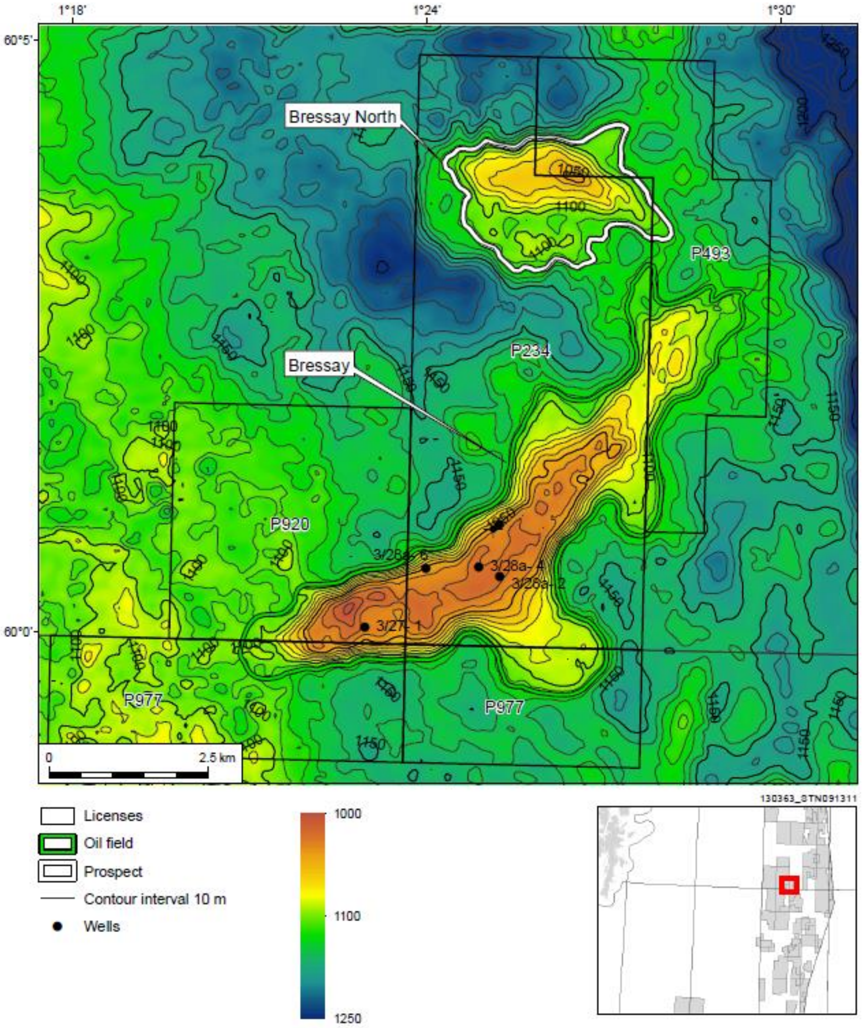


Figure 4-3: Top Reservoir Depth Map (ft tvdss) (source: Equinor)

The low pressure, heavy oil and risk of water breakthrough and poor sweep makes development of the Bressay field difficult. The Operator has carried out studies and prepared conceptual development plans. These involved deploying a mobile offshore production unit ("MOPU") on a leased jack-up rig combined with a floating storage and offtake ("FSO") unit. Eight multi-lateral producers were to be drilled with a gas injector and water injector. However, in 2015 the plans were put on hold. TCM material indicates a decision to proceed with development will depend on experience gained from other heavy oil developments such as Mariner and Kraken.

The Bressay JV is in the process of applying for a licence extension as two of the licences expire at the end of the year. The application proposes to align all four licences, and with licence duration to be dependent on the decision whether to carry out an extended well test, with this decision to be taken within the first year of the licence extension. (After the Effective Date, Equinor announced in July 2020 that, conditional on obtaining a licence extension, EnQuest would purchase a 40.81% interest and takeover operatorship. This would allow the JV to explore options to develop Bressay via its Kraken field facility.)

The Bressay field development has been assigned Contingent Resources within this CPR and are PRMS sub classified as development on hold. The Contingent Resources estimates associated with this project are presented in Table 6-1 of Section 6.

4.2. Norwegian Assets

4.2.1. Grevling Discovery

The Grevling discovery is located in the PL038D licence in the western part of the Norwegian North Sea (Figure 4-4). Chrysaor holds a 35% working interest which it acquired from the operator OKEA. Grevling was discovered by Talisman Norge in 2009 with Well 15/12-21, and subsequently appraised by three further wells in 2009/2010. The Operator has undertaken a number of studies in support of the Norwegian regulatory approval process. In April 2020 the Operator submitted the Decision Gate 2 ("DG2") documentation. The detailed engineering phase is due to start and should culminate in a final investment decision at DG3.

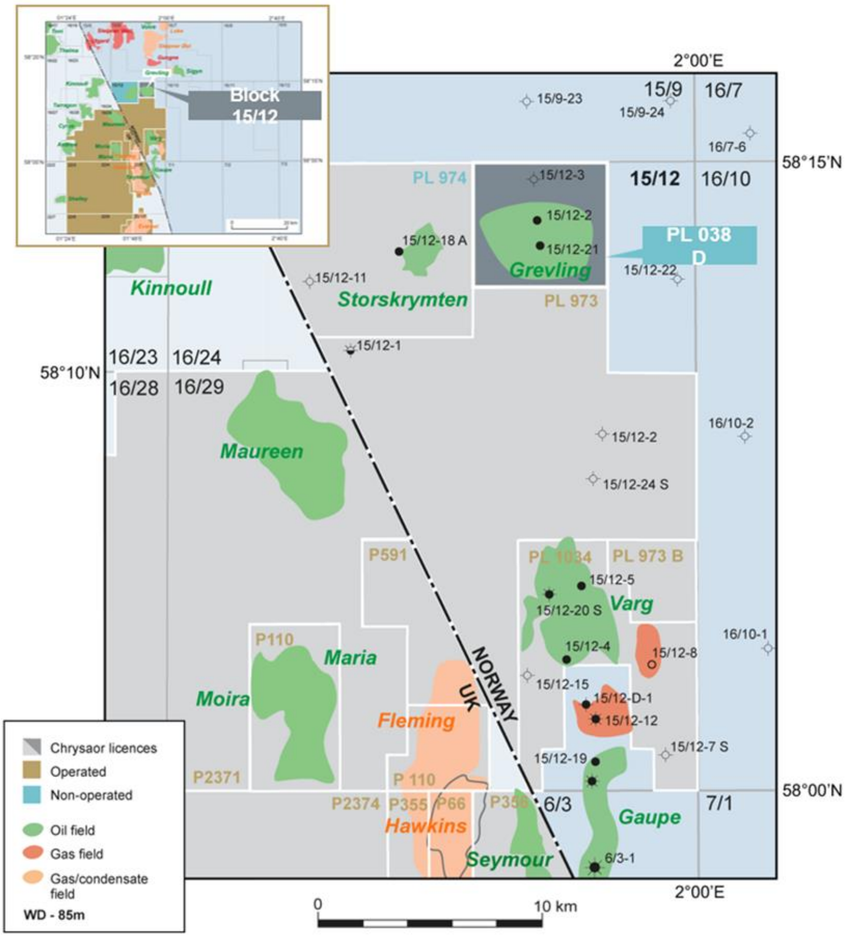


Figure 4-4: Grevling location map (source: Chrysaor)

Grevling is interpreted to be an under saturated oil field. The primary reservoirs are the Bryne and Skagerrak formations, with the Hugin formation providing a secondary reservoir. The oil is variable across the units with 31-34°API gravity oil. From PVT analysis, initial GORs are around 140-190 scf/stb. There is no gas cap and aquifer support is thought unlikely to occur.

Although the Byrne and Skagerrak formations are volumetrically more significant, the best reservoir quality is present in the Hugin formation, with average NTG in excess of 70% and effective porosity approaching 20%. The Skagerrak formation has a NTG and porosity of up to 80% and 17% respectively. The Byrne formation is more heterogeneous due to the variety of depositional facies (channels, mouth bars, splays, etc.) with NTG as low as 10%. Permeabilities are generally low (<100 mD), with the highest values in the Hugin formation.

The Operator is proposing to develop the field using a mobile offshore production unit ("MOPU") on a jack-up rig. Processed oil will be stored (either subsea or at a FSO unit) for export via shuttle tanker. A total of four or five producers and two water injectors are proposed to develop the three reservoirs in two stages.

The Grevling development project has been assigned Contingent Resources within this CPR as there is not yet a firm intent to develop the field. The Contingent Resources are PRMS sub-classified as development on hold. The Contingent Resources estimates associated with this project are presented in Table 6-1 of Section 6.

4.2.2. Storskrymten Discovery

OKEA and Chrysaor were awarded licence PL974 in January 2019 under the Norwegian Petroleum Directorate's APA 2018 awards. Chrysaor holds a 40% working interest and OKEA is the Operator. The licence contains the Storskrymten oil accumulation (Figure 4-5), discovered by Well 15/12-18S in 2007. The block had previously been relinquished in 2017 and has now been awarded with an initial period of two years and a contingent extension period of fifteen years. The block lies immediately to the west of the Grevling discovery (Section 4.2.1).

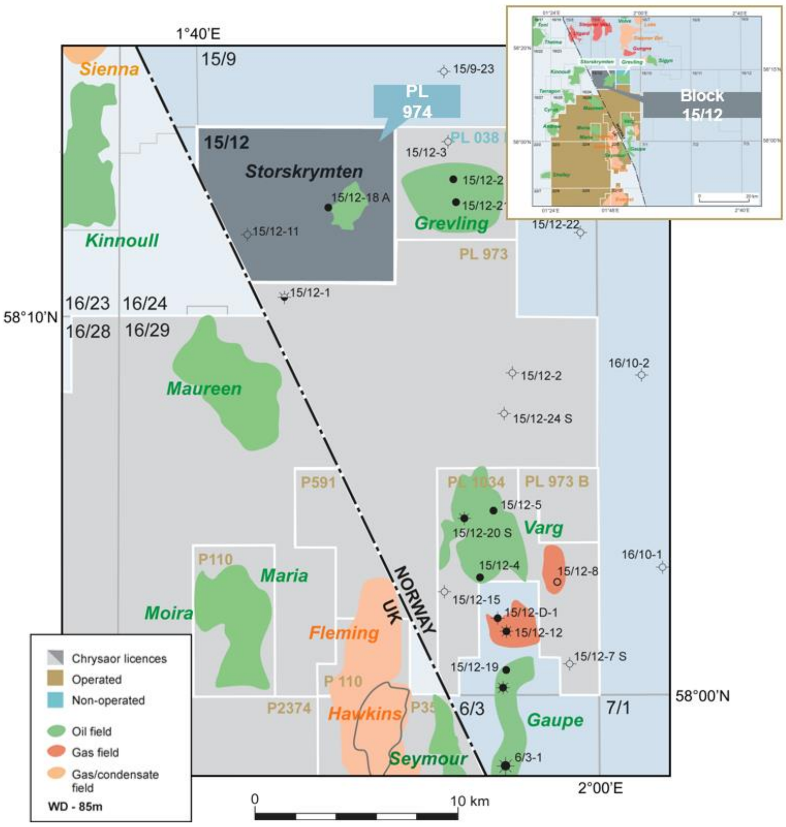


Figure 4-5: Storskrymten location map (source: Chrysaor)

Storskrymten was discovered by Well 15/12-18S in 2007. The well encountered a 16 m oil column in the Palaeocene Ty formation turbidite sands at a depth of 2,545 m tvdss. The well was sidetracked as Well 15/12-18A finding 2 m of oil in the Heimdal formation turbidites at a depth of approximately 2,718 m tvdss. Most of the in-place volumes are associated with the Ty formation which is interpreted to be a simple four-way dip closure. Subsurface work by the Operator interprets a FWL at 2,564 m tvdss and an oil column of up to 30 m. Neither of the wells were tested. Wireline fluid samples recovered 28°API oil with a GOR of 66 scf/stb and an in-situ oil viscosity of 3 cP. No core data was acquired but wireline mobility measurements indicate permeabilities are in the range of 100 – 500 mD.

The Storskrymptenk development plans are being worked up in parallel with the Grevling discovery. As part of the Grevling DG2 documentation, a subsurface document on Storskrympten was also submitted. Two development concepts for Storskrympten were considered. The first option would be to develop Storskrymten using subsea satellite wells tied back to the Grevling MOPU and the second option would be to drill and complete the Storskrymten wells from the Grevling MOPU giving the benefit of dry wellheads. Currently the second option is preferred. Initially a single horizontal producer would be drilled to naturally deplete the Ty formation. Depending on performance a water injector could be added.

The Storskrympten development project has been assigned Contingent Resources within this CPR. The Contingent Resources are PRMS sub-classified as development on hold. The Contingent Resources estimates associated with this project are presented in Table 6-1 of Section 6.

4.2.3. Discovery 2/7-29

Discovery Well 2/7-29 is located in block 2/7 in the Norwegian Southern North Sea, adjacent to the UK and Danish borders (Figure 4-6). Chrysaor holds a 40% working interest and OMV holds the remaining 60% and is the Operator.

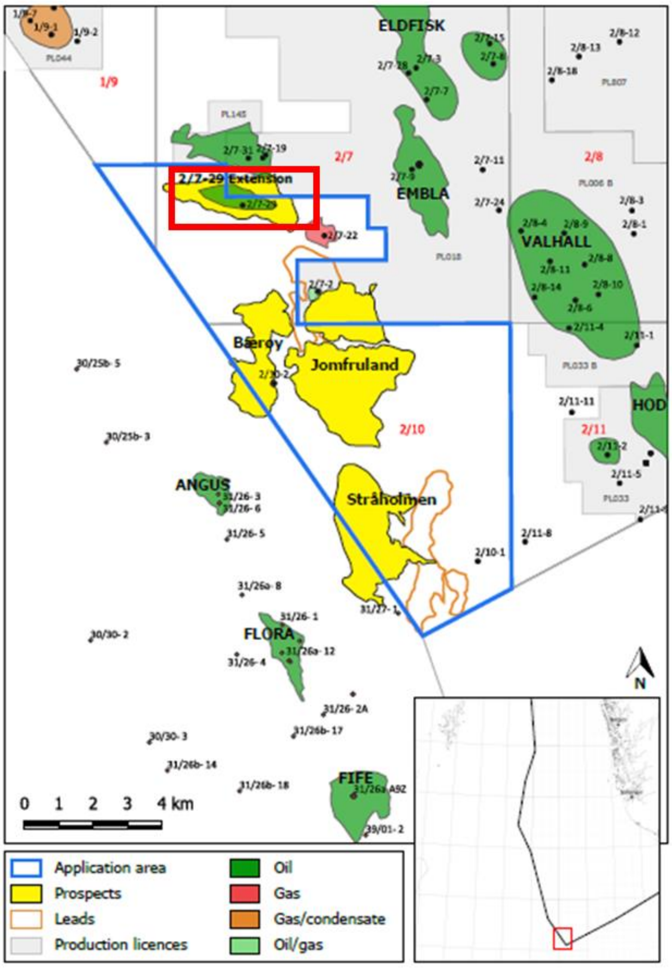


Figure 4-6: Discovery 2/7-29 location map (source: Chrysaor)

Well 2/7-29 was drilled in 1993-94 targeting Jurassic age potential reservoirs. The well encountered a 129 m gross hydrocarbon column (49 m net) in the Eldisk (JU2) formation. An ODT is interpreted at 4,530 m tvdss. An average porosity of 12% and permeability values ranging from 0.01 to 80 mD were measured from core and log data over the pay zone. A well test was not carried out, but wireline fluid samples were collected. A PVT report shows the oil to be 37°API with a GOR of 966 scf/stb.

The discovery is interpreted as being a rotated fault block bounded by a horst towards the south. To the north, it is bounded by another horst. The reservoir is interpreted from seismic to thicken towards the north and thin to the east. ERCE was not given access to the seismic to be able to review this.

Development will likely involve water injection, but no plans have yet been formulated. The original licence application concluded the discovery was not commercial on a standalone basis and would depend on other future discoveries in the area. Contingent Resources have been assigned and are PRMS sub-classified as development unclarified. The Contingent Resources estimates associated with this project are presented in Table 6-1 of Section 6.

5. Economic Evaluation

ERCE has reviewed Chrysaor's economic model encompassing all the UK assets with assigned Reserves. Economic Limit (ELT) and Net Present Value (NPV10) were determined at the 1P/2P/3P Developed and 1P/2P/3P Undeveloped levels of uncertainty based on the fiscal regime in the UK, production and cost profiles generated by ERCE and several economic assumptions listed below. The results are presented in this report both on a 100% gross basis and a net working interest (net entitlement) basis for all Reserves and cost cases.

The ELT was carried out at the asset/hub level rather than at the field level as costs are shared across a hub. Forecasts were prepared on a half year basis and the CoP dates coincide with the end of the final period with positive cash flow. For some assets, the NPV estimates are negative due to future abandonment liabilities; Reserves are still assigned as long as their associated production adds incremental value. ERCE has not considered whether Chrysaor will be able to fund future abandonment liabilities as this was beyond the scope of work. In line with PRMS, Undeveloped Reserves are included if the incremental value associated with the project is NPV10 positive at a 2P level; however, if the project 1P is NPV10 negative, only 2P and 3P Undeveloped Reserves are assigned.

As the CoP date is applied at the hub level, a field with no Undeveloped Reserves may benefit from an extension to the CoP date caused by the other fields and so appear to have Undeveloped Reserves. In some other cases, for the same reasons, the 1P Undeveloped Reserves can appear to be greater than the 2P and/or the 3P. This illustrates that resource estimates presented in Section 3 should be aggregated at the hub level and not at the level of individual fields.

5.1. Fiscal Regime

In the UK, companies engaging in upstream activities are subject to a combination of corporation tax (30%), supplementary charge (10%) and petroleum revenue tax (0% for fields that received development consent before 16 March 1993; reduced to 0% from 50% with effect from 1 January 2016). There is a cost-based basin-wide investment allowance of 62.5% of qualifying expenditure that is deducted from adjusted ring-fence profits, which are liable to supplementary charge. Losses can be carried forward indefinitely. Losses arising in the year of cessation of trade or losses that arise from capital allowances for decommissioning expenditure can be carried back to 17 April 2002.

NPVs were determined on an asset-level without considering corporate level consolidation and therefore, do not represent corporate level taxation.

5.2. Economic Assumptions

The following parameters were assumed in the modelling of discounted cash flows and in determining the economic reserves.

ERCE's 1 July 2020 price forecasts of Brent crude oil and UK NBP natural gas were used for the evaluation and are presented in Table 5-1 and Table 5-2 respectively. Prices are escalated at 2.0% per annum inflation.

Crude oil price differentials for the various assets are presented in Table 5-3 and are based on information provided by Chrysaor; negative values imply a discount to Brent.

Natural gas differentials for the various assets are presented in Table 5-4 and are based on information provided by Chrysaor; negative values imply a % discount to UK NBP.

Table 5-1: ERCE Brent crude oil price forecast as of 1 July 2020

Brent ($/bbl)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030+
Real (constant $, 2020)	42	47	52	57	57	58	58	58	58	58	58
Nominal ($ of the day)	42	48	54	61	62	64	66	67	68	70	+2.0% pa

Table 5-2: ERCE UK NBP natural gas price forecast as of 1 July 2020

UK NBP (p/therm)	2020	2021	2022	2023	2024	2025	2026	2027	2028+
Real (constant pence, 2020)	24.4	36.1	40.5	41.9	43.0	43.6	45.7	46.0	+2.0% pa
Nominal (pence of the day)	24.5	37.0	42.3	44.7	46.8	48.4	51.7	53.0	+2.0% pa

Table 5-3: Brent price differentials

Brent Differential, $/bbl			
Cluster	2020	2021/2022	2023+
Armada	0.66	0.60	0.60
Beryl Area	-1.25	-0.95	-0.95
Buzzard	0.00	0.60	0.60
Clair	-4.50	-4.50	-4.50
East Irish Sea	0.00	0.00	0.00
Elgin Area	0.00	0.60	0.60
Everest Area	0.00	0.60	0.60
Greater Britannia	0.60	0.60	0.60
J-Area XCP	0.80	0.80	0.80
J-Area XRD	0.42	0.82	0.82
Maria	0.31	0.60	0.60
Schiehallion	1.00	1.30	1.30
Seymour	0.49	0.60	0.60

Notes

1. J-Area sales volumes attract different prices depending on whether they are associated with the ConocoPhillips Transaction (XCP) or the Shell Transaction (XRD)

Table 5-4: Gas price differentials

Gas Price Differential, Percentage			
Cluster	2020	2021/2022	2023+
Armada	-1.53%	-0.50%	0.10%
Beryl Area	-1.93%	-0.50%	-0.10%
Buzzard	-45.00%	-45.00%	-45.00%
Clair	-28.00%	-28.00%	-28.00%
East Irish Sea	-2.00%	-2.00%	-2.00%
Elgin Area	-1.93%	-0.50%	-0.10%
Everest Area	-1.93%	-0.50%	-0.10%
Greater Britannia	-0.10%	-0.10%	-0.10%
J-Area XCP	0.01%	0.01%	0.01%
J-Area XRD	-1.93%	-0.50%	-0.10%
Maria	-0.85%	-0.50%	-0.10%
Schiehallion	-28.00%	-28.00%	-28.00%
Seymour	-1.20%	-0.50%	-0.10%

Notes

1. J-Area sales volumes attract different prices depending on whether they are associated with the ConocoPhillips Transaction (XCP) or the Shell Transaction (XRD)

Other Assumptions

- 27.46% of Britannia's gas revenue is calculated using the fixed contract gas price of 51p/therm in real terms (with 2% p.a. inflation).
- Chrysaor's WI in the Brodgar field was increased from 87.5% to 93.75% when the cumulative production since Well H4 came on production is 10 MMboe.
- Capital and operating costs have been determined in 2020 real terms and inflated at the 2.0 per cent inflation rate.
- A flat annual exchange rate of GBP 1.00 /USD 1.30 has been applied.
- Chrysaor's economic model incorporates calculations to reflect the terms of a Service Partnership Contract with Baker Hughes which includes the Armada area and Everest area wells, whereby BHGE provided capital and deferred services to be paid back later on production. Each well has a specific $/boe rate and Chrysaor has provided updated amounts based on ERCE's well production profiles. The specific mechanics of the agreement were not available to ERCE and we rely on Chrysaor's information.
- For each cluster, hub-level costs are shared proportionately based on the production rate.
- Abandonment costs are estimated as a total amount for each field and decommissioning phasing assumptions are applied accordingly. Some of the abandonment costs associated with certain assets are retained by Shell and Spirit Energy and this has been accounted for in the economics.
- Third-party tariff revenue is reflected for each hub as applicable using third-party volumes and unit tariffs provided by Chrysaor.

5.3. Economic Results

The before and after tax, NPV10 estimates as of 30 June 2020 are presented in Section 1, Table 1-10 and Table 1-11, respectively. Though NPVs form an integral part of fair market value estimations, without consideration for other economic criteria they are not to be construed as ERCE's opinion of fair market value. There is no assurance that the forecast production and cost profiles contained in this report will be attained and variances could be material. The recovery and estimates of the company's oil and natural gas Reserves/Resources are estimates only and there is no guarantee that the estimated Reserves/Resources will be recovered. Actual volumes recovered may be greater than or less than the estimates stated in this report.

The Reserves estimates associated with the economic results are presented in the Executive Summary Section at the asset level and in Section 3 at the field level.

The CoP dates for each asset are presented in Table 5-5.

Table 5-5: Asset level CoP Dates

Date of Cessation of Production						
Asset	Developed			Developed + Undeveloped		
	1P	2P	3P	1P	2P	3P
Armada Area	Jun-23	Jun-23	Dec-26	Jun-23	Dec-27	Dec-29
Beryl Area	Jun-25	Jun-28	Dec-30	Jun-27	Dec-30	Dec-34
Buzzard	Dec-31	Dec-41	Jun-45	Dec-31	Dec-41	Jun-45
Clair Phase 1	Dec-38	Dec-38	Dec-38	Dec-38	Dec-38	Dec-38
Clair Ridge	Jun-27	Dec-29	Dec-35	Dec-57	Dec-57	Dec-57
East Irish Sea	Jun-27	Jun-28	Dec-28	Jun-27	Jun-28	Dec-28
Elgin Area	Dec-32	Dec-33	Dec-33	Dec-32	Dec-40	Dec-40
Everest Area	Dec-26	Jun-31	Dec-34	Dec-27	Jun-31	Jun-35
Galleon	Jun-27	Jun-31	Dec-35	Jun-27	Jun-34	Jun-38
Greater Britannia Area	Jun-30	Jun-33	Dec-37	Jun-30	Jun-34	Jun-38
J-Area	Dec-32	Dec-38	Dec-44	Dec-35	Dec-41	Dec-44
Schiehallion	Jun-40	Jun-50	Jun-50	Jun-40	Jun-50	Jun-50

6. Contingent Resources Assessment

ERCE has carried out an audit of Chrysaor's Contingent Resources. Projects which in aggregate comprise just over 70% of Chrysaor's estimate of total net 2C resources (expressed as barrels of oil equivalent, boe), were independently assessed. These comprised 16 out of a total of 59 projects.

Certain projects in the Beryl area were excluded as, although they are associated with further drilling around producing assets, there is a significant geological risk associated with them and as such they should be classified as Prospective Resources. These were the Nevis West NWB6 and NWK Wells and the Skene SWHN Well.

During the audit differences between the ERCE and Chrysaor 2C estimates for Ockley were discussed and resolved; Chrysaor has adopted the ERCE Contingent Resources estimates for Ockley. After this adjustment, ERCE's 1C and 3C estimates in aggregate are within 10% of Chrysaor's aggregate estimates; in the case of the 2C level of confidence, ERCE's aggregate estimate is the same as Chrysaor's.

ERCE is therefore of the opinion that Chrysaor's estimates of Contingent Resources, expressed as barrels of oil equivalent, for those projects reviewed are fair and reasonable. Further, ERCE believes that if its audit had included all of Chrysaor's projects then it would have been able to express the same opinion.

A summary of the Contingent Resources is presented in Table 6-1 and includes their sub-maturity class and whether they were included in the ERCE independently assessed projects.

A summary of the gross Contingent Resources and working interest Contingent Resources by PRMS sub-maturity class are presented in the Executive Summary Section.

No economic analyses have been performed on the Contingent Resources and, therefore, their economic status is undetermined.

Table 6-1: Contingent Resources Summary

Area	Project	Incl. in ERCE Audit	Sub-Class	Gross Gas (Bscf)			Gross Liquids (MMstb)			Gross (MMboe)			Chrysaor WI (%)	Chrysaor Net (MMboe)		
				1C	2C	3C	1C	2C	3C	1C	2C	3C		1C	2C	3C
Armada	Armada Large Scale Chalk (Hod) Dvpt	Yes	DUC	0.0	0.0	0.0	13.0	67.0	226.0	13.0	67.0	226.0	100.0	13.0	67.0	226.0
	Armada LLP, down to 4-6 bar from 10 bar		DP	14.3	18.9	22.5	0.8	1.0	1.2	3.3	4.3	5.1	100.0	3.3	4.3	5.1
	A7 Sidetrack to Chalk		DUC	0.0	0.0	0.0	0.3	1.5	3.0	0.3	1.5	3.0	100.0	0.3	1.5	3.0
	A13 chalk Perforation		DUC	0.0	0.0	0.0	0.1	0.5	1.2	0.1	0.5	1.2	100.0	0.1	0.5	1.2
	Mabel		DNV	0.4	0.7	1.3	2.0	3.4	6.5	2.1	3.5	6.7	100.0	2.1	3.5	6.7
Beryl Area	Beryl Area Further Infill (9 wells)	Yes	DOH	7.0	19.6	32.6	4.4	12.3	20.4	5.6	15.7	26.0	39.4	2.2	6.2	10.3
	Corona	Yes	DUC	1.9	3.1	4.3	8.5	13.9	20.5	8.8	14.4	21.2	39.4	3.5	5.7	8.4
	Solar	Yes	DUC	2.7	4.4	7.2	7.4	12.3	19.4	7.9	13.1	20.6	39.4	3.1	5.2	8.1
	Callater CB5		DOH	5.4	11.7	20.0	2.0	4.5	7.6	2.9	6.5	11.0	45.0	1.3	2.9	5.0
	Callater CB4		DOH	4.1	9.9	12.9	1.1	2.6	3.4	1.8	4.3	5.6	45.0	0.8	1.9	2.5
	Leadon SE		DUC	0.2	0.6	1.7	1.1	3.4	8.7	1.1	3.5	9.0	39.4	0.4	1.4	3.5
	Leadon CS		DUC	0.2	0.6	1.8	1.0	3.4	9.0	1.0	3.5	9.3	39.4	0.4	1.4	3.7
	Ness Nevis Central (NSP)		DOH	0.7	1.0	1.4	1.4	2.0	2.8	1.5	2.2	3.0	39.4	0.6	0.9	1.2
	Ness Nevis Central (NSI)		DP	0.9	1.2	1.4	1.4	2.3	2.7	1.6	2.5	2.9	39.4	0.6	1.0	1.2
	Callater CC4		DP	2.6	3.9	5.6	0.7	1.1	1.5	1.1	1.8	2.5	45.0	0.5	0.8	1.1
	Storr Central Beryl SCB		DOH	3.9	4.3	5.4	1.1	1.2	1.7	1.8	1.9	2.6	41.0	0.7	0.8	1.1
	Callater CSE-2		DOH	1.7	3.0	4.6	0.7	1.2	1.9	1.0	1.7	2.7	45.0	0.4	0.8	1.2
	Loirston SW LSW		DUC	2.4	10.0	19.0	0.0	0.1	0.2	0.4	1.8	3.5	39.4	0.2	0.7	1.4
	Nevis West NCS		DOH	0.6	0.9	1.3	0.3	0.5	0.7	0.4	0.7	0.9	49.1	0.2	0.3	0.5
Bressay	Bressay	Yes	DOH	0.0	0.0	0.0	68.0	101.0	340.0	68.0	101.0	340.0	18.4	12.5	18.6	62.5
Clair	Clair South development	Yes	DOH	0.3	4.0	11.4	214.2	287.1	347.2	214.3	287.8	349.2	7.5	16.1	21.6	26.2
	Clair North development		DUC	4.0	9.8	13.8	18.4	44.6	62.9	19.1	46.3	65.3	7.5	1.4	3.5	4.9
	Ridge Infill, incl. 15 shared conductors	Yes	DUC	7.4	13.5	17.9	23.4	42.6	56.3	24.7	44.9	59.4	7.5	1.9	3.4	4.5
	Clair South further targets (West & Unfract. Phase 1 Core)		DUC	1.6	4.4	5.4	13.7	37.0	45.1	14.0	37.8	46.0	7.5	1.0	2.8	3.5
	Phase 1 further Infill (7 Wells)		DUC	1.9	2.9	4.7	12.8	19.5	31.5	13.1	20.0	32.3	7.5	1.0	1.5	2.4
	Ridge further Infill (8 wells)	Yes	DUC	11.3	17.8	24.5	30.0	46.5	63.8	31.9	49.6	68.0	7.5	2.4	3.7	5.1

Area	Project	Incl. in ERCE Audit	Sub-Class	Gross Gas (Bscf)			Gross Liquids (MMstb)			Gross (MMboe)			Chrysaor WI (%)	Chrysaor Net (MMboe)		
				1C	2C	3C	1C	2C	3C	1C	2C	3C		1C	2C	3C
East Irish Sea	Rivers 2 - Darwen		DOH	31.8	69.4	101.1	0.0	0.0	0.0	5.5	12.0	17.4	100.0	5.5	12.0	17.4
	Rivers 2 - Crossans		DOH	13.4	33.3	62.1	0.0	0.0	0.0	2.3	5.7	10.7	100.0	2.3	5.7	10.7
	LLP down to 5 from 10 bar		DOH	8.2	13.3	16.5	0.0	0.0	0.0	1.4	2.3	2.8	100.0	1.4	2.3	2.8
Elgin-Franklin	EIH Infill well		DP	19.6	27.2	38.1	3.2	4.5	6.3	6.6	9.2	12.9	14.1	0.9	1.3	1.8
	Glenelg G6 Sidetrack		DP	13.5	18.0	25.7	3.4	4.4	6.2	5.7	7.5	10.6	14.7	0.8	1.1	1.6
	Glenelg G10 Workover		DOH	11.1	17.1	23.4	1.6	2.4	3.3	3.5	5.3	7.3	14.7	0.5	0.8	1.1
Everest Area	Erskine 6th Well		DUC	10.8	15.5	20.1	0.8	1.1	1.5	2.7	3.8	5.0	32.0	0.9	1.2	1.6
	Erskine LoF, down to 20-25 bar from 37 bar		DP	5.7	14.2	17.1	0.4	1.0	1.2	1.4	3.4	4.1	32.0	0.4	1.1	1.3
	Erskine ERS1, perf Erskine sand in W1(P1) Pentland		DP	4.1	7.4	10.4	0.3	0.5	0.8	1.0	1.8	2.6	32.0	0.3	0.6	0.8
	Everest LAC Infill well in East Everest		DOH	8.8	11.6	14.2	0.5	0.7	0.9	2.0	2.7	3.3	100.0	2.0	2.7	3.3
	Everest SJ Workover/Sidetrack		DOH	2.4	9.8	11.7	0.2	0.6	0.7	0.6	2.3	2.7	100.0	0.6	2.3	2.7
	Ockley	Yes	DUC	47.0	150.0	477.0	4.0	15.0	53.0	12.1	40.9	135.2	85.0	10.3	34.7	115.0
	Mortimer		DUC	2.7	5.1	9.0	1.0	1.9	3.3	1.5	2.8	4.9	100.0	1.5	2.8	4.9
	Teme		DUC	0.8	1.9	3.7	0.7	1.2	1.9	0.8	1.5	2.5	100.0	0.8	1.5	2.5
	Faraday		DUC	26.0	55.6	87.1	4.0	8.5	13.3	8.5	18.1	28.3	85.0	7.2	15.4	24.1
Galleon	PN02 Redrill		DP	13.3	33.4	55.1	0.0	0.0	0.0	2.3	5.8	9.5	8.4	0.2	0.5	0.8
GBA	MacLeod	Yes	DUC	147.0	235.0	347.0	3.1	5.2	8.5	28.4	45.7	68.3	65.0	18.5	29.7	44.4
	Shirley	Yes	DUC	30.5	80.5	173.7	0.5	1.3	2.9	5.8	15.2	32.8	65.0	3.7	9.9	21.4
	Britannia Infill (5 infill wells)	Yes	DUC	37.6	59.8	85.4	1.3	2.1	3.1	7.8	12.4	17.8	58.7	4.6	7.3	10.5
	Leverett		DOH	26.9	64.0	102.4	0.9	2.2	3.6	5.5	13.2	21.3	43.8	2.4	5.8	9.3
	Brodgar to LTC		DP	5.0	18.8	20.4	0.2	0.8	0.8	1.1	4.0	4.3	93.8	1.0	3.8	4.0
	Callanish F6		DOH	1.6	3.7	6.0	1.7	4.1	6.6	2.0	4.7	7.6	83.5	1.6	4.0	6.4
	Alder Infill (DAB Block)		DUC	14.4	21.4	38.6	1.2	1.7	3.1	3.7	5.4	9.8	25.0	0.9	1.3	2.4
J-Area	Appleton		DUC	5.9	11.2	16.7	6.2	12.6	20.0	7.2	14.5	22.9	100.0	7.2	14.5	22.9
	Talbot	Yes	DP	18.4	47.5	109.8	5.9	11.6	17.0	9.1	19.8	35.9	67.0	6.1	13.3	24.1
	Romeo		DUC	4.5	7.3	12.2	4.6	7.6	12.7	5.4	8.9	14.8	100.0	5.4	8.9	14.8
	Judy South Chalk	Yes	DUC	17.7	27.2	47.7	3.5	7.9	17.2	6.6	12.6	25.4	67.0	4.4	8.4	17.0
	Peach		DNV	0.6	32.0	79.0	0.0	1.8	4.6	0.1	7.3	18.2	67.0	0.1	4.9	12.2
Norway	Grevling	Yes	DOH	0.0	0.0	0.0	30.8	32.6	71.7	30.8	32.6	71.7	35.0	10.8	11.4	25.1

Area	Project	Incl. in ERCE Audit	Sub-Class	Gross Gas (Bscf)			Gross Liquids (MMstb)			Gross (MMboe)			Chrysaor WI (%)	Chrysaor Net (MMboe)		
				1C	2C	3C	1C	2C	3C	1C	2C	3C		1C	2C	3C
Schiehallion	Storskrymten	Yes	DOH	0.0	0.0	0.0	2.8	10.1	14.2	2.8	10.1	14.2	40.0	1.1	4.0	5.7
	APA_2019_2_7-29_Discovery		DUC	0.0	0.0	0.0	0.9	9.4	13.2	0.9	9.4	13.2	40.0	0.4	3.8	5.3
	Tranche 1 Infill (4 wells)		DOH	1.6	4.1	7.0	5.3	12.1	20.1	5.6	12.8	21.3	10.0	0.6	1.3	2.1
	Tranche 2 Infill (7 wells)		DUC	5.1	7.9	11.3	9.2	14.2	20.7	10.1	15.6	22.6	10.0	1.0	1.6	2.3
Total	**All Projects**			**612**	**1,249**	**2,250**	**526**	**892**	**1,618**	**631**	**1,107**	**2,006**		**176**	**381**	**822**

Notes
1. Company net Contingent Resources are based on the working interest share of the gross Contingent Resources.
2. Gas Contingent Resources are based on wellhead volumes and do not allow for processing or fuel and flare requirements.
3. Conversion of gas to boe equivalent is based on 5.8 Mscf/bbl
4. These are unrisked Contingent Resources that have not been risked for chance of development.
5. Totals are added arithmetically which means statistically there is a greater than 90% chance of exceeding the Total 1C and less than a 10% chance of exceeding the Total 3C

Appendix 1 – SPE PRMS Guidelines

This report references the SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Reserves and Resources Classification System and Definitions, as revised in June 2018 (PRMS). The full text of the PRMS document can be viewed at:

https://secure.spee.org/sites/spee.org/files/prmgmtsystem_final_2018.pdf.

Definitions of the key PRMS Reserves and Resource classes, categories and a glossary of related terms can be found at the above address.

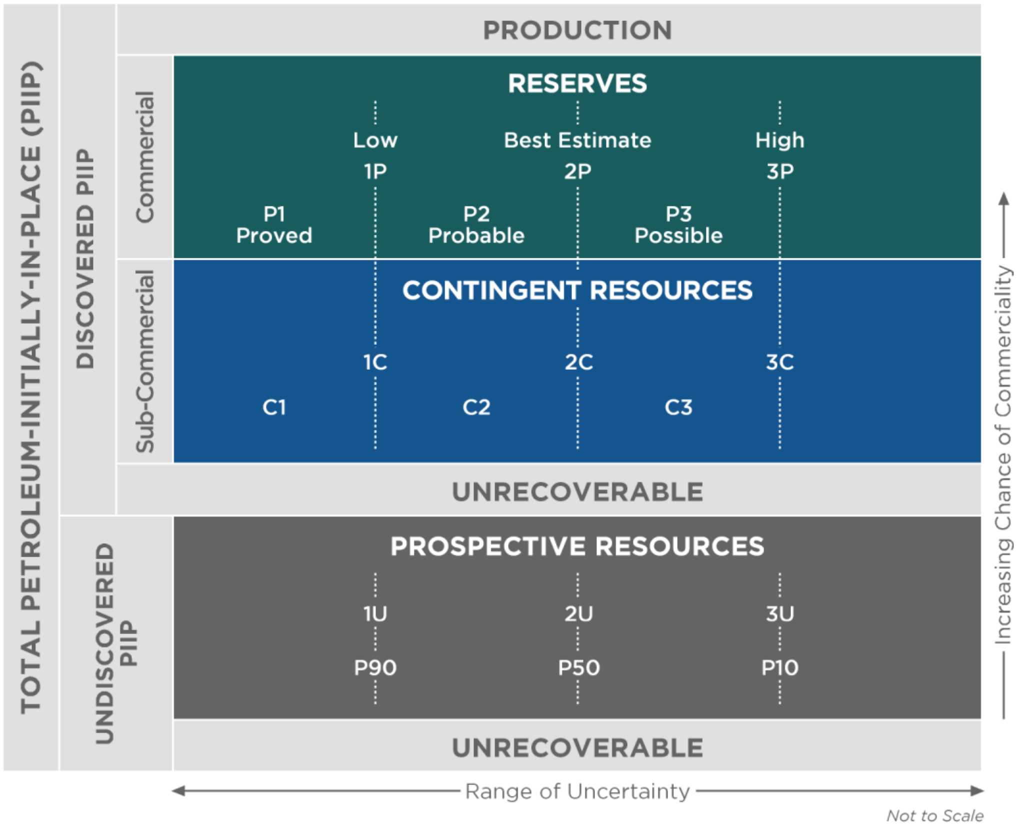


Figure A: PRMS Resources classification framework

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 1.1)

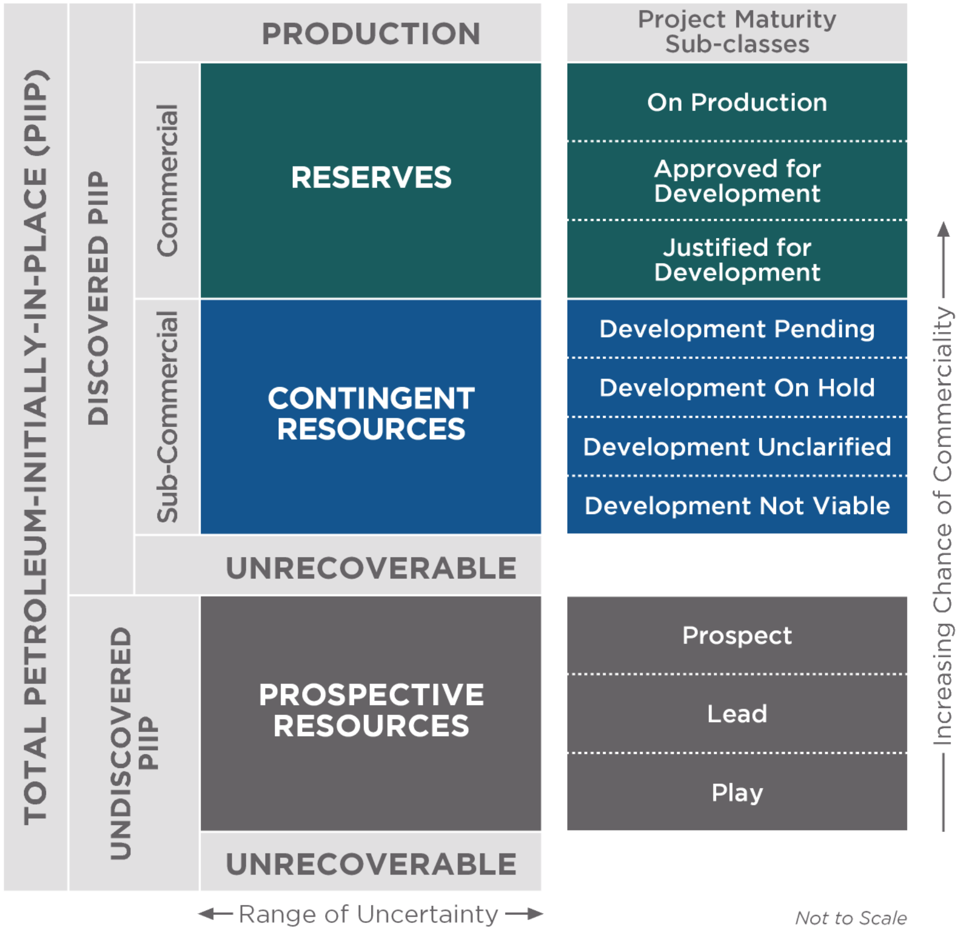


Figure B: PRMS Resources sub-classes

(Modified from Petroleum Resources Management System (PRMS) Revised June 2018, page 8, Figure 2.1)

Table 1: PRMS Recoverable Resources Classes and Sub-Classes

Classes/Sub-classes	Definition	Guidelines
Reserves	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 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 the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market- related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.

Classes/Sub-classes	Definition	Guidelines
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	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 may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. 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.

Classes/Sub-classes	Definition	Guidelines
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.

Classes/Sub-classes	Definition	Guidelines
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: PRMS Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Expected quantities 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	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	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	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.

Table 3: PRMS Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	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. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and 2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates 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 that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.
Possible Reserves	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. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic

		production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Table 4: Glossary of Terms Used in PRMS

Term	Definition
1C	Denotes low estimate of Contingent Resources.
2C	Denotes best estimate of Contingent Resources.
3C	Denotes high estimate of Contingent Resources.
1P	Denotes low estimate of Reserves (i.e., Proved Reserves). Equal to P1.
2P	Denotes the best estimate of Reserves. The sum of Proved plus Probable Reserves.
3P	Denotes high estimate of reserves. The sum of Proved plus Probable plus Possible Reserves.
1U	Denotes the unrisked low estimate qualifying as Prospective Resources.
2U	Denotes the unrisked best estimate qualifying as Prospective Resources.
3U	Denotes the unrisked high estimate qualifying as Prospective Resources.
Abandonment, Decommissioning, and Restoration (ADR)	The process (and associated costs) of returning part or all of a project to a safe and environmentally compliant condition when operations cease. Examples include, but are not limited to, the removal of surface facilities, wellbore plugging procedures, and environmental remediation. In some instances, there may be salvage value associated with the equipment removed from the project. ADR costs are presumed to be without consideration of any salvage value, unless presented as “ADR net of salvage.”
Accumulation	An individual body of naturally occurring petroleum in a reservoir.
Aggregation	The process of summing well, reservoir, or project-level estimates of resources quantities to higher levels or combinations, such as field, country or company totals. Arithmetic summation of incremental categories may yield different results from probabilistic aggregation of distributions.
Appraisal	The phase that may follow successful exploratory drilling. Activities to further evaluate the discovery, such as seismic acquisition, geological studies, and drilling additional wells may be conducted to reduce technical uncertainties and commercial contingencies.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is underway. A project maturity sub-class of Reserves.
Analog	Method used in resources estimation in the exploration and early development stages (including improved recovery projects) when direct measurement is limited. Based on evaluator’s assessment of similarities of the analogous reservoir(s) together with the development plan.
Analogous Reservoir	Reservoirs that have similar rock properties (e.g., petrophysical, lithological, depositional, diagenetic, and structural), fluid properties (e.g., type, composition, density, and viscosity), reservoir conditions (e.g., depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide insight and comparative data to assist in estimation of recoverable resources.
Assessment	See Evaluation.
Associated Gas	A natural gas found in contact with or dissolved in crude oil in the reservoir. It can be further categorized as gas cap gas or solution gas.

Basin-Centered Gas	An unconventional natural gas accumulation that is regionally pervasive and characterized by low permeability, abnormal pressure, gas-saturated reservoirs, and lack of a down dip water leg.
Barrel of Oil Equivalent (BOE)	The term allows for a single value to represent the sum of all the hydrocarbon products that are forecast as resources. Typically, condensate, oil, bitumen, and synthetic crude barrels are taken to be equal (1 bbl = 1 BOE). Gas and NGL quantities are converted to an oil equivalent based on a conversion factor that is recommended to be based on a nominal heating content or calorific value equivalent to a barrel of oil.
Basis for Estimate	The methodology (or methodologies) and supporting data on which the estimated quantities are based. (Also referenced as basis for the estimation.)
Behind-Pipe Reserves	Reserves that are expected to be recovered from zones in existing wells, which will require additional completion work or future re-completion before the start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling and completing a new well including hook-up to allow production.
Best Estimate	With respect to resources categorization, the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
C1	Denotes low estimate of Contingent Resources. C1 is equal to 1C.
C2	Denotes Contingent Resources of same technical confidence as Probable, but not commercially matured to Reserves.
C3	Denotes Contingent Resources of same technical confidence as Possible, but not commercially matured to Reserves.
Chance	Chance equals 1-risk. Generally synonymous with likelihood. (See Risk)
Chance of Commerciality	The estimated probability that the project will achieve commercial maturity to be developed. For Prospective Resources, this is the product of the chance of geologic discovery and the chance of development. For Contingent Resources and Reserves, it is equal to the chance of development.
Chance of Development	The estimated probability that a known accumulation, once discovered, will be commercially developed.
Chance of Geologic Discovery	The estimated probability that exploration activities will confirm the existence of a significant accumulation of potentially recoverable petroleum.
Coalbed Methane (CBM)	Natural gas contained in coal deposits. Coalbed gas, although usually mostly methane, may be produced with variable amounts of inert or even non-inert gases. [Also called coal-seam gas (CSG) or natural gas from coal (NGC).]
Commercial	A project is commercial when there is evidence of a firm intention to proceed with development within a reasonable time-frame. Typically, this requires that the best estimate case meet or exceed the minimum evaluation decision criteria (e.g., rate of return, investment payout time). There must be a reasonable expectation that all required internal and external approvals will be forthcoming. Also, there must be evidence of a technically mature, feasible development plan and the essential social, environmental, economic, political, legal, regulatory, decision criteria, and contractual conditions are met. .
Committed Project	Project that the entity has a firm intention to develop in a reasonable time-frame. Intent is demonstrated with funding/financial plans, but FID has not yet been declared (See also Final Investment Decision.)

Completion	Completion of a well. The process by which a well is brought to its operating status (e.g., producer, injector, or monitor well). A well deemed to be capable of producing petroleum, or used as an injector, is completed by establishing a connection between the reservoir(s) and the surface so that fluids can be produced from, or injected into, the reservoir.
Completion Interval	The specific reservoir interval(s) that is (are) open to the borehole and connected to the surface facilities for production or injection, or reservoir intervals open to the wellbore and each other for injection purposes.
Concession	A grant of access for a defined area and time period that transfers certain entitlements to produced hydrocarbons from the host country to an entity. The entity is generally responsible for exploration, development, production, and sale of hydrocarbons that may be discovered. Typically granted under a legislated fiscal system where the host country collects taxes, fees, and sometimes royalty on profits earned. (Also called a license.)
Condensate	A mixture of hydrocarbons (mainly pentanes and heavier) that exist in the gaseous phase at original temperature and pressure of the reservoir, but when produced, are in the liquid phase at surface pressure and temperature conditions. Condensate differs from NGLs in two respects: (1) NGL is extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGL includes very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensate.
Confidence Level	A measure of the estimated reliability of a result. As used in the deterministic incremental method, the evaluator assigns a relative level of confidence (high/moderate/low) to areas/segments of an accumulation based on the information available (e.g., well control and seismic coverage). Probabilistic and statistical methods use the 90% (P90) for the high confidence (low value case), 50% (P50) for the best estimate (moderate value case), and 10% (P10) for the low (high value case) estimate to represent the chances that the actual value will equal or exceed the estimate.
Constant Case	A descriptor applied to the economic evaluation of resources estimates. Constant-case estimates are based on current economic conditions being those conditions (including costs and product prices) that are fixed at the evaluation date and held constant, with no inflation or deflation made to costs or prices throughout the remainder of the project life other than those permitted contractually.
Consumed in Operations (CiO)	That portion of produced petroleum consumed as fuel in production or lease plant operations before delivery to the market at the reference point. (Also called lease fuel.)
Contingency	A condition that must be satisfied for a project in Contingent Resources to be reclassified as Reserves. Resolution of contingencies for projects in Development Pending is expected to be achieved within a reasonable time period.
Contingent Project	A project that is not yet commercial owing to one or more contingencies that have not been resolved.
Contingent Resources	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.
Continuous-Type Deposit	A petroleum accumulation that is pervasive throughout a large area and that generally lacks well-defined OWC or GWC. Such accumulations are included in unconventional resources. Examples of such deposits include “basin-centered” gas, tight gas, tight oil, gas hydrates, natural bitumen, and oil shale (kerogen) accumulations.
Conventional Resources	Resources that exist in porous and permeable rock with buoyancy pressure equilibrium. The PIIP is trapped in discrete accumulations related to a localized geological structural feature and/or stratigraphic condition, typically with each accumulation bounded by a down dip contact with an aquifer and is significantly affected by hydrodynamic influences such as buoyancy of petroleum in water.

Cost Recovery	Under a typical production-sharing agreement, the contractor is responsible for the field development and all exploration and development expenses. In return, the contractor recovers costs (investments and operating expenses) out of the production stream. The contractor normally receives an entitlement interest share in the petroleum production and is exposed to both technical and market risks.
Crude Oil	Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of pressure and temperature (excludes retrograde condensate). Crude oil may include small amounts of non-hydrocarbons produced with the liquids but does not include liquids obtained from the processing of natural gas.
Cumulative Production	The sum of petroleum quantities that have been produced at a given date. (See also Production). Production is measured under defined conditions to allow for the computation of both reservoir voidage and sales quantities and for the purpose of voidage also includes non-petroleum quantities.
Current Economic Conditions	Economic conditions based on relevant historical petroleum prices and associated costs averaged over a specified period. The default period is 12 months. However, in the event that a step change has occurred within the previous 12-month period, the use of a shorter period reflecting the step change must be justified and used as the basis of constant-case resources estimates and associated project cash flows.
Defined Conditions	Forecast of conditions to exist and impact the project during the time period being evaluated. Forecasts should account for issues that impact the commerciality, such as economics (e.g., hurdle rates and commodity price); operating and capital costs; and technical, marketing, sales route, legal, environmental, social, and governmental factors.
Deposit	Material laid down by a natural process. In resources evaluations, it identifies an accumulation of hydrocarbons in a reservoir. (See Accumulation.)
Deterministic Incremental Method	An assessment method based on defining discrete parts or segments of the accumulation that reflect high, moderate, and low confidence regarding the estimates of recoverable quantities under the defined development plan.
Deterministic Method	An assessment method based on discrete estimate(s) made based on available geoscience, engineering, and economic data and corresponds to a given level of certainty.
Deterministic Scenario Method	Method where the evaluator provides three deterministic estimates of the quantities to be recovered from the project being applied to the accumulation. Estimates consider the full range of values for each input parameter based on available engineering and geoscience data, but one set is selected that is most appropriate for the corresponding resources confidence category. A single outcome of recoverable quantities is derived for each scenario.
Developed Reserves	Reserves that are expected to be recovered from existing wells and facilities. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Reserves that are expected to be recovered from completion intervals that are open and producing at the effective date. Improved recovery reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Developed Reserves that are either shut-in or behind-pipe. (See also Shut-In Resources and Behind-Pipe Reserves.)
Development On Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay. A project maturity sub-class of Contingent Resources.
Development Not Viable	A discovered accumulation for which there are contingencies resulting in there being no current plans to develop or to acquire additional data at the time due to limited commercial potential. A project maturity sub-class of Contingent Resources.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. A project maturity sub-class of Contingent Resources.

Development Plan	The design specifications, timing, and cost estimates of the appraisal and development project(s) that are planned in a field or group of fields. The plan will include, but is not limited to, well locations, completion techniques, drilling methods, processing facilities, transportation, regulations, and marketing. The plan is often executed in phases when involving large, complex, sequential recovery and/or extensive areas.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. This sub-class requires appraisal or study and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity. A project maturity sub-class of Contingent Resources.
Discovered	A petroleum accumulation where one or several exploratory wells through testing, sampling, and/or logging have demonstrated the existence of a significant quantity of potentially recoverable hydrocarbons and thus have established a known accumulation. In this context, “significant” implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for technical recovery. (See also Known Accumulation.)
Discovered Petroleum Initially-In-Place	Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.
Discovered Unrecoverable	Discovered petroleum in-place resources that are evaluated, as of a given date, as not able to be recovered by the commercial and sub-commercial projects envisioned.
Dry Gas	Natural gas remaining after hydrocarbon liquids have been removed before the reference point. It should be recognized that this is a resources assessment definition and not a phase behavior definition. (Also called lean gas.)
Economic	A project is economic when it has a positive undiscounted cumulative cash flow from the effective date of the evaluation, the net revenue exceeds the net cost of operation (i.e., positive cumulative net cash flow at discount rate greater than or equal to zero percent).
Economic Interest	Interest that is possessed when an entity has acquired an interest in the minerals in-place or a license and secures, by any form of legal relationship, revenue derived from the extraction of the mineral to which he must look for a return.
Economic Limit	Defined as the time when the maximum cumulative net cash flow (see Net Entitlement) occurs for a project.
Economically Not Viable Contingent Resources	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.
Economically Viable Contingent Resources	Those quantities associated with technically feasible projects where cash flows are positive under reasonable forecast conditions but are not Reserves because it does not meet the other commercial criteria
Economically Producible	Refers to the situation where the net revenue from an ongoing producing project exceeds the net expenses attributable to a certain entity’s interest. The ADR costs are excluded from the determination.
Effective Date	Resource estimates of remaining quantities are “as of the given date” (effective date) of the evaluation. The evaluation must take into account all data related to the period before the "as of date.”
Entitlement	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license.
Entity	A legal construct capable of bearing legal rights and obligations. In resources evaluations, this typically refers to the lessee or contractor, which is some form of legal corporation (or consortium of corporations). In a broader sense, an entity can be an organization of any form and may include governments or their agencies.

Established Technology	Methods of recovery or processing that have proved to be successful in commercial applications.
Estimated Ultimate Recovery (EUR)	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable plus those quantities that have been aERCEeady produced. For clarity, EUR must reference the associated technical and commercial conditions for the resources; for example, proved EUR is Proved Reserves plus prior production.
Evaluation	The geosciences, engineering, and associated studies, including economic analyses, conducted on a petroleum exploration, development, or producing project resulting in estimates of the quantities that can be recovered and sold and the associated cash flow under defined forward conditions. (Also called assessment.)
Evaluator	The person or group of persons responsible for performing an evaluation of a project. These may be employees of the entities that have an economic interest in the project or independent consultants contracted for reviews and audits. In all cases, the entity accepting the evaluation takes responsibility for the results, including its resources and attributed value estimates.
Exploration	Prospecting for undiscovered petroleum using various techniques, such as seismic surveys, geological studies, and exploratory drilling.
Field	In conventional reservoirs, a field is typically an area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impermeable rock, laterally by local geologic barriers, or both. The term may be defined differently by individual regulatory authorities. For unconventional reservoirs without hydrodynamic influences, a field is often defined by regulatory or ownership boundaries as necessary.
Final Investment Decision (FID)	Project approval stage when the participating companies have firmly agreed to the project and the required capital funding.
Flare Gas	The total quantity of gas vented and/or burned as part of production and processing operations (but not as fuel).
Flow Test	An operation on a well designed to demonstrate the existence of recoverable petroleum in a reservoir by establishing flow to the surface and/or to provide an indication of the potential productivity of that reservoir (such as a wireline formation test). May also demonstrate the potential of certain completion techniques, particularly in unconventional reservoirs.
Fluid Contacts	The surface or interface in a reservoir separating two regions characterized by predominant differences in fluid saturations. Because of capillary and other phenomena, fluid saturation change is not necessarily abrupt or complete, nor is the surface necessarily horizontal.
Forecast Case	A descriptor applied to a scenario when production and associated cash-flow estimates are based on those conditions (including costs and product price schedules, inflation indexes, and market factors) forecast by the evaluator to reasonably exist throughout the evaluation life (i.e., defined conditions). Inflation or deflation adjustments are made to costs and revenues over the evaluation period.
Gas Balance	In gas production operations involving multiple working interest owners, maintaining a statement of volumes attributed to each, depending on each owner's portion received. Imbalances may occur that must be monitored over time and eventually balanced in accordance with accepted accounting procedures.
Gas Cap Gas	Free natural gas that overlies and is in contact with crude oil in the reservoir. It is a subset of associated gas.
Gas Hydrates	Naturally occurring crystalline substances composed of water and gas, in which a solid water lattice accommodates gas molecules in a cage-like structure or clathrate. At conditions of standard temperature and pressure, one volume of saturated methane hydrate will contain as much as 164 volumes of methane gas. Gas hydrates are included in unconventional resources, but the technology to support commercial maturity has yet to be developed.

Gas/Oil Ratio	Ratio that is calculated using measured natural gas and crude oil volumes at stated conditions. The gas/oil ratio may be the solution gas/oil ratio, Rs ; produced gas/oil ratio, Rp ; or another suitably defined ratio of gas production to oil production.
Geostatistical Methods	A variety of mathematical techniques and processes dealing with the collection, methods, analysis, interpretation, and presentation of large quantities of geoscience and engineering data to (mathematically) describe the variability and uncertainties within any reservoir unit or pool, specifically related here to resources estimates.
High Estimate	With respect to resources categorization, this is considered to be an optimistic estimate of the quantity that will actually be recovered from an accumulation by a project. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.
Hydrates	See Gas Hydrates.
Hydrocarbons	Hydrocarbons are chemical compounds consisting wholly of hydrogen and carbon molecules.
Improved Recovery	The extraction of additional petroleum, beyond primary recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes, and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called enhanced recovery.)
Injection	The forcing, pumping, or natural flow of substances into a porous and permeable subsurface rock formation. Injected substances can include either gases or liquids.
Justified for Development	A development project that has reasonable forecast commercial conditions at the time of reporting and there are reasonable expectation that all necessary approvals/contracts will be obtained. A project maturity sub-class of Reserves.
Kerogen	The naturally occurring, solid, insoluble organic material that occurs in source rocks and can yield oil upon heating. Kerogen is also defined as the fraction of large chemical aggregates in sedimentary organic matter that is insoluble in solvents (in contrast, the fraction that is soluble in organic solvents is called bitumen). (See also Oil Shales.)
Known Accumulation	An accumulation that has been discovered.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect. A project maturity sub-class of Prospective Resources.
Learning Curve	Demonstrated improvements over time in performance of a repetitive task that results in efficiencies in tasks to be realized and/or in reduced time to perform and ultimately in cost reductions.
Likelihood	Likelihood (the estimated probability or chance) is equal (1- risk). (See Probability and Risk.)
Low/Best/High Estimates	Reflects the range of uncertainty as a reasonable range of estimated potentially recoverable quantities.
Low Estimate	With respect to resources categorization, this is a conservative estimate of the quantity that will actually be recovered from the accumulation by a project. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
Lowest Known Hydrocarbons (LKH)	The deepest documented occurrence of a producible hydrocarbon accumulation as interpreted from well log, flow test, pressure measurement, core data, or other conclusive and reliable evidence.
Market	A consumer or group of consumers of a product that has been obtained through purchase, barter, or contractual terms.

Marketable Quantities	Those quantities of hydrocarbons that are estimated to be producible from petroleum accumulations and that will be consumed by the market. (Also referred to as marketable products.)
Mean	The sum of a set of numerical values divided by the number of values in the set.
Measurement	The process of establishing quantity (volume, mass, or energy content) and quality of petroleum products delivered to a reference point under conditions defined by delivery contract or regulatory authorities.
Mineral Lease	An agreement in which a mineral owner (lessor) grants an entity (lessee) rights. Such rights can include (1) a fee ownership or lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of the lease; (2) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and/or (3) those agreements with foreign governments or authorities under which a reporting entity participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (as opposed to being an independent purchaser, broker, dealer, or importer).
Monte Carlo Simulation	A type of stochastic mathematical simulation that randomly and repeatedly samples input distributions (e.g., reservoir properties) to generate a resulting distribution (e.g., recoverable petroleum quantities).
Multi-Scenario Method	An extension of the deterministic scenario method. In this case, a significant number of discrete deterministic scenarios are developed by the evaluator, with each scenario leading to a single deterministic outcome. Probabilities may be assigned to each discrete input assumption from which the probability of the scenario can be obtained; alternatively, each outcome may be assumed to be equally likely.
Natural Bitumen	The portion of petroleum that exists in the semi-solid or solid phase in natural deposits. In its natural state, it usually contains sulfur, metals, and other non-hydrocarbons. Natural bitumen has a viscosity greater than 10,000 mPa·s (or 10,000 cp) measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural viscous state, it is not normally recoverable at commercial rates through a well and requires the implementation of improved recovery methods such as steam injection. Natural bitumen generally requires upgrading before normal refining.
Natural Gas	Portion of petroleum that exists either in the gaseous phase or is in solution in crude oil in a reservoir, and which is gaseous at atmospheric conditions of pressure and temperature. Natural gas may include some amount of non- hydrocarbons.
Natural Gas Liquids (NGLs)	A mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects: (1) NGLs are extracted and recovered in gas plants rather than lease separators or other lease facilities, and (2) NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates.
Net Entitlement	That portion of future production (and thus resources) legally accruing to an entity under the terms of the development and production contract or license. Under the terms of PSCs, the producers have an entitlement to a portion of the production. This entitlement, often referred to as “net entitlement” or “net economic interest” is estimated using a formula based on the contract terms incorporating costs and profits.
Net Pay	The portion (after applying cutoffs) of the thickness of a reservoir from which petroleum can be produced or extracted. Value is referenced to a true vertical thickness measured.
Net Revenue Interest	An entity’s revenue share of petroleum sales after deduction of royalties or share of production owing to others under applicable lease and fiscal terms. (See also Entitlement and Net Entitlement)
Netback Calculation	Term used in the hydrocarbon product price determination at reference point to reflect the revenue of one unit of sales after the costs associated with bringing the product to a market (e.g., transportation and processing) are removed.

Non-Hydrocarbon Gas	Associated gases such as nitrogen, carbon dioxide, hydrogen sulfide, and helium that are present in naturally occurring petroleum accumulations.
Non-Sales	That portion of estimated recoverable or produced quantities that will not be included in sales as contractually defined at the reference point. Non-sales include quantities CiO, flare, and surface losses, and may include non- hydrocarbons.
Oil Sands	Sand deposits highly saturated with natural bitumen. Also called "tar sands." Note that in deposits such as the western Canada oil sands, significant quantities of natural bitumen may be hosted in a range of lithologies, including siltstones and carbonates.
Oil Shales	Shale, siltstone, and marl deposits highly saturated with kerogen. Whether extracted by mining or in-situ processes, the material must be extensively processed to yield a marketable product (synthetic crude oil). (Often called kerogen shale.)
On Production	A project maturity sub-class of Reserves that reflects the operational execution phase of one or multiple development projects with the Reserves currently producing or capable of producing. Includes Developed Producing and Developed Non-Producing Reserves.
Overlift/Underlift	Production entitlements received that vary from contractual terms resulting in overlift or underlift positions. This can occur in annual records because of the necessity for companies to lift their entitlement in parcel sizes to suit the available shipping schedules as agreed upon by the parties. At any given financial year- end, a company may be in overlift or underlift. Based on the production matching the company's accounts, production should be reported in accord with and equal to the liftings actually made by the company during the year and not on the production entitlement for the year.
P1	Denotes Proved Reserves. P1 is equal to 1P.
P2	Denotes Probable Reserves.
P3	Denotes Possible Reserves.
Penetration	The intersection of a wellbore with a reservoir.
Petroleum	Defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbon compounds, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content of petroleum can be greater than 50%.
Petroleum Initially-in-Place (PIIP)	The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs, as of a given date. Crude oil in-place, natural gas in-place, and natural bitumen in-place are defined in the same manner.
Pilot Project	A small-scale test or trial operation used to assess technology, including recovery processes, for commercial application in a specific reservoir.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation to define specific Leads or Prospects. A project maturity sub-class of Prospective Resources.
Pool	An individual and separate accumulation of petroleum in a reservoir within a field.
Possible Reserves	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Possible Reserves are those additional reserves that analysis of geoscience and engineering data suggest 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 that the actual quantities recovered will equal or exceed the 3P estimate.

Primary Recovery	The extraction of petroleum from reservoirs using only the natural energy available in the reservoirs to move fluids through the reservoir rock to other points of recovery.
Probability	The extent to which an event is likely to occur, measured by the ratio of the favorable cases to the whole number of cases possible. PRMS convention is to quote cumulative probability of exceeding or equaling a quantity where P90 is the small estimate and P10 is the large estimate. (See also Uncertainty.)
Probabilistic Method	The method of estimation of resources is called probabilistic when the known geoscience, engineering, and economic data are used to generate a continuous range of estimates and their associated probabilities.
Probable Reserves	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that 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 that the actual quantities recovered will equal or exceed the 2P estimate.
Production	The cumulative quantities of petroleum that have been recovered at a given date. Production can be reported in terms of the sales product specifications, but project evaluation requires that all production quantities (sales and non-sales), as measured to support engineering analyses requiring reservoir voidage calculations, are recognized.
Production Forecast	A forecasted schedule of production over time. For Reserves, the production forecast reflects a specific development scenario under a specific recovery process, a certain number and type of wells and particular facilities and infrastructure. When forecasting Contingent or Prospective Resources, more than one project scope (e.g., wells and facilities) is frequently carried to determine the range of the potential project and its uncertainty together with the associated resources defining the low, best, and high production forecasts. The uncertainty in resources estimates associated with a production forecast is usually quantified by using at least three scenarios or cases of low, best, and high, which lead to the resources classifications of, respectively, 1P, 2P, 3P and 1C, 2C, 3C or 1U,2U and 3U.
Production-Sharing Contract (PSC)	A contract between a contractor and a host government in which the contractor typically bears the risk and costs for exploration, development, and production. In return, if exploration is successful, the contractor is given the opportunity to recover the incurred investment from production, subject to specific limits and terms. Ownership of petroleum in the ground is retained by the host government; however, the contractor normally receives title to the prescribed share of the quantities as they are produced. (Also termed production-sharing agreement (PSA).
Project	A defined activity or set of activities that provides the link between the petroleum accumulation's resources sub-class and the decision-making process, including budget allocation. A project may, for example, constitute the development of a single reservoir or field, an incremental development in a larger producing field, or the integrated development of a group of several fields and associated facilities (e.g. compression) with a common ownership. In general, an individual project will represent a specific maturity level (sub-class) at which a decision is made on whether or not to proceed (i.e., spend money), suspend, or remove. There should be an associated range of estimated recoverable resources for that project. (See also Development Plan.)
Property	A defined portion of the Earth's crust wherein an entity has contractual rights to extract, process, and market specified in-place minerals (including petroleum). In general, defined as an area but may have depth and/or stratigraphic constraints. May also be termed a lease, concession, or license.
Prospect	A project associated with an undrilled potential accumulation that is sufficiently well defined to represent a viable drilling target. A project maturity sub-class of Prospective Resources.

Prospective Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.
Proved Reserves	An incremental category of estimated recoverable quantities associated with a defined degree of uncertainty. 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 that the quantities actually recovered will equal or exceed the estimate.
Pure Service Contract	Agreement between a contractor and a host government that typically covers a defined technical service to be provided or completed during a specific time period. The service company investment is typically limited to the value of equipment, tools, and expenses for personnel used to perform the service. In most cases, the service contractor’s reimbursement is fixed by the contract’s terms with little exposure to either project performance or market factors. No Reserves or Resources can be attributed to these activities.
Qualified Reserves Auditor	A reserves evaluator who (1) has a minimum of ten years of practical experience in petroleum engineering or petroleum production geology, with at least five years of such experience being in responsible charge of the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor’s or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer’s license or a registered or certified professional geologist’s license, or the equivalent, from an appropriate governmental authority or professional organization. (see SPE 2007 “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information”)
Qualified Reserves Evaluator	A reserves evaluator who (1) has a minimum of five years of practical experience in petroleum engineering or petroleum production geology, with at least three years of such experience being in the estimation and evaluation of Reserves information; and (2) either (a) has obtained from a college or university of recognized stature a bachelor’s or advanced degree in petroleum engineering, geology, or other discipline of engineering or physical science or (b) has received, and is maintaining in good standing, a registered or certified professional engineer’s license or a registered or certified professional geologist’s license, or the equivalent, from an appropriate governmental authority or professional organization. (modified from SPE 2007 “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information”)
Range of Uncertainty	The range of uncertainty of the in-place, recoverable, and/or potentially recoverable quantities; may be represented by either deterministic estimates or by a probability distribution. (See Resources Categories.)
Raw Production	All components, whether hydrocarbon or other, produced from the well or extracted from the mine (hydrocarbons, water, impurities such as non- hydrocarbon gases, etc.).
Reasonable Certainty	If deterministic methods for estimating recoverable resources quantities are used, then reasonable certainty is intended to express a high degree of confidence that the estimated quantities will be recovered. Typically attributed to Proved Reserves or 1C Resources quantities.
Reasonable Expectation	Indicates a high degree of confidence (low risk of failure) that the project will proceed with commercial development or the referenced event will occur. (Differs from reasonable certainty, which applies to resources quantity technical confidence, while reasonable expectation relates to commercial confidence.).
Recoverable Resources	Those quantities of hydrocarbons that are estimated to be producible by the project from either discovered or undiscovered accumulations.

Recovery Efficiency	A numeric expression of that portion (expressed as a percentage) of in-place quantities of petroleum estimated to be recoverable by specific processes or projects, most often represented as a percentage. It is estimated using the recoverable resources divided by the hydrocarbons initially in-place. It is also referenced to timing; current and ultimate (or estimated ultimate) are descriptors applied to reference the stage of the recovery. (Also called recovery factor.)
Reference Point	A defined location within a petroleum extraction and processing operation where quantities of produced product are measured under defined conditions before custody transfer (or consumption). Also called point of sale, terminal point, or custody transfer point.
Report	The presentation of evaluation results within the entity conducting the assessment. Should not be construed as replacing requirements for public disclosures under guidelines established by regulatory and/or other government agencies.
Reserves	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: they must be discovered, recoverable, commercial, and remaining (as of a given date) based on the development project(s) applied.
Reservoir	A subsurface rock formation that contains an individual and separate natural accumulation of petroleum that is confined by impermeable barriers, pressure systems, or fluid regimes (conventional reservoirs), or is confined by hydraulic fracture barriers or fluid regimes (unconventional reservoirs).
Resources	Term used to encompass all quantities of petroleum (recoverable and unrecoverable) naturally occurring in an accumulation on or within the Earth's crust, discovered and undiscovered, plus those quantities aERCEeady produced. Further, it includes all types of petroleum whether currently considered conventional or unconventional. (See Total Petroleum Initially-in-Place.)
Resources Categories	Subdivisions of estimates of resources to be recovered by a project(s) to indicate the associated degrees of uncertainty. Categories reflect uncertainties in the total petroleum remaining within the accumulation (in-place resources), that portion of the in-place petroleum that can be recovered by applying a defined development project or projects, and variations in the conditions that may impact commercial development (e.g., market availability and contractual changes). The resource quantity uncertainty range within a single resources class is reflected by either the 1P, 2P, 3P, Proved, Probable, Possible, or 1C, 2C, 3C or 1U, 2U, 3U resources categories.
Resources Classes	Subdivisions of resources that indicate the relative maturity of the development projects being applied to yield the recoverable quantity estimates. Project maturity may be indicated qualitatively by allocation to classes and sub-classes and/or quantitatively by associating a project's estimated likelihood of commerciality.
Resources Type	Describes the accumulation and is determined by the combination of the type of hydrocarbon and the rock in which it occurs.
Revenue-Sharing Contract	Contracts that are very similar to the PSCs with the exception of contractor payment in these contracts, the contractor usually receives a defined share of revenue rather than a share of the production.
Risk	The probability of loss or failure. Risk is not synonymous with uncertainty. Risk is generally associated with the negative outcome, the term "chance" is preferred for general usage to describe the probability of a discrete event occurring.
Risk and Reward	Risk and reward associated with oil and gas production activities are attributed primarily from the variation in revenues cause by technical and economic risks. The exposure to risk in conjunction with entitlement rights is required to support an entity's resources recognition. Technical risk affects an entity's ability to physically extract and recover hydrocarbons and is usually dependent on a number of technical parameters. Economic risk is a function of the success of a project and is critically dependent on cost, price, and political or other economic factors.

Risk Service Contract (RSC)	Agreements that are very similar to the production-sharing agreements in that the risk is borne by the contractor but the mechanism of contractor payment is different. With a RSC, the contractor usually receives a defined share of revenue rather than a share of the production.
Royalty	A type of entitlement interest in a resource that is free and clear of the costs and expenses of development and production to the royalty interest owner. A royalty is commonly retained by a resources owner (lessor/host) when granting rights to a producer (lessee/contractor) to develop and produce that resource. Depending on the specific terms defining the royalty, the payment obligation may be expressed in monetary terms as a portion of the proceeds of production or as a right to take a portion of production in-kind. The royalty terms may also provide the option to switch between forms of payment at discretion of the royalty owner.
Sales	The quantity of petroleum and any non-hydrocarbon product delivered at the custody transfer point (reference point) with specifications and measurement conditions as defined in the sales contract and/or by regulatory authorities.
Shale Gas	Although the terms shale gas and tight gas are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight gas production
Shale Oil	Although the terms shale oil and tight oil are often used interchangeably in public discourse, shale formations are only a subset of all low-permeability tight formations, which include sandstones and carbonates, as well as shales, as sources of tight oil production
Shut-In Resources	Resources planned to be recovered from (1) completion intervals that are open at the time of the estimate, but which have not started producing; (2) wells that were shut-in for market conditions or pipeline connections; or (3) wells not capable of production for mechanical reasons that can be remediated at a limited cost compared to the cost of the well.
Split Classification	A single project should be uniquely assigned to a sub-class along with its uncertainty range, For example, a project cannot have quantities categorized as 1C, 2P, and 3P. This is referred to as “split classification.” If there are differing commercial conditions, separate sub-classes should be defined.
Split Conditions	The uncertainty in recoverable quantities is assessed for each project using resources categories. The assumed commercial conditions are associated with resource classes or sub-classes and not with the resources categories. For example, the product price assumptions are those assumed when classifying projects as Reserves, and a different price would not be used for assessing Proved versus Probable reserves. That would be referred to as “split conditions.”
Stochastic	Adjective defining a process involving or containing a random variable or variables or involving likelihood or probability, such as a stochastic simulation.
Sub-Commercial	A project subdivision that is applied to discovered resources that occurs if either the technical or commercial maturity conditions of project have not yet been achieved. A project is sub-commercial if the degree of commitment is such that the accumulation is not expected to be developed and placed on production within a reasonable time-frame. Sub-commercial projects are classified as Contingent Resources.
Sunk Cost	Money spent before the effective date and that cannot be recovered by any future action. Sunk costs are not relevant to future business decisions because the cost will be the same regardless of the outcome of the decision. Sunk costs differ from committed (obligated) costs, where there is a firm and binding agreement to spend specified amounts of money at specific times in the future (i.e., after the effective date).
Synthetic Crude Oil	A mixture of hydrocarbons derived by upgrading (i.e., chemically altering) natural bitumen from oil sands, kerogen from oil shales, or processing of other substances such as natural gas or coal. Synthetic crude oil may contain sulfur or other non-hydrocarbon compounds and has many similarities to crude oil.

Taxes	Obligatory contributions to the public funds, levied on persons, property, or income by governmental authority.
Technical Forecast	The forecast of produced resources quantities that is defined by applying only technical limitations (i.e., well-flow-loading conditions, well life, production facility life, flow-limit constraints, facility uptime, and the facility's operating design parameters). Technical limitations do not take into account the application of either an economic or license cut-off. (See also Technically Recoverable Resources).
Technical Uncertainty	Indication of the varying degrees of uncertainty in estimates of recoverable quantities influenced by the range of potential in-place hydrocarbon resources within the reservoir and the range of the recovery efficiency of the recovery project being applied.
Technically Recoverable Resources	Those quantities of petroleum producible using currently available technology and industry practices, regardless of commercial or accessibility considerations.
Technology Under Development	Technology that is currently under active development and that has not been demonstrated to be commercially viable. There should be sufficient direct evidence (e.g., a test project/pilot) to indicate that the technology may reasonably be expected to be available for commercial application.
Tight Gas	Gas that is trapped in pore space and fractures in very low-permeability rocks and/or by adsorption on kerogen, and possibly on clay particles, and is released when a pressure differential develops. It usually requires extensive hydraulic fracturing to facilitate commercial production. Shale gas is a sub-type of tight gas.
Tight Oil	Crude oil that is trapped in pore space in very low-permeability rocks and may be liquid under reservoir conditions or become liquid at surface conditions. Extensive hydraulic fracturing is invariably required to facilitate commercial maturity and economic production. Shale oil is a sub-type of tight oil.
Total Petroleum Initially-in-Place	All estimated quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.
Uncertainty	The range of possible outcomes in a series of estimates. For recoverable resources assessments, the range of uncertainty reflects a reasonable range of estimated potentially recoverable quantities for an individual accumulation or a project. (See also Probability.)
Unconventional Resources	Unconventional resources exist in petroleum accumulations that are pervasive throughout a large area and lack well-defined OWC or GWC (also called "continuous-type deposits"). Such resources cannot be recovered using traditional recovery projects owing to fluid viscosity (e.g., oil sands) and/or reservoir permeability (e.g., tight gas/oil/CBM) that impede natural mobility.Moreover, the extracted petroleum may require significant processing before sale (e.g., bitumen upgraders).
Undeveloped Reserves	Those quantities expected to be recovered through future investments: (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 and completing a new well) is required to recomplete an existing well.
Undiscovered Petroleum Initially-in-Place	That quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.
Unrecoverable Resources	Those quantities of discovered or undiscovered PIIP that are assessed, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Upgrader	A general term applied to processing plants that convert extra-heavy crude oil and natural bitumen into lighter crude and less viscous synthetic crude oil. While the detailed process varies, the underlying concept is to remove carbon through coking or to increase hydrogen by hydrogenation processes using catalysts.
Wet Gas	Natural gas from which no liquids have been removed before the reference point. The wet gas is accounted for in resources assessments, and there is no separate accounting for contained liquids. It should be recognized that this is a resources assessment definition and not a phase behavior definition.
Working Interest	An entity's equity interest in a project before reduction for royalties or production share owed to others under the applicable fiscal terms.

Appendix 2 - Nomenclature

1P	Proved
2P	Proved + Probable
3P	Proved + Probable +Possible
ABEX	abandonment cost
AFE	authorised for expenditure
API	American Petroleum Institute
Bg	gas formation volume factor, in scf/rcf
BHA	bottom hole assembly
Bo	oil formation volume factor, in rb/stb
Bscf	thousands of millions of standard cubic feet
CAPEX	capital expenditure
CATS	Central Area Transmission System
C&P	cased and perforated
CGR	condensate gas ratio
CO_2	carbon dioxide
CoP	cessation of production
CPI	computer processed interpretation
DCA	decline curve analysis
DG	decision gate (as per the Norwegian Petroleum Directorate)
DST	drill stem test
DSV	diver support vessel
DP	development pending
DOH	development on hold
DNV	development not viable
DUC	development unclarified
E&A	exploration and appraisal
Eg	gas expansion factor
EIS	East Irish Sea
ELT	economic limit test
ERD	extended reach drilling
FBHP	flowing bottom hole pressure

FDP	field development plan
FMB	flowing material balance
FPS	Forties Pipeline System
FPSO	floating production storage and offloading vessel
FSO	floating storage and offtake vessel
ft	feet
FTHP	flowing tubing head pressure
FVF	formation volume factor
FWL	free water level
GAEL	Gannet Area Export Line
GDT	gas down to
GEF	gas expansion factor
GIIP	gas initially in place
GOC	gas oil contact
GOR	gas oil ratio
GRV	gross rock volume
GSA	gas sales agreement
GWC	gas water contact
H_2S	hydrogen sulphide
HIIP	hydrocarbons initially in place
HLV	Heavy Lift Vessel
HPHT	high pressure, high temperature
ICV	interval control valve
kh	permeability thickness
km	kilometres
Kr	relative permeability
LLC	late life compression
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LTC	long term compression
LTP	long term plan
m	metre
M MM	thousands and millions respectively
MPD	managed-pressure-while-drilling

MD	measured depth
md or mD	millidarcy
MDRKB	measured depth below Kelly Bushing
MDT	modular dynamic tester
MOPU	mobile offshore production unit
MSL	mean sea level
mss	metres subsea
N_2	nitrogen
NAG	non-associated gas
NBP	National Balancing Point
NCS	Norwegian Continental Shelf
NGL	natural gas liquid
NPV	net present value
NPV10	net present value at 10% discount rate
NTG	net to gross ratio
NTS	National Transmission System
NUI	normally unattended installation
OCM	operating committee meeting
ODT	oil down to
OE	operating efficiency
OPEX	operating expenditure
OWC	oil water contact
P90	low case (probabilistic) estimate (there should be a 90% probability of exceeding this estimate)
P50	mid or best case (probabilistic) estimate (there should be a 50% probability of exceeding this estimate)
P10	high case (probabilistic) estimate (there should be a 10% probability of exceeding this estimate)
P&A	plug and abandon
Pb	saturation, or bubble point, pressure
Phi	porosity
Phie	effective porosity
Phit	total porosity
PI	productivity index, in stb/d/psi for oil or MMscf/d/psi or Mscf/d/psi for gas
PIIP	petroleum initially in place
POD	plan of development
Possible	Possible, as defined in Appendix 1

Probable	Probable, as defined in Appendix 1
Proved	Proved, as defined in Appendix 1
PSDM	post stack depth migration
PSTM	post stack time migration
PVT	pressure volume temperature experiment
RAT	riser access tower
rb	reservoir barrels
RCA	routine core analysis
rcf	cubic feet at reservoir conditions
RFT	repeat formation tester
ROV	remotely operated vehicle
Rs	solution gas oil ratio
SAGE	Scottish Area Gas Evacuation system
scf	standard cubic feet measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
SEAL	Shearwater Elgin Area Line
SNA	sum of negative amplitudes
ss	sub-sea
SSSV	sub-surface safety valve
stb	stock tank barrel (42 US gallons measured at 14.7 pounds per square inch and 60 degrees Fahrenheit)
STOIIP	stock tank oil initially in place
Sw	water saturation
Swc	connate water saturation
TAR	turn around (facilities related)
TCM	technical committee meeting
TD	total depth
TGPP	Teesside Gas Processing Plant
THP	tubing head pressure
TRR	technically recoverable resources
TVD	true vertical depth
tvdss	true vertical depth sub-sea
TWT	two way time
UKCS	United Kingdom Continental Shelf
WGR	water gas ratio
WI	working interest

WOR	water oil ratio
WoS	West of Shetland
WRFM	well and reservoir facility management
WUT	water up to

Appendix 3 – Gas to Oil Equivalent Conversion Factors

Chrysaor has provided the conversion factors to convert gas to oil equivalent volumes. The conversion from energy to a volume equivalent is based on a factor of 5.8 MMBTU per barrel of oil equivalent (boe). The resulting conversion factors are summarized in the following table.

Field	Caloric Value (BTU/scf)	Conversion Factor (Mscf/boe)
ALDER	1,125	5.155379
ARMADA	1,150	5.041416
BERYL	1,066	5.440453
BRITANNIA	1,125	5.155379
BRODGAR	1,125	5.155379
BUCKLAND	1,065	5.447312
BUZZARD	1,125	5.153809
CALDER	1,031	5.623294
CALLANISH	1,125	5.155379
CALLATER	1,065	5.44377
CLAIR	1,061	5.46751
CLAIR_RIDGE	1,061	5.46751
DALTON	977	5.934184
DRAKE	1,150	5.041416
ELGIN_FRANKLIN	1,092	5.310756
ENOCHDHU	1,125	5.155379
ERSKINE	1,112	5.214583
EVEREST	1,179	4.920579
FLEMING	1,150	5.041416
GALLEON	1,038	5.587346
GLENELG	1,092	5.310486
HAWKINS	1,150	5.041416
JADE	1,064	5.4508
JASMINE	1,064	5.4508
JOANNE	1,064	5.4508
JUDY	1,064	5.4508
LOMOND	1,179	4.920579
MARIA	1,169	4.960718
MILLOM	977	5.934184
NESS	1,066	5.43886
NEVIS_CENTRAL	1,066	5.43886
NEVIS_FAR_NORTH	1,066	5.43886
NEVIS_NORTH	1,066	5.43886
NEVIS_SOUTH	1,061	5.465676
NEVIS_SOUTH_CORMORANT	1,061	5.465676
NEVIS_WEST_BERYL	1,020	5.686275
SCHIEHALLION	1,114	5.207175
SEYMOUR	1,204	4.816303
SKENE	1,064	5.452031
STORR	1,020	5.686275

Appendix 4 – Asset Level Developed plus Undeveloped Gross Production Forecasts

Table A - 1: Armada Area - Developed + Undeveloped Production Forecasts (Sales)

Armada Area - Developed plus Undeveloped Production Forecasts									
Date	1P			2P			3P		
	Oil	NGL	Gas	Oil	NGL	Gas	Oil	NGL	Gas
	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d
2H 2020	2.4	1.5	25.7	2.5	1.6	28.1	2.7	1.7	29.4
1H 2021	1.8	1.3	19.6	2.0	1.4	23.5	2.3	1.6	26.0
2H 2021	1.5	1.2	17.0	1.7	1.4	21.5	2.0	1.6	24.8
1H 2022	1.4	1.2	14.9	1.6	1.4	19.7	1.9	1.6	23.5
2H 2022	1.2	1.1	12.4	1.5	1.3	17.5	1.8	1.6	21.5
1H 2023	1.0	1.0	11.1	1.3	1.3	15.9	1.6	1.5	20.0
2H 2023	0.9	1.2	10.1	1.3	1.9	16.8	1.7	2.6	22.6
1H 2024	1.2	2.5	13.5	1.5	5.2	27.1	2.3	8.1	40.4
2H 2024	1.0	2.2	11.6	1.4	4.4	22.9	2.1	6.7	34.9
1H 2025	0.8	1.6	9.0	1.2	3.1	17.8	1.7	4.7	26.9
2H 2025	0.6	1.5	7.7	1.1	3.5	18.2	1.7	5.2	27.8
1H 2026	0.4	0.8	4.8	1.0	3.0	15.9	1.5	4.5	24.5
2H 2026	0.3	0.7	3.9	1.0	2.9	14.8	1.5	4.3	22.9
1H 2027	0.3	0.6	2.9	0.9	2.5	13.0	1.4	3.7	20.4
2H 2027	0.3	0.5	2.2	0.8	2.3	11.6	1.3	3.6	19.3
1H 2028	0.2	0.4	1.5	0.4	1.3	6.9	1.2	3.0	16.2
2H 2028	0.2	0.4	1.4	0.4	1.2	5.6	0.8	2.0	11.2
1H 2029	0.2	0.2	0.8	0.3	0.7	3.6	0.7	1.2	8.2
2H 2029	0.2	0.3	1.0	0.2	0.8	3.5	0.7	1.4	8.6
1H 2030	0.1	0.0	0.0	0.1	0.0	0.6	0.5	0.2	4.0
2H 2030	0.1	-	-	0.1	0.0	0.2	0.5	0.2	3.6
1H 2031	0.1	-	-	0.1	-	-	0.5	0.2	3.3
2H 2031	0.1	-	-	0.1	-	-	0.4	0.2	3.0
1H 2032	0.1	-	-	0.1	-	-	0.4	0.2	2.7
2H 2032	0.0	-	-	0.1	-	-	0.4	0.2	2.4
1H 2033	0.0	-	-	0.1	-	-	0.4	0.1	2.1
2H 2033	0.0	-	-	0.1	-	-	0.3	0.1	1.2
1H 2034	0.0	-	-	0.1	-	-	0.3	0.1	1.0
2H 2034	0.0	-	-	0.1	-	-	0.3	0.1	0.8
1H 2035	-	-	-	0.1	-	-	0.3	0.1	0.6
2H 2035	-	-	-	0.1	-	-	0.3	0.1	0.4
1H 2036	-	-	-	0.1	-	-	0.3	0.1	0.3
2H 2036	-	-	-	0.1	-	-	0.2	0.0	0.1
1H 2037	-	-	-	0.1	-	-	0.1	-	-
2H 2037	-	-	-	0.1	-	-	0.1	-	-
1H 2038	-	-	-	0.1	-	-	0.1	-	-
2H 2038	-	-	-	0.0	-	-	0.1	-	-
1H 2039	-	-	-	0.0	-	-	0.1	-	-
2H 2039	-	-	-	0.0	-	-	0.1	-	-
1H 2040	-	-	-	0.0	-	-	0.1	-	-
2H 2040	-	-	-	0.0	-	-	0.1	-	-
Rem. 2040+ (MMstb Bscf)	0.0	-	-	0.0	-	-	0.1	-	-
Total (MMstb Bscf)	**3.0**	**3.7**	**31.3**	**4.4**	**7.5**	**55.7**	**6.8**	**11.4**	**83.1**

Table A - 2: Beryl Area - Developed + Undeveloped Production Forecasts (Sales)

Beryl Area - Developed plus Undeveloped Production Forecasts									
Date	1P			2P			3P		
	Oil	NGL	Gas	Oil	NGL	Gas	Oil	NGL	Gas
	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d
2H 2020	17.7	3.9	65.0	19.0	4.4	72.4	20.3	4.8	78.8
1H 2021	14.7	2.9	50.1	16.9	3.6	61.6	18.6	4.0	69.5
2H 2021	13.6	2.5	46.7	17.3	3.5	66.4	20.1	4.2	81.8
1H 2022	12.7	2.2	39.6	17.0	3.3	62.0	20.9	4.3	81.7
2H 2022	10.8	1.8	31.1	14.6	2.8	51.8	18.0	3.7	69.7
1H 2023	9.8	1.6	27.5	13.3	2.6	47.4	16.9	3.5	66.0
2H 2023	9.5	1.8	29.0	13.9	3.4	57.4	18.0	5.0	83.2
1H 2024	8.0	1.2	19.9	11.8	2.7	45.2	15.5	4.3	70.9
2H 2024	7.5	0.9	16.2	11.5	2.2	40.0	15.4	3.7	64.8
1H 2025	6.5	0.7	12.0	10.0	1.8	32.8	13.5	3.1	54.3
2H 2025	5.8	0.6	9.3	9.2	1.6	27.9	12.4	2.6	46.5
1H 2026	5.1	0.4	6.5	8.2	1.3	23.2	11.4	2.3	41.6
2H 2026	4.7	0.4	4.8	7.6	1.1	19.5	10.5	2.1	37.0
1H 2027	4.4	0.3	3.9	7.2	1.0	17.5	10.0	1.9	34.3
2H 2027	4.1	0.2	2.7	6.8	0.9	15.0	9.5	1.8	31.2
1H 2028	3.6	0.2	2.2	6.2	0.7	12.5	8.7	1.6	27.6
2H 2028	3.3	0.2	2.0	5.7	0.6	10.0	8.2	1.4	24.4
1H 2029	3.0	0.1	1.5	5.2	0.5	7.7	7.6	1.3	21.8
2H 2029	2.8	0.1	1.3	4.9	0.4	6.1	7.4	1.2	20.1
1H 2030	2.6	0.1	1.1	4.6	0.3	4.8	6.9	1.1	18.2
2H 2030	2.5	0.1	0.9	4.4	0.3	3.9	6.8	1.0	17.0
1H 2031	2.2	0.1	0.8	4.1	0.2	2.6	6.3	1.0	15.0
2H 2031	2.1	0.1	0.7	3.9	0.2	2.0	6.1	0.9	13.5
1H 2032	1.9	0.1	0.6	3.6	0.1	1.7	5.7	0.8	11.9
2H 2032	1.8	0.0	0.5	3.4	0.1	1.4	5.3	0.7	10.1
1H 2033	1.7	0.0	0.4	3.2	0.1	1.1	5.0	0.6	8.8
2H 2033	1.6	0.0	0.3	3.0	0.1	1.0	4.8	0.6	7.7
1H 2034	1.6	0.0	0.3	2.8	0.1	0.9	4.6	0.5	6.9
2H 2034	1.5	0.0	0.3	2.6	0.1	0.8	4.4	0.5	5.8
1H 2035	1.4	0.0	0.2	2.5	0.1	0.7	4.2	0.4	5.2
2H 2035	1.3	0.0	0.2	2.4	0.0	0.6	4.0	0.4	4.5
1H 2036	1.2	0.0	0.1	2.3	0.0	0.5	3.9	0.4	4.1
2H 2036	1.1	0.0	0.1	2.3	0.0	0.5	3.8	0.3	3.7
1H 2037	1.1	0.0	0.1	2.2	0.0	0.5	3.6	0.3	3.6
2H 2037	1.0	0.0	0.1	2.1	0.0	0.4	3.5	0.3	3.3
1H 2038	1.0	0.0	0.0	2.1	0.0	0.4	3.3	0.3	3.2
2H 2038	0.9	0.0	0.0	2.0	0.0	0.4	3.2	0.3	2.9
1H 2039	0.8	-	-	1.9	0.0	0.3	3.0	0.3	2.9
2H 2039	0.8	-	-	1.8	0.0	0.3	2.9	0.2	2.6
1H 2040	0.7	-	-	1.7	0.0	0.3	2.9	0.2	2.5
2H 2040	0.6	-	-	1.5	0.0	0.3	2.7	0.2	2.3
Rem. 2040+ (MMstb Bscf)	1.3	-	-	4.0	0.0	0.4	7.0	0.0	4.1
Total (MMstb Bscf)	**34.0**	**4.1**	**69.1**	**52.7**	**7.4**	**128.5**	**72.7**	**12.5**	**216.2**

Table A - 3: Buzzard Area - Developed + Undeveloped Production Forecasts (Sales)

Buzzard - Developed plus Undeveloped Production Forecasts									
Date	1P			2P			3P		
	Oil	NGL	Gas	Oil	NGL	Gas	Oil	NGL	Gas
	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d
2H 2020	64.5	0.2	1.4	72.5	0.3	3.1	76.9	0.4	4.0
1H 2021	45.1	0.1	-	54.3	0.1	-	59.1	0.1	0.3
2H 2021	39.9	0.1	-	50.9	0.1	-	56.4	0.1	0.0
1H 2022	50.3	0.1	0.2	71.4	0.5	5.9	81.8	0.7	8.6
2H 2022	42.2	0.1	-	63.0	0.3	3.6	74.3	0.5	6.6
1H 2023	35.6	0.1	-	55.7	0.2	1.6	67.4	0.4	4.6
2H 2023	30.5	0.0	-	49.9	0.1	-	62.0	0.3	3.1
1H 2024	24.9	0.0	-	42.7	0.1	-	54.4	0.2	1.1
2H 2024	21.9	0.0	-	39.1	0.1	-	51.0	0.1	0.2
1H 2025	20.6	0.0	-	38.2	0.1	-	50.9	0.1	0.1
2H 2025	18.4	0.0	-	35.4	0.1	-	48.1	0.1	-
1H 2026	16.5	0.0	-	32.9	0.0	-	45.6	0.1	-
2H 2026	14.9	0.0	-	30.7	0.0	-	43.3	0.1	-
1H 2027	12.8	0.0	-	27.2	0.0	-	39.0	0.1	-
2H 2027	11.7	0.0	-	25.6	0.0	-	37.4	0.1	-
1H 2028	11.5	0.0	-	25.7	0.0	-	38.0	0.1	-
2H 2028	10.6	0.0	-	24.3	0.0	-	36.5	0.1	-
1H 2029	9.8	0.0	-	23.1	0.0	-	35.2	0.1	-
2H 2029	9.1	0.0	-	21.9	0.0	-	33.9	0.0	-
1H 2030	8.4	0.0	-	20.9	0.0	-	32.7	0.0	-
2H 2030	7.8	0.0	-	19.9	0.0	-	31.6	0.0	-
1H 2031	7.3	0.0	-	19.0	0.0	-	30.6	0.0	-
2H 2031	6.8	0.0	-	18.2	0.0	-	29.7	0.0	-
1H 2032	6.4	0.0	-	17.5	0.0	-	28.8	0.0	-
2H 2032	6.0	0.0	-	16.8	0.0	-	27.9	0.0	-
1H 2033	5.7	0.0	-	16.1	0.0	-	27.1	0.0	-
2H 2033	5.4	0.0	-	15.5	0.0	-	26.4	0.0	-
1H 2034	5.1	0.0	-	14.9	0.0	-	25.7	0.0	-
2H 2034	4.8	0.0	-	14.3	0.0	-	25.0	0.0	-
1H 2035	4.5	0.0	-	13.8	0.0	-	24.4	0.0	-
2H 2035	4.3	0.0	-	13.4	0.0	-	23.8	0.0	-
1H 2036	4.1	0.0	-	12.9	0.0	-	23.2	0.0	-
2H 2036	3.9	0.0	-	12.5	0.0	-	22.7	0.0	-
1H 2037	3.7	0.0	-	12.1	0.0	-	22.2	0.0	-
2H 2037	3.5	0.0	-	11.7	0.0	-	21.7	0.0	-
1H 2038	3.3	0.0	-	11.3	0.0	-	21.2	0.0	-
2H 2038	3.1	0.0	-	11.0	0.0	-	20.7	0.0	-
1H 2039	3.0	0.0	-	10.7	0.0	-	20.3	0.0	-
2H 2039	2.8	0.0	-	10.4	0.0	-	19.9	0.0	-
1H 2040	2.6	0.0	-	10.1	0.0	-	19.5	0.0	-
2H 2040	2.5	0.0	-	9.8	0.0	-	19.1	0.0	-
Rem. 2040+ (MMstb Bscf)	3.3	0.0	-	14.0	0.0	-	28.6	0.0	-
Total (MMstb Bscf)	**112.2**	**0.2**	**0.3**	**214.4**	**0.5**	**2.6**	**309.1**	**0.8**	**5.3**

Table A - 4: Clair Area - Developed + Undeveloped Production Forecasts (Sales)

Greater Clair Area - Developed plus Undeveloped Production Forecasts									
Date	1P			2P			3P		
	Oil	NGL	Gas	Oil	NGL	Gas	Oil	NGL	Gas
	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d
2H 2020	57.1	-	1.9	62.5	-	3.1	67.4	-	4.8
1H 2021	61.5	-	3.0	70.3	-	6.1	81.9	-	10.3
2H 2021	63.5	-	3.6	75.2	-	7.7	92.6	-	14.0
1H 2022	82.5	-	10.5	101.4	-	17.2	132.4	-	28.5
2H 2022	76.9	-	8.4	97.1	-	15.4	130.4	-	27.5
1H 2023	80.1	-	9.6	104.0	-	18.0	137.1	-	29.9
2H 2023	82.6	-	10.6	109.8	-	20.1	137.9	-	30.2
1H 2024	86.9	-	12.3	118.0	-	23.3	136.8	-	29.8
2H 2024	83.1	-	11.1	114.7	-	22.2	135.7	-	29.5
1H 2025	85.9	-	12.2	120.3	-	24.3	136.4	-	29.7
2H 2025	91.4	-	14.2	129.5	-	27.7	137.0	-	29.9
1H 2026	85.3	-	12.0	122.1	-	25.0	137.5	-	30.0
2H 2026	77.4	-	9.2	111.9	-	21.2	137.3	-	29.9
1H 2027	87.5	-	13.0	127.3	-	27.1	136.6	-	29.8
2H 2027	81.9	-	11.1	119.9	-	24.4	135.4	-	29.5
1H 2028	77.6	-	9.8	114.1	-	22.4	134.3	-	29.1
2H 2028	70.8	-	7.6	104.6	-	19.0	133.0	-	28.8
1H 2029	65.0	-	5.8	96.5	-	16.0	129.9	-	27.7
2H 2029	60.0	-	4.2	89.4	-	13.5	125.8	-	26.3
1H 2030	55.6	-	2.8	83.1	-	11.2	121.0	-	24.6
2H 2030	51.7	-	1.6	77.6	-	9.3	116.0	-	22.8
1H 2031	48.3	-	0.5	72.7	-	7.5	110.9	-	21.0
2H 2031	45.2	-	-	68.3	-	5.9	105.9	-	19.2
1H 2032	42.5	-	-	64.3	-	4.5	101.1	-	17.5
2H 2032	40.0	-	-	60.7	-	3.4	96.5	-	15.8
1H 2033	37.8	-	-	57.4	-	2.4	92.1	-	14.2
2H 2033	35.8	-	-	54.5	-	1.5	88.0	-	12.8
1H 2034	33.9	-	-	51.8	-	0.7	84.2	-	11.4
2H 2034	32.3	-	-	49.3	-	-	80.5	-	10.1
1H 2035	30.7	-	-	47.0	-	-	77.2	-	8.9
2H 2035	29.3	-	-	44.9	-	-	74.0	-	7.8
1H 2036	28.0	-	-	43.0	-	-	71.1	-	6.7
2H 2036	26.8	-	-	41.2	-	-	68.3	-	5.8
1H 2037	25.7	-	-	39.6	-	-	65.8	-	4.8
2H 2037	24.7	-	-	38.1	-	-	63.4	-	4.0
1H 2038	23.8	-	-	36.6	-	-	61.1	-	3.2
2H 2038	22.9	-	-	35.3	-	-	59.0	-	2.5
1H 2039	16.5	-	-	24.2	-	-	40.7	-	1.6
2H 2039	15.9	-	-	23.3	-	-	39.3	-	1.1
1H 2040	15.3	-	-	22.5	-	-	37.9	-	0.6
2H 2040	14.8	-	-	21.8	-	-	36.6	-	0.1
Rem. 2040+ (MMstb Bscf)	47.1	-	-	69.1	-	-	116.5	-	-
Total (MMstb Bscf)	**440.5**	**0.0**	**32.0**	**625.4**	**0.0**	**73.0**	**862.8**	**0.0**	**130.0**

Table A - 5: EIS Area - Developed + Undeveloped Production Forecasts (Sales)

East Irish Sea - Developed plus Undeveloped Production Forecasts									
Date	1P			2P			3P		
	Oil	NGL	Gas	Oil	NGL	Gas	Oil	NGL	Gas
	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d
2H 2020	-	-	33.1	-	-	33.6	-	-	33.9
1H 2021	-	-	36.0	-	-	36.6	-	-	37.0
2H 2021	-	-	41.8	-	-	42.4	-	-	42.8
1H 2022	-	-	55.1	-	-	56.3	-	-	57.1
2H 2022	-	-	54.9	-	-	56.1	-	-	56.9
1H 2023	-	-	52.0	-	-	55.9	-	-	56.7
2H 2023	-	-	44.0	-	-	53.6	-	-	55.1
1H 2024	-	-	36.5	-	-	45.2	-	-	50.7
2H 2024	-	-	31.9	-	-	39.1	-	-	44.4
1H 2025	-	-	28.0	-	-	34.0	-	-	38.7
2H 2025	-	-	24.5	-	-	29.7	-	-	33.8
1H 2026	-	-	21.5	-	-	25.9	-	-	29.7
2H 2026	-	-	18.8	-	-	22.7	-	-	26.2
1H 2027	-	-	16.5	-	-	20.0	-	-	23.3
2H 2027	-	-	12.9	-	-	17.6	-	-	20.7
1H 2028	-	-	10.2	-	-	15.5	-	-	18.5
2H 2028	-	-	8.6	-	-	13.8	-	-	16.6
1H 2029	-	-	7.3	-	-	12.2	-	-	15.0
2H 2029	-	-	6.1	-	-	10.9	-	-	13.5
1H 2030	-	-	5.1	-	-	9.7	-	-	12.3
2H 2030	-	-	4.2	-	-	8.7	-	-	11.1
1H 2031	-	-	3.4	-	-	7.3	-	-	10.2
2H 2031	-	-	2.7	-	-	5.6	-	-	9.3
1H 2032	-	-	2.1	-	-	4.9	-	-	8.5
2H 2032	-	-	1.5	-	-	4.3	-	-	7.8
1H 2033	-	-	1.1	-	-	3.7	-	-	7.2
2H 2033	-	-	0.7	-	-	2.2	-	-	6.7
1H 2034	-	-	0.5	-	-	1.5	-	-	6.2
2H 2034	-	-	0.5	-	-	1.1	-	-	5.7
1H 2035	-	-	0.5	-	-	0.9	-	-	5.3
2H 2035	-	-	0.4	-	-	0.9	-	-	4.2
1H 2036	-	-	0.4	-	-	0.9	-	-	3.3
2H 2036	-	-	0.4	-	-	0.8	-	-	3.0
1H 2037	-	-	0.4	-	-	0.8	-	-	2.8
2H 2037	-	-	0.3	-	-	0.8	-	-	2.8
1H 2038	-	-	0.3	-	-	0.8	-	-	2.7
2H 2038	-	-	0.3	-	-	0.7	-	-	2.7
1H 2039	-	-	0.3	-	-	0.7	-	-	2.6
2H 2039	-	-	-	-	-	0.2	-	-	2.6
1H 2040	-	-	-	-	-	-	-	-	2.5
2H 2040	-	-	-	-	-	-	-	-	1.7
Rem. 2040+ (MMstb Bscf)	0.0	-	-	-	-	-	-	-	1.4
Total (MMstb Bscf)	**0.0**	**0.0**	**103.1**	**0.0**	**0.0**	**123.7**	**0.0**	**0.0**	**146.1**

Table A - 6: Elgin Hub - Developed + Undeveloped Production Forecasts (Sales)

Elgin Hub - Developed plus Undeveloped Production Forecasts									
Date	1P			2P			3P		
	Oil	NGL	Gas	Oil	NGL	Gas	Oil	NGL	Gas
	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d
2H 2020	39.6	13.1	407.8	41.3	13.7	415.8	43.1	14.3	423.6
1H 2021	29.9	9.9	310.7	32.5	10.8	327.9	35.2	11.7	344.5
2H 2021	32.8	10.9	340.9	36.4	12.1	365.4	40.3	13.4	389.6
1H 2022	32.1	10.6	334.3	36.7	12.2	366.6	41.8	13.8	398.6
2H 2022	28.8	9.5	302.9	33.7	11.2	337.9	39.4	13.0	374.2
1H 2023	26.7	8.8	284.1	31.7	10.5	319.6	38.2	12.6	361.8
2H 2023	23.9	7.9	251.4	29.1	9.6	288.2	35.9	11.9	332.6
1H 2024	19.3	6.4	202.5	24.1	8.0	237.3	30.3	10.0	277.3
2H 2024	20.7	6.8	220.5	26.5	8.8	263.8	33.6	11.1	308.9
1H 2025	17.9	5.9	190.7	23.5	7.8	234.1	30.4	10.1	277.5
2H 2025	16.2	5.4	173.8	21.9	7.3	218.8	29.0	9.6	264.0
1H 2026	14.7	4.9	158.2	20.5	6.8	204.5	27.6	9.1	250.4
2H 2026	13.4	4.4	144.3	19.2	6.4	191.8	26.4	8.8	239.0
1H 2027	10.9	3.6	116.0	16.0	5.3	158.9	22.5	7.5	201.2
2H 2027	11.8	3.9	127.5	17.8	5.9	178.9	25.5	8.4	229.3
1H 2028	10.2	3.4	109.4	15.9	5.3	158.7	23.1	7.7	206.8
2H 2028	9.3	3.1	99.8	14.9	4.9	149.3	22.2	7.3	197.5
1H 2029	8.5	2.8	90.8	14.1	4.7	140.6	21.3	7.0	188.9
2H 2029	7.8	2.6	82.7	13.3	4.4	132.5	20.4	6.8	180.5
1H 2030	6.4	2.1	65.8	11.2	3.7	110.0	17.5	5.8	152.7
2H 2030	6.9	2.3	73.2	12.5	4.1	125.1	19.8	6.6	174.9
1H 2031	6.1	2.0	62.6	11.3	3.7	111.6	18.2	6.0	158.7
2H 2031	5.6	1.8	57.1	10.7	3.5	105.4	17.4	5.8	151.5
1H 2032	5.1	1.7	51.4	9.8	3.2	97.2	15.9	5.3	138.8
2H 2032	4.6	1.5	46.4	9.1	3.0	90.4	14.8	4.9	128.1
1H 2033	3.8	1.3	36.1	7.7	2.6	74.9	12.6	4.2	106.2
2H 2033	4.1	1.3	39.8	8.7	2.9	86.7	14.4	4.8	123.6
1H 2034	3.6	1.2	31.4	7.9	2.6	75.7	13.2	4.4	110.6
2H 2034	3.3	1.1	27.8	7.6	2.5	72.0	12.8	4.2	106.7
1H 2035	3.1	1.0	25.0	7.3	2.4	68.5	12.4	4.1	102.9
2H 2035	2.9	1.0	22.5	7.0	2.3	65.1	12.1	4.0	99.4
1H 2036	2.4	0.8	16.2	6.0	2.0	53.6	10.4	3.5	83.8
2H 2036	2.7	0.9	19.7	6.7	2.2	63.0	12.0	4.0	98.5
1H 2037	2.3	0.8	15.6	6.2	2.0	56.2	11.1	3.7	89.7
2H 2037	2.1	0.7	13.0	5.9	2.0	53.5	10.8	3.6	86.7
1H 2038	2.0	0.7	10.7	5.7	1.9	50.9	10.5	3.5	83.9
2H 2038	1.8	0.6	8.1	5.5	1.8	48.5	10.2	3.4	81.1
1H 2039	1.5	0.5	4.1	4.7	1.6	39.4	8.8	2.9	68.2
2H 2039	1.6	0.5	6.4	5.3	1.8	47.1	10.2	3.4	80.9
1H 2040	1.5	0.5	3.8	4.9	1.6	41.9	9.4	3.1	73.7
2H 2040	1.3	0.4	2.0	4.7	1.6	39.9	9.2	3.0	71.4
Rem. 2040+ (MMstb Bscf)	0.0	-	-	-	-	-	-	-	-
Total (MMstb Bscf)	**82.1**	**27.2**	**838.0**	**116.1**	**38.5**	**1145.0**	**158.9**	**52.6**	**1428.3**

Table A - 7: Everest Area - Developed + Undeveloped Production Forecasts (Sales)

Everest Area - Developed plus Undeveloped Production Forecasts									
Date	1P			2P			3P		
	Oil	NGL	Gas	Oil	NGL	Gas	Oil	NGL	Gas
	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d
2H 2020	6.9	2.8	96.2	7.1	2.9	99.3	7.3	3.0	101.1
1H 2021	6.1	2.5	83.9	6.5	2.7	90.6	6.7	2.7	92.9
2H 2021	5.6	2.3	77.4	6.2	2.6	87.9	6.5	2.7	91.8
1H 2022	6.3	2.8	94.2	7.2	3.3	110.5	7.6	3.5	118.1
2H 2022	5.7	2.4	82.2	6.6	2.9	99.0	7.1	3.2	108.5
1H 2023	5.1	2.2	74.6	6.2	2.8	94.4	6.8	3.1	105.2
2H 2023	4.7	2.0	68.5	6.0	2.7	91.0	6.6	3.0	102.4
1H 2024	3.2	1.4	49.0	5.0	2.2	74.7	5.6	2.5	85.1
2H 2024	2.7	1.2	41.5	4.7	2.0	69.1	5.3	2.3	79.5
1H 2025	2.7	1.2	40.3	4.8	2.0	69.1	5.4	2.4	80.2
2H 2025	2.5	1.0	36.0	4.5	1.9	63.9	5.1	2.2	75.4
1H 2026	2.2	0.9	31.6	4.0	1.7	57.3	4.7	2.0	69.2
2H 2026	2.0	0.8	28.7	3.6	1.5	52.2	4.4	1.9	65.4
1H 2027	1.6	0.7	23.4	3.0	1.3	43.3	4.4	1.8	60.7
2H 2027	1.4	0.6	20.4	2.7	1.1	38.4	4.2	1.7	57.7
1H 2028	1.3	0.6	19.6	2.5	1.1	36.2	3.9	1.6	56.0
2H 2028	1.2	0.5	17.9	2.3	0.9	32.2	3.8	1.6	53.3
1H 2029	1.2	0.5	16.8	2.2	0.8	29.9	3.8	1.5	52.3
2H 2029	1.1	0.4	15.3	2.2	0.8	28.4	3.6	1.4	49.9
1H 2030	1.1	0.4	14.0	2.1	0.8	27.0	3.2	1.3	45.4
2H 2030	1.0	0.4	12.8	2.0	0.7	25.7	2.8	1.2	40.6
1H 2031	1.0	0.3	11.6	1.9	0.7	24.4	2.5	1.1	37.2
2H 2031	0.4	0.2	8.3	1.8	0.6	22.6	2.4	1.0	35.6
1H 2032	0.3	0.2	7.5	1.7	0.6	21.5	2.3	1.0	34.1
2H 2032	0.3	0.2	6.7	1.7	0.6	20.5	2.2	0.9	31.6
1H 2033	0.3	0.2	6.0	1.4	0.5	18.0	2.1	0.9	30.0
2H 2033	0.3	0.2	5.3	1.2	0.4	15.4	2.0	0.8	28.5
1H 2034	0.2	0.1	4.5	1.1	0.4	13.8	1.9	0.7	25.2
2H 2034	0.2	0.1	4.0	1.0	0.4	12.5	1.8	0.7	24.2
1H 2035	0.2	0.1	3.2	1.0	0.3	11.6	1.8	0.7	22.9
2H 2035	0.2	0.1	2.6	1.0	0.3	10.8	1.7	0.6	21.7
1H 2036	0.2	0.1	2.2	0.9	0.3	10.3	1.7	0.6	20.9
2H 2036	0.2	0.1	1.8	0.9	0.3	9.8	1.6	0.6	20.1
1H 2037	0.1	0.0	1.4	0.9	0.3	9.3	1.6	0.5	19.3
2H 2037	0.1	0.0	1.1	0.9	0.3	8.9	1.5	0.5	18.6
1H 2038	0.1	0.0	0.7	0.8	0.2	8.5	1.5	0.5	17.9
2H 2038	0.1	0.0	0.4	0.8	0.2	8.1	1.4	0.5	16.9
1H 2039	0.1	0.0	0.1	0.8	0.2	7.7	1.4	0.5	16.4
2H 2039	0.1	-	-	0.8	0.2	7.3	1.1	0.4	14.1
1H 2040	0.1	-	-	0.8	0.2	6.9	0.9	0.3	12.2
2H 2040	0.1	-	-	0.7	0.2	6.6	0.9	0.3	11.8
Rem. 2040+ (MMstb Bscf)	0.1	-	-	0.3	0.1	4.6	1.2	0.4	14.9
Total (MMstb Bscf)	**12.9**	**5.4**	**184.8**	**21.0**	**8.5**	**292.2**	**27.3**	**11.4**	**389.2**

Table A - 8: Galleon - Developed + Undeveloped Production Forecasts (Sales)

Galleon - Developed plus Undeveloped Production Forecasts									
Date	1P			2P			3P		
	Oil	NGL	Gas	Oil	NGL	Gas	Oil	NGL	Gas
	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d
2H 2020	-	-	30.1	-	-	30.2	-	-	16.8
1H 2021	-	-	26.7	-	-	27.4	-	-	28.7
2H 2021	-	-	23.6	-	-	24.9	-	-	58.4
1H 2022	-	-	38.9	-	-	48.0	-	-	46.7
2H 2022	-	-	31.5	-	-	36.8	-	-	40.0
1H 2023	-	-	26.4	-	-	30.9	-	-	35.2
2H 2023	-	-	22.6	-	-	27.0	-	-	31.7
1H 2024	-	-	19.5	-	-	24.0	-	-	28.8
2H 2024	-	-	17.0	-	-	21.7	-	-	26.5
1H 2025	-	-	14.9	-	-	19.7	-	-	24.5
2H 2025	-	-	13.1	-	-	18.0	-	-	22.8
1H 2026	-	-	11.5	-	-	16.5	-	-	21.3
2H 2026	-	-	10.1	-	-	15.2	-	-	20.0
1H 2027	-	-	8.9	-	-	14.1	-	-	18.8
2H 2027	-	-	7.9	-	-	13.0	-	-	17.7
1H 2028	-	-	6.9	-	-	12.1	-	-	16.7
2H 2028	-	-	6.1	-	-	11.2	-	-	15.8
1H 2029	-	-	5.3	-	-	10.5	-	-	15.0
2H 2029	-	-	4.7	-	-	9.8	-	-	14.2
1H 2030	-	-	4.1	-	-	9.1	-	-	13.5
2H 2030	-	-	3.6	-	-	8.5	-	-	12.9
1H 2031	-	-	3.1	-	-	8.0	-	-	12.3
2H 2031	-	-	2.7	-	-	7.5	-	-	11.7
1H 2032	-	-	2.3	-	-	7.0	-	-	11.2
2H 2032	-	-	1.9	-	-	6.6	-	-	10.7
1H 2033	-	-	1.6	-	-	6.2	-	-	10.2
2H 2033	-	-	1.4	-	-	5.8	-	-	9.8
1H 2034	-	-	-	-	-	5.5	-	-	9.4
2H 2034	-	-	-	-	-	5.1	-	-	9.0
1H 2035	-	-	-	-	-	4.8	-	-	8.6
2H 2035	-	-	-	-	-	4.5	-	-	8.3
1H 2036	-	-	-	-	-	4.3	-	-	7.9
2H 2036	-	-	-	-	-	4.0	-	-	7.6
1H 2037	-	-	-	-	-	3.8	-	-	7.3
2H 2037	-	-	-	-	-	3.5	-	-	7.0
1H 2038	-	-	-	-	-	1.8	-	-	6.8
2H 2038	-	-	-	-	-	1.7	-	-	5.0
1H 2039	-	-	-	-	-	1.5	-	-	4.8
2H 2039	-	-	-	-	-	1.4	-	-	4.6
1H 2040	-	-	-	-	-	1.2	-	-	4.4
2H 2040	-	-	-	-	-	1.1	-	-	4.3
Rem. 2040+ (MMstb Bscf)	0.0	-	-	-	-	1.0	-	-	10.1
Total (MMstb Bscf)	**0.0**	**0.0**	**63.2**	**0.0**	**0.0**	**94.8**	**0.0**	**0.0**	**135.6**

Table A - 9: GBA - Developed + Undeveloped Production Forecasts (Sales)

Greater Britannia Area - Developed plus Undeveloped Production Forecasts									
Date	1P			2P			3P		
	Oil	NGL	Gas	Oil	NGL	Gas	Oil	NGL	Gas
	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d
2H 2020	11.0	2.0	194.7	11.4	2.0	201.4	11.6	2.1	205.3
1H 2021	7.9	1.2	109.3	10.1	1.4	127.1	12.1	1.6	134.9
2H 2021	8.0	1.5	155.1	11.5	2.0	186.1	14.3	2.3	202.1
1H 2022	6.3	1.1	114.7	10.4	1.7	162.6	13.8	2.2	195.0
2H 2022	4.5	0.6	73.1	8.6	1.5	143.8	11.8	2.0	182.2
1H 2023	4.3	0.5	66.3	7.3	1.0	102.6	11.3	1.8	160.0
2H 2023	3.5	0.4	60.1	5.4	0.7	79.1	9.1	1.5	147.8
1H 2024	3.7	0.4	55.2	5.8	0.6	72.0	9.7	1.5	136.8
2H 2024	2.8	0.3	39.8	4.5	0.5	52.4	6.9	0.9	83.4
1H 2025	3.2	0.3	46.3	4.9	0.5	59.8	7.5	0.9	87.5
2H 2025	2.8	0.3	41.9	4.3	0.5	55.5	6.4	0.7	77.5
1H 2026	2.8	0.3	38.0	4.4	0.4	52.0	6.5	0.7	71.6
2H 2026	2.5	0.2	34.3	3.8	0.4	48.2	5.6	0.6	65.7
1H 2027	2.5	0.2	31.0	3.9	0.4	45.1	5.8	0.6	61.3
2H 2027	2.0	0.2	21.5	3.1	0.3	33.0	4.5	0.4	45.6
1H 2028	2.3	0.2	25.5	3.6	0.3	39.5	5.2	0.5	54.8
2H 2028	2.0	0.2	22.8	3.2	0.3	36.4	4.6	0.5	51.7
1H 2029	2.0	0.1	20.3	3.3	0.3	33.9	4.8	0.5	49.4
2H 2029	1.8	0.1	17.9	2.9	0.2	31.2	4.2	0.4	46.6
1H 2030	1.8	0.1	15.8	3.0	0.2	29.0	4.4	0.4	44.6
2H 2030	1.5	0.1	9.7	2.4	0.2	20.3	3.5	0.3	33.2
1H 2031	1.7	0.1	12.2	2.8	0.2	25.0	4.1	0.4	40.5
2H 2031	1.5	0.1	10.5	2.5	0.2	22.8	3.7	0.3	38.1
1H 2032	1.5	0.1	8.9	2.6	0.2	21.0	3.9	0.3	36.3
2H 2032	1.4	0.1	7.4	2.3	0.1	19.0	3.4	0.3	34.1
1H 2033	1.4	0.0	6.0	2.4	0.1	17.5	3.6	0.3	32.5
2H 2033	1.1	0.0	2.1	1.9	0.1	11.3	2.9	0.2	23.5
1H 2034	1.3	0.0	3.7	2.2	0.1	14.6	3.4	0.3	29.3
2H 2034	1.1	0.0	2.6	2.0	0.1	13.1	3.0	0.2	27.4
1H 2035	1.2	0.0	1.6	2.1	0.1	11.7	3.2	0.2	26.1
2H 2035	1.0	0.0	0.6	1.8	0.1	10.5	2.9	0.2	24.4
1H 2036	0.7	0.0	0.4	1.9	0.1	9.3	3.0	0.2	23.1
2H 2036	0.5	-	-	1.6	0.0	4.9	2.5	0.1	16.0
1H 2037	0.6	-	-	1.8	0.1	7.2	2.9	0.2	20.6
2H 2037	0.5	-	-	1.6	0.0	6.2	2.6	0.2	19.1
1H 2038	0.6	-	-	1.7	0.0	5.2	2.7	0.2	18.1
2H 2038	0.5	-	-	1.5	0.0	4.3	2.4	0.1	16.7
1H 2039	0.6	-	-	1.6	0.0	3.5	2.6	0.1	15.8
2H 2039	0.5	-	-	1.3	0.0	0.3	2.1	0.1	10.1
1H 2040	0.6	-	-	1.5	0.0	2.0	2.5	0.1	13.8
2H 2040	0.5	-	-	1.4	0.0	1.3	2.2	0.1	12.6
Rem. 2040+ (MMstb Bscf)	1.2	-	-	3.1	0.0	0.2	5.7	0.1	13.6
Total (MMstb Bscf)	**19.1**	**1.9**	**228.3**	**31.6**	**3.1**	**333.0**	**46.5**	**4.9**	**491.3**

Table A - 10: J-Area - Developed + Undeveloped Production Forecasts (Sales)

J-Area - Developed plus Undeveloped Production Forecasts									
Date	1P			2P			3P		
	Oil	NGL	Gas	Oil	NGL	Gas	Oil	NGL	Gas
	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d
2H 2020	14.0	5.9	126.0	15.0	6.1	129.4	15.8	6.3	131.9
1H 2021	13.2	5.6	120.0	14.8	6.0	126.6	16.2	6.4	132.5
2H 2021	13.2	5.4	114.4	15.4	6.0	124.3	17.2	6.5	133.1
1H 2022	10.1	4.3	92.0	12.3	4.9	102.6	14.2	5.4	112.0
2H 2022	15.9	6.5	138.1	19.1	7.6	158.5	22.6	8.8	182.5
1H 2023	16.4	7.2	153.8	21.3	9.1	192.2	26.4	11.0	233.6
2H 2023	16.7	6.7	141.1	22.2	8.9	187.1	27.8	11.2	234.4
1H 2024	11.2	4.9	104.1	15.8	6.5	137.9	20.4	8.2	172.5
2H 2024	9.8	4.4	93.3	14.2	5.8	123.4	18.5	7.4	153.6
1H 2025	8.7	4.1	88.0	12.7	5.4	114.8	16.6	6.7	141.3
2H 2025	8.8	4.2	90.9	12.9	5.6	118.1	17.0	6.9	144.9
1H 2026	7.9	3.8	82.6	11.9	5.2	110.1	15.9	6.5	137.0
2H 2026	7.1	3.5	76.2	10.8	4.8	103.4	14.5	6.1	129.9
1H 2027	6.0	2.9	64.0	9.4	4.2	89.3	12.8	5.4	114.0
2H 2027	5.5	2.7	59.5	8.7	3.9	83.8	11.8	5.0	107.3
1H 2028	5.2	2.7	58.6	8.1	3.8	82.2	11.0	4.9	104.6
2H 2028	5.0	2.5	56.0	7.9	3.7	80.0	10.8	4.8	102.9
1H 2029	4.7	2.4	53.4	7.6	3.6	77.6	10.5	4.7	100.7
2H 2029	4.4	2.3	51.2	7.3	3.5	75.6	10.1	4.6	99.0
1H 2030	3.9	2.0	43.0	6.7	3.1	65.8	9.5	4.1	87.7
2H 2030	3.8	1.9	41.1	6.6	3.0	64.0	9.4	4.0	86.0
1H 2031	3.7	1.9	41.2	6.5	3.0	64.9	9.3	4.1	87.6
2H 2031	3.5	1.8	39.4	6.3	2.9	63.3	9.1	4.0	86.3
1H 2032	3.3	1.7	38.0	6.0	2.9	62.1	8.7	4.0	85.5
2H 2032	3.1	1.6	35.7	5.7	2.7	59.5	8.3	3.8	82.6
1H 2033	2.8	1.4	31.0	5.5	2.5	53.6	8.3	3.6	75.8
2H 2033	2.6	1.3	28.8	5.6	2.4	51.2	8.5	3.5	73.3
1H 2034	2.6	1.3	29.2	5.0	2.4	51.1	7.5	3.4	72.7
2H 2034	2.5	1.3	28.3	4.8	2.3	50.7	7.1	3.4	72.8
1H 2035	2.4	1.2	26.7	4.6	2.2	49.0	7.0	3.3	71.1
2H 2035	2.3	1.2	25.9	4.6	2.2	48.5	7.1	3.3	71.0
1H 2036	2.0	1.0	21.7	4.1	1.9	42.2	6.4	2.9	62.7
2H 2036	1.8	0.9	19.4	3.9	1.8	39.3	6.1	2.8	59.3
1H 2037	1.9	1.0	21.5	4.1	2.0	42.8	6.4	3.0	64.2
2H 2037	1.8	0.9	19.6	4.0	1.9	40.6	6.3	2.9	61.9
1H 2038	1.8	0.9	19.5	3.8	1.9	40.5	6.1	2.9	62.1
2H 2038	1.7	0.8	17.8	3.6	1.8	38.2	5.8	2.7	59.2
1H 2039	1.3	0.6	13.0	3.0	1.4	30.2	4.8	2.2	48.0
2H 2039	1.2	0.5	11.2	2.7	1.3	27.8	4.5	2.1	44.8
1H 2040	1.2	0.5	11.4	2.8	1.3	28.0	4.6	2.1	44.7
2H 2040	1.1	0.5	10.5	2.7	1.2	26.8	4.4	2.0	43.2
Rem. 2040+ (MMstb Bscf)	1.4	0.5	10.7	3.4	1.5	32.5	5.8	2.6	55.1
Total (MMstb Bscf)	**44.5**	**20.3**	**437.6**	**67.4**	**29.4**	**627.5**	**90.8**	**38.5**	**816.9**

Table A - 11: Schiehallion - Developed + Undeveloped Production Forecasts (Sales)

Schiehallion - Developed plus Undeveloped Production Forecasts									
Date	1P			2P			3P		
	Oil	NGL	Gas	Oil	NGL	Gas	Oil	NGL	Gas
	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d	Mstb/d	Mstb/d	MMscf/d
2H 2020	52.9	-	20.1	54.2	-	20.8	54.9	-	21.2
1H 2021	54.6	-	19.9	59.1	-	22.5	62.0	-	24.1
2H 2021	49.0	-	16.7	55.5	-	20.4	59.7	-	22.8
1H 2022	40.4	-	12.8	47.2	-	16.7	51.7	-	19.2
2H 2022	36.9	-	10.8	44.4	-	15.1	49.2	-	17.8
1H 2023	37.0	-	9.9	45.7	-	14.8	51.4	-	18.1
2H 2023	33.9	-	8.1	42.9	-	13.3	48.9	-	16.7
1H 2024	31.2	-	6.6	40.4	-	11.8	46.6	-	15.3
2H 2024	28.9	-	5.3	38.2	-	10.6	44.5	-	14.1
1H 2025	26.9	-	4.1	36.1	-	9.4	42.5	-	13.0
2H 2025	25.1	-	3.1	34.3	-	8.3	40.7	-	12.0
1H 2026	23.5	-	2.2	32.6	-	7.4	39.1	-	11.1
2H 2026	22.1	-	1.4	31.1	-	6.5	37.5	-	10.2
1H 2027	19.1	-	0.7	27.1	-	5.2	33.0	-	8.6
2H 2027	18.1	-	0.1	26.0	-	4.6	31.9	-	7.9
1H 2028	18.9	-	-	27.4	-	4.4	33.7	-	8.0
2H 2028	17.9	-	-	26.3	-	3.8	32.5	-	7.3
1H 2029	17.1	-	-	25.2	-	3.2	31.4	-	6.7
2H 2029	16.3	-	-	24.2	-	2.6	30.4	-	6.1
1H 2030	15.6	-	-	23.3	-	2.1	29.4	-	5.6
2H 2030	14.9	-	-	22.5	-	1.6	28.5	-	5.0
1H 2031	14.3	-	-	21.7	-	1.2	27.6	-	4.5
2H 2031	13.8	-	-	21.0	-	0.8	26.8	-	4.1
1H 2032	12.1	-	-	18.5	-	0.3	23.8	-	3.3
2H 2032	11.7	-	-	18.0	-	0.1	23.2	-	3.0
1H 2033	12.4	-	-	19.1	-	-	24.7	-	2.9
2H 2033	12.0	-	-	18.5	-	-	24.0	-	2.5
1H 2034	11.6	-	-	18.0	-	-	23.4	-	2.1
2H 2034	11.2	-	-	17.5	-	-	22.8	-	1.8
1H 2035	10.9	-	-	17.0	-	-	22.2	-	1.5
2H 2035	10.5	-	-	16.5	-	-	21.7	-	1.2
1H 2036	10.2	-	-	16.1	-	-	21.1	-	0.9
2H 2036	9.9	-	-	15.7	-	-	20.6	-	0.6
1H 2037	8.8	-	-	13.9	-	-	18.4	-	0.3
2H 2037	8.6	-	-	13.6	-	-	18.0	-	0.1
1H 2038	9.2	-	-	14.6	-	-	19.4	-	-
2H 2038	9.0	-	-	14.2	-	-	18.9	-	-
1H 2039	8.7	-	-	13.9	-	-	18.5	-	-
2H 2039	8.5	-	-	13.6	-	-	18.1	-	-
1H 2040	8.3	-	-	13.3	-	-	17.8	-	-
2H 2040	8.1	-	-	13.0	-	-	17.4	-	-
Rem. 2040+ (MMstb Bscf)	22.4	-	-	37.1	-	-	50.2	-	-
Total (MMstb Bscf)	**170.4**	**0.0**	**22.3**	**236.4**	**0.0**	**37.9**	**289.1**	**0.0**	**54.8**

PART XI

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 or New Equity Warrants. It is assumed that an interest in the Company (whether in the nature of debt or equity) 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 New Ordinary Shares or New Equity Warrants issued in connection with the Merger and the Debt Restructuring), dealers in securities and persons who are participating in the Merger and the Debt Restructuring 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 their participation in the Merger and the Debt Restructuring and that the tax laws of their own country and the country in which the Company is incorporated, and the countries in which the Premier Group 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 £2,000 of dividend income 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 2020/2021:

(i) at the rate of 7.5 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 32.5 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 38.1 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 holds 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 Chrysaor of any disposal of their shares in Chrysaor in connection with the Merger and the Debt Restructuring or the acquisition of New Ordinary Shares by such Chrysaor shareholders. Chrysaor 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 £12,300 for the tax year 2020/2021.

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, currently 19 per cent.. 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.

(C) Subdivision

The conversion and subdivision of the Existing Ordinary Shares into Ordinary Shares and Non-Voting Deferred Shares pursuant to the Subdivision should be regarded as a reorganisation of the Company's share capital. Accordingly, Shareholders should not be treated as having disposed of their Existing Ordinary Shares for the purposes of UK taxation of chargeable gains and no liability to UK tax on chargeable gains should arise in respect of the Subdivision. The Ordinary Shares and the Non-Voting Deferred Shares should be treated as acquired when the Existing Ordinary Shares were acquired and the base cost of the Existing Ordinary Shares should be divided between the Ordinary Shares and the Non-Voting Deferred Shares in proportion to the respective market values of those shares.

For the purposes of dividing the base cost of the Existing Ordinary Shares, the market value of the Ordinary Shares will be the market value of those shares on the first day of dealing of the Ordinary Shares on the London Stock Exchange. The rights attaching to the Non-Voting Deferred Shares, which will not be listed and will not be freely transferable, are likely to render them effectively valueless; hence, it is expected that all of the base cost of the Existing Ordinary Shares should be apportioned to the Ordinary Shares following the Subdivision.

3. Taxation of the New Equity Warrants

The Company will not be required to withhold at source on account of UK tax when issuing the New Equity Warrants.

(A) UK resident corporate New Equity Warrant Holders

For New Equity Warrant Holders within the charge to UK corporation tax, the tax implications of the ownership, disposal or exercise of the New Equity Warrants will depend *inter alia* on their accounting treatment. Thus if these are derivatives (rather than equity instruments) under applicable GAAP, the New Equity Warrants should be taxed broadly in line with their treatment in the accounts of the holder, in accordance with Part 7 of the Corporation Tax Act 2009.

If the New Equity Warrants are not derivatives, a company holding them as an investment should be taxed in much the same manner as an individual (please see below).

(B) UK resident individual New Equity Warrant Holders

For New Equity Warrant Holders who are UK resident individuals and hold their New Equity Warrants as investments, the rules in the Taxation of Chargeable Gains Act 1992 will apply. In particular:

(i) the disposal of a New Equity Warrant by transfer should be subject to the taxation of chargeable gains in the normal way;

(ii) a New Equity Warrant Holder who exercises the subscription rights conferred by their New Equity Warrants should not thereby be treated as disposing of them and the consideration given to acquire the relevant New Equity Warrants, together with the amount the holder pays for the New Warrant Shares acquired on exercise, should constitute the holder's acquisition cost in those New Warrant Shares; and

(iii) if a New Equity Warrant lapses, the New Equity Warrant Holder should not be treated as having made a disposal for chargeable gains purposes.

4. 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 and New Equity Warrant Holders. 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 or New Equity Warrant Holder is resident in the UK.

(A) Issue of the New Ordinary Shares

No stamp duty or SDRT will ordinarily be payable on the issue of New Ordinary Shares by the Company. Similarly, where New Ordinary Shares are first credited in uncertificated form to an account in CREST, no liability to stamp duty or SDRT will generally arise.

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 has confirmed that it will 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. The position may change as a result of or in connection with Brexit, but based on UK government announcements to date, it is not currently anticipated that HMRC will take a different approach at the end of the Brexit implementation period.

(B) Issue of the New Equity Warrants

No SDRT will be chargeable on the issue of New Equity Warrants, subject to the comments below on the issue of New Equity Warrants to a depositary receipt system or clearance service. Based on the current published practice of HMRC and its understanding of the technical position, the Company's view is that no UK stamp duty should be payable on the issue of the New Equity Warrants either.

(C) Subsequent transfers

Except in relation to depositary receipt systems and clearance services (to which the special rules outlined below apply), any dealings in Ordinary Shares (including New Ordinary Shares) or New Equity Warrants following their issue will be subject to stamp duty or SDRT in the normal way. Such stamp duty or SDRT liabilities will be 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 or New Equity Warrants, subject to applicable exemptions and reliefs. An exemption from stamp duty is available on an instrument transferring Ordinary Shares or New Equity Warrants 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 or New Equity Warrants (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 or New Equity Warrants 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 or New Equity Warrants are transferred to a connected company of a Shareholder or New Equity Warrant Holder (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 or New Equity Warrants (as applicable).

(D) Exercise of the New Equity Warrants

The issue of New Warrant Shares on the exercise of New Equity Warrants will not be chargeable to stamp duty or SDRT, subject to the comments below regarding the issue of chargeable securities to a clearance service or depositary receipt system.

As noted above, as a result of certain case law HMRC has confirmed that it will 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. This position may change as a result of or in connection with Brexit but, based on UK government announcements to date, it is not currently anticipated that HMRC will take a different approach at the end of the Brexit implementation period.

(E) Clearance services and depositary receipt systems

Under current UK legislation, where Ordinary Shares or New Equity Warrants are issued or transferred: (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 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 or New Equity Warrants (rounded up to the next multiple of £5 in the case of stamp duty) or in certain circumstances, the value of the Ordinary Shares or New Equity Warrants (as applicable).

As noted above (and subject to the same Brexit-related caveat), HMRC no longer seeks to apply the 1.5 per cent. SDRT charge when shares are first issued to a clearance service or depositary receipt system. However, the 1.5 per cent. SDRT charge continues to apply where New Equity Warrants are issued or transferred to a clearance service or depositary receipt system.

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 or New Equity Warrants into, 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 or New Equity Warrants held within such a service or system, will strictly 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 XII

DIRECTORS, EMPLOYEES AND CORPORATE GOVERNANCE

1. Directors

1.1 Overview

The Board provides leadership to the Premier Group with a view to delivering long-term value to Shareholders and other stakeholders. It sets the strategy and oversees its execution within an agreed framework of internal controls, ensuring that risk is appropriately managed.

The Articles require the Company to have a minimum of two Directors and a maximum of 20. 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 his intention to recommend the relevant individual along with the individual's consent. 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.

1.2 Current Board of Directors

The following table sets out the name, year of appointment and position of each member of the current board:

Name	*Current position in respect of Premier*	*Year of appointment*
Richard Rose	Interim Chief Executive Officer and Finance Director	2014
Roy A Franklin	Chairman	2017
Dave Blackwood	Non-Executive Director	2017
Anne Marie Cannon	Senior Independent Non-Executive Director	2014
Iain Macdonald	Non-Executive Director	2016
Mike Wheeler	Non-Executive Director	2017
Elisabeth Proust	Non-Executive Director	2020

The business address of each of the Directors is 23 Lower Belgrave Street, London SW1W 0NR.

Each of the Directors (other than Anne Marie Cannon) are expected to resign from the Board with effect from completion of the Merger and the Debt Restructuring, at which point, the following individuals listed in paragraph 1.3 below will be appointed to the Board.

1.3 New Board of Directors

The following table sets out the name and position of each member of the Board from completion of the Merger:

Name	*Position after completion of the Merger*
Linda Cook	Chief Executive Officer
Phil Kirk	President and Chief Executive Officer, Europe
R. Blair Thomas	Chairman
G. Steven Farris	Non-Executive Director
Simon Henry	Senior Independent Non-Executive Director
Anne L. Stevens	Independent Non-Executive Director
Anne Marie Cannon	Independent Non-Executive Director

It is also expected that prior to completion of the Merger, the Company will identify a new Chief Financial Officer and three additional Independent Non-Executive Directors who will be appointed from completion of the Merger. The Company will make an announcement by way of a Regulatory Information Service at the relevant time confirming such appointments.

The business address of each of the Proposed Directors immediately after the completion of the Merger will be 23 Lower Belgrave Street, London SW1W 0NR.

1.4 Biographies of the new Board

The business experience and principal business activities outside of Premier of each member of the Board from completion of the Merger are as follows:

(A) **Linda Cook (*Chief Executive Officer designate*)**

Linda Cook is chief executive officer (CEO) of Harbour Direct Holdings Ltd and managing director and member of the Investment and Executive Committees of EIG Global Energy Partners ("**EIG**"), positions she has held since 2014. Since 2017, Linda has also served as the Non-Executive Chairman of Chrysaor Holdings Limited. She retired from Royal Dutch Shell plc in 2010, at which time she was a member of the Board of Directors and the Executive Committee. During her 29 years with the company, she held positions including CEO of Shell Gas and Power (London); CEO of Shell Canada Limited (Calgary); Executive Vice President Strategy and Finance for Global Exploration and Production (The Hague); and various US Exploration & Production management, operational and engineering roles. She received a B.S. in Petroleum Engineering from the University of Kansas and is currently a trustee for the University's Endowment Association, a member of the Society of Petroleum Engineers and a non-executive director on the Board of BNY Mellon.

(B) **Phil Kirk (*President; Chief Executive Officer, Europe designate*)**

Phil Kirk is Chief Executive Officer (CEO) for the Chrysaor Group. After qualifying as a chartered accountant with Ernst & Young in 1991, he joined Hess in 1996 where he served a variety of roles including head of finance, North West Europe. In 2002, Phil set up CH4 Energy with two ex-colleagues where he was joint managing director. CH4 acquired and operated the Markham field and associated satellites on the UK/Dutch median line. After selling CH4 to Venture Production in 2006, he founded Chrysaor in 2007 and has led the group since then. Phil has been a member of the Board of Oil and Gas UK since 2013 and currently serves as its co-chair. He is also a past co-chair of the OGA UK Exploration Board, one of six boards responsible for driving the industry's response to the OGA's MER UK (Maximising Economic Recovery) strategy, and he is a Fellow of the Energy Institute and a member of the Society of Petroleum Engineers. Phil has a BSc in Mathematics from Warwick University.

(C) **R. Blair Thomas (*Non-Executive Chairman designate*)**

R. Blair Thomas has more than 30 years' experience in the investment management business, with a focus on energy and energy-related infrastructure. Blair is the Chief Executive Officer of EIG, and chairs the firm's Investment and Executive Committees. EIG is among the largest institutional investors in the energy sector and is active across the energy value chain and around the globe. Blair is also a member of the Board of Directors and the Investment Committee of FS/EIG Advisor, the investment advisor to FSEP, a non-traded business development company focused on the energy sector. EIG was formerly part of Trust Company of the West, where Blair was a Group Managing Director and a member of the Board of Directors of TCW Asset Management Company. Prior to joining EIG in 1998, Blair was a senior investment officer with the Inter-American Development Bank and a project finance attorney at the law firm of Brown & Wood in New York. Blair also served in the administration of President George H. W. Bush as an advisor on energy and budget policy. Blair received a B.A. from the University of Virginia, a J.D. from New York Law School and an L.L.M. from Georgetown University Law Center. Blair is also the Chairman of Limetree Bay Ventures, and Prumo Logistica S.A., both private companies. Since 2014, Blair has served as the Chairman of the Board of Directors of Harbour Direct Holdings Ltd. and has been a member of the Board of Directors of Chrysaor Holdings Ltd. since 2017.

(D) **G. Steven Farris (*Non-Executive Director designate*)**

Steven Farris served as chairman and chief executive officer of Apache Corporation, an oil and natural gas exploration and production company with operations in the United States, Canada, the United Kingdom sector of the North Sea, Egypt, and Australia. Steve was named chairman of Apache in January 2009, upon the retirement of company Founder Raymond Plank. He was promoted to president in 1994 and chief executive officer in May 2002. Steve joined Apache in June 1988 as vice president of domestic exploration and production and was promoted to senior vice president in May 1991. Prior to joining Apache, Steve was vice president, finance and business development, of Terra Resources, a subsidiary of Sempra Energy. Before working at Terra, he was executive vice president of Robert W. Berry, Inc., an independent exploration and production company. Steve began his career with Deloitte, Haskins & Sells as a Certified Public Accountant, earning his CPA license in 1972. Steve is the former chairman of America's Natural Gas Alliance, the American chairman of the US-Egypt Business Council, a member of the Business Roundtable, a member of the Executive Committee of the M.D. Anderson Cancer Center Board of Visitors, and a member of the Fund for Teachers Board of Directors. He holds bachelor's degrees in history and accounting from Oklahoma State University. Steve has served as a non-executive director of Chrysaor Holdings Ltd since 2017 and has been a member of the Board of Directors of Harbour Direct Holdings Limited since 2015.

(E) **Simon Henry (*Senior Independent Non-Executive Director designate*)**

Simon spent 35 years in an executive career with Royal Dutch Shell plc, retiring as CFO and Executive Director in March 2017. He has since developed a portfolio of non-executive and advisory roles, in both the public and private sector. He has a particular interest in strategy, financial performance, risk management and corporate governance. He became Chief Financial Officer and a member of the Board of Royal Dutch Shell plc in May 2009. In addition to responsibility for all financial activities of the company, he was responsible for Strategy, Planning and Information Technology, and acted as Regional Executive Director for Asia Pacific with specific oversight of new business development in China. Simon is a member of the boards of Rio Tinto, where he chairs the Audit Committee, and the Ministry of Defence, where he chairs the Audit and Risk Assurance Committee. He is also a member of board of PetroChina, where he is a member of the Investment and Development Committee. He joined the Board at Lloyds Banking Group in 2014 and Chaired the Audit Committee for 3 years before resigning from the Board at the end of September 2020. Simon was previously a member of the Main Committee of the 100 Group of UK FTSE CFOs and Chair of the European Round Table CFO Taskforce, and remains a member of the Advisory Board of the Centre for European Reform, a UK based think tank. He provides advisory services to a venture capital company through Oxford Sciences Innovation. He is a Fellow and member of the Advisory Panel of CIMA (Chartered Institute of Management Accountants), and a Trustee of the Cambridge China Development Trust. Simon was born in the UK in 1961 and joined Shell after graduating in Mathematics from Churchill College, University of Cambridge in 1982, initially working as an engineer at Stanlow refinery in the UK.

Simon will serve as the Senior Independent Non-Executive Director from completion of the Merger.

(F) **Anne Stevens (*Independent Non-Executive Director designate*)**

Anne Stevens has over 30 years of experience in manufacturing and management, becoming the first female Vice President Executive of Ford Motor Company and the first female CEO of Carpenter Technology. Anne started her career in 1980 at the Exxon Chemical Company, where she served in multiple engineering and manufacturing positions before joining the Ford Motor Company in 1990 as a marketing specialist. She became Vice President of North America Vehicle Operations in 2000 and Chief Operating Officer for the Americas in 2005. She was the recipient of various awards including the Shingo Prize for Leadership and the Eli Whitney Award from the Society of Manufacturing Engineers, resulting in her being honoured by the Automotive Hall of Fame. Anne served as Chairman, President and CEO of Carpenter Technology from 2006 until 2009. In 2018 she was appointed as CEO of GKN Aerospace on an interim basis to prevent a hostile takeover. Anne has also previously served as chairman, CEO and principal of SA IT from 2011 to 2014, as a non-executive director on the board of XL Group from 2014 to 2018 (where she chaired the operations and technology committee and served on the risk and finance and audit committees) and Lockheed Martin from 2002 until 2017 (where she chaired the management development and compensation committee and served on the audit, ethics and sustainability and nominations committees). She has been a non-executive director at Anglo American since 2012 (where she chairs the remuneration committee and serves on the audit and nomination committees). Anne received a B.S. in Materials and Mechanical Engineering from Drexel University in 1980 and was elected to the National Academy of Engineering in 2004.

Anne will serve as chairman of the Remuneration Committee from completion of the Merger

(G) **Anne Marie Cannon (*Independent Non-Executive Director designate*)**

Anne Marie Cannon joined the Board as a Non-Executive Director in February 2014. She has over 30 years' experience in the energy and banking sectors, including roles at Thomson North Sea, Shell Exploration and Production and J Henry Schroder Wagg. She was previously a senior advisor to the natural resources group at Morgan Stanley, focussing on upstream mergers and acquisitions. She is currently the deputy chair of the board of Aker BP ASA, a non-executive director of Aker Energy AS, a non-executive director of STV Group plc and chairs the remuneration committee of STV Group plc. She is also a Senior Advisor at PJT Partners Inc. She has previously held executive director roles on the boards of Hardy Oil and Gas and British Borneo.

Anne Marie is currently a member of the Audit and Risk Committee, the Nomination Committee and the Remuneration Committee.

1.5 Biographies of the Directors

The business experience and principal business activities outside of Premier of each of the Directors are as follows:

(A) Richard Rose (*Interim Chief Executive Officer and Finance Director*)

Richard Rose joined Premier in September 2014 as Finance Director. He qualified as a chartered accountant with Ernst & Young LLP and has spent over 25 years in the energy sector, including 13 years working with a range of international banks and brokers in equity capital markets and corporate finance. He joined Premier from Ophir Energy where he was Strategy and Head of Corporate Communications. He was appointed Interim Chief Executive Officer as of the date of this document.

(B) Roy A Franklin (*Chairman*)

Roy A Franklin has more than 45 years' experience as an executive in the oil and gas industry. He spent 18 years at BP after which he was Group Managing Director of Clyde Petroleum and then CEO of Paladin Resources, until its acquisition by Talisman Energy in 2005. Since then, Roy has served on a number of international energy boards in non-executive roles. Roy is Non-Executive Chairman of J Wood plc and Chairman of Energean Israel Limited. He is also a member of the advisory board of Kerogen Capital LLC. In 2004, Roy was awarded the OBE for services to the UK oil and gas industry.

Roy chairs the Nomination Committee.

(C) Dave Blackwood (*Non-Executive Director*)

Dave Blackwood has over 40 years' experience in the oil and gas sector, 27 years of which were spent in various global roles within BP, including heading up BP's upstream business in the UK and Norway. Dave has held various non-executive and advisory roles, including Valiant Petroleum plc where he was Senior Independent Director. He is currently a Senior Advisor with Evercore, a global independent investment banking advisory firm. In 2006 Dave was awarded the CBE for his contribution to the UK oil and gas industry.

Dave chairs the Health, Safety, Environment & Security Committee and is a member of the Audit and Risk Committee and the Nomination Committee.

(D) Anne Marie Cannon (*Senior Independent Non-Executive Director*)

For details on Anne Marie Cannon's experience, please see section 1.4 of this Part XII (Directors, Employees and Corporate Governance) above.

(E) Iain Macdonald (*Non-Executive Director*)

Iain Macdonald joined the Board in May 2016 as a Non-Executive Director. Before joining Premier he spent 30 years at BP in a variety of engineering, licensing, business management and finance roles culminating in three years as Deputy Group CFO for BP plc. He also served as a non-executive director of TNK-BP Ltd from 2009 to 2011. He is currently a non-executive director of The WorkForce Development Trust Limited and Well North Enterprises CIC and was previously a non-executive director and chair of the audit committee of SUEK JSC.

Iain chairs the Audit and Risk Committee and is a member of the Nomination Committee.

(F) Elisabeth Proust (*Non-Executive Director*)

Elisabeth spent more than 35 years with Total SA holding several senior leadership roles including Vice President Development Engineering and managing director of Total's affiliates in Indonesia, Nigeria and the UK. Elisabeth was also president of the oil and gas association in Indonesia (IPA), then in Nigeria (OPTS) and, whilst in the UK, as director at the Oil and Gas UK Association board, Oil and Gas Technology Centre, Step Change in Safety and the Technology Leadership boards. Elisabeth is currently a non-executive director for Subsea 7, the Oslo-listed leading subsea engineering construction and services company servicing the offshore energy industry and a Senior Advisor at Renoir Group.

Elisabeth is a member of the Health, Safety, Environment and Security Committee and the Nomination Committee.

(G) **Mike Wheeler (*Non-Executive Director*)**

Mike Wheeler has held senior roles in businesses in a variety of sectors, including serving, as the Global Managing Partner Financial Advisory Services and Member of KPMG's international executive board. His career at KPMG spanned thirty years, which included serving as Global Chairman, Restructuring. He has held various non-executive director roles and is currently serving as Non-executive Chairman of Glitnir and Non-executive Director and Chairman of the Audit Committee of Sunseeker International. In 2014, Mike was awarded the CBE for his services to healthcare following several years as a non-executive director at the UK Department of Health.

Mike is a member of the Audit and Risk Committee, the Nomination Committee and chairs the Remuneration Committee.

1.6 Other directorships and partnerships

The details of those companies and partnerships outside the Premier Group in which the Directors and the Proposed Directors are, or have been, members of the administrative, management and supervisory bodies or partners at any time during the five years prior to the Latest Practicable Date are as follows:

Directors	*Interests*	*Status (Current / Previous)*
Dave Blackwood	Evercore – Senior Advisor	Current
	Aberdeen Science Centre – Director	Previous (resigned 26 September 2019)
Anne Marie Cannon	STV plc – Non-Executive Director	Current
	Aker ASA – Non-Executive Director	Previous (resigned 26 April 2019)
	Aker BP ASA – Deputy Chair	Current
	Aker Energy AS – Non-executive director	Current
	PJT Partners, Inc – Senior Advisor	Current
Roy A Franklin	Kerogen Energy Fund LLP (Hong Kong) – Advisory board Member	Current
	Cuadrilla Resources Holdings Limited – Chairman	Previous (resigned 30 June 2020)
	Energean Israel Ltd — Chairman	Current
	Equinor (Formerly Statoil ASA) – Deputy Chairman	Previous (resigned 30 June 2019)
	John Wood Group plc – Chairman	Current
	Santos Limited – Non-Executive Director	Previous (resigned 30 September 2017)
Iain Macdonald	The Workforce Development Trust Limited – Director	Current
	SUEK JSC – Non-executive director and Chairman	Previous (resigned April 2020)
	Well North Enterprises CIC — Non-Executive Director	Current
Elisabeth Proust	Subsea 7 S.A. – Non-executive Director	Current
	Renoir Group – Senior Advisor	Current
Richard Rose	N/A	N/A
Mike Wheeler	Gilitnir hf – Chairman	Current
	Citadel Securities (Europe) Limited – Chairman	Previous (resigned 22 June 2018)
	Sunseeker International Holdings Limited – Non- Executive Director	Current
	Manufacturing Capital Limited – Director	

Directors	*Interests*	*Status (Current / Previous)*
		Previous (resigned 2 March 2020)
Proposed Directors	**Interests**	**Status (Current / Previous)**
Linda Cook	Chrysaor Holdings Limited – Chairman	Current
	EIG Global Energy Partners – Managing Director	Current
	EIG Swift Co-Investment, L.P. – Limited Partner	Current
	EIG Energy Fund XVII-E, L.P. – Limited Partner	Current
	Elba Liquefaction Company, L.L.C. – Director	Previous (resigned April 2018)
	Harbour Direct Holdings Ltd – CEO	Current
	Harbour Energy LP – Limited Partner	Current
	Bank of New York Mellon – Non-Executive Director	Current
	Maverick Natural Resources LLC – Chairman	Current
	Zedd Energy Holdco Ltd.	Previous (resigned December 2015)
Phil Kirk	Chrysaor Holdings Limited – Chief Executive Officer	Current
	Chrysaor Resources (UK) Holdings Limited – Director	Current
	Chrysaor Resources (Irish Sea) Limited – Director	Current
	Chrysaor Production Holdings Limited – Director	Current
	Chrysaor Production Limited – Director	Current
	Chrysaor Production (U.K.) Limited – Director	Current
	Chrysaor Petroleum Company U.K. Limited – Director	Current
	Chrysaor Petroleum Limited – Director	Current
	Chrysaor Developments Limited – Dircetor	Current
	Chrysaor (U.K.) Alpha Limited – Director	Current
	Chrysaor (U.K.) Beta Limited – Director	Current
	Chrysaor (U.K.) Delta Limited – Director	Current
	Chrysaor (U.K.) Eta Limited – Director	Current
	Chrysaor (U.K.) Sigma Limited – Director	Current
	Chrysaor (U.K.) Theta Limited – Director	Current
	Chrysaor (U.K.) Zeta Limited – Director	Current
	Chrysaor (U.K.) Britannia Limited – Director	Current
	Chrysaor Oil Company Limited – Director	Previous (resigned April 2020)
	Chrysaor (U.K.) Kappa Limited – Director	Previous (resigned April 2020)
	Chrysaor Investments Limited – Director	Current
	Chrysaor Petroleum Chemicals U.K. Limited – Director	Current
	Chrysaor Production Oil (GB) Limited – Director	Current
	Chrysaor (U.K.) Finance Limited – Director	Previous (resigned April 2020)
	Chrysaor (U.K.) Phi Limited – Director	Previous (resigned April 2020)
	Chrysaor (U.K.) Chi Limited – Director	Previous (resigned April 2020)
	Chrysaor Supply & Trading Limited – Director	Current
	Chrysaor (Glen) Limited	Current Current
	Cliffe Storage Limited – Director	Previous (resigned April 2020)
	Glen Petroleum Limited – Director	Previous (resigned April 2020)

Directors	*Interests*	*Status (Current / Previous)*
	Chrysaor (U.K.) Lambda Limited – Director	Current
	Chrysaor Marketing Limited – Director	Current
	Chrysaor North Sea Limited – Director	Current
	Chrysaor E&P Services Limited – Director	Current
	Chrysaor E&P Limited – Director	Current
	Chrysaor Limited – Director	Current
	Chrysaor E&P Finance Limited – Director	Current
	Callirhoe Limited – Director	Previous (resigned May 2018)
R. Blair Thomas	Chrysaor Holdings Limited – Board Member	Current
	FS Energy and Power Fund – Trustee	Current
	FS/EIG Advisor, LLC – Director	Current
	Harbour Direct Holdings Ltd. – Board Member	Current
	Prumo Logistica S.A. – Chairman/ Director	Current
	Limetree Bay Ventures, LLC – Chairman	Current
	EIG Atacama Holdings (Cayman) GP, Ltd. – Chief Executive Officer and Director	Current
	TCW Crescent Mezzanine V – Limited Partner	Current
	Madrono LP – Limited Partner	Current
	EIG Separate Investments, LP – Limited Partner	Current
	EIG Principals Incentive Carry Vehicle III, LP – Limited Partner	Current
	EIG Principals Incentive Carry Vehicle III-A, LP – Limited Partner	Current
	EIG Employee Co (Special Retention Vehicle), LP – Limited Partner	Current
	EIG Principals Incentive Carry Vehicle II, LP – Limited Partner	Current
	EIG Principals Incentive Carry Vehicle II-A, LP – Limited Partner	Current
	Breakwater Acquisition Corp – Director	Current
	EIG Asset Management, LLC – Chief Executive Officer	Current
	EIG Atacama Holdings (Cayman) GP, Ltd. – Director	Current
	EIG Credit Management Company, LLC – Chief Executive Officer	Current
	EIG Energy Investors XV (Scotland) Ltd. – Director	Current
	EIG Global Energy (Asia) Limited – Director	Current
	EIG Global Energy (Australia) Pty Limited – Director	Current
	EIG Global Energy (Europe) Limited – Director	Current
	EIG Global Energy Korea, Ltd. – Director	Current
	EIG Global Energy Partners, LLC – Chief Executive Officer	Current
	EIG Harbour Energy Feeder GP, Ltd. – Director	Current
	EIG Investment Management Company, LLC – Chief Executive Officer	Current
	EIG Management Company, LLC – Chief Executive Officer	Current
	FS/EIG Advisor, LLC – Director	Current
	Gateway Debt Holdings Offshore, Ltd. – Director	Current

Directors	*Interests*	*Status (Current / Previous)*
	Global LNG Holdings Ltd. – Director	Current
	Harbour Energy GP, Ltd. – Director	Current
	Senex Energy Limited – Board Observer	Previous (resigned December 2017)
G. Steven Farris	Chrysaor Holdings Limited – Director	Current
	Harbour Direct Holdings Ltd. – Board Member	Current
	Blackwell Farris, LLC – Partner	Current
	Forager LLC – Partner	Current
	Sabine Oil and Gas – Director	Previous (resigned August 2020)
Simon Henry	PetroChina Company Ltd. – Director	Current
	Rio Tinto plc – Non-Executive Director	Current
	Ministry of Defence (Government Department) – Non Executive Board Member	Current
	Royal Dutch Shell plc – Executive Director	Previous (resigned March 2017)
	Lloyds Banking Group plc – Non-Executive Director	Previous (resigned September 2020)
Anne Stevens	Anglo American plc – Non-Executive Director	Current
	GKN plc – Chief Executive Officer	Previous (resigned April 2018)
	XL Group plc – Non-Executive Director	Previous (resigned October 2018)
	Lockheed Martin Corporation – Non-Executive Director	Previous (resigned December 2017)

This table only includes references to commercial, profit-making companies and partnerships. It does not include positions held in charitable, non-profit or voluntary initiatives, industry associations, professional bodies, educational institutions or interest groups.

1.7 Potential conflicts of interest

There are the following potential conflicts of interests between the duties of the Directors of Premier (and the Proposed Directors of Premier after completion of the Merger) and their private interests and/or other duties. Each conflict has been authorised by the Board.

Directors	*Potential conflict(s)*
Roy A Franklin	Mr Franklin is an advisory board member of Kerogen Energy Fund LLP. He is Chairman of Energean Israel Limited and Chairman of John Wood Group plc.
Anne Marie Cannon	Ms Cannon is deputy chair of Aker BP ASA, a non-executive director of Aker Energy AS and a senior adviser to PJT Partners.
Richard Rose	Mr Rose is a director of Premier Pension Plan Trustee Limited, the trustee company for the Premier Oil plc Retirement and Death Benefits Plan.
Elisabeth Proust	Ms Proust is a Senior Advisor at Renoir Group.
Linda Cook	Ms Cook is CEO of Harbour Direct Holdings Ltd and Managing Director, member of the Executive and Investment Committees of EIG Global Energy Partners. Linda will resign from these positions prior to completion of the Merger. She will assume a role as advisor of EIG at the time. Linda is indirectly interested in an EIG affiliated entity which will, following completion of the Merger, receive a quarterly management fee from an EIG-managed entity related to the value of Harbour's interest in the Company. Linda was recently appointed as non-executive Chairman of Maverick Natural Resources, LLC, a private U.S.-based oil and gas company controlled by EIG, with a long-standing focus on U.S. shale.
R. Blair Thomas	Mr Thomas is the Chief Executive Officer of EIG, as well as Chairman of the firm's Investment and Executive Committees. Blair is also the Chairman of the Board of Directors of Harbour Direct Holdings Ltd. Blair is indirectly interested in an EIG affiliated entity which will, following completion of the Merger, receive a quarterly management fee from a Harbour affiliated entity related to the value of Harbour's interest in the Company
G. Steven Farris	Mr Farris is a member of the Board of Directors of Harbour Direct Holdings Ltd.
Simon Henry	Mr Henry is a member of the board of directors of PetroChina Company Limited and an adviser to the Board of Oxford Flow Ltd, which supplies valves and related technology to the oil and gas industry.

Apart from the potential conflicts disclosed above, there are no actual or potential conflicts of interest between the duties owed by the Directors and their private interests and/or other duties that they may also have.

1.8 Confirmations

As at the date of this document, none of the Directors or the Proposed Directors have, during the five years prior to the date of this document:

- been convicted in relation to a fraudulent offence;
- been associated with any bankruptcies, receiverships or liquidations while acting in the capacity of a member of the administrative, management or supervisory bodies or as a partner, founder or senior manager of any partnership or company;
- been subject to any official public incrimination and/or sanctions by any statutory or regulatory authorities (including any designated professional bodies); or

- been disqualified by a court from acting as a director of a company or from acting as a member of the administrative, management or supervisory bodies of any company or from acting in the management or conduct of the affairs of any company.

Save as set out below, none of the Directors or Proposed Directors were selected to act in such capacity pursuant to any arrangement or understanding with any major shareholder, customer, supplier or other person having a business connection with the Premier Group:

- R. Blair Thomas will be appointed as Non-Executive Chairman of the Company and G. Steven Farris will be appointed as Non-Executive Director with effect from completion of the Merger pursuant to Harbour's right to appoint two directors to the Board of Directors of the Company under the Relationship Agreement.

Save as set out below, as at the date of this document, no restrictions have been agreed by any Director or Proposed Director on the disposal within a certain time period of their holdings of their Existing Ordinary Shares.

- Linda Cook, Phil Kirk and G. Steven Farris will enter into lock-up agreements on completion of the Merger pursuant to which, subject to certain exceptions, they will be restricted from disposing of their respective Consideration Shares for a period of six months immediately following completion of the Merger (the "**Lock-Up Period**").

There are no family relationships between any of the Directors or Proposed Directors.

2. Interests of the Directors and Proposed Directors

2.1 Interests in the Existing Ordinary Shares

As at the Latest Practicable Date, the interests of the Directors, the Proposed Directors their immediate families and (so far as is known to them or could with reasonable diligence be ascertained by them) the persons closely associated with them (within the meaning of the Market Abuse Regulation) in the Existing Ordinary Shares, including those arising pursuant to transactions notified to Premier pursuant to the Market Abuse Regulation, together with such interests as are expected to subsist immediately following the completion of the Merger:

	As at the Latest Practicable Date		*Immediately following the Merger*	
	Number of Ordinary Shares held	*Percentage of issued share capital of Premier (%)*	*Number of Ordinary Shares held*[(1)]	*Percentage of issued share capital of Premier (%)*[(1)]
Directors:				
Dave Blackwood	10,000	less than 0.01	10,000	less than 0.01
Anne Marie Cannon	10,000	less than 0.01	10,0000	less than 0.01
Roy A Franklin	60,000	less than 0.01	60,000	less than 0.01
Iain Macdonald	23,076	less than 0.01	23,076	less than 0.01
Elisabeth Proust	10,000	less than 0.01	10,000	less than 0.01
Richard Rose	419,492	0.045	419,492	less than 0.01
Mike Wheeler	30,000	less than 0.01	30,000	less than 0.01
Proposed Directors:				
Linda Cook[(2)(6)]	0	0	38,905,053	0.21
Phil Kirk[(3)(6)]	0	0	231,759,367	1.25
R. Blair Thomas[(4)]	0	0	0	0
G. Steven Farris[(5)(6)]	0	0	2,169,314	0.01
Simon Henry	0	0	0	0
Anne Stevens	0	0	0	0

Notes:

(1) Assuming that all of the New Ordinary Shares available pursuant to the Top-Up Election are subscribed for in full.

(2) Immediately following completion of the Merger, Ms Cook will also be indirectly interested in 0.94 per cent. of Premier's issued share capital through her interest in certain EIG-managed entities. Her indirect interest in Premier's issued share capital immediately following completion of the Merger may increase above this percentage interest depending on whether any profit allocations in respect of the year ending 31 December 2020 are made to certain EIG-managed entities in which she is interested.

(3) Immediately following completion of the Merger, the level of Mr Kirk's interest in Premier's issued share capital will depend on the value of the total number of Ordinary Shares to be issued to Chrysaor shareholders on completion. The number shown in the table above represents the level of his interest based on that value as at the Latest Practicable Date.

(4) Immediately following completion of the Merger, Mr Thomas will also be indirectly interested in 1.61 per cent. of Premier's issued share capital through his interest in certain EIG-managed entities. His indirect interest in Premier's issued share capital immediately following completion of the Merger may increase above this percentage interest depending on whether any profit allocations in respect of the year ending 31 December 2020 are made to certain EIG-managed entities in which he is interested.

(5) Mr Farris will continue to be remunerated for his role as a director of Chrysaor until completion of the Merger, pursuant to which he will receive additional shares in Chrysaor in an amount to be determined based on the value of Chrysaor as at 31 December 2020. Mr Farris' shareholding in Premier immediately completion of the Merger will accordingly increase from the number shown in the table above. Immediately following completion of the Merger, Mr Farris will also be indirectly interested in 0.02 per cent. of Premier's issued share capital through his interest in certain Harbour and EIG affiliated entities.

(6) The allocation of Consideration Shares among Chrysaor shareholders, including Ms Cook, Mr Kirk and Mr Farris, will depend on the value of those Consideration Shares in the period up to the completion of the Merger.

2.2 Interests of the Directors pursuant to the Employee Share Schemes

A description of each of the Employee Share Schemes can be found at section 6 of this Part XIII.

In addition to their interests as detailed above, as at the Latest Practicable Date, the Directors held the following options in respect of Existing Ordinary Shares, and awards of Ordinary Shares, under the terms of the Employee Share Schemes:

(A) **Share awards**

As at the Latest Practicable Date, the Executive Directors have been granted the following deferred share awards under the 2009 LTIP, which remain outstanding:

Executive Director	*Date of grant*	*Awards held at the Latest Practicable Date*	*Deferral period*	*Earliest vesting date*
Richard Rose	01.01.19	151,499	01.01.19 – 31.12.21	01.01.22

As at the Latest Practicable Date, the Executive Directors have been granted the following deferred bonus awards under the 2017 LTIP, which remain outstanding:

Executive Director	*Date of grant*	*Awards held at the Latest Practicable Date*	*Earliest vesting date*
Richard Rose	15.03.18	129,077	15.03.21
	14.03.19	74,113	14.03.22
	25.06.20	193,517	25.06.23

As at the Latest Practicable Date, the Executive Directors have been granted the following performance share awards under the 2017 LTIP, which remain outstanding:

Executive Director	*Date of grant*	*Awards held at the Latest Practicable Date*	*Performance period*	*Earliest vesting date*
Richard Rose	15.03.18	865,458	01.01.18 – 31.12.20	15.03.21
	14.03.19	787,010	01.01.19 – 31.12.21	14.03.2

As at the Latest Practicable Date, the Executive Directors have been granted the following restricted share awards under the 2017 LTIP, which remain outstanding:

Executive Director	*Date of grant*	*Awards held at the Latest Practicable Date*	*Performance period*	*Earliest vesting date*
Richard Rose	01.09.17	85,758	01.01.17 – 31.12.19	01.09.21
	15.03.18	98,909	01.01.18 – 31.12.20	15.03.21
	14.03.19	89,944	01.01.19 – 31.12.21	14.03.22

(B) **Share options**

As at the Latest Practicable Date, the following Executive Directors have been granted the following options to subscribe for Ordinary Shares under the Company's 2009 Savings Related Share Option Scheme, which remain outstanding:

Executive Director	*Date of grant*	*Exercisable dates*	*Acquisition price per share (£)*	*Options held at the Latest Practicable Date*
Richard Rose	05.05.20	01.06.23 – 30.11.23	0.2767	65,052

3. Directors' service contracts and letters of appointment

Details of Executive Directors' service contracts and Non-Executive Directors' letters of appointment providing for benefits upon termination of employment are set out at pages 94 to 95 of the Premier Group's 2019 Annual Report and Financial Statements.

Linda Cook and Phil Kirk will be appointed as Executive Directors of the Company from completion of the Merger and it is also expected that the Company will identify a Chief Financial Officer to be appointed from completion of the Merger (together, the "Proposed Executive Directors"). Each Proposed Executive Director will enter into a letter of appointment with the Company which will take effect on completion of the Merger. New service agreements will be put in place between each Proposed Executive Director and Premier following completion of the Merger. No discussions have taken place as to the terms of the new service agreements to date. The terms, including remuneration arrangements, will be considered and reviewed by the Premier Remuneration Committee after completion of the Merger. It is intended that the terms will be appropriate for an executive director of a group of the size, complexity and nature of the Combined Group, which will take into account appropriate and recognised benchmarking and existing remuneration arrangements. Until a new service agreement is agreed, Linda Cook and Phil Kirk will remain on their existing Chrysaor contractual terms, including salaries of £850,000 for Linda Cook and £600,000 for Phil Kirk, but with the contractual terms amended as necessary to comply with Premier's current directors' remuneration policy.

R. Blair Thomas will be appointed as Chairman of the Company, G. Steven Farris will be appointed as a Non-Executive Director, Simon Henry will be appointed as Senior Independent Non-Executive Director and Anne Stevens will be appointed as an Independent Non-Executive Director of the Company from completion of the Merger and it is also expected that the Company will identify three additional Independent Non-Executive Directors to be appointed from completion of the Merger (together, the "**Proposed Non-Executive Directors**"). Anne Marie Cannon will also remain on the Board as an Independent Non-Executive Director. Each of R. Blair Thomas, G. Steven Farris, Simon Henry and Anne Stevens have entered into a letter of appointment with the Company to that effect, provided that certain provisions will be agreed in due course including appointments to Board Committees and fees. Such letters of appointment are on terms consistent with the current Non-Executive Directors' letters of appointment set out at page 95 of the Premier Group's 2019 Annual Report and Financial Statements and in the case of R. Blair Thomas and G. Steven Farris, consistent with the terms of the Relationship Agreement. The terms of the Proposed Non-Executive Directors' appointments will, when such appointments take effect, also be in accordance with Premier's current directors' remuneration policy but it is intended that the Remuneration Committee of Premier will review those terms following completion of the Merger, considering the size, complexity and nature of the Combined Group.

4. Remuneration and benefits

This section 4 provides information on the remuneration arrangements for the Directors. As required by UK law, Premier's remuneration policy was approved by Shareholders at its 2017 AGM.

The table below reports total remuneration for the year ended 31 December 2019 for each Executive Director.

Director	*Salary (£'000s)*	*Taxable benefits (£'000s)[(1)]*	*Annual bonus (£'000s)*	*Long-term incentives (£'000s)*	*Pension benefits (£'000s)[(2)]*	*Other payments (£'000s)[(3)]*	*Total (£'000s)*
Richard Rose	353.8	22.4	275.9	295.3	63.4	1.8	1,012.6

Notes:

(1) Taxable benefits include car allowance, healthcare and other taxable benefits.

(2) Richard Rose's pension figure includes a combination of pension contributions to the defined contribution scheme and a salary supplement.

(3) Other payments comprise Share Incentive Plan ('**SIP**') awards only. SIP awards are valued as the number of Matching Awards granted, multiplied by the share price at the date of award. Other payments would normally include both SIP and Save As You Earn ('SAYE') awards. No discount was applied to SAYE awards granted in 2019 and therefore the embedded value of those options was nil.

The table below reports total remuneration for the year ended 31 December 2019 for each Non-Executive Director.

Director	*Base fee (£'000s)*	*Additional fees (£'000s)*	*Expenses (£'000s)*[(1)]	*Total (£'000s)*
Roy A Franklin (Chairman).	169.6	—	5.2	174.8
Dave Blackwood.	53.0	—	—	53.0
Anne Marie Cannon	53.0	—	—	53.0
Iain Macdonald	53.0	10.6	—	63.6
Mike Wheeler.	53.0	—	—	53.0

Notes:

(1) Amounts disclosed relate to travel and accommodation expenses paid to Non-Executive Directors in respect of qualifying services during the year.

The total amount set aside or accrued by the Premier Group for the year ended 31 December 2019 to provide pension, retirement or similar benefits to the Directors was £63.4 million (which includes the pension numbers in the table above and target funding payments, as described on page 99 of the Premier Group's 2019 Annual Report and Financial Statements).

5. Employees

5.1 Premier Group

As at 31 December 2017, 31 December 2018 and 31 December 2019, the Premier Group had 781, 783 and 766] employees, respectively. As at the Latest Practicable Date, the total number of employees of the Premier Group was 777.

The following table sets out the Premier Group's employees as at 31 December 2017, 31 December 2018 and 31 December 2019 by geographic location.

Location	*2017*	*2018*	*2019*
Falkland Islands	1	1	1
Indonesia	446	441	438
Pakistan[(1)].	13	12	—
United Kingdom	226	231	231
Vietnam.	90	92	90
Brazil	5	6	6
Mexico.	—	—	—
Total.	**781**	**783**	**766**

Notes:

(1) The sale of the Pakistan business unit was announced in April 2017 and completed on 28 March 2019.

The following table shows the average number of employees by main category of activity during the year to December 2017, December 2018 and December 2019.

Category of activity	*2017*	*2018*	*2019*
Technical and operations	531	508	500
Management and administration.	258	274	275
Total	**789**	**782**	**775**

The Company strategically has pursued an operational outsourcing model to both integrated service providers in the UK and contingent labour across global operations. By pursuing this strategy, Premier seeks to optimise scale, capability, flexibility and costs while being highly selective with project development in challenging market conditions.

The Directors believe that the Premier Group has satisfactory working relationships with its employees and has not experienced any significant labour disputes or work stoppages. The

Directors believe that the Premier Group has good working relationships with its employees in all territories.

5.2 Chrysaor Group

As at 31 December 2017, 31 December 2018 and 31 December 2019, the Chrysaor Group had 352, 409 and 1,070 employees, respectively and 36, 55 and 211 contractors respectively. As at the Latest Practicable Date, the total number of employees of the Chrysaor Group was 1,054 and the total number of contractors was 190.

The following table sets forth the Chrysaor Group's employees and contractors as at 31 December 2017, 31 December 2018 and 31 December 2019 by geographic location.

Location	*2017*	*2018*	*2019*
United Kingdom employees	352	399	1,051
United Kingdom contactors	36	54	208
Norway employees.	0	10	19
Norway contractors	0	1	4
Total.	388	464	1,282

The following table shows the average number of employees by main category of activity during the year to December 2017, December 2018 and December 2019.

Category of activity	*2017*	*2018*	*2019*
Technical and operations	283	328	871
Management and administration.	69	81	199
Total	352	409	1,070

Chrysaor has an established team of professionals in all core disciplines of operations, subsurface, project management, drilling and commercial. As necessary, Chrysaor augments core disciplines by leveraging the UKCS supply chain to deliver specific and specialist work in partnership with Chrysaor core team. Chrysaor has developed a strong company culture based upon its values, good working relationships and open engagement with the workforce. Chrysaor operates a defined contribution pension plan for its employees.

6. Employee Share Schemes

The Premier Group currently operates four Employee Share Schemes: (i) 2009 Long Term Incentive Plan (the "2009 LTIP"); (ii) the 2017 Long Term Incentive Plan (the "**2017 LTIP**"); (iii) a Share Incentive Plan ("**SIP**"); and (iv) a Save As You Earn ("**SAYE**") share option scheme.

The principal features of the Employee Share Schemes are summarised below.

6.1 2009 LTIP

From 2009 to 2017, annual conditional awards of equity pool points, performance shares and matching shares were made under the 2009 LTIP. Following shareholder approval of the 2017 LTIP at the annual general meeting of the Company held on 17 May 2017, annual awards of conditional shares are made under the 2017 LTIP, as described in section 6.2 below.

At the Latest Practicable Date, a total of 1,249,641 Ordinary Shares were the subject of outstanding awards under the 2009 LTIP. The 2009 LTIP expired on 28 May 2019 therefore no further awards will be granted under this plan.

(A) Vesting

On vesting, participants will also receive additional shares or a cash sum equivalent to the dividends that would have been paid on the vested shares in respect of dividend record dates occurring between grant and vesting.

(B) **Variation of capital**

On any variation of the share capital of the Company or other similar event which affects the market price of shares to a material extent, the Remuneration Committee may make such adjustments as it considers appropriate to the number of shares comprised in an award and/or the base or terminal valuation of the equity pool.

(C) **Alterations**

Except as noted below, the Remuneration Committee may at any time alter the 2009 LTIP or the terms of any award granted under it. Save for minor alterations to benefit the administration of the 2009 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.

No alteration to the material disadvantage of participants shall be made unless the alteration is approved by the majority of participants who have indicated whether or not they approve the change.

6.2 2017 LTIP

(A) **General**

Approved by Shareholders in 2017 and amended in 2020, 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) deferred bonus awards; (ii) performance share awards; (iii) value share awards (also known as PVSP awards); and (iv) conditional share awards. Prior to amendments made in 2020, the 2017 LTIP also allowed the Remuneration Committee to grant restricted share awards.

As at the Latest Practicable Date, a total of 50,949,090 Ordinary Shares (excluding cash settled awards) were the subject of the outstanding awards under the 2017 LTIP.

(B) **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: (i) Executive Directors cannot be granted value share awards; (ii) Executive Directors will only be eligible to be granted conditional share awards on recruitment; and (iii) no individual may be granted a performance share award and a value share award during the same financial year.

(C) **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.

(D) **Performance conditions**

Performance share awards and the multiplier element of any value share awards normally vest based on Premier's TSR performance relative to a comparator group of international oil and gas sector peers. Up to 25 per cent. vests for median performance, with full vesting for upper decile performance and straight-line vesting in between.

Restricted share awards vest subject to a financial underpin based on the Company's capital structure and balance sheet strength, and the Remuneration Committee's assessment of overall Company performance.

(E) **Overall limits**

- Performance share awards – up to 200 per cent. of salary.
- Value share awards – base awards up to 50 per cent. of salary and multiplier awards up to 50 percent. of salary.

(F) **Vesting**

Performance share awards will normally vest on the third anniversary of grant, subject to the satisfaction of the performance targets.

Restricted share awards will normally vest in three equal tranches on each of the third, fourth and fifth anniversaries of grant, subject to the satisfaction of the performance underpin.

Performance share awards and restricted share awards are both be 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) until the fifth anniversary of grant. 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, he will forfeit without payment any ordinary shares received pursuant to the 2017 LTIP but which remain subject to the post-vesting holding period.

Value share awards will normally vest three years after grant subject, in the case of the multiplier awards, to the satisfaction of the performance target.

Deferred bonus awards will normally vest three years after grant.

On vesting, participants will also receive additional shares or a cash sum equivalent to the dividends that would have been paid on the vested shares in respect of dividend record dates occurring between grant and vesting.

(G) **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, restricted share awards and value 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, restricted share awards and/or value share awards on cessation and/or waive any performance targets (other than in respect of performance share awards or restricted share awards held by Executive Directors) and/or time pro-rating.

Deferred bonus awards held by good leavers vest in full on cessation.

Conditional share awards held by good leavers vest on cessation subject to any performance targets and a time *pro rata* reduction.

(H) **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.

(I) **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.

(J) **Malus and clawback**

Malus and clawback can be operated until the later of: (i) one year after vesting; and (ii) the completion of the next audit after vesting in the event of (a) a material misstatement of the Company's financial results, (b) gross misconduct, (c) material error in the calculation of performance conditions or (d) in such other exceptional circumstances as the Remuneration Committee sees fit.

(K) **Alterations**

Except as noted below, 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.

No alteration to the material disadvantage of participants shall be made unless the alteration is approved by the majority of participants who have indicated whether or not they approve the change.

6.3 SIP

(A) **General**

The SIP is an HMRC approved scheme. An equivalent, unapproved scheme operates for the Premier Group's expatriate employees. Under the SIP, employees may buy 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.

(B) **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.

(C) **Matching shares**

For every one partnership share an employee buys, Premier 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.

(D) **Performance conditions**

No performance conditions apply.

(E) **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.

6.4 SAYE

(A) **General**

The SAYE is an HMRC approved scheme open to all employees of nominated Premier Group companies with the relevant qualifying period of service.

As at the Latest Practicable Date, a total of 234,156 Ordinary Shares were the subject of the outstanding options under the SAYE scheme.

On 16 May 2019, Shareholders approved a new SAYE scheme to replace the existing SAYE. As at the Latest Practicable Date, a total of 10,187,765 Ordinary Shares were the subject of the outstanding options under the new SAYE scheme.

(B) **Eligibility**

Under the SAYE, all Premier employees (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.

(C) **Performance conditions**

Consistent with the relevant legislation, no performance conditions apply.

(D) **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.

(E) **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.

(F) **Alterations**

Except as noted below, 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.

7. Pension benefits

All Premier UK employees are invited to participate in a Premier Group personal pension plan which is a defined contribution pension. A 15 per cent. company contribution is made, conditional upon a 5 per cent. employee contribution. The only pensionable element of pay is salary. Contributions are capped by an internal earnings cap which is reviewed annually.

Employees may elect to take a cash allowance in lieu in the following circumstances: (i) they can provide 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.

Richard Rose receive the same benefit as other UK staff (i.e. a defined contribution pension and/or an equivalent cash allowance), but equal to 20 per cent. of salary.

8. Corporate governance and Board Committees

8.1 Board practices

The Board is collectively responsible for the governance of Premier on behalf of Shareholders and is accountable to Shareholders for the long-term success of the Premier Group.

The Board governs the Premier Group in accordance with authority set out in the Articles. The Board is responsible for maintaining sound risk management and internal control systems. In meeting this responsibility, the Board monitors Premier's risk management and internal control systems throughout the year and, on an annual basis, carries out a review of their effectiveness. The Board meets at least six times each year and, in addition, update conference calls may take place in the months when no formal meeting is scheduled.

The Board has established the Audit and Risk Committee, the Health, Safety, Environment and Security Committee, the Remuneration Committee and the Nomination Committee (together, the "**Board Committees**"). Each Board Committee has formal terms of reference approved by the Board. The Company Secretary provides advice and support to the Board and all Board Committees. Board Committees are authorised to engage the services of external advisers as they deem necessary.

Upon completion of the Merger, the Company expects to comply fully with the provisions of the UK Corporate Governance Code, save that R. Blair Thomas will be appointed as Non-Executive Chairman of the Company. Blair will not be regarded as independent for purposes of the UK Corporate Governance Code by virtue of being appointed pursuant to Harbour's right to appoint up to two directors to the Board of Directors under the Relationship Agreement, one of whom will be Chairman. Blair has more than 30 years' experience in the investment management business, with a focus on energy and energy-related infrastructure and he has been a member of the Board of Directors of Chrysaor Holdings Limited since 2017. The Board believe that Blair's industry experience and knowledge of the Chrysaor Group justifies his appointment as Chairman and will benefit the Premier Group, as enlarged following completion of the Merger, and shareholders as a whole.

It is also expected that prior to completion of the Merger, the Company will identify a Chief Financial Officer and three additional Independent Non-Executive Directors, each to be appointed from completion of the Merger, such that on completion the Board will comprise three Executive Directors (Linda Cook, Phil Kirk and the Chief Financial Officer), the Chairman (R. Blair Thomas), one non-independent Non-Executive Director (G. Steven Farris) and up to six Independent Non-Executive Directors (Simon Henry (who will serve as Senior Independent Non-Executive Director), Anne Stevens, Anne Marie Cannon and three additional Independent Non-Executive Directors). Board Committee appointments will also be finalised prior to completion of the Merger but it is expected that the composition of the Board Committees will be fully compliant with the provisions of the UK Corporate Governance Code. The Company will make an announcement by way of a Regulatory Information Service at the relevant time confirming the appointments of such additional Directors, as well as the composition of the Board Committees.

8.2 Board Committees

(A) Nomination Committee

The Nomination Committee currently consists of all Non-Executive Directors. At the Latest Practicable Date, its members were Roy Franklin (Chair), Dave Blackwood, Anne Marie Cannon, Elisabeth Proust, Iain Macdonald, Richard Rose and Mike Wheeler. Mike Fleming, Group HR Director, attends meetings as appropriate. Rachel Rickard acts as secretary to the Nomination Committee.

The Nomination Committee's main responsibilities are:

- to plan Board member succession and oversee plans for senior management succession, taking into account the strategy of Premier, skills, knowledge, diversity and experience required to deliver the strategy;
- to regularly review the structure, size and composition of the Board and the Board Committees; and
- to lead the process for Board appointments, identifying and nominating for the approval of the Board, candidates to fill Board vacancies.

The Nomination Committee is required to meet at least two times a year and may arrange additional ad hoc meetings. The Nomination Committee met four times in 2019.

(B) Remuneration Committee

The Remuneration Committee consists solely of Non-Executive directors. At the Latest Practicable Date, its members were Mike Wheeler (Chair), Anne Marie Cannon and Roy Franklin. All members of the Remuneration Committee are deemed to be independent. Members of the Remuneration Committee meet without any executives present for part of each meeting. Rachel Rickard acts as secretary to the Remuneration Committee. Members of the Board and any other employees attending Remuneration Committee meetings leave the meeting where their own remuneration is being discussed.

Following Admission, the Chair of the Remuneration Committee will be Anne Stevens.

The Remuneration Committee's main responsibilities are:

- determining the remuneration policy for Executive Directors and senior management;
- determining the individual remuneration packages for each Executive Director and any changes thereto;
- considering the design of, and determining targets for, the annual bonus plan;
- reviewing and recommending to the Board the establishment of any new employee share plans and any material amendments to Premier's existing share plans;

- determining the quantum and performance conditions for long-term incentive awards;
- reviewing pension arrangements, service agreements and termination payments for Executive Directors;
- approving the Directors' remuneration report, ensuring compliance with related governance provisions and legislation;
- reviewing bonus outcomes for the Premier Group, including Executive Directors; and
- considering the remuneration policies and practices across the Premier Group.

The Remuneration Committee is required to meet at least three times per year and may arrange additional ad hoc meetings. The Remuneration Committee met five times in 2019.

The Remuneration Committee received advice on executive remuneration from Mercer Kepler ('**Kepler**') until August 2019. From August 2019 PricewaterhouseCoopers LLP ('**PwC**') were appointed by the Remuneration Committee as independent adviser following a formal competitive selection process. During 2019, PwC provided support and advice on remuneration for senior executives including the Policy review for Executive Directors, market practice and corporate governance developments, shareholder consultation and other stakeholder obligations. They also assisted with the drafting of the Directors' remuneration report and attended Committee meetings. Other than in relation to advice on remuneration, PwC provides support to management in relation to tax reporting, tax compliance and ad hoc tax and accounting advice. PwC and Kepler are founding members of the Remuneration Consultants Group and voluntarily operate under its Code of Conduct in dealings with the Committee. The Committee evaluates the support provided by its advisers annually and is satisfied that the advice it received from both PwC and Kepler was objective and independent, and that there are no connections with Premier that may impair their independence. PwC has since resigned from its role as independent remuneration adviser given the conflict generated by its Reporting Accountants responsibilities to Premier. As such, the Company has appointed Aon Hewitt as its interim remuneration advisor to the Remuneration Committee until completion of the Merger and the Debt Restructuring occurs.

(C) **Audit and Risk Committee**

The Audit and Risk Committee consists solely of Non-Executive Directors. At the Latest Practicable Date, its members were Iain Macdonald (Chair), Dave Blackwood, Anne Marie Cannon and Mike Wheeler. All members of the Audit Committee are deemed to be independent. The Board is satisfied that the membership of the Audit Committee meets the requirements for recent and relevant financial experience.

The meetings of the Audit Committee are normally attended by the Finance Director, the Group Financial Controller, the Group Audit and Risk Manager and representatives of the auditors. Other Executive Directors or senior managers are required to attend when significant risk management or control issues relating to their area of responsibility are considered by the Audit Committee. During the year, the Audit Committee meets privately with the Group Audit and Risk Manager, and with Premier's auditors. Rachel Rickard acts as secretary to the Audit Committee.

The Audit Committee's main responsibilities are:

- monitoring and reviewing the effectiveness of Premier's risk management and internal control systems, including in particular the identification of emerging risks and the effectiveness of actions taken to mitigate them, together with the results of the programme of reviews of these systems and management's response to the review findings;
- monitoring and reviewing the effectiveness and objectivity of the Premier's Group Audit and Risk function, the appropriateness of its work plan, the results of reviews undertaken, and the adequacy of management's response to matters raised;
- monitoring the integrity of the Company's financial statements and any formal announcements relating to the Company's financial performance and the significant financial reporting judgements they contain;
- reviewing the external auditor's independence and objectivity and the effectiveness of the audit process;

- developing and implementing policy on the engagement of the external auditor to supply non-audit services; and
- monitoring the enforcement of the Company's Code of Conduct and the adequacy and security of its whistleblowing procedure.

The Audit Committee is required to report its findings to the Board, identifying any matters on which it considers that action or improvement is needed, and make recommendations on the steps to be taken.

The Audit Committee may engage the services of external advisers as it deems necessary in the furtherance of its duties, at Premier's expense. No external advisers materially assisted the Audit Committee during the year. The Audit Committee's terms of reference include all matters indicated by the DTR 7.1 and the UK Corporate Governance Code.

The Audit Committee is required to meet at least three times per year and has an agenda linked to events in Premier's financial calendar. The Audit Committee met four times in 2019.

(D) **Health, Safety, Environment and Security Committee**

The Health, Safety, Environment and Security Committee consists solely of Non-Executive Directors. At the Latest Practicable Date, its members were Dave Blackwood (Chair) and Elisabeth Proust. All members of the Health, Safety, Environment and Security Committee are deemed to be independent.

The Health, Safety, Environment and Security Committee's main responsibilities are:

- monitoring and reviewing the Premier Group's health, safety, environment and security strategy;
- evaluating the effectiveness of the Premier Group's policies and systems for delivering the Premier Group's health, safety, environment and security strategy;
- monitoring the quality and integrity of the Premier Group's internal and external reporting of health, safety, environment and security performance and issues; and
- assessing the policies and systems within the Premier Group for ensuring compliance with health, safety, environment and security regulatory requirements.

The Health, Safety, Environment and Security Committee is required to report its findings to the Board, identifying any matters on which it considers that action or improvement is needed, and make recommendations on the steps to be taken.

The Health, Safety, Environment and Security Committee is required to meet at least three times per year. The Health, Safety, Environment and Security Committee was formed in March 2020.

PART XIII

ADDITIONAL INFORMATION

1. Responsibility Statement

The Company, the Directors and the Proposed Directors, whose names appear in sections 1.2 and 1.3 of Part XII, accept responsibility for the information contained in this document. To the best of the knowledge of the Company, the Directors and the Proposed Directors, the information contained in this document is in accordance with the facts and this document makes no omission likely to affect its import.

2. The Company

Premier was incorporated and registered with the name of Dalglen (No. 836) Limited in Scotland on 31 July 2002 with registration number SC234781. The name of the Company was changed from Dalglen (No. 836) Limited to Premier Oil Group Limited pursuant to a written resolution passed on 13 September 2002. Premier was reregistered as a public limited company on 10 March 2003, and its name was changed from Premier Oil Group Limited to Premier Oil plc pursuant to a special resolution passed on 3 March 2003 and which became effective on 15 July 2003.

The principal legislation under which Premier operates is the Companies Act 2006 and regulations made thereunder.

Premier is domiciled in the United Kingdom and its registered office is 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh EH1 2EN. Premier's head office is 23 Lower Belgrave Street, London SW1W 0NR. The telephone number of its head office is +44 (0)20 7730 1111. Premier's website can be found at www.Premier-oil.com. Except otherwise disclosed in this Prospectus, the information on Premier's website does not form part of this Prospectus. The legal entity identifier of the Company is 213800YPC42DYBKVPF97.

3. Share capital of the Company

3.1 Issued share capital of the Company

The Company has only one class of share capital which is the Ordinary Shares.

The following table shows the issued share capital of the Company at the Latest Practicable Date, and the issued fully paid ordinary share capital of the Company following completion of the Merger and the Debt Restructuring:

	Existing Ordinary Shares at the Latest Practicable Date		*Ordinary Shares following completion of the Merger and the Debt Restructuring (assuming no take-up of the Partial Cash Alternative)*	
	Number	*£*	*Number*	*£*
Issued and fully paid	925,532,676	115,691,584.50	18,510,653,520	1,851,065.35

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.

Following the Subdivision, the Company will have two classes of share capital: the Ordinary Shares and the Non-Voting Deferred Shares. The Non-Voting Deferred Shares will be effectively worthless. They will have no voting or dividend rights and, on a return of capital or on a winding up of the Company, will have the right to receive the amount paid up thereon only after holders of all Ordinary Shares have received, in aggregate, any amounts paid up on each Ordinary Share plus £10 million on each Ordinary Share. The Non-Voting Deferred Shares will not give the holder the right to receive notice of, nor attend, speak or vote at, any general meeting of the Company.

3.2 History of the share capital

As at 1 January 2017, being the first day covered by the financial statements incorporated by reference into this document, the issued and fully paid share capital of the Company comprised 525,045,801 Ordinary Shares.

The following paragraphs provide information on the movements in the issued share capital of the Company between 1 January 2017 and the Latest Practicable Date:

(A) Between 1 January 2017 and 31 December 2017, 14,222,135 Ordinary Shares were issued. As at 31 December 2017, Premier's issued and fully paid share capital comprised 525,045,801 Ordinary Shares.

(B) Between 1 January 2018 and 31 December 2018, 292,024,124 Ordinary Shares were issued. As at 31 December 2017, Premier's issued and fully paid share capital comprised 817,069,925 Ordinary Shares.

(C) Between 1 January 2019 and 31 December 2019, 14,466,154 Ordinary Shares were issued. As at 31 December 2019, Premier's issued and fully paid share capital comprised 831,536,079 Ordinary Shares.

(D) Between 1 January 2020 and the Latest Practicable Date, 93,996,597 Ordinary Shares were issued.

Other than the issues of Ordinary Shares referred to above in this section 3.2 of this Part XIII, there have been no changes to the issued share capital of the Company between 1 January 2017 and the Latest Practicable Date.

4. Information about the New Ordinary Shares

4.1 Description and type of securities being offered

The New Ordinary Shares will be issued credited and fully paid with a nominal value of 0.0001 pence. When admitted to trading, the New Ordinary Shares will be registered with ISIN GB00BLGYGY88. The New Ordinary Shares will trade under ticker symbol "HBR".

Immediately following Admission, assuming that the maximum number of Creditor Shares are issued and allotted, it is expected that Premier will have 18,510,653,520 fully paid Ordinary Shares in issue (none of which will be held in Treasury).

If Admission occurs, it will result in the issue and allotment of 14,253,203,210 Consideration Shares and up to 3,331,917,634 Creditor Shares. Existing Shareholders will suffer an immediate dilution as a result of Admission, following which they will hold:

– assuming that the maximum number of Creditor Shares are issued and allotted and no take-up of New Equity Warrants, approximately 5 per cent. of the enlarged share capital of the Company; and

– assuming that the minimum number of Creditor Shares are issued and allotted and maximum take-up of New Equity Warrants, approximately 5.45 per cent. of the enlarged share capital of the Company.

The net asset value per share as at 30 June 2020 was US$0.58.

4.2 Legislation under which the New Ordinary Shares will be created

The New Ordinary Shares will be created under the Companies Act 2006.

4.3 Confirmations

As at the Latest Practicable Date and save as otherwise disclosed in this Part XIII:

(A) no share or loan capital of the Company has, since the incorporation of the Company, been issued or agreed to be issued, or is now proposed to be issued, fully or partly paid, either for cash or for consideration other than cash, to any person;

(B) no commission, discounts, brokerages or other special terms have been granted by the Company in connection with the issue or sale of any share or loan capital;

(C) other than in respect of the Employee Share Schemes, no share or loan capital of the Company is under option or agreed, conditionally or unconditionally, to be put under option; and

(D) the Company held no treasury shares (as defined in the Companies Act 2006).

4.4 Listing

Applications will be made to the FCA for the Existing Ordinary Shares to be readmitted and the New Ordinary Shares to be admitted to the premium listing segment of the Official List and to the London Stock Exchange for the Existing Ordinary Shares to be readmitted and the New Ordinary Shares to be admitted to trading on the London Stock Exchange's main market for listed securities.

4.5 Form and currency

The New Ordinary Shares will be in registered form and will be capable of being held in certificated and uncertificated form.

Title to certificated Ordinary Shares (if any) will be evidenced by entry into the register of members of the Company and title to uncertificated Ordinary Shares will be evidenced by entry in the operator register maintained by the Registrar (which will form part of the register of members of the Company).

It is expected that the New Ordinary Shares, when allotted and issued, will be capable of being held and transferred by means of CREST.

The Existing Ordinary Shares are priced in pounds sterling, and the New Ordinary Shares will be quoted and traded in pounds sterling.

The Existing Ordinary Shares are, and the New Ordinary Shares will be, freely transferable and there are no restrictions on transfer in the United Kingdom.

4.6 Rights attached to the New Ordinary Shares

The New Ordinary Shares will, following Admission, rank *pari passu* in all respects with the Existing Ordinary Shares, including in relation to dividends or other distributions. Following Admission, the Company will have one class of shares, the rights of which will be as set out in the Articles, a summary of which is set out in section 5 of this Part XIII.

Subject to the Companies Act 2006, any equity securities issued by Premier for cash must first be offered to Shareholders in proportion to their holdings of Ordinary Shares. The Companies Act 2006 and the Listing Rules allow for the disapplication of pre-emption rights, which may be waived by a special resolution of the Shareholders, either generally or specifically for a maximum period not exceeding five years.

At the General Meeting, Shareholders will be asked to consider and vote on the Resolutions proposed, further details of which are set out in the Circular. Resolutions 6 and 7 which are special resolutions to disapply pre-emption rights and will pass if more than 75 per cent. of the votes cast (either in person or by proxy) are in favour. The purpose of Resolution 6 is to disapply pre-emption rights in connection with the issue of equity securities for cash in connection with the Debt Restructuring. The purpose of Resolution 7 is to disapply pre-emption rights in connection with any issue of equity securities for cash under the authority proposed to be granted to Directors under Resolution 5 until 12 March 2022.

If the Merger and Debt Restructuring Resolutions are passed by the Shareholders and the Restructuring Plans are sanctioned by the relevant Courts, as a matter of company law pre-emption rights would not apply in respect of the allotment of equity securities in connection with the Merger and the Debt Restructuring, but this would not necessarily be the case under the Listing Rules. Resolution 6 is therefore being proposed to enable the Company to comply with its continuing obligation under the Listing Rules to seek the disapplication of pre-emption rights in connection with an issue of equity securities for cash to the extent that such disapplication is required.

If the Merger proceeds, the Directors will exercise powers to allot and issue New Ordinary Shares to Chrysaor's shareholders in exchange for Chrysaor shares, a form of non-cash consideration. The allotment and issue of New Ordinary Shares in connection with the Merger would therefore would not constitute an issue of equity securities for cash to which pre-emption rights apply. However, for technical reasons the proposed allotment and issue of New Ordinary Shares and New Equity Warrants in connection with the Debt Restructuring may, depending on how the transaction is structured, constitute an issue of equity securities for cash under the Listing Rules as the statutory definition of cash consideration includes a release of a liability of the company for a liquidated sum. The Directors have not made a final decision on the implementation steps for the Debt Restructuring and are therefore seeking the authority under Resolution 6 to have the flexibility to pursue a structure which for Listing Rules purposes would be considered an issue of equity securities for cash. The Directors may ultimately decide to implement the Debt Restructuring by other means which do not require use of the authority under Resolution 6, for example, by issuing New Ordinary Shares and New Equity Warrants in consideration for the transfer to the Company of certain shares in a Jersey-incorporated subsidiary of the Company, which will result in the Company owning the entire issued share capital of the Jersey subsidiary the assets of which would comprise debt claims transferred as part of the Debt Restructuring and any cash payable in connection with the Top-up Election. Accordingly, instead of receiving cash (including the release of liabilities) as consideration for the New Ordinary Shares and New Equity Warrants the Company would receive shares in the Jersey subsidiary, a form of non-cash consideration, and pre-emption rights would therefore not apply with respect to equity securities issued in connection with the Debt Restructuring.

4.7 Existing Shareholder authorities

At the 2020 AGM, the following resolutions were passed by Shareholders:

(A) an ordinary resolution authorising the Directors generally and unconditionally to exercise all the powers of the Company pursuant to, and in accordance with, section 551 of the Companies Act 2006, to allot shares in the Company and to grant rights to subscribe for, or to convert any security into, shares in the Company:

(i) up to a nominal amount of £34,994,356 (such amount to be reduced by the nominal amount allotted or granted under part (ii) below in excess of such sum); and

(ii) comprising equity securities (as defined in section 560(1) of the Companies Act 2006) up to a nominal amount of £69,988,713 (such amount to be reduced by any allotments or grants made under part (i) above) in connection with an offer by way of a rights issue:

(a) to holders of Ordinary Shares in proportion (as nearly as may be practicable) to their existing holdings; and

(b) to holders of other equity securities as required by the rights of those securities or, if the Directors otherwise consider it necessary, as permitted by the rights of those securities,

and so that the Directors may impose any limits or restrictions and make any arrangements which they consider necessary or appropriate to deal with treasury shares, fractional entitlements, record dates, legal, regulatory or practical problems in, or under the laws of, any territory or any other matter, provided that these authorities shall expire at the conclusion of the annual general meeting of the Company to be held in 2021 or at the close of business on 24 September 2021, whichever is the sooner, save that the Company may before such expiry make offers and enter into agreements which would, or might, require shares to be allotted or rights to subscribe for or convert securities into shares to be granted after such expiry and the Directors may allot shares or grant rights to subscribe for or convert securities into shares in pursuance of such an offer or agreement as if the authorities conferred hereby had not expired;

(B) a special resolution giving the Directors the powers pursuant to section 571 of the Companies Act 2006, to allot equity securities (within the meaning of section 560(1) of the Companies Act 2006) for cash under the authority conferred by resolution (A) above and/or sell Ordinary Shares held by the Company as treasury shares for cash as if section 561 of the Companies Act 2006 did not apply to any such allotment or sale provided that this power shall be limited:

(i) to the allotment of equity securities and sale of treasury shares for cash in connection with an offer of, or invitation to apply for, equity securities (but in the case of an authority granted under part (ii) of resolution (A) above, by way of a rights issue only):

(a) to Shareholders (excluding any Shareholder holding shares as treasury shares) in proportion (as nearly as may be practicable) to their existing holdings of Ordinary Shares; and

(b) to holders of other equity securities, as required by the rights of those securities, or as the Directors otherwise consider necessary,

and so that the Directors may impose any limits or restrictions and make any such arrangements which they consider necessary or appropriate to deal with treasury shares, fractional entitlements, record dates, legal, regulatory or practical problems in, or under the laws of, any territory or any other matter; and

(ii) in the case of the authority granted under part (i) of resolution (A) above and/or in the case of any sale of treasury shares for cash, to the allotment (otherwise than pursuant to subparagraph (i) above) of equity securities or sale of treasury shares up to a nominal amount of £5,249,153,

such power shall apply until the conclusion of the annual general meeting of the Company to be held in 2021 or at the close of business on 24 September 2021, whichever is the sooner, save that, in each case, the Company may during this period make offers and enter into agreements which would, or might, require equity securities to be allotted (and/or treasury shares to be sold) after the power ends and the Directors may allot equity securities (and/or sell treasury shares) in pursuance of such an offer or agreement as if the power conferred hereby had not expired.

(C) a special resolution granting the Directors the power, in addition to the authority described in resolution (B) above, to allot equity securities (within the meaning of section 560(1) of the Companies Act 2006) for cash under the authority conferred by resolution (A) above and/or sell Ordinary Shares held by the Company as treasury shares for cash as if section 561 of the Companies Act 2006 did not apply to any such allotment or sale, such power to be:

(i) limited to the allotment of equity securities or sale of treasury shares up to a nominal amount of £5,249,153; and

(ii) used only for the purposes of financing (or refinancing, if the power is to be used within six months after the original transaction) a transaction which the Directors determine to be an acquisition or other capital investment of a kind contemplated by the Statement of Principles on Disapplying Pre-Emption Rights most recently published by the Pre-Emption Group prior to the date of the notice of the 2020 AGM,

such power shall apply until the conclusion of the annual general meeting of the Company to be held in 2021 or at the close of business on 24 September 2021, whichever is the sooner, save that, in each case, the Company may during this period make offers, and enter into agreements, which would, or might, require equity securities to be allotted (and/or treasury shares to be sold) after the power ends and the Directors may allot equity securities (and/or sell treasury shares) in pursuance of such an offer or agreement as if the power conferred hereby had not expired.

At the General Meeting, Shareholders will be asked to consider and vote on the Resolutions proposed, which will, if passed, authorise the Directors to allot 14,253,203,210 Consideration Shares and up to 3,331,917,634 Creditor Shares in connection with the Merger and the Debt Restructurings. In addition, the Resolution 5 will, if passed, also authorise the Directors to allot Ordinary Shares or equity securities with an aggregate nominal amount of £12,340.44 in substitution for the similar authorities granted by Shareholders at the 2020 AGM. Accordingly, the New Ordinary Shares to be issued in connection with the Merger and the Debt Restructuring will be created, allotted and issued pursuant to the authority conferred on the Company under the Resolutions proposed at the General Meeting.

5. The Articles of Association

The following is a summary of the Articles, which are available on the Company's website and at Premier's registered office. The Articles, which were adopted in May 2010, contain provisions (among others) to the following effect:

(A) Objects

The Company's objects are unrestricted.

(B) **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.

(C) **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.

(D) **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 Premier'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 12 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.

(E) **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.

(F) **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 may publish a notice in a national and local newspaper stating its intention to sell the shares. If, during the three months following the notice, the Shareholder still fails to respond, the Company may sell the shares. If the untraced Shareholder does not claim the proceeds of the sale of his/her shares within six years of such sale (i.e. it has been at least 18 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.

(G) **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:

(i) 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;

(ii) is in respect of more than one class of share; and

(iii) 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.

(H) **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.

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 Chairman 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. 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.

(I) **Change of name**

The Directors may change the name of the Company by passing a board resolution.

(J) **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 his 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 nonexecutive Director for more than nine years at the date of the meeting. Any retiring Director may offer himself up for reappointment and can be reappointed by an ordinary resolution of the Shareholders.

Vacation of office by Directors

In addition to the legislative provisions on vacation of a Directors' office, any Director automatically vacates his office as Director if; he gives the Company written notice of his resignation; he offers to resign and this offer is accepted; all of the other Directors (where there are at least three) pass a resolution requiring him to vacate; he is suffering from a physical or mental health illness and the Directors pass a resolution removing him from office; he has missed Directors' meetings for a continuous six month period without permission and the Directors pass a resolution removing him; or a bankruptcy order is made against him.

Alternate Directors

Any Director can appoint another person to act as a Director in his 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 £600,000 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 his 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. Each Director may be paid his 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 him in connection with the Company's business or in the performance of his duties as a Director. The Company can also fund a Director or a Director of its holding 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 his 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 his 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 his 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:

(i) have any kind of interest in a contract with or involving the Company;

(ii) hold any office (except that of auditor) with the Company;

(iii) do paid professional work for the Company;

(iv) become a director of any holding company or subsidiary of the Company; and/or

(v) 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 his appointment to a position within the Company or a company in which Premier 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 he has an interest. A Director can only vote where his interest cannot reasonably be regarded as material or where the only material interest he has in it is included in the following list:

(i) a resolution about giving him any security or any indemnity for any money which he, or any other person, has lent at the request, or for the benefit, of the Company or any of its subsidiary undertakings;

(ii) 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;

(iii) a resolution giving him any other indemnity where all Directors are also being offered indemnities on substantially similar terms;

(iv) a resolution about the Company funding any expenditure incurred defending proceedings where all Directors are also being offered indemnities on substantially similar terms;

(v) 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 he is a holder of shares, debentures or other securities, or if he takes part in the underwriting or sub-underwriting of the offer;

(vi) a resolution about a contract in which he has an interest because of his interest in securities of the Company;

(vii) 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 he does not hold an interest in shares representing one percent or more of any class of equity share capital of that company or of the voting rights in that company;

(viii) a resolution relating to a pension fund, superannuation scheme, retirement, death or disability fund where these benefits are provided to employees generally;

(ix) any arrangement for the benefit of employees of the Company or any of its subsidiary undertakings which gives him benefits which are also generally given to the employees to whom the arrangement relates; or

(x) 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 the Premier Group so as to ensure that no money is borrowed if the total amount of the borrowings of the Premier Group then exceeds, or would as a result of such borrowing exceed, a multiple of four times the Premier Group'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 2016 AGM, the Shareholders passed an ordinary resolution to increase the borrowing limit such that the total amount of the Premier Group's borrowings may not exceed an amount equal to the greater of: (i) US$4 billion; or (ii) five times the Company's adjusted capital and reserves.

(K) 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.

(L) **Subdivision**

Pursuant to the proposed Subdivision, the Company intends to amend the Articles of Association by passing the Subdivision Resolution in order to reflect the creation of additional class of share in the Company, namely the Non-Voting Deferred Shares.

6. Mandatory bids and compulsory acquisition rules relating to the Ordinary Shares

The Company is subject to the Takeover Code. Other than as provided by the Companies Act 2006 and the Takeover Code, there are no rules or provisions relating to mandatory bids and/or squeeze out and sell out rules in relation to Premier's Ordinary Shares. There is not in existence any current mandatory takeover bid in relation to the Company. There have been no takeover bids by third parties during the period from incorporation to 31 December 2019 or in the current financial year to date.

7. Organisational structure

7.1 Significant subsidiaries

Premier is the parent company of the Premier Group.

The following table contains a list of the significant subsidiaries and subsidiary undertakings of the Company, being those which are considered by the Company to be likely to have a significant effect on the assessment of the Company's assets and liabilities, financial position or profits and losses.

Unless otherwise stated, the registered office of all companies registered in Scotland is 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh EH1 2EN; the registered address of all companies registered in England and Wales is 23 Lower Belgrave Street, London SW1W 0NR; and the registered address of all companies registered in The Netherlands is Herikerbergweg 88, 1101 CM, Amsterdam, the Netherlands.

Name	*Country of incorporation*	*Principal activity*	*Percentage ownership interest (%)*
Premier Oil Group Limited	Scotland	Holding company	100%
Premier Oil Group Holdings Limited	England and Wales	Holding company	100%
Premier Oil Finance (Jersey) Limited	Jersey *(Registered office: IFC5, St Helier, Jersey, JE1 1ST)*	Finance company	100%
Premier Oil Holdings Limited	England and Wales	Holding company	100%
Premier Oil Overseas BV	The Netherlands	Holding company	100%
Premier Oil UK Limited	Scotland	Operating company	100%
Premier Oil E&P Holdings Limited	England and Wales	Holding company	100%
Premier Oil E&P UK Limited	England and Wales	Operating company	100%
Premier Oil E&P UK EU Limited	England and Wales	Operating company	100%
Premier Oil E&P UK Energy Trading Limited	England and Wales	Operating company	100%
Premier Oil Natuna Sea BV	The Netherlands	Operating company	100%
Premier Oil Vietnam Offshore BV	The Netherlands	Operating company	100%
Premier Oil (Vietnam) Limited	British Virgin Islands *(Registered office: Commerce House, Wickhams Cay 1, Road Town, Tortola, VG1110)*	Operating company	100%
Premier Oil Exploration and Production Limited	England and Wales	Operating company	100%
Premier Oil do Brasil Petroleo e Gas Ltda	Brazil *(Registered office: Rua Lauro Muller, 116 – Sala 2006, Botafogo, Rio de Janeiro, 22.290-906)*	Operating company	100%
Premier Oil Exploration and Production Mexico, S.A de C.V	Mexico *(Registered office: Calles Montes Urales, 424, Oficina 03-110 y 03-117 Lomas de Chapultepec V Seccion, Miguel Hidalgo, Ciudad de Mexico, 11000)*	Operating company	100%
Premier Oil Andaman Limited	England and Wales	Operating company	100%
Premier Oil South Andaman Limited	England and Wales	Operating company	100%
Premier Oil Andaman I Limited	England and Wales	Operating company	100%

7.2 Major shareholder notifications

As at the Latest Practicable Date, Premier had received notification from the following major shareholders, in accordance with Chapter 5 of the Disclosure Guidance and Transparency Rules, of their significant holdings of voting rights (3 per cent. or more) of Premier's issued share capital:

Shareholder	*Date of notification*	*Notified number of voting rights*	*Notified percentage of voting rights (%)*	*Nature of holding*
Aberforth Partners	11 November 2020	69,389,053	7.50	Indirect
Schroder Investment Management	17 September 2020	46,563,242	5.03	Indirect
Artemis Investment Management LLP	13 May 2015	25,451,951	4.98	Direct & Indirect
Aviva plc and its subsidiaries(1)	27 April 2009	3,933,529	4.95	Direct & Indirect
AXA Investment Managers SA	3 March 2017	23,907,981	4.68	Indirect
Ameriprise Financial Inc	20 January 2012	24,666,346	4.66	Direct & Indirect
Dimensional Fund Advisors	12 June 2020	43,531,400	4.38	Indirect

Note

(1) Interests shown for Aviva plc and its subsidiaries pre-date the Share Split in 2011.

None of Premier's major Shareholders set out above has different voting rights from any other holder of Ordinary Shares.

As at the Latest Practicable Date, the Company is not aware of any person who, directly or indirectly, owns or controls the Company, nor is it aware of any arrangements the operation of which may at a subsequent date result in a change of control of the Company.

Immediately following completion of the Merger and the Debt Restructuring, and assuming full take up by Restructuring Plan Creditors of the partial cash alternative and assuming no Top-Up Election, Harbour North Sea together with its concert parties will hold up to 40.42 per cent. of the Ordinary Shares in the Company, Purple Green Investment Pte Ltd (a wholly owned subsidiary of GIC (Ventures) Pte Ltd) will hold up to 13.83 per cent. of the Ordinary Shares in the Company and Coller Partners 705 LP Incorporated will hold up to 4.01 per cent. of the Ordinary Shares in the Company (the allocation of Consideration Shares among Chrysaor shareholders, including Harbour North Sea, together with its concert parties, Purple Green Investment Pte Ltd and Coller Partners 705 LP Incorporated, will depend on the value of those Consideration Shares in the period up to the completion of the Merger). As such Harbour will be deemed a controlling shareholder of Premier and, in compliance with the Listing Rules, has agreed to enter into a relationship agreement with the Company (for more detail, please see paragraph 8.1(A) of this Part XIII (*Additional Information*) below.

8. Material contracts

8.1 Premier Group

In addition to the Merger Agreement and the Management Warranty Deed, which have been summarised in the Circular, a summary of all other contracts (not being contracts entered into in the ordinary course of business) that have been entered into by any member of the Premier Group either: (i) within the two years immediately preceding the date of this document which are, or may be, material; or (ii) which have been entered into by any member of the Premier Group and which contain provisions under which any member of the Premier Group has an obligation or entitlement that is material as at the date of this document, is set out below.

(A) **Relationship Agreement**

The Relationship Agreement to be entered into between Premier and Harbour North Sea, will take effect on Admission and will continue in force unless and until Harbour North Sea and its affiliates 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 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 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 the Company from complying with its obligations under the Listing Rules;

(B) 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;

(C) 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 Relationship Agreement;

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

(E) vote its Ordinary Shares and shall use its reasonable endeavors 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

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 and the Corporate Governance Code.

In connection with the Merger Agreement and the Relationship Agreement, Premier and Harbour, will, prior to completion of the Merger and Debt Restructuring (but conditional on Admission), enter into: (i) a lock-up deed whereby Harbour North Sea undertakes that it will not sell its Ordinary Shares for a period of 12 months following completion of the Merger and Debt Restructuring (after which Harbour will be subject to a further 12 month orderly market covenant); and (ii) a standstill agreement whereby Harbour North Sea undertakes that neither it nor any member of the Concert Party will acquire Ordinary Shares or make an offer for Ordinary Shares for a period of 24 months following completion of the Merger and Debt Restructuring.

(B) **ARCM Settlement Agreement and Subscription Agreement**

On 5 June 2020, the Company entered into a settlement agreement with ARCM under which ARCM agreed to withdraw its appeal of the Court of Session's judgment approving the 2020 Schemes with effect from 1 July 2020 and support the Company's entry into the Stable Platform Agreement and proposal in relation to the acquisitions of interests in the Andrew Area and the Shearwater Field and related funding arrangements. The settlement agreement with ARCM also provided for a comprehensive settlement of all claims relating to the 2020 Schemes and related matters (including costs).

In connection with the settlement agreement, the Company and ARCM also entered into a subscription agreement under which the Company agreed to issue 82,164,064 Ordinary Shares, representing 8.91 per cent. of the Company's enlarged share capital (as at 5 June 2020), to several funds owned and/or managed by ARCM at a price of 26.69 pence per share. The issue raised approximately US$27.5 million for the Company. ARCM undertook to use the Ordinary Shares issued to it in order to reduce its short position (being approximately 16.69 per cent as at 5 June 2020).

(C) **Support Letter**

On 6 October 2020, the Company agreed a term sheet with Chrysaor and a sub-set of the Premier Group's creditors in respect of the Debt Restructuring and, the wider group of Private Creditors and XCCY Hedge Counterparties were invited to approve the term sheet by entering into the Support Letter.

Under the terms of the Support Letter, Participating Creditors have given certain undertakings to Premier and Chrysaor, and Premier and Chrysaor have given certain undertakings to the Participating Creditors, including:

(i) to support the Debt Restructuring, including (in the case of the Participating Creditors) by voting in favour of the Restructuring Plans;

(ii) not to take any action which would be inconsistent with the Merger or the Debt Restructuring in any material respect;

(iii) to instruct their legal advisers to negotiate the documentation required to implement the Debt Restructuring on the terms of the agreed term sheets in good faith; and

(iv) (in the case of the Participating Creditors) not to transfer their rights under the existing finance documents, unless the proposed transferee of such rights accedes to the Support Letter (subject to limited carve-outs).

In addition to the undertakings described above, the Participating Creditors have agreed to waive any default, event of default or breach of representation arising as a result of the Merger and the Debt Restructuring or any steps taken by any member of the Premier Group to implement the Merger and the Debt Restructuring.

The lock-up binds the parties to the Support Letter for the duration of the Support Letter's effectiveness, subject to certain limited termination rights.

The Support Letter also allows any Private Creditor or XCCY Hedge Counterparty to accede to the Support Letter and requires any Participating Creditor that wishes to transfer its debt, to ensure that any such transferee accedes to the Support Letter.

The Support Letter is subject to termination rights, including the ability of the Majority Creditors to terminate upon the occurrence of certain events of default under the Existing Debt Facilities, the material breach by Chrysaor or Premier of certain undertakings given in the Support Letter or following a decision by the Board to withdraw its recommendation of the Merger. In addition, the Support Letter will automatically terminate on the earliest to occur of the following: (i) where the Merger Agreement is terminated in accordance with its terms, the Interim Maturity Extension becomes effective; (ii) an insolvency event occurs in relation to certain Premier Group companies; (iii) the Long-Stop Date (see below); and (iv) the Debt Restructuring becomes effective.

In particular, the Support Letter may be terminated at the election of the Majority Creditors if the events or circumstances set out below occur:

- the Merger and Debt Restructuring Resolutions are not approved by Shareholders at the General Meeting and an alternative plan for implementation of the Merger and the Debt Restructuring has not been agreed between Premier, Chrysaor and the Participating Creditors within 20 business days of the General Meeting;
- an event of default arises under the Existing Debt Facilities or the XCCY Swaps (other than an event of default which has been remedied or waived or has arisen, or deemed to have arisen, directly as a result of the implementation of the Merger or the Debt Restructuring);
- relevant members of the Premier Group breach the terms of the Support Letter in any material respect or any representation or warranty by the relevant members of the Premier Group under the Support Letter is materially incorrect or misleading;
- either Chrysaor or Premier breach certain undertakings given by them under the Support Letter in any material respect. These undertakings include, among other things: (i) to support the Debt Restructuring; (ii) not to take any action which would be inconsistent with the Merger or the Debt Restructuring in any material respect; and (iii) to instruct their legal advisers to negotiate the documentation required to implement the Debt Restructuring on the terms of the agreed term sheets in good faith;
- the Board decides to withdraw, suspend, qualify or adversely modify or amend, the recommendation of the Merger set out in the Circular in circumstances where Chrysaor has not elected to terminate the Merger Agreement and an alternative plan for implementation of the Merger and the Debt Restructuring has not been agreed between Premier, Chrysaor and the Participating Creditors;
- at any Restructuring Plan Creditor Meeting the requisite majorities by value of creditors entitled to vote on such Restructuring Plan have not voted for such Restructuring Plan such that any of the Restructuring Plans are not approved;

– certain milestones are not completed (including the posting of the explanatory statement relating to the Restructuring Plans to the Restructuring Plan Creditors by 28 February 2021 and the Merger and Debt Restructuring Resolutions being approved by Shareholders by 30 April 2021) within the relevant timeframe (as may be extended) other than where Premier has provided evidence that this is as a result of a breach by Chrysaor of its obligation under the Support Letter to provide reasonable assistance to enable Premier meet those milestones;

– either the English Court or the Scottish Court issues a judgment refusing to sanction all or any of the Restructuring Plans which is either (a) not appealed by any party within the period of time in which to bring such an appeal under Scottish or English law (as applicable), or (b) appealed within such period of time and such appeal is unsuccessful;

– either the English Court or the Scottish Court issues an order preventing the Company, POUK or POHL from implementing the Debt Restructuring or Restructuring Plans which is either (a) not appealed by any party, or (b) appealed and such appeal is unsuccessful; or

– where Chrysaor has notified the Company that the Company has breached the Merger Agreement in a manner which provides any of the Harbour/Chrysaor Parties the right to terminate the Merger Agreement and none of the Harbour/Chrysaor Parties exercises its termination right, or the Merger and Debt Restructuring Resolutions are not approved by shareholders at the General Meeting, an alternative plan for implementation of the Merger and the Debt Restructuring has not been agreed between Premier, Chrysaor and the Participating Creditors within 20 business days of such notification.

The Long Stop Date for completion of the Merger and the Debt Restructuring, as set out in the Support Letter, is 30 September 2021 or such later date as Premier, Chrysaor and the Majority Creditors agree provided such date is not later than 1 December 2021. If any of the conditions to the Debt Restructuring becoming effective summarised above does not take place by the Long Stop Date (as amended or extended), then the Debt Restructuring will not proceed.

Should the Support Letter terminate, the parties to it would not be obliged to support the Debt Restructuring, including by voting in favour of the Restructuring Plans.

(D) **Sponsor Agreement**

On or around the date of this document, Premier and RBC entered into a sponsor's agreement pursuant to which RBC has agreed, subject to certain conditions, to act as Premier's sponsor in relation to the Merger and Admission (the "**Sponsor Agreement**"). Premier is providing RBC with: (i) certain undertakings which will require it to consult with RBC before taking certain actions; and (ii) certain warranties in relation to Premier and Chrysaor. In addition, Premier is providing RBC with certain indemnities which are customary for an agreement of this nature. Pursuant to the terms of the Sponsor Agreement, RBC may terminate the Sponsor Agreement on the occurrence of certain customary events including a material breach of the Sponsor Agreement or a material misstatement in or omission from this document.

Premier has agreed to bear all of RBC's fees, costs, charges and expenses of, or which are incidental to, the Merger and Admission, including 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 Merger, any CREST charges and the fees of the FCA and London Stock Exchange.

(E) **Non-XCCY Hedging Support Letters**

As the Restructuring Plans will not affect the rights of (nor bind) the Non-XCCY Hedge Counterparties, in order to implement the Merger and Debt Restructuring, the Company is required to seek certain consents from the Non-XCCY Hedge Counterparties, including consent from each of the Non-XCCY Hedge Counterparties to resign from relevant documents forming part of the Existing Debt Facilities from completion of the Interim Maturity Extension (if applicable).

As such, consents from the Non-XCCY Hedge Counterparties has been sought and received from each the Non-XCCY Hedge Counterparty on an individual and consensual basis under the terms of individual Non-XCCY Hedging Support Letters (each of which is substantively identical).

The consents provided by the Non-XCCY Hedge Counterparties pursuant to the Non-XCCY Hedging Support Letters may only be terminated by the Non-XCCY Hedge Counterparties if the Support Letter is terminated.

None of the Non-XCCY Hedge Counterparties has been paid a consent fee or other incentives to sign a Non-XCCY Hedging Support Letter. The Company has given an equivalent undertaking as under the Support Letter to pay the costs and expenses of each Non-XCCY Hedge Counterparty (including certain fees and taxes) reasonably incurred by that Non-XCCY Hedge Counterparty in connection with entering into their Non-XCCY Hedging Support Letter.

(F) **Creditor Lock-Up Agreement**

In accordance with the Debt Restructuring, any Restructuring Plan Creditor whose individual holding (not measured on an aggregate basis across groups or funds under common control) exceeds more than 2.7 per cent. of the enlarged share capital of the Company on Admission will enter into a lock-up agreement which will be conditional on Admission and Readmission. Under the terms of the Creditor Lock-Up Agreement, the relevant creditors shall undertake not to, during the Creditor Lock-Up Period: (i) directly or indirectly dispose of their Creditor Shares (which shall include the New Equity Warrants and the New Warrant Shares but shall exclude any Creditor Shares issued pursuant to the Top-Up Election); or (ii) take or increase any net short position (or other derivative arrangement having a similar effect) in the Ordinary Shares. However, such restrictions shall not apply in certain circumstances, including in connection with: rights issues, takeovers or disposals to affiliates who enter into a pro-forma deed of adherence.

The Creditor Lock-Up Agreement will terminate on the earliest of:

– 12 months following the end of the Creditor Lock-Up Period;

– if the relevant creditor who is party to the Creditor Lock-Up Agreement no longer holds, directly or indirectly, any Creditor Shares;

– the Company enters into winding up, administration or any creditor protection procedures;

– on a direct or indirect change of control in the Company; or

– if the Ordinary Shares cease to be listed on the premium listing segment of the FCA's Official List and traded on the London Stock Exchange's main market.

(G) **Override Agreement**

The Override Agreement was entered into on 20 July 2017 in connection with Premier's 2017 Refinancing. The purpose of the Override Agreement is to provide common provisions which are explicitly incorporated into Premier's other finance documents relating to representations, warranties, mandatory prepayment, covenants and events of default. Certain of these key provisions are summarised below.

Mandatory prepayment

The Override Agreement contains certain mandatory prepayment events requiring the outstanding loans and letters of credit under the Senior Secured Debt Facilities and the Super Senior Secured RCF/LC Facilities, the USPP Notes and the Retail Bonds to be immediately repaid in full. These events include the occurrence of a change of control of the Company. The Override Agreement also contains additional mandatory prepayment requirements in respect of the proceeds of disposals, insurance claims and any Premier Group cash being held by the Premier Group in excess of the prescribed headroom.

Representations

The Override Agreement contains customary representations and warranties for each obligor and the Company, including that all material assets of the Premier Group are secured in favour of the creditors and the secured hedge counterparties.

Financial covenants and cash management

The Override Agreement contains financial covenants including specified leverage and interest cover ratios and minimum liquidity requirements. If there is a projected breach of the leverage ratio, POUK will be restricted from making further utilisations.

Guarantees

Each guarantor jointly and severally guarantees the performance of the Premier Group's obligations under the finance documents. Guarantees are required from members of the Premier Group contributing at least 95 per cent. of consolidated operating profit, proved plus probable reserves, intangible exploration and evaluation assets, property, plant and equipment total assets, net assets, and EBITDA of the Premier Group in aggregate.

General covenants

The Override Agreement contains a number of customary covenants for the obligors including a negative pledge, a disposals covenant, restrictions on members of the Premier Group from being a creditor or providing certain guarantees. The financial indebtedness covenant restricts members of the Premier Group from incurring or allowing to remain outstanding certain financial indebtedness.

Events of default

The Override Agreement includes customary events of default which will entitle the financiers to terminate the relevant finance documents and demand immediate repayment in accordance with the Intercreditor Agreement, including non-compliance with financial covenants and covenants relating to acquisitions, disposals, security and financial indebtedness and any financial indebtedness of any member of the Premier Group not being paid when due or becoming prematurely due and payable.

(H) **Senior RCF/LC Facility Agreement**

Pursuant to the amendment and restatement of the original RCF facility agreement on 28 July 2017 in connection with Premier's 2017 Refinancing, an amount equal to the drawings under the original RCF facility agreement (which comprised US$1,550 million drawn by way of cash loans and approximately US$231 million drawn by way of letters of credit) formed the Senior RCF Facilities.

The Senior Secured Cash Loan Facility may only be used for general corporate purposes. The Senior Secured LC Sub-Facilities may only be used for: (i) the issuance of letters of credit to a beneficiary approved by the Senior Secured LC Sub-Facility lenders; and (ii) the funding of cash collateral where a Senior Secured LC Sub-Facility lender no longer meets the criteria of an "approved lender".

POUK must repay each loan and LC on the earlier of its maturity date and 31 May 2021. Cash loans bear interest at the aggregate of a margin of 5.00 per cent. per annum plus LIBOR or, in relation to any loan in Euro, EURIBOR (subject to a LIBOR/EURIBOR zero floor). A letter of credit fee is payable at the rate of 5.00 per cent. per annum in respect of the outstanding amount of each LC for the period from the effective date of that LC until its maturity date.

POUK must pay commitment fees at the rate of 35 per cent. per annum of the applicable margin on the daily undrawn, uncancelled amount made available under the Senior RCF Facilities. Utilisation fees are payable at the rate of 0.40 per cent. per annum on outstanding loans under the Senior Secured Cash Loan Facility.

Provisions of the Senior RCF/LC Facility Agreement relating to representations, warranties, mandatory prepayment, covenants and events of default are incorporated from, and are consistent with, those set out in the Override Agreement.

(I) **Super Senior Secured RCF/LC Facility Agreement**

Pursuant to the amendment and restatement of the original RCF facility agreement on 28 July 2017 in connection with Premier's 2017 Refinancing, an amount equal to the undrawn facilities under the original RCF facility agreement of US$500 million in respect of cash loans and approximately US$219 million in respect of letters of credit formed the Super Senior Secured RCF/LC Facilities.

Under the Super Senior Secured RCF/LC Facility Agreement, the Super Senior Creditors have made available the Super Senior Secured RCF/LC Facilities.

The Super Senior Secured Revolving Credit Facility may only be used for general corporate purposes. The Super Senior Secured LC Sub-Facilities may only be used for: (i) the issuance of letters of credit to a beneficiary approved by the Super Senior Secured LC Sub-Facility lenders; and (ii) the funding of cash collateral where a Super Senior Secured LC Sub-Facility lender no longer meets the criteria of an "approved lender".

POUK must repay each loan and letter of credit on the earlier of its maturity date or 31 May 2021. Cash loans bear interest at the aggregate of a margin of 5.00 per cent. per annum plus LIBOR or, in relation to any loan in Euro, EURIBOR (subject to a LIBOR/EURIBOR zero floor). A letter of credit fee is payable at the rate of 5.00 per cent. per annum in respect of the outstanding amount of each letter of credit (after deducting the amount of any cash collateral provided in respect of any such letter of credit) for the period from the effective date of that letter of credit until its maturity date.

POUK must pay commitment fees equal to 35 per cent. per annum of the applicable margin on the daily undrawn, uncancelled amount made available under the Super Senior Secured RCF/LC Facilities. Utilisation fees are payable at the rate of 0.40 per cent. per annum on outstanding loans under the Super Senior Secured Revolving Credit Facility.

Provisions of the Super Senior Secured RCF/LC Facility Agreement relating to representations, warranties, mandatory prepayment, covenants and events of default are incorporated from, and are consistent with, those set out in the Override Agreement.

(J) **Nelson Bilateral LC Facility Agreement**

The terms of the Nelson Bilateral LC Facility Agreement were amended and restated on 20 July 2017 in connection with Premier's 2017 Refinancing. A revolving credit facility in an aggregate amount of £4,380,000 is made available to POUK under the facility.

The Nelson Bilateral LC Facility Agreement may only be used for the issuance of letters of credit to a beneficiary in relation to Nelson or save that if the lender from time to time under the facilities ceases to meet the applicable ratings criteria, the commitments can be used to cash collateralise the obligations of another financial institution who provides a replacement letter of credit to the Nelson beneficiary or a loan for general corporate purposes.

POUK must repay each LC on or before 31 May 2021. The rate of interest is the aggregate of a margin of 5.00 per cent. per annum plus LIBOR. A letter of credit fee is payable at the rate of 5.00 per cent. per annum in respect of the outstanding amount of each letter of credit (after deducting the amount of any cash collateral provided in respect of any such letter of credit) for the period from the effective date of that letter of credit until its maturity date.

POUK must pay commitment fees equal to 35 per cent. per annum of the applicable margin on the daily undrawn, uncancelled amount made available under the Senior RCF Facilities.

Provisions of the Nelson Bilateral LC Facility Agreement relating to representations, warranties, mandatory prepayment, covenants and events of default are incorporated from, and are consistent with, those set out in the Override Agreement.

(K) **Term Loan Facility Agreement**

The terms of the Term Loan Facility Agreement were amended and restated on 20 July 2017 in connection with Premier's 2017 Refinancing.

The creditors under the Term Loan Facility Agreement have made available the following amounts: (i) a term loan facility of £100,000,000 ("**Term Loan Facility A**"); and (ii) a term loan facility of US$150,000,000 ("**Term Loan Facility B**").

The facilities may only be used for general corporate purposes. POUK may not voluntarily prepay the loans advanced under the Term Loan Facility Agreement in whole or in part at any time whilst the Super Senior Secured RCF/LC Facilities are outstanding.

POUK must repay each loan in full on or before 31 May 2021. The rate of interest is the aggregate of a margin of (i) 4.60 per cent. per annum in respect of the Term Loan Facility A; and (ii) 4.75 per cent. per annum in respect of the Term Loan Facility B, plus LIBOR (subject to a LIBOR zero floor).

Provisions of the Term Loan Facility Agreement relating to representations, warranties, mandatory prepayment, covenants and events of default are incorporated from, and are consistent with, those set out in the Override Agreement.

(L) **USPP Note agreements and the USPP Notes**

POUK has issued the following USPP Notes under the 2011 USPP Note Agreement.

(i) the €75,000,000, series A senior notes (of which €35,000,000 in principal amount is outstanding);

(ii) the US$70,000,000, series B senior notes (of which US$13,000,000 in principal amount is outstanding);

(iii) the US$174,000,000, series C senior notes (of which US$128,000,000 in principal amount is outstanding);

(iv) the €1,689,561.33 series A make-whole notes;

(v) the US$383,663.83 series B make-whole notes; and

(vi) the US$17,170,086.89 series C make-whole notes.

POUK has issued the following USPP Notes under the 2012 USPP Note Agreement:

(i) the €25,000,000, series A senior notes (of which €25,000,000 in principal amount is outstanding);

(ii) the US$70,000,000, series B senior notes (of which US$35,000,000 in principal amount is outstanding);

(iii) the US$94,000,000, series C senior notes (of which US$84,000,000 in principal amount is outstanding);

(iv) the US$38,000,000, series D senior notes (of which US$38,000,000 in principal amount is outstanding);

(v) the €1,953,108.90 series A make-whole notes;

(vi) the US$1,610,833.55 series B make-whole notes;

(vii) the US$11,107,772.44 series C make-whole notes; and

(viii) the US$6,727,353.96 series D make-whole notes.

The make-whole notes were issued by POUK as part of Premier's 2017 Refinancing. The principal amount of each make-whole note represents an amount equal to the aggregate make-whole amount which would have been payable in respect of the relevant series of USPP Notes if such USPP Notes had been accelerated on the effective date of Premier's 2017 Refinancing in accordance with the relevant USPP Note Agreement.

The entire unpaid principal balance of each series of USPP Notes is due and payable on 31 May 2021. Each USPP Note bears interest on its outstanding principal amount. The rate of interest for USPP Notes issued under the 2011 USPP Note Agreement is (i) 9.17 per cent. in respect of the series A notes; (ii) 8.96 per cent. in respect of the series B notes; and (iii) 9.63 per cent. in respect of the series C notes. The rate of interest for USPP Notes issued under the 2012 USPP Note Agreement is (i) 8.43 per cent. in respect of the series A notes; (ii) 8.52 per cent. in respect of the series B notes; (iii) 9.14 per cent. in respect of the series C notes; and (iv) 9.29 per cent. in respect of the series D notes.

Provisions of the USPP Note agreements relating to representations, warranties, mandatory prepayment, covenants and events of default are incorporated from, and are consistent with, those set out in the Override Agreement.

(M) **Converted Facility Agreement**

The terms of the Converted Facility Agreement were amended and restated on 20 July 2017 in connection with Premier's 2017 Refinancing.

The lenders under the Converted Facility Agreement have made available to POUK: (i) a term loan facility of US$60,000,000 ("**Converted Facility A**"); (ii) a term loan facility of US$50,000,000 ("**Converted Facility B**"); and (iii) a term loan facility of US$20,000,000 ("**Converted Facility C**").

POUK must repay each loan in full on 31 May 2021. The rate of interest is the aggregate of a margin of (i) 6.65 per cent. per annum in respect of Converted Facility A; (ii) 6.65 per cent. per annum in respect of Converted Facility B; and (iii) 6.85 per cent. per annum in respect of Converted Facility C, plus LIBOR (subject to a LIBOR zero floor).

Provisions of the Converted Facility Agreement relating to representations, warranties, mandatory prepayment, covenants and events of default are incorporated from, and are consistent with, those set out in the Override Agreement.

(N) Retail Bonds

On 11 December 2013, the Company issued £150,000,000 notes due 11 December 2020 (being the "**Retail Bonds**") pursuant to the Euro medium term note programme. The terms and conditions of the Retail Bonds are set out in the Retail Bond Terms and Conditions and the Retail Bond Final Terms, which were amended and restated pursuant to an amendment and restatement agreement dated 20 July 2017 in connection with Premier's 2017 Refinancing. The maturity date of the Retail Bonds is 31 May 2021.

The Retail Bonds bear interest at a fixed rate of 6.50 per cent. on its outstanding nominal amount. Premier shall pay default interest of 1.00 per cent. per annum over the applicable interest rate in respect of the Retail Bonds in the event of a payment default. The Retail Bonds do not have the benefit of any financial covenant undertakings contained in the Override Agreement.

(O) Equity warrant and convertible equity warrant instruments

As part of Premier's 2017 Refinancing, the Company issued 71,012,952 registered equity warrants to the Super Senior Creditors and the Senior Creditors pursuant to an equity warrant instrument dated 20 July 2017 (the "**Existing Equity Warrants**") to allow the Senior Creditors and the Super Senior Creditors to participate in any increase in the equity value of the Premier Group following Premier's 2017 Refinancing. Each Existing Equity Warrant confers the right to subscribe in cash for one Ordinary Share. Warrant holders may elect at their sole discretion to: (i) pay a cash price on exercise of the warrant; or (ii) opt for cashless exercise of the warrant whereby the number of shares they receive on exercise will be reduced accordingly. Given the current strike price of the Existing Equity Warrants, being £0.4081 as at the Latest Practicable Date, if the maximum number of outstanding warrants were issued and exercised for a cash price, Premier would receive approximately £11,173,525 in cash proceeds. The Existing Equity Warrants benefit from customary anti-dilution protections and as such the exercise price shall be adjusted to take account of certain dilutive events. The Merger and the Debt Restructuring will likely constitute a dilutive event under the outstanding Existing Equity Warrants. Accordingly, in accordance with the terms of the Existing Equity Warrants, Premier has instructed an independent expert to determine the required adjustment to the exercise price to be paid or to the number of Ordinary Shares to be issued upon exercise of an Existing Equity Warrant. The independent expert will consider the economic effect of the dilutive event on the outstanding Existing Equity Warrants when determining a suitable adjustment. No adjustment will be made to the extent it would result in the exercise price falling below the nominal value of one Ordinary Share. In this instance, any further adjustment required will instead be effected by increasing the number of Ordinary Shares issuable upon exercise of an Existing Equity Warrant.

The Existing Equity Warrants will expire on 31 May 2022. As at the Latest Practicable Date, the Company has allotted 31,523,320 Ordinary Shares as a result of the exercise of Existing Equity Warrants and 27,379,381 Existing Equity Warrants remain outstanding. As part of Premier's 2017 Refinancing, the Company also issued 18,097,019 registered convertible equity warrants to convertible bondholders pursuant to a convertible equity warrant instrument dated 26 July 2017 (the "**Convertible Equity Warrants**") to allow convertible bondholders to participate in any increase in the equity value of the Premier Group following Premier's 2017 Refinancing. Each Convertible Equity Warrant confers the right to subscribe in cash for one Ordinary Share. The key terms of the Convertible Equity Warrants (including the price payable upon exercise of a Convertible Equity Warrant) are substantially the same as those which apply to the Existing Equity Warrants.

Given the current strike price of the Convertible Equity Warrants, being £0.4081 as at the Latest Practicable Date, if the maximum number of warrants were issued and exercised for a cash price, Premier would receive approximately £2,700,547 in cash proceeds. As at the Latest Practicable Date, the Company has allotted 11,430,484 Ordinary Shares as a result of the exercise of Convertible Equity Warrants and 6,617,367 Convertible Equity Warrants remain outstanding. As previously announced by the Company on 5 September 2018, the Premier Group does not have any convertible bonds outstanding.

(P) Security documents

The obligations of the Company and the guarantors in respect of the finance documents are secured pursuant to various security documents. The net proceeds of any enforcement of the security shall be applied by GLAS Trust Corporation Limited (as security agent) in accordance with the Intercreditor Agreement. English law governed debentures grant (among other things): (i) first equitable mortgages in respect of the shares in all of the obligors incorporated in England and Wales; (ii) first legal mortgage over certain freehold and leasehold property in England and Wales; (iii) assignments in respect of material contracts governed by English law; (iv) fixed charges in respect of the licences in the jurisdiction of England and Wales, intellectual property, plant and machinery, goodwill, certain mandatory prepayment bank accounts and all intercompany receivables; and (v) a floating charge over all other present and future assets not subject to fixed charge or assignment.

Where an obligor has material assets in any jurisdiction other than England and Wales, it has entered into local law governed security documents granting equivalent security to that provided in each English law governed debenture where applicable and in accordance with the agreed security principles in the Override Agreement.

(Q) **Intercreditor Agreement**

The purpose of the Intercreditor Agreement is to regulate the rights and obligations of the Super Senior Creditors, the Senior Creditors, the secured hedge counterparties and the administrative parties following Premier's 2017 Refinancing. It dictates the order in which the liabilities and obligations of any member of the Premier Group owed to creditors rank in right and priority of payment. It also subordinates the claims of the intragroup lenders and restricts the rights of the intra-group lenders to receive payments and take enforcement action, as well as the ability of the relevant members of the Premier Group to make payments to them.

Enforcement of security

The security shall only be enforceable upon the occurrence of an acceleration event following an instruction to GLAS Trust Corporation Limited (as security agent) from the instructing group. An "acceleration event" occurs if an event of default is outstanding under the Override Agreement and the relevant majority of creditors have given notice to the Company.

Restrictions on secured hedge counterparties

The Intercreditor Agreement places certain restrictions on the secured hedge counterparties including: (i) not taking any enforcement action (subject to certain exceptions); (ii) the requirement to terminate or close-out all secured hedging agreements following an acceleration event; and (iii) restricting amendments and waivers of any terms of any secured hedging agreement prior to the Secured Obligations Discharge Date.

Premier Group members

If any member of the Premier Group incurs any liabilities to a party to the Intercreditor Agreement, that member should accede to the Intercreditor Agreement.

8.2 Chrysaor Group

(A) **Merger Agreement**

Please see Part I (*Background to and Reasons for the Merger and the Debt Restructuring*).

(B) **ConocoPhillips Acquisition Agreement**

On 18 April 2019, Chrysaor entered into a deed granting put and call options (the "**ConocoPhillips PCOA**") with ConocoPhillips, pursuant to which Chrysaor acquired the entire issued share capital of ConocoPhillips Holdings Limited and Burlington Resources (UK) Holdings Limited, for a total consideration of US$2,675,000,000, subject to adjustment in accordance with the terms of the ConocoPhillips PCOA. The acquisition completed on 30 September 2019 but had an effective date of 1 January 2018.

The assets acquired by Chrysaor as a result of the acquisition comprised the majority of North Sea assets held by ConocoPhillips, however the transaction did not include ConocoPhillips' London-based commercial trading business nor its interest in the Teesside oil terminal, which were hived out prior to completion and excluded from the acquisition.

Pursuant to the terms of the ConocoPhillips PCOA, Chrysaor has indemnified ConocoPhillips for certain decommissioning and environmental liabilities relating to the entities acquired by Chrysaor, irrespective of when such liabilities are or were incurred. The ConocoPhillips PCOA contains customary warranties for a transaction of this nature which expire 18 months following the date of completion. The ConocoPhillips PCOA is governed by English law and the courts of England have exclusive jurisdiction to settle any dispute which may arise out of or in connection with the ConocoPhillips PCOA.

(C) **New RBL Facility**

Please see Part II (*Details of the Debt Restructuring*).

(D) **Chrysaor Junior Facility**

On 9 December 2020, Chrysaor Holdings Limited (as parent), Chrysaor E&P Finance Limited (as borrower) and the Shell Junior Lender entered into an amendment and restatement agreement to amend and restate the Shell Junior Facility Agreement.

The Shell Junior Facility Agreement comprises a single term loan facility of US$400 million, which was previously drawn by Chrysaor E&O Finance Limited at the time the loan arrangement was entered into. The term debt provided under the Shell Junior Facility Agreement will mature on 30 June 2026.

The Shell Junior Lender will benefit on a *pari passu* basis in respect of the same security arrangements entered into in respect of the New RBL Facility (as described above).

The interest rate is LIBOR plus a margin equal to the margin under the New RBL Facility plus 2 per cent. per annum.

The Shell Junior Facility Agreement contains prepayment and cancellation provisions, affirmative and negative covenants and information covenants which substantively reflect those provided under the New RBL Facility (to the extent relevant).

(E) **STASCO Offtake Arrangements**

The Chrysaor Group is party to eight offtake arrangements with Shell International Trading and Shipping Company Limited ("**STASCO**"), a subsidiary of Shell (the "**STASCO Offtake Arrangements**"), pursuant to which the Chrysaor Group has agreed to sell and STASCO has agreed to buy the Chrysaor Group's production across various fields and products which in aggregate equated to approximately 94 per cent. of the Chrysaor Group's production across all fields and products for the year ended 31 December 2019 (including all the crude oil produced by the Chrysaor Group), and which in aggregate represented approximately 95 per cent. of the Chrysaor Group's revenues for the year ended 31 December 2019. These arrangements do not provide for any minimum or maximum production volumes (i.e. STASCO is required to purchase all of the Chrysaor Group's production which is subject to such arrangements, regardless of the level of that production). These arrangements therefore secure sales of a substantial proportion of the Chrysaor Group's production and limit its exposure to offtake risk.

Seven of the STASCO Offtake Arrangements were entered into on 31 October 2017 in parallel with the Shell Junior Facility Agreement, with the other entered into 30 September 2019 in connection with the ConocoPhillips UK Acquisition. The Chrysaor Group is able to terminate the STASCO Offtake Arrangements on repayment of the Chrysaor Junior Facility (but no earlier than 31 October 2024). STASCO is able to terminate the STASCO Offtake Arrangements from 31 October 2022 and in certain other limited and customary circumstances, including in the event that the Chrysaor Group fails to deliver STASCO's entitlement to the Chrysaor Group's production which is available for delivery in accordance with the arrangements or the Chrysaor Group through wilful default is in material breach of its obligations under the arrangements (and fails to remedy such breach within an agreed period). The STASCO Offtake Arrangements also include mutual termination rights in the event of various insolvency and financial distress related events in respect of either party or in the event that either party has failed to pay undisputed amounts due (subject to notice periods).

The STASCO Offtake Arrangements were all entered into on arm's length commercial terms, which are typical for North Sea oil and gas offtake arrangements. In particular, the arrangements provide that the price payable by STASCO will be determined by reference to benchmarked prices published by third parties, such as Platts for crude oil (subject to customary protections for the Chrysaor Group, including in some cases having the right to require STASCO to sell its production by way of realised onward sales pricing less a marketing fee rather than by reference to benchmarked pricing).

In addition to being obliged to purchase the majority of the Chrysaor Group's current production, under the STASCO Offtake Arrangements, STASCO will automatically be required to purchase the additional production (i.e. new to the Chrysaor Group) from any field in respect of which an equity interest was originally acquired by the Chrysaor Group from Shell under the Shell Acquisition where the Chrysaor Group acquires an additional equity interest in such field. In addition, STASCO has a right to match the terms offered by third parties to the Chrysaor Group for production from any field in respect of which the Chrysaor Group acquires a new or additional equity interest where the Chrysaor Group did not acquire an equity interest in such field under the Shell Acquisition (provided such production is not already contracted to another party). As such, on completion of the Merger, under the STASCO Offtake Arrangements, STASCO will automatically be required to purchase some of Premier's production (in particular the production of the Elgin Franklin field), which would have equated to approximately 8 per cent. of Premier's production for the year ended 31 December 2019 and will have a right to match the terms offered by third party offtakers for the production of Premier's other fields for certain products, which would have equated to approximately 64 per cent. of Premier's production for the year ended 31 December 2019.

Accordingly, on a Combined Group basis, under the STASCO Offtake Arrangements STASCO would be required to purchase approximately 60 per cent. of the Combined Group's production, which would have represented approximately 55 per cent. of the Combined Group's revenues on a combined basis for the year ended 31 December 2019. In addition, STASCO would have been entitled to purchase (if it had exercised all of its rights to match) approximately 85 per cent. of the Combined Group's production, which would have represented approximately 90 per cent. of the Combined Group revenues on a combined basis for the year ended 31 December 2019.

9. Related party transactions

9.1 Premier Group

Save as disclosed in: (i) note 25 to the 2019 Annual Report and Financial Statements, (ii) note 25 to the 2018 Annual Report and Financial Statements; and (iii) note 25 to the 2017 Annual Report and Financial Statements, each of which are incorporated by reference into this document, there are no related party transactions between the Premier Group and its related parties that were entered into during the financial years covered by the historical financial information and up to the Latest Practicable Date.

9.2 Chrysaor Group

Save as disclosed in note 27 of the Historical Financial Information for the three years ended 31 December 2017, 31 December 2018 and 31 December 2019 set out in Section B of Part VIII (*Historical Financial Information relating to the Chrysaor Group*), there were no related party transactions (which for these purposes are those set out in the standards adopted according to the Regulation (EC) No 1606/2002) entered into by Chrysaor during the six months ended 30 June 2020 and the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019.

Prior to but conditional on completion of the Merger, Harbour will transfer to Chrysaor all its intellectual property relating to the Harbour name for nil consideration.

10. Litigation

10.1 Premier Group

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 Premier is aware) during the 12 months preceding the date of this document which may have, or have had in the recent past, significant effects on the financial position or profitability of the Premier Group.

(A) **Settlement with ARCM**

In order to obtain consent to enter into the acquisitions of interests in the Andrew Area and Shearwater Field and the related fund raising, during Q4 2019, the Company sought the approval of its lenders through a creditor consent process conducted in accordance with the terms of its existing finance documents. As part of this process, Premier's largest lender by value, ARCM, voted against providing its approval with the effect that the Company was unable to obtain the required consent from its lender group to proceed with the acquisitions and the related fund raising.

Accordingly, in January 2020, the Company and POUK launched the 2020 Schemes in order to obtain the consent of lenders to the amendment and extension of the Premier Group's existing debt facilities and to the acquisitions and related funding arrangements. Provided that a sufficient number of the Premier Group's other creditors voted in favour of the 2020 Schemes, and the Court of Session sanctioned the 2020 Schemes, ARCM's approval would not be required. As part of this process, the required creditor meetings were held on 12 February 2020, at which 86.81 per cent. of the super senior secured commitments in value of those voting and 83.86 per cent. of the senior commitments in value of those voting, voted in favour of the 2020 Schemes. While ARCM opposed the 2020 Schemes at the creditor meeting, a sufficient number of lenders, by both number and value, had voted in favour. The Court hearing to sanction the 2020 Schemes was held in March 2020. The Court's judgment, which was published on 29 April 2020, found in favour of the Company, but provided ARCM with leave to appeal the judgement. ARCM subsequently appealed on 6 May 2020.

As further detailed in section 8 of Part XIII (*Additional Information*) of this document, on 5 June 2020, the Company and ARCM subsequently entered into the Settlement Agreement and the related subscription agreement. These agreements provided for a comprehensive settlement of all claims relating to the 2020 Schemes and related matters (including costs), as well as an issuance of 82,164,064 Ordinary Shares to funds owned and/or managed by ARCM at a price of 26.69 pence per share. As agreed in the settlement, the Company did not proceed with the registration of the 2020 Schemes.

(B) **Indonesian branch profits tax repayment claim**

With effect from 2011, the Indonesian Tax Authority imposed a 20 per cent. branch profit tax rate to the Premier Group's operations in Indonesia for each financial year from 2003 onwards. The Premier Group is contesting this imposition on the grounds that, under the Netherlands-Indonesia Tax Treaty, the Premier Group is entitled to a 10 per cent. branch profit tax rate. In accordance with due process in Indonesia, Premier paid the disputed amount, which totalled US$155 million up to the end of 2019. Premier has submitted objection letters, appeals, Mutual Agreement Procedures and Judicial Reviews where applicable for all affected years. In 2018 and 2019 the Premier Group received five rulings in its favour from the Supreme Court of Indonesia totalling US$21 million, US$16 million (in respect of Natuna financial years 2004 and 2013), and US$5 million (in respect of Kakap financial years 2003,2007 and 2012). The Premier Group has received all of the US$21 million of these repayments from the Indonesian Tax Authority. In 2020 so far, the Premier Group received 4 rulings in its favour from the Tax Courts in Indonesia totalling US$17 million, US$12 million (in respect of Natuna financial year 2010) and US$5 million (in respect of Kakap financial years 2009, 2010 and 2013). The Premier Group has received all of the US$17 million repayments in full. It is unclear when the Premier Group will be successful in recovering the total additional payment of US$114 million. The Supreme Court of Indonesia has announced that it has granted an appeal by the Indonesian Tax Authority in respect of the Tax Court's award for Natuna financial year 2010.

(C) **Huntington daily base hire dispute**

The dispute concerned the original E.ON / Sevan (now Premier / Altera) bareboat charter and associated over-arching agreement for the lease and operation of the Voyageur Spirit FPSO for the exploitation of the Huntington field. Altera's invoiced daily base hire ("**DBH**") rate under these agreements for 2014 to 2018 was disputed by Premier on the basis that Altera had incorrectly calculated the bonus / malus which was to apply to the DBH rate. Altera raised formal proceedings in October 2019 and a trial date was set for July 2020. Altera claimed US$12,108,072.50 and Premier counter-claimed US$3,837,580.91, with each also claiming interest and costs. A one day hearing took place remotely on 8 July 2020 and the judges' decision was handed down on 17 July 2020. The judge found in favour of Altera and Premier paid the awarded amount. Premier is considering the merits for appealing the judge's decision.

(D) **Huntington Line Flushing**

On 28 March 2018, Premier Oil E&P UK Limited and Altera Voyageur Production Limited ("**Altera**") entered into an operating services agreement in connection with the Huntington FPSO (the "**Huntington Agreement**"). Premier has disputed and withheld payment of four invoices (the "**Disputed Invoices**") received from Altera for services provided with respect to the Huntington FPSO under the Huntington Agreement between 24 April 2020 and 28 June 2020. During this period, the Huntington FPSO was being prepared for demobilisation from Huntington at the end of the field's life. Premier is disputing the Disputed Invoices on the basis that the demobilisation of the Huntington FPSO was delayed as a result of failures by Altera to perform its obligations under the Huntington Agreement and as such the Huntington FPSO remained on station for longer than planned. Premier is therefore claiming that no fees are payable pursuant to the Disputed Invoices. The aggregate value of the Disputed Invoices is US$7,745,000 (excluding VAT and statutory interest). Under the terms of the Huntington Agreement, interest on the Disputed Invoices accrues from the due date for payment at a rate which is undefined. Altera has issued Premier with a Notice of Dispute under the Huntington Agreement with respect to the Disputed Invoices but no formal court proceedings have been commenced.

10.2 Chrysaor Group

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 Premier is aware) during the 12 months preceding the date of this document which may have, or have had in the recent past, significant effects on the financial position or profitability of the Chrysaor Group.

Chrysaor completed the purchase of ConocoPhillips' UK oil and gas business on 30 September 2019. Under the relevant transaction document, Chrysaor agreed to pay the specified consideration of USD2.675 billion, subject to certain adjustments. In the context of discussions concerning the amount to be paid on completion, a dispute arose between Chrysaor and ConocoPhillips as to the exchange rate to be applied in respect of certain dividend and related payments (the "**Relevant Payments**"). The Relevant Payments were to be made in GBP, but accounted for as adjustments under the transaction document in USD. Without prejudice to that dispute, the transaction completed. ConocoPhillips commenced proceedings on 5 December 2019 in the High Court of England and Wales, seeking declarations in relation to the GBP:USD FX rate that applies in respect of the Relevant Payments. If ConocoPhillips succeeds in the case, there will be no further payment to ConocoPhillips under the post completion adjustments. If Chrysaor succeeds in the case, it will be entitled to a refund in respect of overpaid consideration of approximately USD120 million. A four day trial is scheduled for May 2021.

11. Working capital

11.1 Combined Group working capital statement

Premier is of the opinion that: (i) assuming the Merger and the Debt Restructuring complete; and (ii) taking into account the financing facilities that will be available to the Combined Group after completion of the Merger and the Debt Restructuring, the working capital available to the Combined Group is sufficient for the Combined Group's present requirements, that is for at least the next 12 months following the date of this document.

11.2 Premier Group standalone working capital statement

In addition to the working capital statement above, which is made on a Combined Group basis, Premier is required as a technical matter to provide a working capital statement on a standalone Premier Group basis (i.e. not taking into account the Merger and the Debt Restructuring). This standalone working capital statement is required due to the fact that the Merger would be accompanied by the issue of Creditor Shares pursuant to the Debt Restructuring (including the Top-Up Election), which constitutes a public offer under the Prospectus Regulation Rules, notwithstanding that if the Merger and the Debt Restructuring do not complete and no alternative transaction is agreed with Chrysaor and the Restructuring Plan Creditors, the public offer which forms part of the Debt Restructuring would fall away and the Creditor Shares would not be issued.

Premier therefore confirms that it is of the opinion that, absent the Merger and the Debt Restructuring completing, the Premier Group does not have sufficient working capital for its present requirements, that is for at least the next 12 months following the date of this document. This standalone working capital statement is made on the basis that the Premier Group's Existing Debt Facilities all reach maturity on 31 May 2021, which is within the 12-month forecast period. If the Merger and the Debt Restructuring complete, the Existing Debt Facilities and XCCY Swaps will be repaid, released and/or cancelled and certain members of the Premier Group will accede to the New RBL Facility.

Action plan and conditions

In order to effect the Merger and the Debt Restructuring, Premier has at the date of this document:

– negotiated the terms of the Merger with Chrysaor which will result in the Existing Debt Facilities and XCCY Swaps being repaid, released and/or cancelled and certain members of the Premier Group acceding to the New RBL Facility upon completion of the Merger;

– agreed the financial covenant deferrals contained in the Support Letter and the Stable Platform Agreement;

– negotiated the terms of the Debt Restructuring and the Interim Maturity Extension with its creditors and obtained commitments from Private Creditors and XCCY Hedge Counterparties under the Support Letter to vote in favour of the Restructuring Plans;

– negotiated the terms on which cash would be paid and Creditor Shares would be issued in consideration of the cancellation of existing indebtedness as part of the Debt Restructuring and the opportunity for Restructuring Plan Creditors to subscribe for unallocated Creditor Shares through the Top-Up Election;

– issued this Prospectus in relation to the Consideration Shares and the Creditor Shares and the Circular to convene the General Meeting; and

– taken steps to convene the creditor meetings for the purpose of the Restructuring Plans.

The Debt Restructuring is subject to certain conditions which must be satisfied or waived, including:

(A) the Merger and Debt Restructuring Resolutions having been passed by Shareholders at the General Meeting;

(B) the Restructuring Plans (which are inter-conditional) having been approved by the requisite majorities at the Restructuring Plan Creditor Meetings, sanctioned by the relevant Courts and a copy of the sanction orders delivered to the Registrar of Companies for Scotland or the Registrar of Companies for England and Wales (as applicable);

(C) each of the Non-XCCY Hedge Counterparties having given any consents required in connection with the Debt Restructuring, which the Non-XCCY Hedge Counterparties have undertaken to do pursuant to the Non-XCCY Hedging Support Letters;

(D) satisfaction of certain documentary conditions in respect of conditions precedent that are customary for a secured financing transaction and/or are within the control of the Premier Group;

(E) the FCA and the London Stock Exchange each having approved the applications for Admission to taken place (by not later than 30 September 2021, or such later date as may be agreed by Premier, Chrysaor and the Majority Creditors provided that such later date may not be later than 1 December 2021); and

(F) payment of certain transaction costs associated with the Debt Restructuring.

Each Restructuring Plan requires approval from either (i) 75 per cent. in value of each class of Restructuring Plan Creditors in that Restructuring Plan, or (ii) 75 per cent. in value of at least one class of Restructuring Plan Creditors in that Restructuring Plan with would receive a payment, or have a genuine economic interest in Premier, POUK or POHL (as relevant) in the event of the relevant alternative to that Restructuring Plan, present and voting either in person or by proxy at the relevant meeting ordered to be summoned by (in the case of Premier and POUK) the Scottish Court and (in the case of POHL) the English Court. If (ii) applies, then the Scottish Court and the English Court (as applicable) may only sanction the Restructuring Plans if, among other things, none of the members of the dissenting class of classes of Restructuring Plan Creditors would be any worse off under the Restructuring Plan than they would be in the event of the relevant alternative.

Super Senior XCCY Restructuring Plan Creditors representing 100 per cent. of the aggregate of the estimated Super Senior XCCY Exposures as at 30 November 2020, Super Senior RCF/LC Restructuring Plan Creditors representing 92 per cent. of the aggregate outstanding commitments under the Super Senior Secured RCF/LC Facilities and Senior Restructuring Plan Creditors representing 86 per cent. of the aggregate exposure under (i) outstanding commitments under the Senior Secured Debt Facilities, and (ii) the aggregate of the Senior XCCY Exposures, have entered into the Support Letter whereby they have undertaken to support the Debt Restructuring, including by voting in favour of the Restructuring Plans.

The Support Letter is subject to termination rights, including the ability of the Majority Creditors to terminate upon the occurrence of certain events of default under the Existing Debt Facilities, the material breach by Chrysaor or Premier of certain undertakings given in the Support Letter or following a decision by the Board to withdraw its recommendation of the Merger. In addition, the Support Letter will automatically terminate on the earliest to occur of the following: (i) where the Merger Agreement is terminated in accordance with its terms, the Interim Maturity Extension becomes effective; (ii) an insolvency event occurs in relation to certain Premier Group companies; (iii) the Long Stop Date; and (iv) the Debt Restructuring becomes effective.

The Directors believe that, based on the level of support which the Debt Restructuring has received to date, and subject to the remaining conditions of the Merger Agreement being satisfied and Shareholders resolving to pass the Merger and Debt Restructuring Resolutions at the General Meeting, the risk of the conditions described in (B), (C), (D) and (F) above not being satisfied is remote and that it is therefore likely that the Debt Restructuring will have completed by 31 May 2021. Likewise, the Directors have no reason to believe that the applications for Admission will not be approved by the FCA and the London Stock Exchange and accordingly consider the non-satisfaction of condition (E) to be very low risk.

As a contingency in case the Debt Restructuring has not completed by 31 May 2021, the Participating Creditors have undertaken pursuant to the Support Letter to support, and vote in favour of the Restructuring Plans in order to implement, the Interim Maturity Extension, which once effective, would extend the maturity date of Premier's existing debt facilities from 31 May 2021 to 31 March 2022. The Interim Maturity Extension is subject to certain conditions which must be satisfied or waived, including:

(A) the Restructuring Plans (which are inter-conditional) having been approved by the requisite majorities at the Restructuring Plan Creditor Meetings, sanctioned by the relevant Courts and a copy of the sanction orders delivered to the Registrar of Companies for Scotland or the Registrar of Companies for England and Wales (as applicable);

(B) each of the Non-XCCY Hedge Counterparties having given any consents required in connection with the Debt Restructuring, which the Non-XCCY Hedge Counterparties have undertaken to do pursuant to the Non-XCCY Hedging Support Letters;

(C) satisfaction of certain documentary conditions in respect of conditions precedent that are customary for a secured financing transaction and/or are within the control of the Premier Group; and

(D) payment of certain costs associated with the Debt Restructuring.

The Directors believe that, given the undertakings given by Participating Creditors pursuant to the Support Letter and the limited number of conditions to the effectiveness of the Interim Maturity Extension, it is very unlikely that the Interim Maturity Extension will not have completed by 31 May 2021. In addition, there are no further circumstances which could lead to the Interim Maturity Extension not completing once the conditions (A) to (D) listed above have been satisfied. However, if any of the conditions described above were not satisfied or waived, the Interim Maturity Extension would not become effective, and it would be likely that the Premier Group would enter into insolvency proceedings on or before 31 May 2021.

Timing

If neither the Debt Restructuring nor the Interim Maturity Extension becomes effective by 31 May 2021, the outstanding debt under the Existing Debt Facilities and exposures under the XCCY Swaps will mature or crystallise on that date. Premier does not consider that it will be able to repay this outstanding debt, in which case the Private Creditors, the XCCY Hedge Counterparties and the Retail Bondholders could take immediate steps to enforce their security over shares in the companies comprising the Premier Group and other key assets of the Premier Group. As at 31 October 2020, the amount outstanding under the Premier Group's financing arrangements which could be required to be repaid following a breach of its financial covenants was approximately US$2.2 billion.

Further, the Premier Group's leverage and interest cover financial covenants for the testing periods ended on 30 June 2020 and 30 September 2020 have been deferred under the Support Letter (and, prior to that, under the Stable Platform Agreement). The Support Letter waives the Premier Group's financial covenants until the date which is 45 days after the termination of the Support Letter, other than in certain limited circumstances, including where the Support Letter terminates on the date on which the Debt Restructuring or (where the Merger Agreement has terminated) the Interim Maturity Extension becomes effective. For further information on the termination events under the Support Letter, please refer to the Risk Factor entitled "*The Support Letter may be terminated in accordance with its terms on the occurrence of certain specified events*".

If the deferrals contained in the Support Letter (and, prior to that, the Stable Platform Agreement) had not been obtained, the Premier Group would have breached the financial covenants contained in the Override Agreement in respect of the testing periods ended on 30 June 2020 and 30 September 2020. Accordingly if the Support Letter terminates (other than as a result of the Debt Restructuring becoming effective or (where the Merger Agreement has terminated) the Interim Maturity Extension becoming effective), there will be an event of default 45 days after such termination unless the Premier Group is able to secure further deferrals of a similar nature and unless the Majority Creditors have previously exercised a right to terminate the Support Letter. If the Support Letter terminates as a result of (where the Merger Agreement has terminated) the Interim Maturity Extension becoming effective, there will be an immediate event of default unless the Premier Group is able to secure further deferrals of a similar nature and unless the Majority Creditors have previously exercised a right to terminate the Support Letter. If an event of default were to occur in these circumstances, the Private Creditors would have the right to declare the Private Debt Facilities (which totalled US$2.2 billion as at 31 October 2021) immediately due and payable, which if exercised would in turn trigger an event of default under the XCCY Swaps and cross-default under the Retail Bonds (which total £150 million). The Private Creditors, the XCCY Hedge Counterparties and the Retail Bondholders would also have the right to take immediate steps to enforce their security over shares in the companies comprising the Premier Group and other key assets of the Premier Group.

As a result, regardless of whether the Interim Maturity Extension becomes effective prior to 31 May 2021, unless the Premier Group can obtain equivalent financial covenant deferrals to the ones contained in the Support Letter, it is possible that the Premier Group's facilities and exposures under the XCCY Swaps will become payable before 31 May 2021 as a consequence of the events of default and acceleration of the Premier Group's debt described above. Premier considers that the Premier Group would not be able to repay the facilities and exposures under the XCCY Swaps in these circumstances. As noted above, the amount outstanding under the Premier Group's financing arrangements which could be required to be repaid following a breach of its financial covenants was approximately US$2.2 billion as at 31 October 2020.

Covenant shortfall and implications of default

In circumstances where neither the Debt Restructuring nor the Interim Maturity Extension completes, the ability of members of the Premier Group to continue trading will therefore depend upon:

- a significant portion of its creditors providing further financial covenant deferrals upon termination of the Support Letter; and
- the Premier Group agreeing, before 31 May 2021, either: (i) an alternative plan for the implementation of the Debt Restructuring with its creditors and Chrysaor within the timeframe contained within the Support Letter; or (ii) an alternative transaction to address its debt facilities with its creditors.

While Premier has obligations under the Support Letter in respect of the preparation and agreement of contingency plans for a scenario where the Debt Restructuring does not complete, there is no certainty that any alternative plan for the implementation of the Debt Restructuring or alternative transaction to address its debt facilities will be agreed and implemented prior to 31 May 2021. In particular, factors such as the very limited time until the maturity date under the Premier Group's existing debt facilities, the Premier Group's large and diverse creditor group, volatile credit markets and/or the outlook for oil and gas prices may impact the Premier Group's ability to achieve this. It would therefore be likely that the Premier Group would enter into insolvency proceedings on or before the existing maturity date under the Existing Debt Facilities of 31 May 2021, which the Directors consider would likely result in no value being returned to Shareholders.

In circumstances where the Merger and the Debt Restructuring does not complete but the Interim Maturity Extension does complete, the ability of members of the Premier Group to continue trading will therefore depend upon:

– a significant portion of its creditors providing further financial covenant deferrals upon termination of the Support Letter; and

– the Premier Group agreeing, before 31 March 2022, either: (i) an alternative plan for the implementation of the Merger and the Debt Restructuring with its creditors and Chrysaor within the timeframe contained within the Support Letter; or (ii) an alternative transaction to address its debt facilities with its creditors.

Even if Premier could agree and implement an alternative plan for the implementation of the Merger and Debt Restructuring or an alternative transaction to address its debt facilities while at the same time ensuring that a significant portion of its creditors continue to provide further financial covenant deferrals, the terms of any such alternative plan or alternative transaction are likely to be materially worse for the Shareholders than the Merger and the Debt Restructuring, and may involve no value being returned to Shareholders.

If Premier cannot negotiate an alternative plan or transaction with its creditors, Premier would likely enter into insolvency proceedings, which the Directors consider would likely result in no value being returned to Shareholders.

This is because even if the Interim Maturity Extension is implemented, the Premier Group will be dependent on continued deferrals of its financial covenants from a significant portion of its creditors in order to continue to trade. Even if Premier is able to secure financial covenant deferrals for the period until 31 March 2022, the Directors do not consider that the Premier Group will be able to repay its outstanding debt when it matures on that date.

12. No significant change

12.1 Premier Group

Save as set out below, there has been no significant change in the financial position or financial performance of the Premier Group since 30 June 2020, being the date to which the latest interim consolidated financial statements were published.

– the Premier Group has been dependent on the covenant deferrals granted by certain of its creditors (under the Support Letter, and prior to that, the Stable Platform Agreement) to continue as a going concern. For further details, please see section 5.2 Part I (*Background to and reasons for the Merger and the Debt Restructuring*);

– in addition, Premier has revised full year production guidance down to 61-64 kboepd, for further details please see section 7.1 of Part I (*Background to and reasons for the Merger and the Debt Restructuring*); and

– moreover, the Premier Group continues to benefit from access to liquidity from its Existing Debt Facilities.

12.2 Chrysaor Group

There has been no significant change in the financial position or financial performance of the Chrysaor Group since 30 June 2020, being the date to which the most recent financial information has been prepared.

13. Third party information

13.1 External publications

Certain information has been obtained from external publications and is referenced in this document where the information is included. Premier confirms that this information has been accurately reproduced and, so far as Premier is aware and is able to ascertain from the information published by third parties, no facts have been omitted which would render the reproduced information inaccurate or misleading. Unless otherwise stated, such information has not been audited.

13.2 Chrysaor CPR

There have been no material changes since the date of the Chrysaor CPR, the omission of which would make such report misleading.

14. Consents and auditor

The Company has received the following written consents, which are available for inspection at the times and locations set out in section 15 of this Part XIII, in connection with the publication of this document:

– Ernst & Young LLP has given and has not withdrawn its written consent to the inclusion in this document of its report included in Section B of Part IX (*Unaudited pro forma* financial information), 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 3 of Commission Delegated Regulation (EU) 2019/980. Since the New Ordinary Shares have not been and will not be registered under the US Securities Act, Ernst & Young LLP has not filed and will not file a consent under the US Securities Act;

– PwC has given and has not withdrawn its written consent to the inclusion in this document of its reports included in Section A of Part VIII (*Accountant's report in respect of the historical financial information relating to the Chrysaor Group*) and in Section C of Part VIII (*Accountant's report in respect of the historical financial information relating to the Combined COP Subsidiaries)*, and has authorised the contents of these reports 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 3 of Commission Delegated Regulation (EU) 2019/980. Since the New Ordinary Shares have not been and will not be registered under the US Securities Act, PricewaterhouseCoopers LLP has not filed and will not file a consent under the US Securities Act;

– ERCE has given and not withdrawn its written consent to the inclusion in this document of the Chrysaor CPR in Part X (*Competent Person's Report on the Chrysaor Group*) and has authorised the contents of that 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 3 of Commission Delegated Regulation (EU) 2019/980; and

The auditor of the Company is Ernst & Young LLP, whose address is at 1 More London Place, London SE1 2AF. Ernst & Young LLP is registered to perform audit work by the Institute of Chartered Accountants in England and Wales. Ernst & Young LLP was appointed as the Company's auditor with effect from the financial year commencing on 1 January 2017.

RBC has given and not withdrawn its written consent to the inclusion of its name in this document.

15. Documents available for inspection

Copies of the following documents will be available for inspection on the Premier Group's website at www.Premier-oil.com, for a period of at least 12 months from the date of publication of this document. As shareholder will be unable to attend the General Meeting, and given the current restrictions imposed by the government due to COVID-19, the following documents will not be available for physical inspection at the Company's office. Should you require a hard copy version of the documents below, please contact the Company secretary.

(A) the Articles;

(B) the Premier Group's 2017 Annual Report and Financial Statements;

(C) the Premier Group's 2018 Annual Report and Financial Statements;

(D) the Premier Group's 2019 Annual Report and Financial Statements;

(E) the Chrysaor CPR contained in Part X (*Competent Person's Report on the Chrysaor Group*);

(F) the consents referred to in section 14 of this Part XIII;

(G) the Circular and Notice of General Meeting;

(H) the agreed form Lock-up Deed;

(I) the agreed form Standstill Agreement; and

(J) a copy of this document and the Form of Proxy.

DEFINITIONS

The following definitions apply throughout this document unless the context requires otherwise:

2009 LTIP	the Premier Group's 2009 long term incentive plan;
2011 USPP Note Agreement	the note purchase and guaranty agreement dated 9 June 2011 entered into between POUK, the Company and the note purchasers therein as amended and restated pursuant to an amendment and restatement agreement dated 20 July 2017;
2012 USPP Note Agreement	the note purchase and guaranty agreement dated 15 March 2012 entered into between POUK, the Company and the note purchasers listed therein as amended and restated pursuant to an amendment and restatement agreement dated 20 July 2017;
2017 LTIP	the Premier Group's 2017 long term incentive plan;
2017 Refinancing	the refinancing of the Premier Group's debt facilities in July 2017;
2020 AGM	the annual general meeting of the Company held on 25 June 2020;
2020 Schemes	the schemes of arrangement announced by Premier and POUK in January 2020 which proposed an amendment and extension of the Premier Group's Existing Debt Facilities and were registered with Companies House on 1 July 2020;
Admission	the admission of the Consideration Shares and the Creditor Shares to listing on the premium segment of the FCA's Official List and to trading on the main market of the London Stock Exchange;
Annual Reports and Accounts	the audited annual reports and accounts of Premier;
ARCM	Asia Research & Capital Management Ltd, as investment manager of certain affiliated funds;
Articles or Articles of Association	the articles of association of Premier as at the date of this document;
Audit and Risk Committee	the audit and risk committee of Premier from time to time;
Band Limit	has the meaning given to it in paragraph 1.2(A) of Part XI (*United Kingdom Taxation*);
Board	the board of directors of the Company from time to time;
Board Committees	the Audit and Risk Committee, the Health, Safety, Environment and Security Committee, the Remuneration Committee and the Nomination Committee;
BP	BP plc;
Brexit	the United Kingdom's withdrawal from the European Union;
Burlington Acquisition	the acquisition by the Chrysaor Group of the UK oil and gas assets and associated infrastructure interests owned by Burlington Resources (UK) Holdings Limited;
certificated or in certificated form	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 certificated form (that is, not in CREST);
Chrysaor	Chrysaor Holdings Limited, an exempted company with limited liability incorporated in the Cayman Islands;

Chrysaor CPR	the competent person's report on the Chrysaor Group at Part X (*Competent person's report on the Chrysaor Group*) of this document;
Chrysaor Existing RBL Facility	the US$1.5 billion RBL facility entered into by the Chrysaor Group in April 2017;
Chrysaor Financial Information	the information contained in Part VI Section A (*Operating and Financial Review Relating to the Chrysaor Group*);
Chrysaor Group	Chrysaor and each of its subsidiary undertakings;
Chrysaor Junior Facility	the US$400 million facility made available to the Chrysaor Group pursuant to the Shell Junior Facility Agreement;
CGU	has the meaning given to it in Part VI, Section A (*Operating and financial review relating to the Chrysaor Group*);
Circular	the circular issued by Premier in connection with the Merger and the Debt Restructuring, containing the Notice of General Meeting;
Combined COP Subsidiaries	Chrysaor Petroleum Company U.K. Limited (formerly ConocoPhillips Petroleum Company U.K. Limited), Chrysaor Resources (Irish Sea) Limited (formerly Burlington Resources (Irish Sea) Limited), Chrysaor (U.K.) Sigma Limited (formerly ConocoPhillips (U.K.) Sigma Limited) and their subsidiary and associate undertakings;
Combined Group	the Premier Group following the completion of the Merger;
Companies Act 2006	the Companies Act 2006, as amended from time to time;
Company or Premier	Premier Oil plc, a company incorporated in Scotland with registered number SC234781, whose registered office is 4th Floor, Saltire Court, 20 Castle Terrace, Edinburgh EH1 2EN;
Concert Party	the concert party for the purposes of the Takeover Code as more particularly described in paragraph 2 of Part V (Details of the Takeover Panel waiver and whitewash) of the Circular dated on or about the date of this Prospectus;
Conoco Acquisition	the acquisition by the Chrysaor Group of the UK oil and gas assets and associated infrastructure interests owned by ConocoPhillips Holdings Limited;
ConocoPhillips	ConocoPhillips Company;
ConocoPhillips PCOA	the put and call option agreement dated 18 April 2019 between ConocoPhillips and Chrysaor;
Consideration Shares	the 14,253,203,210 New Ordinary Shares to be issued to Harbour and Chrysaor's other shareholders on completion of the Merger pursuant to the Merger Agreement;
Converted Facility A	a term loan facility of US$60,000,000 under the Converted Facility Agreement;
Converted Facility Agreement	the US$130,000,000 term loan facility agreement between, among others, Premier, POUK, and Global Loan Agency Services Limited (as facility agent) which replaced certain Schuldschein loans dated 25 September 2013 and 28 October 2013, as amended and restated pursuant to an amendment and restatement agreement dated 20 July 2017;
Converted Facility B	a term loan facility of US$50,000,000 under the Converted Facility Agreement;
Converted Facility C	a term loan facility of US$20,000,000 under the Converted Facility Agreement;

Convertible Equity Warrants	the 18,688,692 registered convertible equity warrants issued by the Company to convertible bondholders pursuant to a convertible equity warrant instrument dated 26 July 2017;
COP Acquisition	the Conoco Acquisition and the Burlington Acquisition, together;
CPR	competent person's report;
Creditor Lock-up Agreement	the lock-up agreement entered into between certain Restructuring Plan Creditors and the Company, as further detail in section 8.1 of Part XIII (*Additional Information*)
Creditor Lock-Up Period	(i) in respect of the first 50 per cent. of a relevant creditor holder's Creditor Shares, the period of three months immediately following the completion of the Debt Restructuring; and (ii) in respect of the remaining 50 per cent. of a relevant creditor holder's Creditor Shares, the period of six months immediately following the date in which completion of the Debt Restructuring occurs;
Creditor Record Time	5 p.m. on 18 February 2021 or, if the date of the Restructuring Plan Meetings changes, 5 p.m. on the date which is two business days before the Restructuring Plan Meetings;
Creditor Shares	the 3,331,917,634 Ordinary Shares to be issued by the Company pursuant to the Debt Restructuring;
CREST	the relevant system (as defined in the CREST Regulations) in respect of which Euroclear UK & Ireland Limited is the operator (as defined in the CREST Regulations);
CREST Manual	the rules governing the operation of CREST as published by Euroclear;
CREST member	a person who has been admitted by Euroclear as a system member (as defined in the CREST Regulations);
CREST Regulations	the Uncertificated Securities Regulations 2001 (S.I. 2001 No. 3755), as amended;
CGU	cash generating unit;
DB Plan	the Company's Defined Benefit Retirement Plan;
DD&A	depreciation, depletion and amortization;
Debt Restructuring	the restructuring of the Premier Group's indebtedness as announced on 6 October 2020 and as described in Part II (*Details of the Debt Restructuring*), including the Interim Maturity Extension;
Disputed Invoices	has the meaning given to it in paragraph 10.1(D) of Part XIII (*Additional Information*);
Directors	the current directors of the Company, and "**Director**" shall mean any one of them;
Document or document	this Prospectus;
DTR or Disclosure Guidance and Transparency Rules	the Disclosure Guidance and Transparency Rules made by the FCA under section 73A of FSMA, as amended from time to time;
E&E	has the meaning given to it in Section A of Part VI (*Operating and financial review relating to the Chrysaor Group*)
EBITDA	earnings before interest, tax, depreciation and amortisation;
EBITDAX	earnings before interest, tax, depreciation, amortisation, impairment, exploration spend and certain other one-off items;
ECLs	expected credit losses;

EIG	EIG Global Energy Partners;
EIR	the effective interest rate method;
Employee Share Schemes	together, the 2009 LTIP, the 2017 LTIP, the 2017 SIP and the SAYE;
English Restructuring Plan	the restructuring plan proposed pursuant to Part 26A of the Companies Act between POHL and its relevant creditors;
English Restructuring Plan Creditor Meetings	the creditor meetings anticipated to take place on 22 February 2021 in respect of the English Restructuring Plan;
Equity Adjustment Event	the events listed in paragraph 6(J) of Part II (*Details of the Debt Restructuring*);
ERCE	ERC Equipoise Limited;
ESG	Environmental, Social and Governance;
EU	the European Union;
EU ETS	the EU emissions trading system;
EUR, euro or €	the lawful currency of the EU;
EURIBOR	Euro Interbank Offered Rate;
Euroclear	Euroclear UK & Ireland Limited, the operator of CREST;
Executive Directors	collectively, the Directors who hold the position of executive director, and "**Executive Director**" shall mean any one of them;
Exercise Notice	an Exercise Notice in the appropriate form appended to the New Equity Warrant Deed Poll;
Exercise Period	the period between the date on which the Refinancing completes and the two year anniversary of such date;
Existing Debt Facilities	the Senior RCF/LC Facility Agreement, the Super Senior Secured RCF/LC Facility Agreement, the Nelson Bilateral LC Facility Agreement, the Term Loan Facility Agreement and the Converted Facility Agreement, the USPP Notes and NPAs and the Retail Bonds;
Existing Equity Warrants	the 71,012,952 registered equity warrants issued by the Company to the Super Senior Creditors and the Senior Creditors pursuant to an equity warrant instrument dated 20 July 2017;
Existing Maturity Date	31 May 2021;
Existing Ordinary Shares	the Ordinary Shares in issue immediately prior to the completion of the Merger and the Debt Restructuring;
Explanatory Statement	the explanatory statement relating to the Restructuring Plans;
FCA	the Financial Conduct Authority, including in its capacity as the competent authority for the purposes of Part VI of FSMA;
Finance Act 1986	the Finance Act 1986, as amended from time to time;
Form of Proxy	the form of proxy enclosed with the Circular for use in connection with the General Meeting;
FSMA	the Financial Services and Markets Act 2000, as amended from time to time;
FVLCD	fair value less cost of disposal method;
FVOCI	fair value through other comprehensive income;
FVTPL	fair value through profit or loss;

General Meeting	the general meeting of the Company proposed to be held at 23 Lower Belgrave Street, London SW1W 0NR at 2 p.m. on 12 January 2021 to approve the Resolutions, the notice of which is contained in the Circular;
Global Warrant Certificates	the form of the Regulation S Global Warrant Certificate and/or the US Global Warrant Certificate as set out in the New Equity Warrant Deed Poll;
Harbour	certain EIG-managed entities, including Harbour Chrysaor Equity Holdings Ltd., Harbour North Sea EIG Swift Co-Investment, L.P and EIG Swift Co-Investment GP, Ltd.;
Harbour/Chrysaor Parties	Harbour Chrysaor Equity Holdings Ltd., Harbour North Sea, EIG Swift Co-Investment, L.P., EIG Swift Co-Investment GP, Ltd. and Chrysaor;
Harbour North Sea	Harbour North Sea Holdings, Ltd, an exempted company with limited liability incorporated in the Cayman Islands;
Health, Safety, Environment and Security Committee	the health, safety, environment and security committee of Premier from time to time;
Hedge Counterparties	the financial institutions which are party to ISDA Master Agreements with members of the Premier Group and which are party to the Override Agreement and the Intercreditor Agreement in such capacity;
HMRC	Her Majesty's Revenue and Customs;
IFRS	International Financial Reporting Standards;
Individual Warrant Certificate	the form of the Regulation S Global Warrant Certificate and/or the US Global Warrant Certificate as set out in the New Equity Warrant Deed Poll;
Intercreditor Agreement	the intercreditor agreement dated 20 July 2017 entered into between, amongst others, the Company, POUK, Global Loan Agency Services Limited (as global agent) and GLAS Trust Corporation Limited (as security agent);
Interest Cover Ratio	has the meaning given to it in paragraph 3.4 of Part II (*Details of the Debt Restructuring*);
Interim Maturity Extension	the proposed extension of the Premier Group's maturity dates under the Existing Debt Facilities from 31 May 2021 to 31 March 2022 in order to allow time for the Merger to complete, or alternatively as a fall-back contingency plan in order to allow an alternative transaction to address the Premier Group's Existing Debt Facilities in the event that the Merger does not complete by 31 May 2021;
Investor Letter	a letter from a New Equity Warrant Holder substantially in the form set out in the New Equity Warrant Deed Poll;
ISA	individual savings account;
ISIN	international securities identification number;
ISDA Master Agreement	the 1992 ISDA Master Agreement or the 2002 ISDA Master Agreement;
IWG	the informal working group of institutions who constitute a subset of the Premier Group's largest existing creditors in connection with the Existing Debt Facilities;
Latest Practicable Date	14 December 2020;
LIBOR	London Inter-bank Offered Rate;

Lifetime ECL	credit losses expected over the remaining life of the exposure, irrespective of the timing of the default;
Listing Rules	the listing rules made by the FCA under section 73A of FSMA, as amended from time to time;
Lock-up Deed	the share lock-up deed to be entered into between Harbour North Sea and Premier subject to completion of the Merger and Debt Restructuring and conditional on Admission;
Long Stop Date	30 September 2021 (or such later date as may be agreed by Premier, Chrysaor and Majority Creditors provided that such later date may not be later than 1 December 2021);
Majority Creditors	the Private Creditors and XCCY Hedge Counterparties who represent, in aggregated, more than two thirds of the commitments in respect of the Premier Group's Existing Debt Facilities;
Management Warranty Deed	the warranty deed given by certain members of Chrysaor Group management in connection with the Merger dated 6 October 2020;
Market Abuse Regulation	Regulation (EU) No. 594/2014 of the European Parliament and the Council of 16 April 2014 on market abuse;
Merger	the proposed merger of Chrysaor with Premier by way of a reverse takeover and in consideration for the allotment and issue of the Consideration Shares;
Merger Agreement	the merger agreement between Premier, Chrysaor and certain members of the Harbour and EIG groups dated 2 November 2020;
Merger and Debt Restructuring Resolutions	resolutions 1 to 4 and, to the extent required to implement the Merger and the Debt Restructuring, Resolution 6, in the Notice of General Meeting forming part of the Circular;
Nelson Bilateral LC Facility	the credit facility made available to the Company and POUK pursuant to the terms of the Nelson Bilateral LC Facility Agreement;
Nelson Bilateral LC Facility Agreement	the bilateral revolving letter of credit facility agreement for £4,380,000 between the Company, POUK and DBS Bank Ltd., London branch as amended and restated pursuant to an amendment and restatement agreement dated 20 July 2017;
Net Leverage Ratio	has the meaning given to it in paragraph 3.4 of Part II (*Details of the Debt Restructuring*);
New Equity Warrant Deed Poll	the deed poll pursuant to which the New Equity Warrants will be constituted;
New Equity Warrant Holder	any holder of a New Equity Warrant;
New Equity Warrant Exercise Price	0.001 pence, as adjusted from time to time;
New Equity Warrants	the equity warrants issued to electing Restructuring Plan Creditors, the terms of which are governed by the New Equity Warrant Deed Poll as described in paragraph 6 of Part II (*Details of the Debt Restructuring*) of this document;
New Ordinary Shares	the Ordinary Shares to be issued pursuant to the Merger and the Debt Restructuring (including the Consideration Shares and the Creditor Shares);

New RBL Facility	the amended and restated senior secured revolving borrowing base facility agreement entered into on 23 November 2020 between Chrysaor and New RBL Lenders in accordance with the Merger Agreement;
New Warrant Shares	the New Ordinary Shares issuable upon the exercise of New Equity Warrants, as the same may be adjusted from time to time in accordance with the terms of the New Equity Warrants;
Nil Rate Amount	has the meaning given to it in paragraph 1.1(A) of Part XI (*United Kingdom Taxation*);
Nomination Committee	the nomination committee of Premier from time to time;
Non-Executive Directors	collectively, the Directors who hold the position of Chairman or non-executive director, and "**Non-Executive Director**" shall mean any one of them;
Non-IFRS measures	certain unaudited supplementary financial measures contained in this document that are not defined by or recognised under IFRS or any other generally accepted accounting principles, including EBITDAX, operating cost per barrel, DD&A per barrel, net debt and liquidity;
Non-Voting Deferred Shares	the new class of share which the Company proposes to create pursuant to the Subdivision and Resolution 4 in the Notice of Meeting, the terms of which are set out in Resolution 4;
Non-XCCY Hedge Counterparties	a Hedge Counterparty other than a XCCY Hedge Counterparty;
Non-XCCY Hedging Support Letter	means each support letter signed by a Non-XCCY Hedge Counterparty under which each such Non-XCCY Hedge Counterparty agrees to support the Merger and Debt Restructuring, as more fully described in paragraph 8.1 of Part XIII (*Additional Information*);
Notice of General Meeting	the notice of General Meeting contained in Part X (*Notice of General Meeting*) of the Circular;
NPAs	the note purchase agreements relating to the USPP Notes;
Official List	the official list of the FCA;
Ordinary Shares	the ordinary shares with a nominal value of 12.5 pence each (and, following the Subdivision, 0.0001 pence each) in the capital of the Company in issue from time to time;
Override Agreement	the override agreement dated 20 July 2017 between, amongst others, the Company, various of the Company's subsidiaries (as guarantors), Global Loan Agency Services Limited (as global agent) and GLAS Trust Corporation Limited (as security agent);
Overseas Shareholders	Shareholders who are resident in, ordinarily resident in, or citizens of, jurisdictions outside the United Kingdom, and "**Overseas Shareholder**" shall be construed accordingly;
Participating Creditors	Private Creditors and XCCY Hedge Counterparties which are party to the Support Letter;
Partial Cash Alternative	as part of the Debt Restructuring, the further cash payment which Restructuring Plan Creditors may elect to receive instead of receiving Creditor Shares, the aggregate amount of which is capped at approximately US$175 million;
PCOA	put and call options agreement;
POBL	Premier Oil Belgravia Limited;

POFJL	Premier Oil Finance (Jersey) Limited;
POGHL	Premier Oil Group Holdings Limited;
POHL	Premier Oil Holdings Limited;
POUK	Premier Oil UK Limited;
Pounds Sterling, Sterling, GBP, pence or £	the lawful currency of the United Kingdom;
Premier Group	Premier, together with its subsidiaries and subsidiary undertakings from time to time;
Private Creditors	the creditors of the relevant members of the Premier Group in respect of the Private Debt Facilities;
Private Debt Facilities	the Super Senior Secured RCF/LC Facility Agreement, the Senior RCF/LC Facility Agreement, the Term Loan Facility Agreement, the USPP Notes, the Converted Facility Agreement and the Nelson Bilateral LC Facility Agreement;
Proposed Directors	Linda Cook, Phil Kirk, R. Blair Thomas, G. Steven Farris, Simon Henry, and Anne Stevens;
Prospectus	this document;
Prospectus Regulation	Regulation (EU) 2017/1129, as amended;
Prospectus Regulation Rules	the prospectus regulation rules made by the FCA under section 73A of FSMA, as amended from time to time;
PRT	Petroleum Revenue Tax;
RBC	RBC Europe Limited (trading as RBC Capital Markets);
RBL	has the meaning given to it in paragraph 3.2 of Part II (*Details of the Debt Restructuring*);
Readmission	readmission of the Existing Ordinary Shares to the premium listing segment of the Official List and to trading on the London Stock Exchange's main market for listed securities;
Registrar	Link Asset Services, of The Registry, 34 Beckenham Road, Beckenham, Kent, BR3 4TU;
Regulation S	Regulation S under the US Securities Act;
regulatory authority	any central bank, ministry, governmental, quasi-governmental (including the EU), supranational, statutory, regulatory or investigative body or authority (including any national or supranational antitrust or merger control authority), national, state, municipal or local government (including any subdivision, court, administrative agency or commission or other authority thereof), private body exercising any regulatory, taxing, importing or other authority, trade agency, association, institution or professional or environmental body or any other person or body whatsoever in any relevant jurisdiction, including for the avoidance of doubt, the takeover panel, the FCA, the FCA and the London Stock Exchange;
Regulatory Information Service	one of the regulatory information services authorised by the FCA to receive, process and disseminate regulatory information from listed companies;
Relationship Agreement	a relationship agreement to be entered into by the Company prior to the completion of the Merger (but conditional on Admission) with Harbour North Sea Holdings, Ltd;
Remuneration Committee	the remuneration committee of Premier from time to time;

Resolutions	each of the Resolutions 1 to 7, which are set out in the Notice of General Meeting and "**Resolution**" shall be construed accordingly;
Restricted Territory	has the meaning given to it on page 2 of this document;
Restructuring Plans	the English Restructuring Plan and the Scottish Restructuring Plans;
Restructuring Plan Creditors	the creditors of the Premier Group who are entitled to vote on the Restructuring Plans, being those creditors in respect of: (i) the Super Senior Secured RCF/LC Facility Agreement, (ii) the Senior RCF/LC Facility Agreement, (iii) the Term Loan Facility Agreement, (iv) the USPP Notes and the NPAs, (v) the Converted Facility Agreement, (vi) the Nelson Bilateral LC Facility Agreement; (vii) the Retail Bonds; and (viii) the XCCY Swaps, as at the Creditor Record Time;
Restructuring Plan Creditor Meetings	the Scottish Restructuring Plan Creditor Meetings and the English Restructuring Plan Creditor Meetings;
Retail Bondholders	the holders of the Retail Bonds as at the Creditor Record Time;
Retail Bond Final Terms	as described in paragraph 8 of Part XIII (*Additional Information*);
Retail Bond Terms and Conditions	as described in paragraph 8 of Part XIII (*Additional Information*);
Retail Bonds	the retail bonds described in paragraph 8 of Part XIII (*Additional Information*);
ROU	right of use;
SAYE	the Premier Group's save as you earn scheme, approved by Shareholders on 29 May 2009;
Scottish Restructuring Plan	the restructuring plan proposed pursuant to Part 26A of the Companies Act between the Company and POUK and each of their relevant Restructuring Plan Creditors in order to implement the proposed Debt Restructuring and/or the Interim Maturity Extension;
Scottish Restructuring Plan Creditor Meetings	the creditor meetings anticipated to be held on 22 February 2021 in respect of the Scottish Restructuring Plan;
SDRT	UK stamp duty reserve tax;
SEC	the US Securities and Exchange Commission;
Senior RCF/LC Facilities	together, the Senior Secured Cash Loan Facility and the Senior Secured LC Sub-Facilities;
Senior RCF/LC Facility Agreement	a syndicated revolving and letter of credit facility agreement for up to US$1,781,032,945.80 with the effective date of 28 July 2017 between, among others, the Company, POUK, Premier Oil Holdings Limited, Premier Oil Exploration and Production Limited and Barclays Bank PLC (as facility agent), which is utilised by way of the Senior RCF Facilities;
Senior Restructuring Plan Creditors or Senior Creditor	the creditors of the Premier Group who are entitled to vote on the Restructuring Plans, being those creditors in respect of: (i) the Senior RCF/LC Facility Agreement, (ii) the Term Loan Facility Agreement, (iii) the USPP Notes and the NPAs, (iv) the Converted Facility Agreement, (v) the Nelson Bilateral LC Facility Agreement; (vi) the Retail Bonds; and (vii) the Senior XCCY 565931188 279 Swaps, as at the Creditor Record Time;

Senior Secured Cash Loan Facility	the loan facility made available pursuant to the Senior RCF/LC Facility Agreement;
Senior Secured Debt Facilities	the Senior RCF/LC Facilities, the facilities under the Term Loan Facility Agreement, the Nelson Bilateral LC Facility, the USPP Notes, the Retail Bonds and the facilities under the Converted Facility Agreement;
Senior Secured LC Sub-Facilities	the LC sub-facilities made available pursuant to the Senior RCF Facility Agreement;
Senior XCCY Hedge Counterparties	the XCCY Hedge Counterparties with Senior XCCY Exposures;
Senior XCCY Exposures	the exposure of XCCY Hedge Counterparties under the XCCY Swaps as at a reference date of 15 March 2016 that ranks senior in accordance with the Intercreditor Agreement;
Senior XCCY Swaps	has the meaning given to it in paragraph 2 of Part II (*Details of the Debt Restructuring*);
Shareholder	any holder of Ordinary Shares registered on the register of members of the Company from time to time;
Shell	Royal Dutch Shell plc, together with its subsidiaries and subsidiary undertakings from time to time;
Shell Acquisition	the acquisition by the Chrysaor Group of interests in the Armada hub and Elgin-Franklin, Glenelg, Everest, Lomond, Erskine, Buzzard, Beryl, J-Area, Schiehallion and Bressay fields from Shell for US$3.0 billion in November 2017;
Shell Assets	assets acquired by the Chrysaor Group in connection with the Shell Acquisition;
Shell Junior Facility Agreement	the US$400,000,000 junior facility agreement dated 30 January 2017 (as amended from time to time) and made between, among others, Chrysaor and the Shell Junior Lender;
Shell Junior Lender	Shell Treasury Dollar Company Limited;
SIP	the share incentive plan, approved by Shareholders on 16 May 2019 and the equivalent unapproved scheme operated for the Premier Group's expatriate employees;
Sponsor	RBC;
Sponsor Agreement	the agreement, entered into on or around the date of this Prospectus, between Premier and RBC pursuant to which RBC has agreed, subject to certain conditions, to act as Premier's sponsor in relation to the Merger and Admission;
Stable Platform Agreement	the stable platform agreement entered into between certain members of the Premier Group and the requisite majorities of its creditors on 8 July 2020 which, among other things, waived the forecasted breaches of certain financial covenants contained in the Override Agreement in respect of the testing period ended 30 June 2020;
Standstill Agreement	the standstill agreement to be entered into between Harbour North Sea and Premier subject to completion of the Merger and Debt Restructuring and conditional on Admission, whereby Harbour North Sea undertakes that neither it nor any member of the concert party will acquire Ordinary Shares or make an offer for Ordinary Shares for a period of 24 months following completion of the Merger and Debt Restructuring;

Standalone Transaction	the (previously) proposed extension of the Premier Group's maturity dates under its existing debt facilities to 31 March 2025, in connection with an equity raise of up to US$530 million and the acquisition of the Andrew and Shearwater assets from BP, as announced on 5 June 2020 and 20 August 2020, which is no longer being pursued by the Company;
Stamp Duty Reserve Tax Regulations 1986	the Stamp Duty Reserve Tax Regulations 1986, as amended from time to time;
STASCO	Shell International Trading and Shipping Company Limited;
STASCO Offtake Arrangements	the eight offtake arrangements between STASCO and the Chrysaor Group;
Subdivision	the proposed subdivision of the Company's Ordinary Shares into (a) one Ordinary Share with a nominal value of 0.0001 pence each; and (b) one Non-Voting Deferred Share with a nominal value of 12.4999 pence each, as set out in paragraph 5.4 Part I (*Background to and reasons for the Merger and the Debt Restructuring*);
Subdivision Record date	anticipated to be on 25 March 2020;
Subdivision Resolution	Resolution 4 as set out in the Notice of General Meeting;
Super Senior Creditors	the creditors under the Super Senior Secured RCF/LC Facility Agreement;
Super Senior RCF/LC Restructuring Plan Creditors	the creditors of the Premier Group who are entitled to vote on the Restructuring Plans, being those creditors in respect of the Super Senior Secured RCF/LC Facility Agreement, as at the Creditor Record Time;
Super Senior Secured LC Sub-Facilities	the LC sub-facilities made available by the Super Senior Creditors pursuant to the Super Senior Secured RCF/LC Facility Agreement;
Super Senior Secured RCF/LC Facilities	together, the Super Senior Secured Revolving Credit Facility and the Super Senior Secured LC Sub-Facilities;
Super Senior Secured RCF/LC Facility Agreement	a syndicated revolving and letter of credit facility agreement for up to US$718,967,054.20 with the effective date of 28 July 2017 between (amongst others) the Company, POUK as borrower and Barclays Bank PLC (as facility agent);
Super Senior Secured Revolving Credit Facility	the revolving credit facility made available by the Super Senior Creditors pursuant to the Super Senior Secured RCF/LC Facility Agreement;
Super Senior XCCY Exposures	in respect of the XCCY Hedge Counterparties, the increased exposure which ranks senior since the reference date of 15 March 2016;
Super Senior XCCY Hedge Counterparties or Super Senior XCCY Restructuring Plan Creditors	the XCCY Hedge Counterparties with Super Senior XCCY Exposures;
Super Senior XCCY Swaps	has the meaning given to it in paragraph 2 of Part II (*Details of the Debt Restructuring*);
Support Letter	the support letter as described in paragraph 8.1 of (*Part XIII Additional Information*);
Takeover Code	the City Code on Takeovers and Mergers;
Term Loan Facilities	Term Loan Facility A and Term Loan Facility B;

Term Loan Facility A	the term loan facility of £100,000,000 available under the Term Loan Facility Agreement;
Term Loan Facility Agreement	the term loan facility agreement dated 29 November 2013, entered into between, amongst others, Lloyds Bank plc (as facility agent), the Company, and POUK as amended and restated on 28 July 2017;
Term Loan Facility B	the term loan facility of US$150,000,000 available under the Term Loan Facility Agreement;
Tolmount	the Tolmount gas field;
Top-Up Election	as part of the Debt Restructuring, the Senior Creditors and Senior XCCY Hedge Counterparties may subscribe, in cash at a pre-agreed price, for those Creditor Shares which would have been issued to Senior Creditors and Senior XCCY Hedge Counterparties had they not elected instead to take the Partial Cash Alternative;
TSR	total shareholder return;
UK Corporate Governance Code	the corporate governance code issued by the Financial Reporting Council in the United Kingdom from time to time;
UK Government	the government of the United Kingdom, from time to time;
UK NBP	the Heren Day-ahead UK National Balancing Point;
Unallocated Creditor Shares	has the meaning given to it in paragraph 5 of Part II (*Details of the Debt Restructuring*);
uncertificated or in uncertificated form	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;
Uncertificated Securities Regulations	the Uncertificated Securities Regulations 2001 as amended from time to time;
United Kingdom or UK	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;
Upfront Cash Consideration	the upfront cash payment of US$1.23 billion (subject to certain adjustments) to Restructuring Plan Creditors in satisfaction of part of the Premier Group's Existing Debt Facilities and XCCY Swaps as part of the Debt Restructuring;
USD, US$ or US dollar	the lawful currency of the United States;
USPP Notes	the tranches of notes issued by POUK under the 2011 USPP Note Agreement and the 2012 USPP Note Agreement;
US Exchange Act	the US Securities and Exchange Act of 1934, as amended;
US Securities Act	the United States Securities Act of 1933, as amended;
WACC	weighted average cost of capital;
Warrant Agent	the warrant agent to be appointed by the Company in respect of the New Equity Warrants;
Warrant Holder	any holder of Existing Equity Warrants;
West Texas Intermediate	a trading classification of crude oil, the underlying asset in the New York Mercantile Exchange's oil futures contract;

Withdrawal Agreement	a withdrawal agreement agreed between the UK and the EU in October 2019;
XCCY Hedge Counterparties	the counterparties to the XCCY Swaps;
XCCY Swaps	has the meaning given to it in paragraph 2 of Part II (*Details of the Debt Restructuring*).

GLOSSARY OF TECHNICAL TERMS

The following definitions shall apply to the technical terms used in this document. Definitions in respect of technical terms used in the Chrysaor CPR can be found therein.

2C resources	best estimate discovered hydrocarbons that are potentially recoverable but not yet considered mature enough for commercial development due to technological or business hurdles;
2P reserves	proved plus probable reserves;
88 Energy	88 Energy Limited;
Alder	the Alder field located in block 15/29a of the UKCS operated by Ithaca Energy, approximately 27 kilometres west of the Britannia facilities;
ALELE	Armada, Everest, Lomond and Erskine fields;
Altera	Altera Voyageur Production Limited;
Andrew Area	the Andrew, Arundel, Cyrus, Farragon and Kinnoull fields located in Blocks 16/23a (Arundel), 16/23c (E), 16/23c (South), 16/24a (All), 16/28a (Cyrus), 16/28a (Rest), 16/28b (Andrew) and 16/28b (Rest), each of which is situated in the Central North Sea;
Andaman I	the Andaman I block located adjacent to Andaman II;
Andaman II	the Andaman II licence in the emerging South Andaman Sea gas play in Indonesia;
ANP	the Brazilian National Agency of Petroleum;
Apache	Apache Corporation;
Area A	Area A of the conventional Project Icewine acreage of 88 Energy and Burgundy Xploration LLC;
Armada or Armada Area	a cluster of fields developed from the Armada facilities located in block 22/5b approximately 250 kilometres east of Aberdeen;
Bacton	the Shell-operated Bacton terminal;
Balmoral Area Fields	the Balmoral, Glamis, Stirling, Brenda and Nicol fields located in blocks 16/21a, 16/21b and 16/21c in the UK Central North Sea;
Beryl Alpha	has the meaning given to it in paragraph 5.2(E) of Part IV (*Information on the Chrysaor Group*);
Beryl Area	the area containing Beryl, Buckland, Callater, Ness, Nevis, Skene and Storr fields, located in blocks 9/12, 9.13, 9/18 and 9/19 in the Central North Sea area of the UKCS, approximately 340 kilometres north east of Aberdeen;
Beryl Bravo	has the meaning given to it in paragraph 5.2(E) of Part IV (*Information on the Chrysaor Group*);
Block 12W	the operated interest approximately 300 kilometres to the south west of the West Natuna Sea area;
BMS	the Business Management System implemented by Chrysaor;
BPS	the Brent Pipeline System;
Brenda	the Brenda field located in the Balmoral Area;
Britannia	the Britannia gas condensate field approximately 210 kilometres northeast of Aberdeen, Scotland, in the Central North Sea area of the UKCS in Blocks 15/29a, 15/30a, 16/26a, 16/27b and 16/27c;

Brodgar	the Brodgar gas condensate field located in block 21/3a (ALL) in the Central North Sea area in the UKCS, approximately 40 kilometres west of the Britannia field;
Burgman	the Burgman field located in the Cather Area;
Buzzard	an oil and gas field located in blocks 19/5a, 19/10a, 20/6a and 20/1a in the Outer Moray Firth area of the North Sea, approximately 100 kilometres north-east of Aberdeen;
Cairn	Cairn Energy PLC;
Calder	the Calder producing field in the EIS Area;
CalEnergy	CalEnergy Resources Limited;
Callanish	the Callanish oil field located in blocks 21/4a (ALL) and 15/29b (ALL) in the Central North Sea area in the UKCS, approximately 20 kilometres west of the Britannia field.
Catcher Area or Catcher	the Catcher area of the UK North Sea;
CATS	the Central Area Transmission System;
Chevron	Chevron Corporation;
Chim Sáo	the Chim Sáo discovery in Block 12W;
Clair	a large oil field located in blocks 206/7, 206/8, 206/9, 206/11, 206/12, 206/13 and 206/15 in the UKCS, approximately 80 kilometres north west of Shetland;
Clair North	the North accumulation within the Clair field;
Clair Phase 1	the Phase 1 accumulation within the Clair field;
Clair Ridge	the Ridge accumulation within the Clair field;
Clair South	the South accumulation within the Clair field;
Cleeton	the Perenco-operated Cleeton platform in the Southern North Sea;
CMS or CMS Area	the Caister Murdoch System Area, consisting of the Murdoch, Caister, Boulton, CMS III, Kelvin, Katy and Munro fields;
CNH	the National Hydrocarbon Commission of Mexico;
CNR	Canadian Natural Resources Limited;
Cost Recovery Petroleum	has the meaning given to it in paragraph 6.4(A) of Part III (*Information on the Premier Group*);
Cost Recovery Oil	has the meaning given to it in paragraph 6.6(B) of Part III (*Information on the Premier Group*);
CRP	the CATS Riser Platform;
Cruden Bay	the terminal located in Cruden Bay, Scotland;
Dalton	the Dalton producing field in the EIS Area;
Dana Petroleum	Dana Petroleum plc;
DBH	daily based hire;
DBEIS	the Department for Business, Energy and Industrial Strategy;
DEA	DEA Deutsche Erdoel AG;
DECC	the Department of Energy and Climate Change;

Decomissioning Notice	a notice under the Petroleum Act to 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;
Directorate General of Oil & Gas	the Directorate General of Oil and Gas of the Republic of Indonesia;
DRD	decommissioning relief deed;
DSA	decommissioning security agreements;
Dua	the Dua discovery in Block 12W;
Dyas	One-Dyas B.V.;
EnCore Acquisition	the Premier Group's acquisition of EnCore Oil plc, an AIM listed independent exploration and appraisal company, in October 2011;
EIS or EIS Area	the East Irish Sea area;
Elgin	the Elgin field located in the Elgin-Franklin area;
Elgin-Franklin or Elgin-Franklin Area	the Elgin-Franklin area (including the Elgin, Franklin and West Franklin fields) located in the Central North Sea;
Elgin PUQ	a TGP-500 jack-up design production, utilities and quarters platform located on the Elgin field;
ENI	Eni S.p.A;
Enochdu	the Enochdhu oil field located in block 21/5a (ALL) in the Central North Sea area in the UKCS, approximately 18 kilometres west of the Britannia field;
EnQuest	EnQuest plc;
Equinor	Equinor ASA;
Erskine	the Erskine high-pressure, high-temperature gas condensate field, operated by Ithaca Energy, is located in blocks 23/26a and 23/26b, approximately 250 kilometres east of Aberdeen, in the Central North Sea area of the UKCS;
Esso	Esso Exploration and Production UK Limited;
ETS	the Esmond Transportation System;
Everest	a gas-condensate field located in block 22/10a-A in the Central North Sea area of the UKCS, approximately 240 kilometres east of Aberdeen;
ExxonMobil	Exxon Mobil Corporation;
E.ON North Sea Acquisition	the Premier Group's acquisition of E.ON's UK North Sea assets in early 2016;
F5 Well	has the meaning given to it in paragraph 5.2(C) of Part IV (*Information on the Chrysaor Group*);
FDP	field development plan;
FEED	front end engineering and design;
FlowStream	FlowStream Commodities Ltd;
FPS	Forties Pipeline System;
FPSO	floating, production, storage and offloading;
Franklin	the Franklin field, located in the Elgin-Franklin Area;

GAEL	the Graben Area Export Line
GHG	greenhouse gas;
Glenelg	the Glenelg gas condensate field is located in blocks 29/4D and 29/5B in the Central North Sea, four kilometres to the west of the Elgin-Franklin Area;
Greater Britannia Area or GBA	the area approximately 210 kilometres northeast of Aberdeen in the Central North Sea area of the UKCS;
GSA1	the gas sales agreement signed in in 1999 with SembCorp;
GSA2	the gas sales agreement signed in in 2008 with SembCorp;
Hound Point	the INEOS FPS Limited operated facilities at Hound Point;
Huntington	the Huntington oil field in the Central North Sea, 230 kilometres north-east of Aberdeen;
HSES	health, safety, environment and quality;
HSEQ	health, safety, environmental and security;
HSFO	high sulfur fuel oil;
Hydrocarbons Revenue Law	the Hydrocarbons Revenue Law, published in the Mexican Federal Official Gazette on 11 August 2014;
ILX	infrastructure-led exploration;
Ithaca Energy or Ithaca	Ithaca Energy Limited;
J-Area	the area approximately 265 kilometres east of Aberdeen in the Central North Sea area of the UKCS;
Jade	the high-pressure, high-temperature gas condensate field located in block 30/2c in the Central North Sea area of the UKCS.
Jasmine	the high-pressure, high-temperature gas condensate field located in block 30/6a and 30/7a in the Central North Sea area of the UKCS
Joanne	the Joanne oil and gas condensate field located in the J-Area;
Johnston	a dry gas accumulation discovered in 1990 and located within blocks 43/26a and 43/27a in the UK Southern North Sea;
Judy	the Judy oil and gas condensate field located in the J-Area;
JRP	the Judy Riser Platform;
Kinneil Terminal	the Kinneil processing plant at Grangemouth;
Kyle	Kyle oil field, contained in the P748 licence;
KUFPEC	Kuwait Foreign Petroleum Exploration Company;
LOGGS or LOGGS Area	the LOGGS Area, consisting of the North Valiant, South Valiant, Vanguard, Vulcan, Vampire, Viscount, Saturn, Mimas, Tethys and Jupiter fields;
Lomond	a late-life lean gas-condensate field located in block 23/21a in the Central North Sea area of the UKCS, approximately 255 kilometres east of Aberdeen;
Marnock	the BP-operated Marnock field
Merganser	the Merganser gas and condensate field located in blocks 22/30a and 22/25a in the Central North Sea;
Mexican Petroleum Fund	Fondo Mexican del Petroleo para la Estabilizacion y el Desarrollo;
Mineral Oil Ordinance	the Falkland Islands' Offshore Mineral Ordinance 1994;

Minerals Ordinance Model Clauses	the model clauses set out in the statutory instruments deriving from the Falkland Islands' Mineral Oil Ordinance;
Millom	the Millom producing field in the EIS Area;
Mitsui Oil Exploration	Mitsui Oil Exploration Co.,Ltd;
Model Clauses	the model clauses set out in the statutory instruments deriving from the UK Petroleum Act 1998;
MOIT	the Vietnamese Ministry of Industry and Trade;
MOL	MOL plc;
Mongour	the Mongour discovery;
MPE	the Norweigan Ministry of Petroleum & Energy;
Natuna Sea Block A	the Natuna Sea Block A offshore Indonesia, comprising the Anoa oil field and substantial undeveloped gas fields, as well as exploration prospects;
Navitas Petroleum	Navitas Petroleum LP;
NGL	natural gas liquids;
NCS	the Norwegian Continental Shelf;
Nelson	the Nelson oil and gas field located to the south east of the Forties field;
new model PSC	a new form of model PSC issued by the Vietnamese Government in 2013 which applies to all PSCs signed after 8 June 2013;
Nicol	the Nicol field, operated by Premier, is located in block 15/25a in the Central North Sea in the UKCS, approximately 210 kilometres north east of Aberdeen and approximately 25 kilometres north of the Britannia facilities;
Noble Energy	Noble Energy, Inc.;
NPA	the Norwegian Petroleum Act (of 29 November 1996 no.72);
NUI	normally unmanned installation;
OGA	Oil and Gas Authority;
Oil and Gas Law	Law of the Republic of Indonesia, Number 22 of 2001 regarding Oil and Natural Gas;
Oilexco	Oilexco North Sea Limited;
Oilexco Acquisition	the Premier Group's acquisition of Oilexco from administration for US$500.1 million, funded with a combination of new debt facilities and a rights issue to shareholders of £171 million, in 2009;
Pemex	Petróleos Mexicanos
Perenco	Perenco S.A.;
Peridido	a proven deep water fold belt in the Burgos Basin, Mexico;
Pertamina	PT Pertamina;
Petrobas	Petróleo Brasileiro S.A.;
Petrofac	Petrofac Limited;
Petroleum Act	the Petroleum Act 1998;
Petroleum Law	Brazilian Federal Constitution, Federal Laws No. 9,478/1997
Petronas	Petroliam Nasional Berhad;
PetroVietnam	Vietnam Oil and Gas Group;

PG	has the meaning given to it in paragraph 5.2(J) of Part IV (*Information on the Chrysaor Group*)
Pict Acquisition	the Premier Group's acquisition of Pict Petroleum plc in 1995;
PN	has the meaning given to it in paragraph 5.2(J) of Part IV (*Information on the Chrysaor Group*);
PRT	UK petroleum revenue tax;
PRMS	the Petroleum Resources Management System;
Project Icewine	the Project Icewine conventional oil field located in the North Slope of Alaska;
PSC	production sharing contract;
Ravenspurn North	a dry gas field within blocks 42/30a and 43/26a in the Southern North Sea;
Repsol Sinopec	Repsol Sinopec Resources UK Limited;
RFCT	ring fence corporation tax;
Rockhopper	Rockhopper Exploration plc;
Rockhopper Acquisition	Premier's acquisition of Rockhopper licence interests in the Falkland Islands;
SAGE	the Scottish Area Gas Evacuation System;
Sapura Energy	Sapura Energy Berhad;
Scapa Flow	the Scapa Flow area in the Orkney Islands, Scotland;
Schiehallion	an oil and gas field located in blocks 204/19, 204/20, 204/25a, 205/21b, and 205/16a in the UKCS, approximately 130 kilometres west of the Shetland Islands;
Scoter	the Scoter field located in blocks 23/26d and 22/30a in the Central North Sea;
Sea Lion	the Sea Lion pre-development project;
Sea Lion Phase I	the Sea Lion Phase I project;
SEAL	the Shearwater Elgin Area Line;
SembCorp	a government-controlled Singaporean utility entity;
SENER	the Mexican Ministry of Energy;
Serica Energy	Serica Energy plc;
Shearwater Field or Shearwater	the Shearwater field located in Block 22 230b (B-Rst) in the Central North Sea;
Siccar Point Energy	Siccar Point Energy Limited;
SILK	SEAL Interconnector Link Pipeline;
SKKMIGAS	the Special Task Force for Upstream Oil and Gas Business Activities Republic of Indonesia;
SNS	the Chrysaor Group's southern North Sea area;
Solan	the Solan field 150 kilometres west of the Shetland Islands;
Solan FDP	has the meaning given to it in paragraph 6.3(E) of Part III (*Information on the Premier Group*);
Spirit Energy	Spirit Energy Limited;
St Fergus	the Shell-operated terminal facilities at St Fergus on the north east coast of Scotland;

Sumatra Acquisition	the acquisition of Sumatra Gulf Oil by the Group in 1996;
Suncor Energy	Suncor Energy, Inc;
Supplementary Charge	has the meaning given to it in paragraph 6.3(N) of Part III (*Information on the Premier Group*);
SVT	the Sullom Voe Terminal;
Talos Energy	Talos Energy Inc.;
Taqa	The Abu Dhabi National Energy Company;
Teekay	Teekay Petrojarl;
Tolmount	the Tolmount gas field situated in block 42/28d, in the UK Southern North Sea;
Tolmount Far East	the Tolmount Far East discovery;
Tolmount East	the Tolmount East discovery;
Tolmount Area	the wider area containing Tolmount, Tolmount East, Tolmount Far East and Mongour;
Total	Total SE;
Tuna or Tuna Block	the Tuna offshore block in Indonesia;
Tullow Oil	Tullow Oil plc
UUOA	Unitisation and Unit Operating Agreement;
UKCS	the UK Continental Shelf;
Varadero	the Varadero field located in the Catcher Area;
Viking or Viking Area	the Viking Area consisting of the Viking, Vixen and Victor fields;
Voyageur FPSO	has the meaning given to it in paragraph 6.3(C) of Part III (*Information on the Premier Group*);
West Franklin	the West Franklin field, located in the Elgin-Franklin area;
WHP	wellhead platform;
WNTS	the West Natuna Transportation System;
WOSPS	the West of Shetland Pipeline System;
Yetagun	the Yetagun gas field in Myanmar.
Zama	the Zama prospect offshore Mexico;
Zama-ST1	has the meaning given to it in paragraph 6.6(B) of Part III (*Information on the Premier Group*);
Zarubezhneft	JSC Zarubezhneft;
Zennor Petroleum	Zennor Petroleum Ltd.